

INDIANA COAL COUNCIL’S COMMENTS ON NIPSCO 2016 INTEGRATED RESOURCE PLAN

A. INTRODUCTION. The Indiana Coal Council (“ICC”) conducted a review of the Integrated Resource Plan (“IRP”) that Northern Indiana Public Service Company (“NIPSCO”) prepared and submitted to the Indiana Utility Regulatory Commission (“IURC”) on November 1, 2016. In response to the NIPSCO’s IRP, ICC submits the comments below.

B GENERAL COMMENTS. Indiana’s electric utilities are required to furnish reasonably adequate service and facilities at a reasonable and just cost. Ind. Code § 8-1-2-4. In order to do so, utilities must strategically plan on both a short-term and long-term basis. The IRP requirement is found in Title 170 Indiana Administrative Code (IAC) 4-7 and commonly referred to as “Rule 7.”

In 2010, the IURC ordered that Rule 7 be updated to reflect market changes. *In the Matter of the Comm’n’s Investigation into any and all Matters Related to the Comm’n’s Guidelines for Integrated Resource Planning*, Cause No. 43643, 2010 Ind. PUC LEXIS 353 (IURC Oct. 10, 2010). Subsequently, several draft rules have been proposed, but none have been finalized. The utilities preparing IRPs in 2016 elected which Draft Proposed Rule upon which to base their IRPs. NIPSCO chose the July 5, 2016 draft rule. (**Attachment A.**)

To comply with the Draft Proposed Rule, NIPSCO used deterministic modeling of five scenarios with varying assumptions for a total of 15 cases. NIPSCO calculated a Net Present Value of Revenue Requirements (“NPVRR”) for each of the cases to determine their relative cost rankings. While NIPSCO’s IRP analysis found that the lowest cost case was the one in which all of its coal capacity was retired, NIPSCO’s recommended case was the one that included the retirement of two coal units in 2018 (Bailly 7/8) and two coal units by 2023 (Schahfer 17/18).

All of the scenarios assumed that NIPSCO would comply with the new Effluent Limitation Guidelines (“ELGs”)¹, Coal Combustion Residuals (“CCR”), and, where necessary, Cooling Water Intake (316 (b)) and the Cross States Air Pollution Rule (“CSAPR”) Update. NIPSCO also assumed a non-specific carbon regime would become effective in 2023 in all but four cases. Three cases assumed a no carbon regime over the IRP period: one scenario assumed a two-year delay until 2025. The non-specific carbon regime used a carbon price added to operating costs as a proxy for a specific program.

ICC’s review focused on NIPSCO’s compliance with the IRP draft rule guidelines NIPSCO selected, commodity price forecasts, regulatory assumptions, and supply-side resources.

ICC asserts that the IRP and NIPSCO’s recommendations are not based on reasonable assumptions with appropriate analysis. Further, since the submission of the IRP, there has been a major unexpected change warranting a reopening of the IRP given the need to adjust key assumptions.

ICC strongly recommends that NIPSCO revise its IRP analysis to reflect appropriate commodity price assumptions and regulatory obligations and that NIPSCO incorporate modeling techniques that are considered to be best practices for IRP development. The ICC also recommends that no actions should

¹ The retirement and optimization analyses were sequential. Compliance with ELGs was an assumption of the retirement analysis.

be taken by NIPSCO pending such revision. Finally, the ICC recommends that if any coal plants are retired pending completion of such review, that cost recovery related to undepreciated capital and closing costs as well as the cost of replacement power be at risk.

C. DETAILED COMMENTS.

COMMENT 1. NIPSCO IS NON-COMPLIANT WITH A NUMBER OF ASPECTS OF THE DRAFT PROPOSED RULE AS IT RELATES TO FUEL PRICE FORECASTING AND THE ASSOCIATED REQUIRED DISCLOSURES.

- 1.1 NIPSCO indicated its IRP was prepared under the July 5, 2016 Draft Proposed Rule (“Draft Proposed Rule”). The Draft Proposed Rule is provided in **Attachment A**.
- 1.2 Fuel cost assumptions are an integral part of the forecasting process. On page 2 of the IRP, NIPSCO states: “Key factors referred to in the IRP include market conditions, **fuel prices**, environmental regulations, economic conditions and technology advancements.” (Emphasis added).
- 1.3 The specific references to what is required vis-à-vis fuel costs in the IRP in the Draft Proposed Rule include the following:

Section 2.6 (b) states: “The Utility shall provide information requested by an interested party relating to the development of the utility’s IRP.”

Section 2.6 (d) states: “The Utility retains full responsibility for the content of its IRP.”

Section 4.12 states: “If the IRP references third party data sources, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data.”

Section 6.3 states that the utility must include “a fuel price forecast by generating unit”
- 1.4 The importance of fuel costs in an IRP is not surprising. Power plants are dispatched based upon their variable operating costs, the largest component of which is fuel. Further, the main reason for NIPSCO’s heavy reliance on coal generation is historically competitive coal pricing combined with other issues related to gas such as deliverability and price volatility.
- 1.5 Despite both the importance of fuel costs and the required fuel-related elements to the IRP, the fuel cost projections and assumptions are treated dismissively in the IRP by NIPSCO despite an obligation to be transparent. The entire discussion of fuel markets in the IRP is provided in **Attachment B**. In addition to the brevity of the discussion (which is inappropriate given the significance of fuel costs to the IRP analysis), its focus is on recent history and the near-term, not on the long-term factors which could affect fuel markets. For example, there is no discussion of the decline rates in the shale plays. Further, the limited discussion is replete with

misstatements, and its conclusions are inconsistent with the price forecasts used in the analysis.² Examples of both concerns are provided below.

- 1.6 The IRP states: “[w]ith its higher sulfur content, ILB coal is viewed as being a potential export resource.” The reality is that *despite* its high sulfur, Illinois Basin (“ILB”) coal is viewed as a potential resource *because of its low cost and competitive access to the U.S. Gulf export facilities*. The statement as provided suggests exports could reduce ILB coal available to NIPSCO. The truth is the potential supply of ILB greatly exceeds domestic demand and ILB coal could supplement its markets through exports because of its low-cost structure. There is ample supply of ILB coal for NIPSCO.
- 1.7 The discussion regarding coal from the Powder River Basin is not accurate. The IRP states: “Powder River Basin (“PRB”) coal from Wyoming and Montana has a lower heat content per pound of coal than coal mined in other regions. Domestic utilities that have not traditionally burned PRB coal are now blending or are evaluating blending PRB coal with Central Appalachia, ILB, or Northern Appalachian (“NAPP”) coals to reduce their overall fuel costs. Prior to the softening in Asian economies (China in particular), Asian demand for PRB coal grew as Japan and China were building new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand.”

The impression, intended or not, is that domestic demand for PRB coal is growing and there will be strong competition for PRB coal from Asia. Once again the reality is quite different. A more accurate summary paragraph would be as follows.

The PRB is the largest coal supply region in the U.S. The coal produced in the PRB is subbituminous low-sulfur coal. The initial market for this coal was utility power plants designed for it. For over two decades, many plants not designed for this coal have switched fully or partially to PRB coal as a result of its low sulfur content, low production costs, and competitive transportation. As a result, about half of the market for PRB coal has been in plants designed for it; the remaining market is in plants that were modified to burn it. With the exception of some conversion of lignite plants in Texas to PRB coal, future conversions in existing plants are not expected. Production from the PRB peaked in 2008 at almost 0.5 billion tons per year. Since then, production has declined for a variety of reasons including coal plant retirements. In 2015, PRB coal production was less than 400 million tons; production in 2016 was about 310 million tons. Only limited quantities of PRB coal are exported (well less than five percent) due to the lack of proximate export terminal capacity in the Pacific Northwest and the low heat content of PRB coal, which makes other transportation routings (e.g., the west coast of Canada, the U.S. Gulf and/or the Great Lakes) disproportionately higher cost. If export terminals in the Pacific Northwest are ultimately built (an assumption that is both unstated in the commentary and extremely relevant to future forecasts of PRB demand), PRB exports will come, at least in part, from mines likely to be developed for the export market. There is ample supply of PRB coal for NIPSCO.

² It appears part of the problem with the write-up is much of it is copied from the 2014 IRP which was possibly copied from earlier versions. As a result, the text does not describe the current state of the industry.

1.8 The IRP states that NAPP is also a potential source of supply. Specifically, the IRP states “NAPP coal used by NIPSCO as a blend fuel in two of its cyclone units was historically heavily exported however, the international demand for metallurgical and steam coal has been drastically reduced.” NIPSCO further states “NAPP producers have brought that supply back to the domestic markets **which helped drive prices lower.**” (emphasis added) Interestingly enough, even though NIPSCO acknowledges the historic use of NAPP coal in blends and its lower prices, there is no price forecast for NAPP coal and it was apparently not considered in the IRP.

1.9 The natural gas discussion is also limited. This is inconsistent with NIPSCO’s recommendations from the IRP to increase reliance on natural gas-fired generation.

1.10 The IRP states: “Recent energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources...” The IRP states:

Lower cost and highly efficient natural gas extraction processes ... have caused an oversupply resulting in a reduction in natural gas prices. ... These dynamics are expected to keep natural gas pricing low in the near term. **Longer term natural gas prices are expected to recover somewhat with the addition of new combined cycle natural gas generation and increased liquefied natural gas export capacity.**” (emphasis added)

It is not clear that the base forecasts for natural gas prices capture the expected price increase.

1.11 Neither the body of the IRP nor a Confidential Appendix contains a supply-demand balance provided for natural gas, projected production from individual shale plays, projected production levels for conventional gas, discussion of pipeline issues and related basis differentials, quantification of the expected level of LNG exports, discussion or quantification of the increased exports of natural gas via pipeline to Mexico, discussion or quantification of increased industrial use of natural gas, or discussion or quantification of the conversion of fleet traffic to compressed natural gas (CNG). In other words, the outlook for natural gas supply, which is clearly the most important consideration in NIPSCO’s IRP, is without any depth or context.

1.12 Also missing in the discussion of natural gas (although included in the coal discussion) is a discussion of the spate of bankruptcies in the natural gas supply chain as a result of low natural gas prices. If anything, the bankruptcies in the natural gas supply chain should be a greater cause for concern as they suggest that production at current pricing is not sustainable.

1.13 Without discussion of the respective supply and demand for coal and natural gas, NIPSCO did not (and could not) provide the required discussion of risks and uncertainties for these sources of fuel, as required in the Draft Proposed Rule, §§ 4(23) and (8)(c)(8).

1.14 The discussion of carbon prices is problematic from our perspective. The IRP simply states that because of legal challenges to the Clean Power Plan, “it does not appear likely that widespread GHG reductions will be required until 2022 or later.” Given the Stay of the Clean Power Plan by

the Supreme Court in February 2016, there is simply no basis for assuming the commencement of a carbon regime in 2023 in all but one of the carbon cases considered by NIPSCO.³

- 1.15 There are three cases which are represented to assume no carbon and one case in which the carbon price is delayed until 2025.
- 1.16 If the Supreme Court upholds the Clean Power Plan, which was not deemed to be all that likely even prior to the 2016 election and less likely now, 2025 could arguably be a reasonable start date. If the DC Circuit Court or the Supreme Court remands the Clean Power Plan to the EPA for further rule-making, the schedule could be extended further depending upon the nature of the remand.⁴ If the Clean Power Plan is vacated by the Supreme Court, EPA would need to commence a new rulemaking if deemed to be required by a prior Supreme Court ruling which would delay even further a carbon regime and may not include carbon prices at all.⁵
- 1.17 According to NIPSCO, the carbon price does not actually reflect the Clean Power Plan. Rather it is intended as a proxy for a carbon regime as the type of carbon control program is uncertain. While it is reasonable to use a carbon price as a proxy, a 2023 commencement of the generic carbon program for the IRP analysis for all but four cases is not reasonable. As noted above, 2025 could be a reasonable date for the Clean Power Plan if it is upheld but not for an alternative to the Clean Power Plan, which is not even on the table. Had NIPSCO wanted to consider an alternative to the Clean Power Plan, the earliest implementation date would more appropriately have been 2028.
- 1.18 A large part of the lack of transparency relates to the source of the commodity price forecasts and the terms by which they were acquired. NIPSCO effectively out-sourced its commodity price forecasting to PIRA, an energy consultancy with whom it has a retainer agreement. According to the IRP “(t)he fundamental commodity prices that serve as the key scenarios assumptions were provided by PIRA Energy Consultants.”
- 1.19 The IRP did not include the actual price points provided by PIRA. Rather the prices were presented in price curves.⁶ NIPSCO claimed it was not able to provide the actual price points because of the confidentiality provisions in its agreement with PIRA.

³ Ironically in the 2014 IRP, which was submitted after the Clean Power Plan was first proposed, NIPSCO’s position was that “it does not appear likely that widespread GHG reductions will be required until, at a minimum, the latter half of this decade. NIPSCO is estimating that a price on carbon will not be established prior to 2025 due to the current economic and political environment, in addition to the time required for a widespread program to be developed and implemented.”

⁴ As discussed later, this discussion has become somewhat academic following the election given the Administration’s plans to stop the Clean Power Plan from being implemented.

⁵ The Clean Power Plan derives from Endangerment Finding related to *Massachusetts v. EPA* (549 U.S. 497). If deemed necessary, the Trump administration could develop an achievable efficiency standard for existing coal plants.

⁶ As necessary for its analysis, ICC translated the price curves into single point estimates.

- 1.20 In response to an informal data request, NIPSCO provided ICC with a copy of the PIRA retainer agreement. Under the terms of the PIRA retainer, Licensee (NIPSCO) [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED] At a minimum, the information about the forecasts should have been provided to those parties willing to enter a confidentiality agreement.
- 1.21 More significantly, NIPSCO claims that it does not know what PIRA's assumptions were and PIRA provided no written documents to NIPSCO in support of the forecasts. This is highly unusual. If the forecasts are the consultant's standard forecast, they would come with accompanying assumptions. If the forecasts are customized to the client's request, which is often the case, the specific assumptions would be noted. For example, NIPSCO's 2014 IRP included a confidential appendix related to fuel assumptions.
- 1.22 By failing to instruct PIRA as to what assumptions should be assumed in the price forecasts, NIPSCO has no way of knowing whether the assumptions in the price forecasts are consistent with other parts of the IRP analysis.
- 1.23 By failing to understand PIRA's assumptions vis-à-vis the price forecast, NIPSCO by definition cannot accept full responsibility for the content of the IRP because it claims no knowledge of what those assumptions are.
- 1.24 NIPSCO either knew or should have known the stakeholders and the IURC would want to review the commodity price assumptions. If NIPSCO's interpretation of the PIRA Retainer precluded such disclosure (which is hard to understand) then NIPSCO should not have purchased the PIRA forecast or not just the PIRA forecast. Forecasts are available from a variety of sources. Vectren in its 2016 IRP *averaged* coal and natural gas price forecasts from four sources: Ventyx, Wood MacKenzie, EVA, and PIRA. (Page 74 of Vectren 2016 IRP) In this way, Vectren did not violate any confidentiality provisions even if such provisions existed in its agreements.
- 1.25 At the request of several stakeholders, NIPSCO held one webinar on the PIRA forecasts, which was available only to parties who had executed confidentiality agreements and who agreed not to copy the screens or take notes. In the webinar, the annual price points were presented. Given the commitment to neither copy nor take notes, an adequate review could not be performed. It is not known whether a PIRA representative participated. The NIPSCO personnel were unable to explain PIRA's assumptions or methodology beyond the simple verbiage provided in the IRP.

- 1.26 In the webinar and at other times and through informal data requests, NIPSCO was repeatedly asked to provide information about the assumptions behind the PIRA forecasts including copies of any reports provided by PIRA to NIPSCO. NIPSCO indicated it had not received any reports from PIRA and had no information other than the limited information provided in the IRP.
- 1.27 As a result of NIPSCO's lack of knowledge and control over the fuel inputs into the IRP scenarios, NIPSCO failed in its obligation to be responsible for the content of the IRP. As a result of NIPSCO's commitment to confidentiality, NIPSCO failed in its obligations to disclose adequate information to stakeholders about the forecasts.

COMMENT 2. THE NET PRESENT VALUE REVENUE REQUIREMENTS (NPVRR) RESULTS WERE EFFECTIVELY HARD-WIRED THROUGH NIPSCO'S USE OF ONLY CORRELATED COMMODITY PRICE FORECASTS EXCEPT WHERE IT USED EVEN LOWER NATURAL GAS PRICE FORECASTS, BOTH OF WHICH CONTRIBUTED TO IF NOT INSURED GAS-FIRED GENERATION WOULD BE LOWER IN COST THAN COAL GENERATION.

- 2.1 **Attachment C** lists the five scenarios with the sensitivities examined by NIPSCO in the IRP. The scenarios and sensitivities resulted in 15 cases. NIPSCO calculated the net present value of revenue requirements ("NPVRR") for each case to determine the relative cost rankings of each of the scenarios.
- 2.2 NIPSCO defined its cases based upon five variables: NIPSCO Load, CO2 prices, Natural Gas Prices, Power Prices and Renewable Portfolio Standard. NIPSCO indicated it did not need to identify which Coal Price assumptions it used as a variable because they were the same as the Natural Gas Price assumptions. In other words, if the case assumed high gas prices, it also assumed high coal prices; if the case assumed low gas prices, it also assumed low coal prices.
- 2.3 NIPSCO indicated this was the case because it used "correlated" commodity price assumptions. The term correlated was not specifically defined.
- 2.4 ICC reviewed the forecasts and confirmed that Pearson's R coefficient (which is the statistical measure for correlation) for the ILB and PRB coal price forecasts and for the coal and gas price forecasts was statistically significant. As shown in Exhibit 2-1, there a significantly significant correlation between the ILB and PRB price forecast data and the coal and gas price forecast data.

Exhibit 2-1. PEARSON R FOR PIRA FORECASTS

	ILB					PRB					NG				
	Base	Low	High	Very High	Base Delayed CO2	Base	Low	High	Very High	Base Delayed CO2	Base	Low	High	Very High	Base Delayed CO2
2016	\$1.65	\$1.50	\$2.05	\$2.05	\$ 1.50	\$0.62	\$0.58	\$0.75	\$0.75	\$ 0.56	\$3.00	\$2.50	\$4.00	\$ 4.00	\$ 2.50
2017	\$1.70	\$1.40	\$2.00	\$2.50	\$ 1.55	\$0.65	\$0.55	\$0.75	\$0.95	\$ 0.60	\$3.50	\$3.00	\$4.25	\$ 6.00	\$ 3.00
2018	\$1.80	\$1.55	\$2.40	\$2.55	\$ 1.60	\$0.68	\$0.59	\$0.90	\$0.95	\$ 0.62	\$4.20	\$3.40	\$5.00	\$ 6.50	\$ 3.40
2019	\$1.85	\$1.58	\$2.50	\$2.75	\$ 1.65	\$0.70	\$0.61	\$0.94	\$1.05	\$ 0.63	\$4.10	\$3.25	\$5.35	\$ 7.25	\$ 4.10
2020	\$1.91	\$1.60	\$2.60	\$3.00	\$ 1.70	\$0.72	\$0.61	\$0.97	\$1.10	\$ 0.65	\$4.10	\$3.40	\$5.10	\$ 8.00	\$ 4.10
2021	\$1.96	\$1.68	\$2.70	\$3.10	\$ 1.75	\$0.74	\$0.62	\$1.03	\$1.17	\$ 0.67	\$4.20	\$3.55	\$5.25	\$ 8.50	\$ 4.00
2022	\$2.01	\$1.76	\$2.80	\$3.15	\$ 1.80	\$0.76	\$0.64	\$1.06	\$1.19	\$ 0.69	\$4.50	\$3.65	\$5.80	\$ 8.75	\$ 3.85
2023	\$2.06	\$1.84	\$2.90	\$3.10	\$ 1.85	\$0.77	\$0.66	\$1.10	\$1.16	\$ 0.71	\$4.90	\$3.95	\$6.20	\$ 8.70	\$ 3.90
2024	\$2.12	\$1.92	\$2.92	\$3.00	\$ 1.90	\$0.79	\$0.68	\$1.11	\$1.12	\$ 0.73	\$5.40	\$4.50	\$6.40	\$ 8.60	\$ 4.00
2025	\$2.17	\$2.00	\$2.94	\$3.07	\$ 1.95	\$0.81	\$0.69	\$1.12	\$1.15	\$ 0.75	\$5.40	\$4.50	\$6.45	\$ 8.70	\$ 4.25
2026	\$2.22	\$2.04	\$2.95	\$3.14	\$ 2.00	\$0.83	\$0.71	\$1.13	\$1.17	\$ 0.77	\$5.40	\$4.50	\$6.50	\$ 8.60	\$ 4.50
2027	\$2.28	\$2.08	\$3.00	\$3.20	\$ 2.05	\$0.85	\$0.73	\$1.15	\$1.20	\$ 0.79	\$5.56	\$4.21	\$6.96	\$ 9.09	\$ 4.35
2028	\$2.33	\$2.12	\$3.05	\$3.27	\$ 2.10	\$0.87	\$0.75	\$1.17	\$1.22	\$ 0.81	\$5.72	\$4.33	\$7.22	\$ 9.25	\$ 4.46
2029	\$2.38	\$2.16	\$3.10	\$3.34	\$ 2.15	\$0.89	\$0.77	\$1.19	\$1.25	\$ 0.83	\$5.88	\$4.44	\$7.47	\$ 9.42	\$ 4.56
2030	\$2.44	\$2.20	\$3.15	\$3.41	\$ 2.20	\$0.91	\$0.79	\$1.21	\$1.27	\$ 0.85	\$6.04	\$4.55	\$7.73	\$ 9.58	\$ 4.67
2031	\$2.49	\$2.24	\$3.20	\$3.48	\$ 2.25	\$0.92	\$0.81	\$1.23	\$1.30	\$ 0.87	\$6.21	\$4.66	\$7.98	\$ 9.75	\$ 4.78
2032	\$2.54	\$2.28	\$3.26	\$3.55	\$ 2.30	\$0.94	\$0.82	\$1.24	\$1.32	\$ 0.89	\$6.37	\$4.77	\$8.24	\$ 9.91	\$ 4.88
2033	\$2.59	\$2.32	\$3.33	\$3.61	\$ 2.35	\$0.96	\$0.84	\$1.26	\$1.35	\$ 0.91	\$6.53	\$4.88	\$8.49	\$10.07	\$ 4.99
2034	\$2.65	\$2.36	\$3.39	\$3.68	\$ 2.40	\$0.98	\$0.86	\$1.28	\$1.37	\$ 0.93	\$6.69	\$4.99	\$8.75	\$10.24	\$ 5.09
2035	\$2.70	\$2.40	\$3.45	\$3.75	\$ 2.45	\$1.00	\$0.88	\$1.30	\$1.40	\$ 0.95	\$6.85	\$5.10	\$9.00	\$10.40	\$ 5.20

PEARSON R

	Base	Low	High	VH	BD CO2
ILBvPRB	100%	99%	100%	100%	100%
Significant	Yes	Yes	Yes	Yes	Yes
ILBvNG	99%	96%	97%	98%	93%
Significant	Yes	Yes	Yes	Yes	Yes
PRBvNG	99%	92%	96%	99%	93%
Significant	Yes	Yes	Yes	Yes	Yes

Note: Prices are estimated from cost curves in IRP

- 2.5 The coal price forecasts are for coals from two supply regions with different reserve profiles. The Powder River Basin consists of 16 mines, the vast majority of which have been in operations for decades. All of the mines employ surface mining techniques. Over time, the distances from the active mining areas to the tippie (loadout) have increased as have the mine ratios, which are a measure of the cover over the coal seam that has to be moved to recover the coal. In other words, costs have increased over time as a result of higher ratios and the increasing distance from the tippie. The Illinois Basin, while a region which has also produced coal for decades, has reinvented itself in the last decade or so. Most of the mines are relatively new and underground, employing state of the art mining techniques. The Illinois Basin has a vast reserve basin (the largest in the eastern U.S.) and a flat supply curve, which means that production can be maintained at expected levels with similar costs over time. There is simply no basis to forecast virtually the same growth rates in PRB and ILB prices over time. Yet, as shown in **Exhibit 2-2**, this is exactly what PIRA has assumed.

Exhibit 2-2. PIRA FORECASTS FOR PRB AND ILB COAL⁷

Figure 8-4: Power River Basin (PRB) Coal Prices

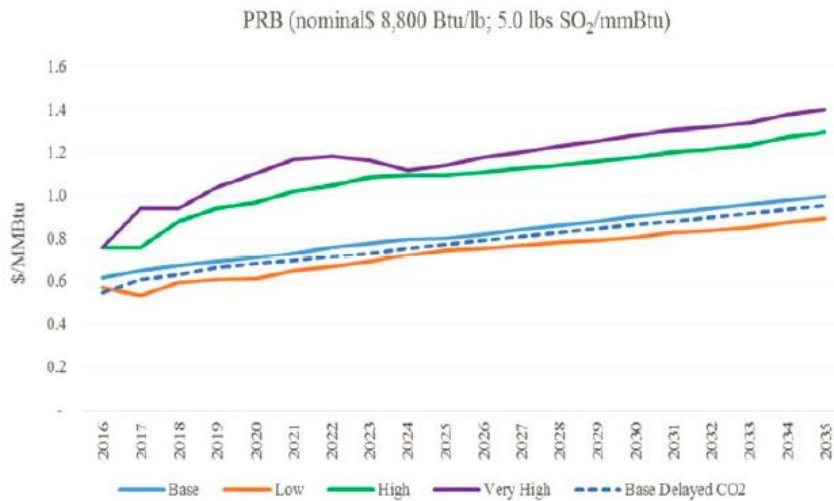
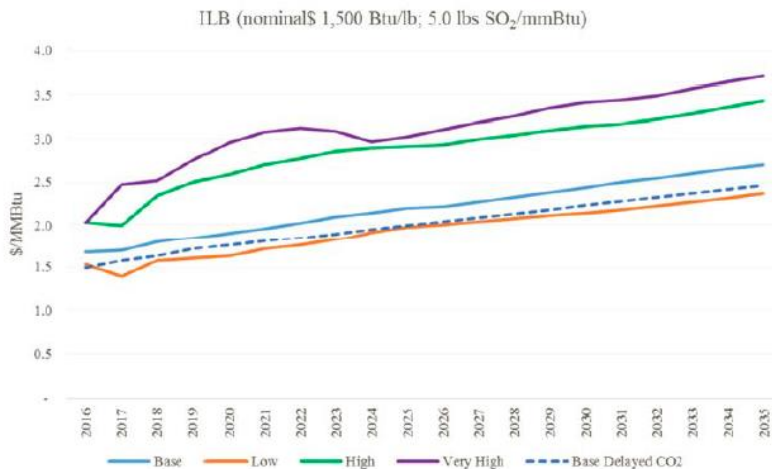


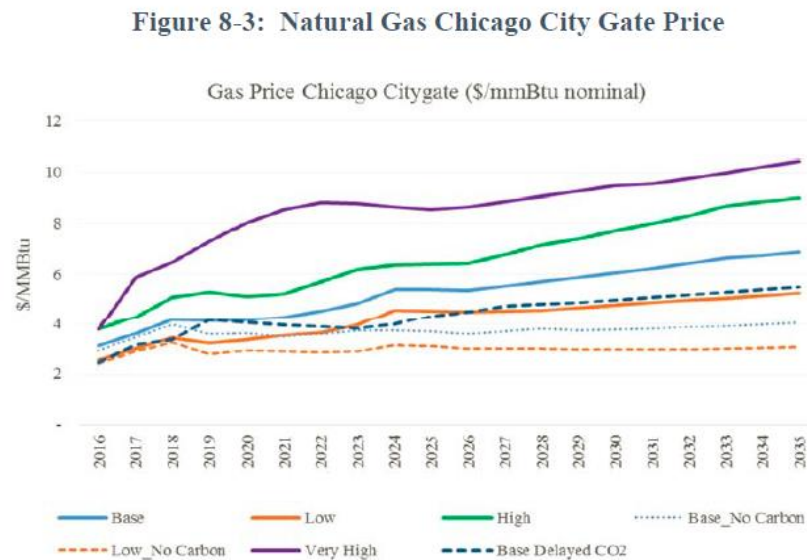
Figure 8-5: Illinois Basin (ILB) Coal Prices



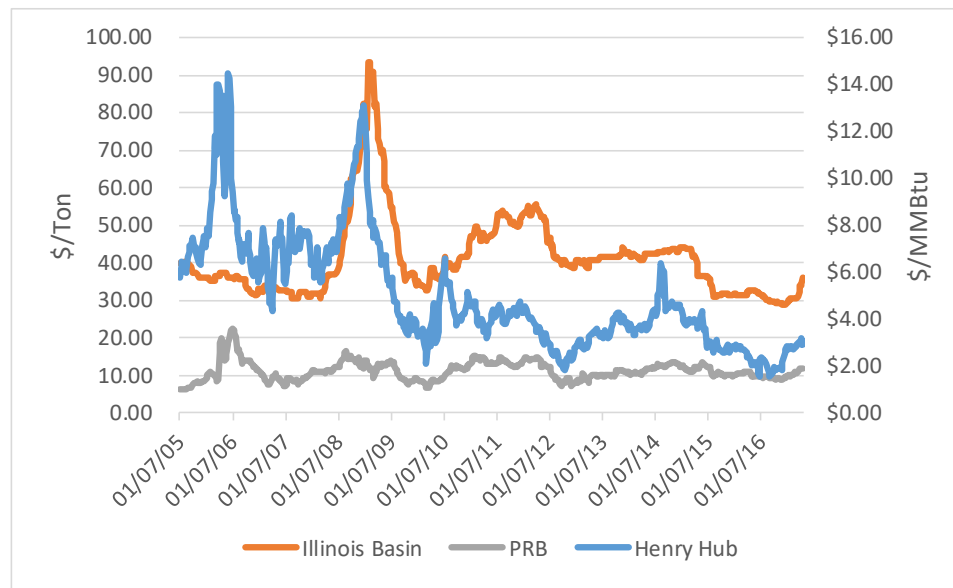
⁷ Both graphs have errors in their headers. Power River Basin should be Powder River Basin. PRB coal price is for a 0.5# SO₂ coal. ILB typically Btu/lb is 11,500.

- 2.6 The natural gas price forecast, which is shown in **Exhibit 2-3**, is priced at the Chicago City Gate hub which is a reasonable hub for natural gas to the Sugar Creek combined-cycle plant.

Exhibit 2-3. PIRA NATURAL GAS CHICAGO CITY GATE PRICE FORECAST

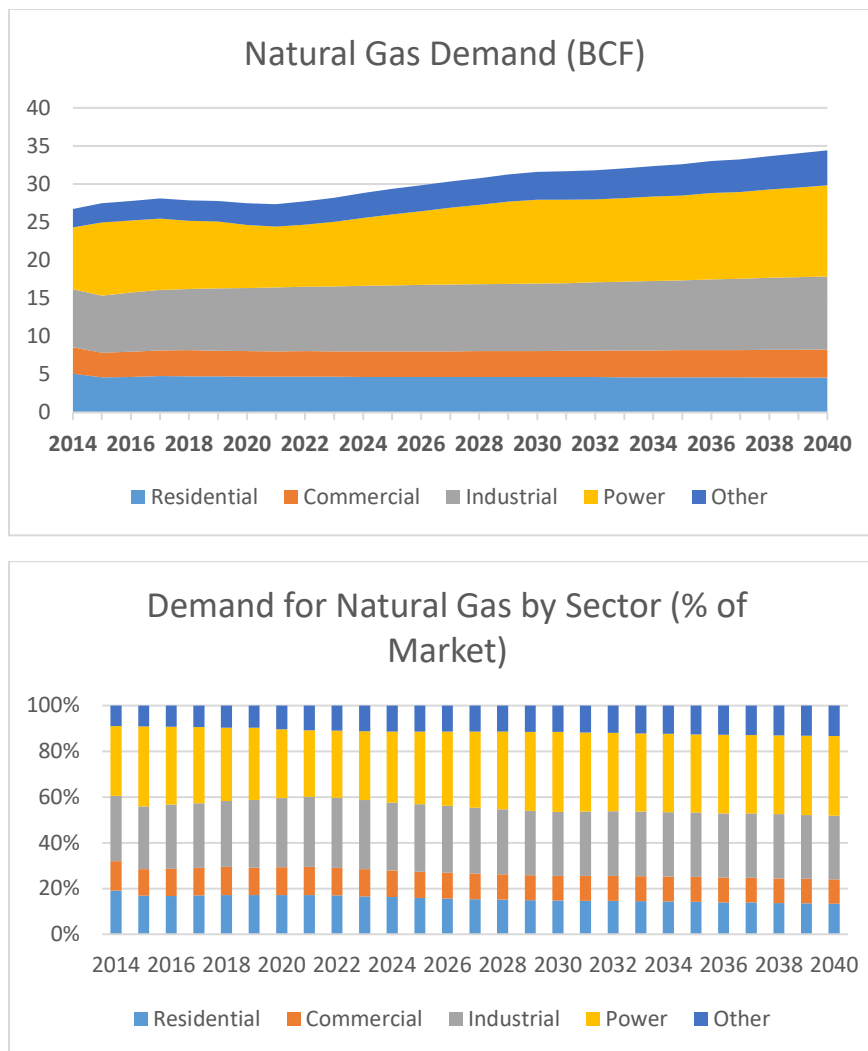


- 2.7 NIPSCO's use of a correlated price forecast between coal and gas prices is not explained. An analysis of historical prices shows that the Pearson's r coefficient between coal and gas prices is not statistically significant. Yet, an analysis of NIPSCO's forecast coal and gas prices shows that the Pearson's r coefficient between coal and gas is statistically significant. Historical prices and Pearson R's are shown in **Exhibit 2-4**

Exhibit 2-4 HISTORICAL PRICES AND CORRELATIONS

	Henry Hub (\$/MMBtu)	ILB (\$/Ton)	PRB (\$/Ton)
2005	\$ 8.90	\$ 37.08	\$ 10.61
2006	\$ 7.04	\$ 33.77	\$ 12.56
2007	\$ 6.91	\$ 32.85	\$ 10.03
2008	\$ 8.89	\$ 66.44	\$ 13.16
2009	\$ 3.90	\$ 38.62	\$ 9.08
2010	\$ 4.39	\$ 43.84	\$ 12.82
2011	\$ 3.99	\$ 52.13	\$ 13.54
2012	\$ 2.75	\$ 40.55	\$ 9.10
2013	\$ 3.72	\$ 41.97	\$ 10.85
2014	\$ 4.34	\$ 41.80	\$ 12.45
2015	\$ 2.61	\$ 32.00	\$ 10.43
2016*	\$ 2.36	\$ 30.43	\$ 9.89
HH vs ILB HH v PRB			
Pearson R		0.353	0.349
Statistically Significant		No	No

- 2.8 Among the reasons coal and natural gas prices have not been historically correlated relates to their markets. The domestic power generation market accounts for 80 to 90 percent of the demand for U.S. coal while the domestic power generation accounts for about a 35 percent share of the demand for natural gas.
- 2.9 The current and projected markets for natural gas according to the Energy Information Administration's 2016 Annual Energy Outlook are shown in **Exhibit 2-5**. According to EIA, the power sector share of natural gas demand is not expected to grow throughout the forecast period.

Exhibit 2-5. ACTUAL AND FORECAST MARKETS FOR NATURAL GAS

Source: 2016 Annual Energy Outlook

- 2.10 By assuming a correlation and alignment of the forecasted coal and gas prices, NIPSCO effectively hard-wired its results by assuming that coal and gas prices would move in the same direction in a statistically significant manner. As a result, the coal gas price differential was never sufficient to overcome the differences in operating costs given the regulatory assumptions.
- 2.11 Further, NIPSCO's three of its coal price forecasts were without explanation or justification not consistent with its representation that it used correlated price forecasts. The three cases were the no carbon scenarios in which NIPSCO used no carbon gas price forecasts with the same coal price forecasts it used in the carbon cases.

- 2.12 NIPSCO included no explanation for not having a comparable coal price scenario in its IRP for its base gas no carbon and low gas no carbon cases. Nor did NIPSCO provide an explanation of or support for the no carbon gas cases. As shown above on **Exhibit 2-3** the no carbon gas price forecasts are materially below their comparable gas price forecasts.
- 2.13 The effect of NIPSCO's unsupported assumptions is that coal generation is uneconomic even in a no carbon scenarios.
- 2.14 The differential between the gas price forecasts with and without carbon can be translated into an implied carbon price. As shown in **Exhibit 2-6**, the differential produced an implied carbon value equal to or greater than the base carbon price forecast. This means that NIPSCO's no carbon analysis simply transferred the carbon cost charged to coal in the carbon case to a discount on the gas price in the no carbon case.

Exhibit 2-6. IMPLIED CARBON PRICE IN GAS PRICES FORECASTS WITHOUT CARBON

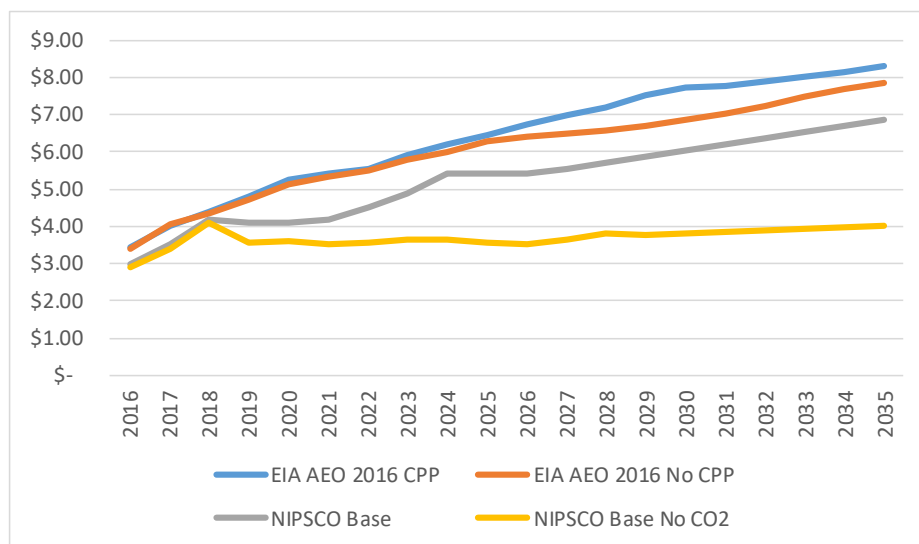
	CO2 Price (\$nominal/ton)		NG Chicago Citygate (\$Nominal/MMBtu)				CO2 Price (\$nominal/ton)	
	Base	Very High	Base	Low	Base No Carbon	Low No Carbon	Implied Carbon Price in Base Case	Implied Carbon Price in Low Case
2016	\$ -	\$ -	\$ 3.00	\$ 2.50	\$ 2.90	\$ 2.40	\$ 1.69	\$ 1.69
2017	\$ -	\$ -	\$ 3.50	\$ 3.00	\$ 3.40	\$ 2.90	\$ 1.69	\$ 1.69
2018	\$ -	\$ -	\$ 4.20	\$ 3.40	\$ 4.10	\$ 3.30	\$ 1.69	\$ 1.69
2019	\$ -	\$ -	\$ 4.10	\$ 3.25	\$ 3.55	\$ 2.80	\$ 9.32	\$ 7.63
2020	\$ -	\$ -	\$ 4.10	\$ 3.40	\$ 3.60	\$ 3.00	\$ 8.47	\$ 6.78
2021	\$ -	\$ -	\$ 4.20	\$ 3.55	\$ 3.50	\$ 2.95	\$ 11.86	\$ 10.17
2022	\$ -	\$ -	\$ 4.50	\$ 3.65	\$ 3.55	\$ 2.90	\$ 16.10	\$ 12.71
2023	\$ 8.00	\$ 9.00	\$ 4.90	\$ 3.95	\$ 3.65	\$ 2.95	\$ 21.19	\$ 16.95
2024	\$ 14.00	\$ 18.00	\$ 5.40	\$ 4.50	\$ 3.65	\$ 3.10	\$ 29.66	\$ 23.73
2025	\$ 18.00	\$ 22.00	\$ 5.40	\$ 4.50	\$ 3.58	\$ 3.08	\$ 30.93	\$ 24.15
2026	\$ 20.00	\$ 31.00	\$ 5.40	\$ 4.50	\$ 3.50	\$ 3.05	\$ 32.20	\$ 24.58
2027	\$ 21.67	\$ 40.00	\$ 5.56	\$ 4.21	\$ 3.65	\$ 3.03	\$ 32.39	\$ 20.16
2028	\$ 23.33	\$ 49.00	\$ 5.72	\$ 4.33	\$ 3.80	\$ 3.00	\$ 32.58	\$ 22.46
2029	\$ 25.00	\$ 58.00	\$ 5.88	\$ 4.44	\$ 3.75	\$ 2.98	\$ 36.16	\$ 24.76
2030	\$ 26.67	\$ 67.00	\$ 6.04	\$ 4.55	\$ 3.80	\$ 2.95	\$ 38.04	\$ 27.06
2031	\$ 28.33	\$ 67.00	\$ 6.21	\$ 4.66	\$ 3.85	\$ 2.96	\$ 39.92	\$ 28.77
2032	\$ 30.00	\$ 67.00	\$ 6.37	\$ 4.77	\$ 3.90	\$ 2.97	\$ 41.81	\$ 30.47
2033	\$ 31.67	\$ 67.00	\$ 6.53	\$ 4.88	\$ 3.93	\$ 2.98	\$ 44.03	\$ 32.18
2034	\$ 33.33	\$ 67.00	\$ 6.69	\$ 4.99	\$ 3.96	\$ 2.99	\$ 46.25	\$ 33.89
2035	\$ 35.00	\$ 67.00	\$ 6.85	\$ 5.10	\$ 4.00	\$ 3.00	\$ 48.31	\$ 35.59

Carbon and gas prices are estimated from the price curves in the IRP

- 2.15 NIPSCO did not validate its fuel price assumptions with either the forecasts provided by EIA or third parties. NIPSCO indicated it did not validate with other third party forecasts because it would have had to spend money acquiring third party forecasts.

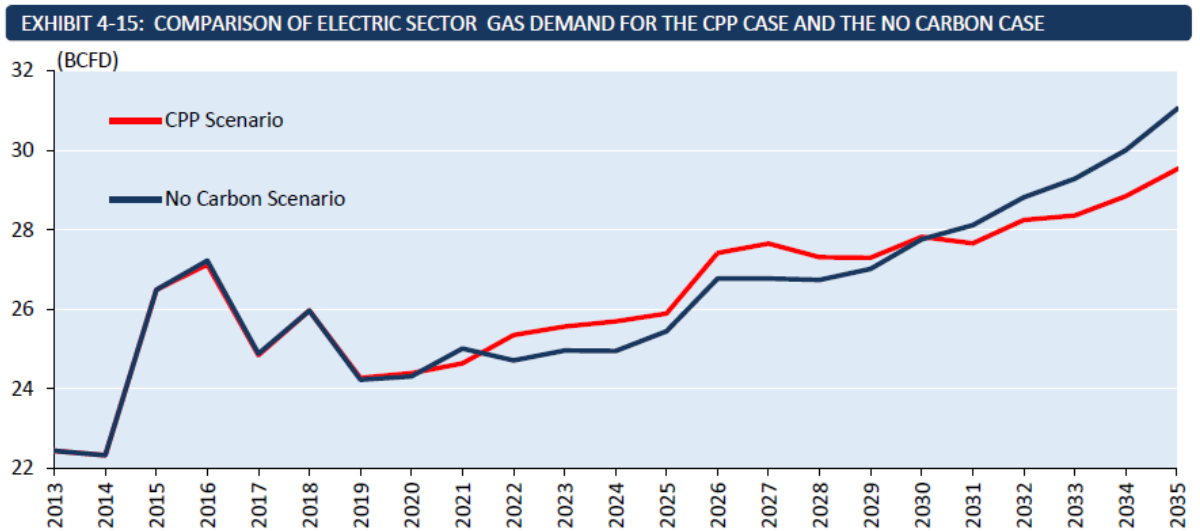
- 2.16 Just as NIPSCO did not validate any of its price forecasts, it also did not validate the differences between the carbon and no carbon gas price forecasts. The differential between the carbon and no carbon gas price forecasts is inconsistent with the forecasts produced by the EIA as part of the 2016 Annual Energy Outlook (AEO). As shown in **Exhibit 2-7** in the AEO the gas price forecast without carbon is also lower than the gas price forecast with carbon but by a much smaller amount. Further, the difference declines over time in contrast to the PIRA forecast in which they increase over time.

Exhibit 2-7. Comparison of EIA North Central NG Prices and PIRA Chicago City Gate Gas Prices (Nominal \$/MMBtu)

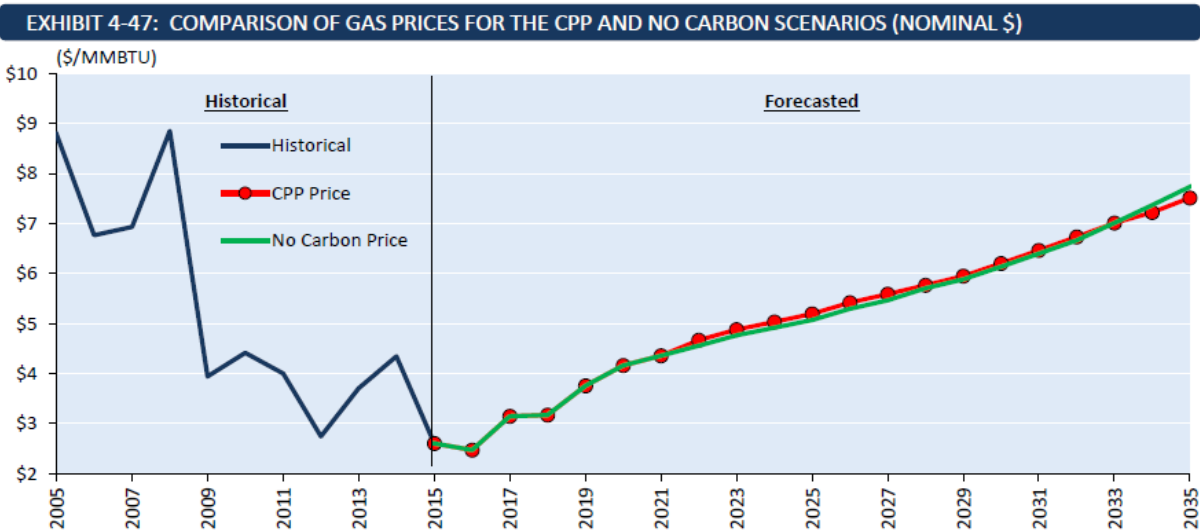


- 2.17 The differential is also inconsistent with published forecasts from ICC's consultant, Energy Ventures Analysis, Inc. (EVA). As shown in **Exhibit 2-8**, EVA's forecast with and without carbon are even closer than EIA's. Of note, EVA's natural gas price forecast without carbon moves higher than its forecast with carbon around 2033 because its modeling shows that under the Clean Power Plan a combination of factors including lower electricity demand, higher renewables, distributed generation, and higher nuclear generation reduce the demand for natural gas in the power sector around 2033.

Exhibit 2-8 EVA Long-Term Natural Gas Price Forecast



1.



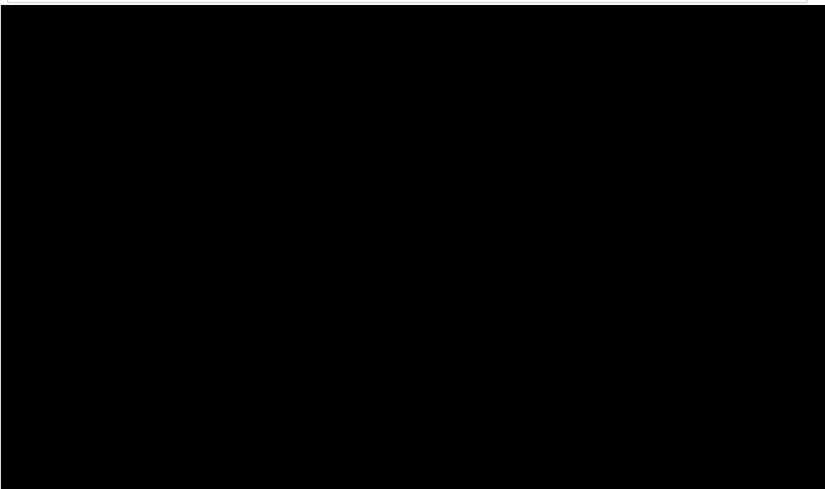
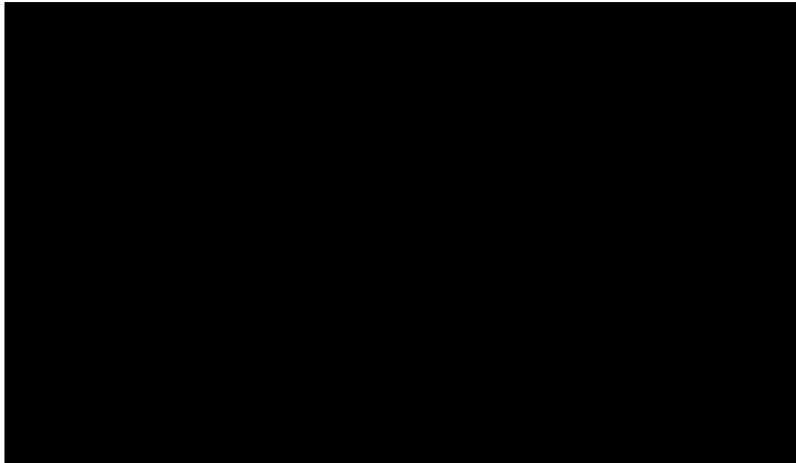
Source: FUELCAST, THE LONG-TERM OUTLOOK, FALL 2016

- 2.18 NIPSCO neither justified its natural gas price forecasts without carbon nor validated its forecasts with third party forecasts. It is unknown how the PIRA forecasts used by NIPSCO compare to PIRA's other forecasts with no carbon.
- 2.19 It is also unknown whether PIRA's standard forecasts, i.e. the forecasts PIRA prepares for others, for coal and gas are *correlated*. Correlated forecasts are not believed to be the norm.

- 2.20 The norm is “integrated” forecasts which means that natural gas prices are tied to total gas demand (not just demand from the power sector). Similarly, coal price forecasts are tied to total coal demand, which includes demand from the power sector and other domestic demand as well as export demand. In the limited information provided in the IRP and from PIRA, there is no discussion about its forecasts being integrated.
- 2.21 There are a number of fundamental problems using correlated price forecasts in the IRP.
- a. There is no justification for coal and natural gas prices to be correlated in this manner.
 - b. By using a correlated price forecast for coal and natural gas, the results of the analysis are effectively being hard-wired. It is well known that coal generation is lower cost than gas generation only when there is a sufficient difference in delivered prices. By defining input assumptions that preclude this from happening, it does not matter how many scenarios are run the results will likely be the same.
- 2.22 The single greatest risk associated with the closure of coal generation capacity relates to a return to gas prices that are materially higher than coal prices. The only way to evaluate this threshold risk is by considering scenarios in which gas prices rise independent of coal prices. No scenario in the NIPSCO IRP remotely considered this potential.

COMMENT 3: NIPSCO MADE A NUMBER OF ASSUMPTIONS IN THE IRP THAT INAPPROPRIATELY DISADVANTAGED COAL.

- 3.1 NIPSCO did not consider any case which addressed the threshold issue for consideration in the retirement of any coal plant which is what if natural gas prices rise independent of coal prices, such as what has occurred over much of the last decade.
- 3.2 The Chicago City Gate prices that NIPSCO represented in its IRP to be its gas price forecast was in fact not its gas price forecast. The Chicago City Gate gas prices in the IRP were employed as if they were the maximum monthly gas price forecast in each year. NIPSCO applied a monthly seasonal adjustment factor that ranged between [REDACTED] to determine the relevant gas price for each month. The net effect of these adjustments was to reduce the average annual gas price. The reductions varied by case and year. Examples of actual versus maximum gas prices for three cases are provided in **Exhibit 3-1**. In addition to the fact that the gas prices in the IRP were seemingly misrepresented, the lower gas prices contributed to the lower NPVRRs in each case. The standard industry practice in providing annual price forecasts is to provide annual average prices, not the maximum price per month.

Exhibit 3-1. Actual vs Maximum Gas Prices in Three IRP Cases

- 3.3 NIPSCO used the average annual delivered coal price forecasts to determine the economics of coal versus gas generation, ignoring a growing trend and willingness among producers and transporters to modify pricing structures in order to improve the economic dispatch of coal

plants. The CSX Railroad offers fixed and variable pricing options in certain markets.⁸ Some coal suppliers have offered variable pricing to improve plant dispatch. NIPSCO, itself, has periodically used decrement pricing to improve dispatch for its coal units.⁹ NIPSCO failed to consider flexible pricing for coal while making seasonal adjustments to the natural gas price. It is unreasonable not to consider flexible coal pricing in evaluating the economics of the coal plants. To the best of ICC's knowledge, none of its members were approached by NIPSCO to discuss alternative coal pricing strategies.

- 3.4 NIPSCO used 2015 as the first year of its calculations of the NPVRR even though 2015 (and 2016 for that matter) is past and irrelevant in the comparison of the NPVRR for the IRP scenarios. The 2015 and 2016 natural gas prices used by NIPSCO in the Strategist model were significantly below coal prices in those years on a dollars per MMBtu basis. Starting the NPVRR calculations in 2015 affects the NPVRR calculations in at least two ways. It includes price data which are irrelevant and it magnifies the importance of such data because of the discounting of future years. As a result, the ICC believes the inclusion of 2015 and 2016 in the NPVRR results in an overstatement of the cost differences between the cases.¹⁰
- 3.5 It is not exactly clear what prices NIPSCO used in the early years as the reported numbers do not align with the PIRA forecasts. It appears that there may have been some "blending" of the PIRA forecasts with NYMEX (traded) numbers. No information was provided about the NYMEX numbers or how they were used. Given the low gas prices in 2015 and 2016, this approach most likely favored non-coal generation.
- 3.6 NIPSCO assumed in 11 of the 15 cases a carbon price would be in effect starting in 2023. This assumption is inconsistent with NIPSCO's position in its 2014 IRP that the earliest a carbon price would go into effect would be 2025. It is inconsistent with NIPSCO's position that the carbon price does not represent the Clean Power Plan per se but is a proxy for a carbon reduction program. No program outside of the Clean Power Plan could be developed and implemented by 2023. It is inconsistent with NIPSCO's acknowledgement that there are "legal challenges" to the Clean Power Plan. The application of a carbon tax in 2023, which disproportionately affects coal over gas, inappropriately increases the cost of coal generation in the near term.
- 3.7 With the exception of carbon, NIPSCO did not consider either the vacatur or moderation of the assumed environmental regulations. With respect to carbon, NIPSCO represents it considered three cases with no carbon prices. As discussed above, in the three scenarios which assume no carbon regime, NIPSCO reduced the gas price forecasts by an amount equal to or greater than the assumed carbon prices and made no changes to the coal price forecasts. In other words, NIPSCO transferred the carbon cost associated with coal into a discount in the gas price. No explanation or support was provided for the no carbon gas price forecasts and the differential

⁸ CSX Quarterly Financial Report, Fourth Quarter 2014

⁹ <https://www.hubs.com/power/explore/2016/08/nipsco-continues-to-use-decrement-pricing-to-burn-more-contracted-coal>

¹⁰ Starting the analysis in 2015 may also have affected the retirement analyses.

between the carbon and no carbon gas price forecasts is not consistent with industry forecasts. NIPSCO did not actually consider a no carbon case despite its representation that it had.

- 3.8 NIPSCO also did not consider any scenarios in which the Effluent Limitation Guidelines (ELGs) are modified. The final ELG rule was published in the Federal Register on November 17, 2015 which established the relevant date for judicial review. Various petitioners filed seven separate petitions for judicial review in multiple U.S. Courts of Appeal. The petitions were consolidated in the Fifth Circuit. Opening briefs were filed with the Court on December 5, 2016. The industry brief, which is provided in **Attachment D**, argues that substantive challenges to the ELG rules are difficult because the EPA did not disclose critical documents in the proceedings. The new EPA administrator is likely to release these documents which undoubtedly will lead to further litigation if the Trump EPA cannot find a way to withdraw the rule.
- 3.9 The industry, including NIPSCO, has found ELG compliance costs much higher than what was assumed by EPA in the development of the rule. NIPSCO indicated it was investigating lower cost compliance options although none were considered in the IRP. The ELG is the primary reason for NIPSCO's decisions as to which power plants to retire as both Bailly 7/8 and Schahfer 17/18 have wet scrubbers. Assuming lower or no ELG compliance costs, the conclusions would likely have been different.
- 3.10 In any event, compliance with ELGs can be deferred until 2023. Given the uncertainty of the future of this regulation, a decision to close a plant based upon ELG compliance is premature.
- 3.11 NIPSCO did not assume the potential for a federal tax incentive to support any additional retrofits of pollution control technology on coal plants, which is being considered by some parties.
- 3.12 The coal transportation costs NIPSCO added to the coal price forecasts are significantly higher than current transportation costs based upon information provided in CONFIDENTIAL EXHIBIT H. No justification was provided for the rail rates.

COMMENT 4. NIPSCO DID NOT USE BEST PRACTICES MODELING TECHNIQUES RECOMMENDED TO THE IURC AND USED BY NIPSCO'S PEERS IN THEIR 2016 IRPS TO PERFORM RISK ANALYSIS AS REQUIRED BY THE DRAFT PROPOSED RULE. AS A RESULT, THE RESULTS PRODUCED BY NIPSCO IN ITS IRP DID NOT ADEQUATELY ADDRESS RISK AND CANNOT BE CONSIDERED DISPOSITIVE WITH RESPECT TO ITS FINDINGS.

- 4.1 As laid out in the Draft Proposed Rule, a major aspect of the IRP analysis is to perform risk analysis.
- 4.2 In March 2016, the Berkley Research Group ("BRG") provided a presentation on "Uncertainty in IRP: Common Pitfalls and Best Practices." at the IURC's IRP Contemporary Issues Technical Conference, which NIPSCO attended. This presentation is provided in **Attachment E**.
- 4.3 BRG speaks to the importance of using stochastic modeling for each key source of portfolio risk. A stochastic model incorporates probability distributions of potential outcomes by allowing for

random variation in one or more inputs over time. The random variation is usually based on fluctuations observed in historical data for a selected period using standard time-series techniques.

- 4.4 Stochastic modeling is an alternative or supplement to deterministic modeling in which the output of the model is fully determined by the assumed parameter values.
- 4.5 BRG provided an example in its presentation of where the least cost strategies as measured by the present value revenue requirements (PVRR) were different based on the modeling approach. This is because the results are more robust when probability distributions are considered.
- 4.6 Stochastic modeling is not new. The advantages of stochastic modeling have been discussed at an earlier issues forum sponsored by the IURC.
- 4.7 IPL indicated it incorporated stochastic modeling in its 2016 IRP in part because of comments it had received on its 2014 IRP.
- 4.8 IPL explained the advantages of stochastic modeling in public advisory sessions. An excerpt from one of IPL's public advisory session providing the advantages of stochastic model on the quality of results from the IRP is provided in **Attachment F**.
- 4.9 IPL provided a detailed explanation of its stochastic modeling in its 2016 IRP. **Attachment G** provides an excerpt related to stochastic model in the 2016 IRP.
- 4.10 Similarly, Vectren incorporated stochastic modeling in its IRP. Vectren recognized that "a single deterministic price forecast may introduce bias that skews the forecast path." While this statement was with respect to capital costs for batteries, it holds true across all price projections. Vectren noted "[f]or the development of [its] scenarios, stochastic distributions of each of the key variables (e.g. load, gas prices, technology costs, etc.) were developed...". Vectren further noted "[s]tochastic distributions that reflect a combination of historical data and informed judgment tend to capture "black swan events" that are impossible to forecast, but tend to occur quite frequently.¹¹
- 4.11 Vectren did not do the modeling itself. Rather it contracted with a third party, PACE Global, which had the experience and capability to perform the stochastic modeling. Under Rule 7, the utilities are not obligated to perform the modeling themselves. They simply have to accept ownership of the modeling results.
- 4.12 In its 2014 IRP, NIPSCO claimed that it could perform sensitivity analysis using "stochastic or Monte Carlo analysis." NIPSCO correctly explained in the 2014 that "Monte Carlo is generally applied when it is infeasible to compute an exact result using deterministic methods." In 2014,

¹¹ ICC found that Vectren's analysis did not actually accomplish this goal. Nevertheless, Vectren was correct in its intent.

NIPSCO claimed its issue was the difficulty in generating the probability distributions, not that it could not do them. In 2014, NIPSCO stated it used deterministic modeling because it was “the most cost-effective approach to quantifying risk.”

- 4.13 NIPSCO argues in its 2016 IRP that despite its use of only deterministic modeling, its results were robust because it considered multiple scenarios. This is simply not the case for many of the reasons explained above including the reasons NIPSCO itself gave in 2014 that it was “infeasible to compute an exact result using deterministic modeling.”
- 4.14 NIPSCO in the 2016 IRP confirms that “a more dynamic effort would involve the inclusion of a stochastic process in the IRP modeling.”
- 4.15 NIPSCO’s partial excuse in the 2016 IRP is that the Strategist model which NIPSCO selected to use for its IRP modeling, was “unfortunately incapable of directly utilizing statistical tools within its engine.” This seems inconsistent with the representations in the 2014 IRP.
- 4.16 Of course, it is not relevant whether NIPSCO could or could not do stochastic modeling in 2014. In 2016, NIPSCO knew or should have known the importance of incorporating stochastic modeling, NIPSCO should not have chosen to use a model that could not incorporate stochastic modeling, and NIPSCO should not have drawn definitive conclusions from what it acknowledges was a flawed process.
- 4.17 NIPSCO stated in the IRP that it will “evaluate new software that can incorporate statistical uncertainty directly in the modeling process” for future IRPs. NIPSCO’s position is problematic given that its recommendations in its 2016 IRP are significantly different than recommendations from prior IRPs. NIPSCO even refers to it being at a “cross roads.” Given the known problems with the modeling it has done combined with all the input uncertainties, additional analysis should be required before the short-term plan is implemented.

COMMENT 5. NIPSCO DID NOT CONSIDER THE SALE OF BAILLY 7/8 AND SCHAHFER 17/18 TO A THIRD PARTY AS A POTENTIAL SUPPLY-SIDE RESOURCE.

- 5.1 Section 7-30 of the Draft Proposed Rule requires utilities to provide a “detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.”
- 5.2 To comply with this requirement, NIPSCO worked with Sargent & Lundy to compile a list of supply-side resources. According to the IRP, “Sargent & Lundy conducted a preliminary screening for new utility scale self-build central and distributed generation supply-side resource options.”¹²
- 5.3 For existing capacity, NIPSCO only considered two options: retire or operate.

¹² NIPSCO assumed that the New Source Performance Standard for Greenhouse Emissions would be upheld thereby requiring partial carbon capture and sequestration (“CCS”). While this assumption is also problematic, it is less critical to the results of this IRP.

- 5.4 NIPSCO did not fully consider conversion options for the Bailly and Schahfer plants. While Sargent & Lundy developed conversion assumptions including costs “upon further analysis following the completion of the engineering study, NIPSCO determined that additional information was needed to effectively model these options.” NIPSCO stated that it intended to “evaluate these options in subsequent IRPs.”
- 5.5 NIPSCO failed to note that the consideration of a conversion post-closing (as would be the case if the 2019 IRP considered a conversion of Bailly) would have its own attendant problems further complicating or compromising the conversion economics.
- 5.6 One resource option NIPSCO admittedly did not consider in its IRP is the sale of the Bailly 7/8 station and/or Schahfer 17/18 to a third party.
- 5.7 In a meeting with NIPSCO personnel, NIPSCO indicated it was not really interested in selling its generation to a third party, preferring to maintain control over its system generation. This is perfectly understandable in the context of traditional rate-making wherein the utility earns much of its revenue through returns on invested capital. Without the existing capacity (e.g., Bailly) and without the need for new capacity (e.g., capacity to replace Bailly), the potential earnings for NIPSCO would be diminished.
- 5.8 However, the question for the IURC and in theory any regulated utility is not the utility’s return on investment, but what generates the lowest cost of power for the utility’s customers.
- 5.9 NIPSCO indicated it had informal conversations with parties that had either purchased other coal generation or had expressed an interest in doing so. These conversations were not independently confirmed. NIPSCO concluded from these informal conversations, a sale could not be realized that would be acceptable to NIPSCO. Therefore, NIPSCO was not interested in a sale process.
- 5.10 There have been multiple sales (and resales) of coal generating capacity. For example, Dominion Resources sold its Brayton Point and Kincaid power plants to Equipower in 2013. These plants were sold to Dynegy in 2015. In January 2017, AEP completed the sale of the Gavin coal plant along with three gas plants to Lightstone Generation LLC, a joint venture of Blackstone Group LP and an Arclight Capital Partners affiliate.
- 5.11 NIPSCO indicated it was contacted recently by one party and due diligence is in its early stages
- 5.12 The question remains absent a sale process how can NIPSCO confirm such a sale would not produce lower costs to costumers. The answer is NIPSCO cannot.
- 5.13 There are several reasons why a third party may believe that Bailly 7/8 and Schahfer 17/18 may have more value than NIPSCO is ascribing to these units.

- a. NIPSCO has adopted a very conservative forecast with respect to the coal versus gas price differentials. A third party may have a different market view regarding these differentials which would result in higher generation assumptions for the coal units and hence higher value.
 - b. NIPSCO is assuming a number of environmental regulations that because of the most recent election have become speculative. If these regulations are either vacated or moderated, coal generation is likely to be lower cost.
 - c. NIPSCO is assuming conservative costs of compliance with these regulations. For example, NIPSCO confirmed that the assumed ELG compliance costs are conservative and there may be ways to reduce these costs. A third party may be more willing to take the risk that is the case.
 - d. Coal producers and transporters are increasingly flexible with respect to their pricing structure to improve the dispatch of coal plants. As previously mentioned, the CSX railroad has adopted pricing in certain markets in which there is a fixed and variable component. Such pricing could alter the dispatch costs for coal units if the fixed component is not included in the Variable O & M. In other markets, coal producers have been known to provide discounts and premiums to the coal price based upon real-time power pricing. Depending upon the discounts, this could reduce the fuel cost to very low levels during off-peak periods allowing plants to dispatch ahead of gas. NIPSCO is not believed to have talked to its coal suppliers about alternative pricing options and only considered the delivered price forecasts for coal using the PIRA forecasts and the NIPSCO transportation numbers.
 - e. Coal producers are concerned about maintaining market. With increased numbers of plant retirements, they are looking to maintain the demand for their coal through plant acquisitions.
 - f. Third parties may be more optimistic than NIPSCO regarding future changes to MISO pricing that allow coal generators to realize higher values. Interestingly, NIPSCO falls in this category. NIPSCO states in the IRP it believes there is a reasonable chance that “capacity prices in MISO Planning Resource Auction (PRA) and bilateral market are likely to continue to increase in the MISO North region in the next five years.”
- 5.14 Should NIPSCO decide (because of third party interest) or an IURC order (that requires a sale process be conducted to determine a least cost strategy) that prior to any plant closure/retirement there must be a process to determine whether the market value of the asset being retired can reasonably be expected to reduce ratepayer costs, the IURC and its staff need to be involved in this process. The reason is simple. It is not in NIPSCO’s corporate interest to sell these plants.
- 5.15 In New Hampshire, where the Public Service Commission of New Hampshire ordered the auctioning of Eversource’s generating capacity, the Public Service Commission ordered that the

auction be conducted by a third party financial advisor selected by the Commission through an RFP. While there is a cost associated with third-party involvement, there is every reason to believe that a competitively run process will produce value well in excess of the incremental sales cost. A copy of the New Hampshire Commission's RFP for the final advisor is provided in **Attachment H**.

- 5.16 NIPSCO believes it does not need IURC approval to retire Bailly 7/8 or to recover its undepreciated investment in the units as well as its related closing expenses because the IRP demonstrates this action to be lowest cost. In fact, NIPSCO has reportedly already informed MISO of its intention to retire Bailly 7/8 in 2018.
- 5.17 ICC believes that NIPSCO has been premature. Given the problems identified with the underlying analyses in the IRP which call into question whether in fact the plant closure is least cost, recovery could and would be contested.

COMMENT 6. NIPSCO IS IGNORING ITS OBLIGATION TO REVISIT THE IRP FOLLOWING A SUBSTANTIAL UNEXPECTED EVENT

- 6.1 The IRPs are intended to support each utility's obligation to supply power at the lowest reasonable cost, while providing safe, adequate and reliable service.
- 6.2 Despite initiating Cause 43643 in 2009 and the ensuing 2010 IURC Order¹³ requiring an update the IAC provisions covering the IRP, an update was not completed to guide the preparation of the 2016 IRPs. Without a revised Rule 7 to guide the preparation of the 2016, the utilities made independent decisions as to which of the Proposed Rule drafts to use. NIPSCO indicated it followed the July 5, 2016 draft while Indianapolis Power & Light and Vectren respectively stated they followed the October 4, 2012 rule.
- 6.3 All of the Draft Proposed Rules are believed to contain the addition of a Section 10. As shown in **Attachment I**, there are several versions of Section 10. Regardless of the version, the intent is clear. A "Substantial Unexpected Event" should be grounds for reconsideration of the findings of the IRP whether such review is triggered by the utility, the IURC or IURC staff.
- 6.4 NIPSCO filed its IRP on November 1, 2016. On November 8, 2016, the result of the presidential election was unexpected based upon national polling at the time. While an unexpected result in and of itself may not have qualified as a "Substantial Unexpected Event", the election of Donald Trump is with respect to the NIPSCO IRP. This is because Candidate Trump specifically campaigned on reducing the regulatory burden related to coal consumption. President Trump named Scott Pruitt, the former Attorney General for the State of Oklahoma which is a plaintiff in the Clean Power Plan appeal, to be EPA Administrator.
- 6.5 Making the Presidential election even more significant was the Republicans retaining control of the U.S. Senate. This was significant because it put into play the Congressional Review Act

¹³ https://www.in.gov/iurc/files/Order_in_Cause_No._43643.pdf

which makes rules put into place within 60 legislative days prior to the change in administration subject to withdrawal with a simple majority in each house and the President's signature. The Stream Protection Rule was either the first or one of the first rules to be "revoked" in this manner. Other coal-related rules may be addressed through the Congressional Review Act. Control of the Senate is also likely to make a Supreme Court nominee, Neil Gorsuch, easier to confirm.

- 6.6 Also with control of both house of Congress, the President will have an opportunity to put forth legislative changes as well.
- 6.7 In an informal data request to NIPSCO subsequent to the election, NIPSCO was asked what its plans were vis-à-vis incorporating consideration of the election results. NIPSCO advised it had no plans to reconsider the IRP in light of the election results. The specific statement was that, NIPSCO did "not have plans to revise any scenarios based on any changes that occurred post-November 1." According to NIPSCO, "(a)n IRP Is a snapshot it time."
- 6.8 This position is inconsistent with the intent of the addition of Section 4-10 to Rule 7. Section 4-10 was added precisely to address unexpected changes subsequent to the preparation of an IRP that could have a significant effect.
- 6.9 It also appears to be contrary to NIPSCO's own position stated on Page 2 of the IRP. "It's important to note that due to this inherent uncertainty, our course of action is subject to change as new information becomes available."
- 6.10 The election of Donald Trump combined with the Republican retention of control of the Senate literally defines a "Substantial Unexpected Event" in the context of an IRP. Given the results of the IRP analysis are integrally tied to regulations that may now not go into effect which the IRP scenarios largely assumed, a justification for not reviewing the IRP results is hard to construct.
- 6.11 The ICC believes that if NIPSCO does not voluntarily revise its IRP to take into account the "Substantial Unexpected Event", the IURC staff, the IURC itself, and/or the legislature should consider advising NIPSCO to do so. Further, the ICC believes that NIPSCO should be advised that its recovery of the undepreciated capital and closing costs of its coal-fired power plants is at jeopardy because absent a review it has no basis that its recommended plan of action is least cost for ratepayers.

Attachment A. DRAFT PROPOSED RULE DATE JULY 5, 2016**TITLE 170 INDIANA UTILITY REGULATORY COMMISSION****Proposed Rule**

LSA Document #15-xxx

DIGEST

Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans and amends 170 IAC 4-8 to update the commission's rule regarding utilities' energy efficiency plans. Effective 30 days after filing with the Publisher.

170 IAC 4-7-0.5**170 IAC 4-7-1****170 IAC 4-7-2****170 IAC 4-7-2.1****170 IAC 4-7-2.2****170 IAC 4-7-2.5****170 IAC 4-7-2.6****170 IAC 4-7-2.7****170 IAC 4-7-3****170 IAC 4-7-4****170 IAC 4-7-5****170 IAC 4-7-6****170 IAC 4-7-7****170 IAC 4-7-8****170 IAC 4-7-9****170 IAC 4-7-10****170 IAC 4-8-1****170 IAC 4-8-2****170 IAC 4-8-3****170 IAC 4-8-4****170 IAC 4-8-5****170 IAC 4-8-6****170 IAC 4-8-7****170 IAC 4-8-8****SECTION 1. 170 IAC 4-7-0.5 IS ADDED TO READ AS FOLLOWS****170 IAC 4-7-0.5 Purpose and Applicability**

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 0.5 (a) The purpose of this rule is to provide the specific requirements for submission of utilities' integrated resource plans required by IC 8-1-8.5-3(e).

(b) This rule applies to a utility, as defined in this rule, unless otherwise noted. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-0.5*)

SECTION 2. 170 IAC 4-7-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-1 Definitions

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 1. (a) The definitions in this section apply throughout this rule.

(b) "Avoided cost" means the incremental cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP.

(c) "Candidate resource portfolio" means one of multiple long-term resource portfolios selected for further evaluation through the utility's portfolio screening process to determine the preferred resource portfolio.

(d) "Cogeneration facility" means the following:

(1) A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3.

(2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility.

(3) The transmission or distribution facilities necessary to conduct the energy produced by the facility to a user located at or near the project site.

(e) "Commission" means the Indiana utility regulatory commission.

(f) "Commission analysis" means the required state energy analysis developed by the commission under IC 8-1-8.5-3.

(g) "Contemporary issues" means any topic that may affect the inputs, methods, or judgment factors in an IRP and is common to the utilities. Topics may include, but are not limited to, the following:

(1) Economic.

(2) Financial.

(3) Environmental.

(4) Energy.

(5) Demographic.

(6) Customer.

(7) Methodological.

(8) Regulatory.

(9) Technological

(h) "Demand-side management program" or "DSM program" means a utility program designed to implement demand response, energy efficiency, or both.

(i) "Demand response" means a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions.

(j) "Demand-side resource" means one or more demand-side management programs.

(k) “Director” means an employee of the commission designated as the IRP director by the commission’s agency head appointed under IC 8-1-1-2(d).

(l) “Distributed generation” means an electrical generating facility located at or near a customer’s point of use, which may be connected in parallel operation to the utility system.

(m) “DSM costs” refers to all expenses incurred by a utility in a given year for operation of a DSM program, whether the cost is capitalized or expensed. Expenses include, but are not limited to, the following:

- (1) Administration.
- (2) Equipment.
- (3) Incentives paid to program participants.
- (4) Marketing and advertising.
- (5) Evaluation, measurement and verification.

(n) “Emission allowance” means the authority to emit one (1) unit of any air pollutant as specified by a federal or state regulatory system.

(o) “End-use” means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity

(p) “Energy efficiency” means reduced energy use for a comparable or improved level of energy service.

(q) “Energy service” means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

(r) “Energy storage” means a:

- (1) technology; or
- (2) set of technologies;

Capable of storing previously generated energy and discharging that energy as electricity at a later time.

(s) “Engineering estimate” means a calculated estimate of the change in energy (kWh) and demand (kW) resulting from a DSM program, accounting for dynamic interactions between or among the DSM programs.

(t) “FERC Form 715” means the annual transmission planning and evaluation report required by the Federal Energy Regulatory Commission (FERC), as adopted in 58 FR 52436, Oct. 8, 1993, and as amended by Order 643, 68 FR 52095, Sep. 2, 2003.

(u) “Firm wholesale power sale” means a power sale intended to be available to the purchaser at all times, including under adverse conditions, during the period covered by the commitment.

(v) “Integrated resource plan” or “IRP” means a utility’s document or documents submitted to the commission in order to meet the requirements of this rule.

(w) “Load research” means the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

(x) “Load shape” means the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

(y) “North American Industrial Classification System” or “NAICS” refers to the system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which a business is engaged.

(z) “OUCC” means the Indiana office of utility consumer counselor.

“Penetration” means the ratio of the number of a specific type of new appliances or end-use equipment installed to the total number installed during a given time.

(aa) “Power transfer capability” means the amount of power that can be transferred from one point or part of the bulk electric system to another without exceeding any reliability criteria pertinent to the utility.

(bb) “Preferred resource portfolio” means the utility’s selected long-term supply-side resource and demand-side resource mix that safely, cost-effectively, and reliably meets the electric system demand taking cost, risk, and uncertainty into consideration.

(cc) “Present value” means the current value of a future sum or stream of money, calculated by discounting the sum or stream of money by an interest rate.

(dd) “Program Participant” means a utility customer participating in a DSM program.

(ee) “Public advisory process” refers to the procedures in section 2.1 of this rule in which customers and interested parties have the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility’s IRP.

(ff) “Regional transmission organization” or “RTO” means the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the utility’s assigned service area as defined in IC 8-1-2.3-2.

(gg) “Renewable resource” means a renewable energy resource as defined in IC 8-1-8.8-10.

(hh) “Resource” means a facility, project, contract, or other mechanism used by a utility to assist in providing electric energy service to the customer.

(ii) “Resource action” means a resource change or addition proposed by a utility in a formally docketed commission proceeding.

(jj) “Risk metric” means a measure used to gauge the risk associated with a resource portfolio. As applied to the cost of a resource portfolio, risk metric includes measures of the variability of costs and the magnitude of outcomes.

(kk) “Saturation” means the ratio of the number of a specific type of similar appliances or end use equipment to the total number of customers in that class or the total number of similar appliances or end use equipment in use.

(ll) “Screening” means an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility’s preferred resource portfolio

(mm) “Short term action plan” means a schedule of activities and goals developed by a utility to begin efficient implementation of its preferred resource portfolio as required by subdivision 4(10) of this rule.

(nn) “Smart grid” means use of digital electronics, equipment, or data, and the associated communications networks, to monitor and control aspects of the electrical transmission and distribution system from generation to consumption.

(oo) “Supply-side resource” means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource may include, but is not limited to, the following:

- (1) A utility-owned generation capacity addition.
- (2) A wholesale power purchase.
- (3) Refurbishing or upgrading an existing utility-owned generation facility.
- (4) A cogeneration facility.
- (5) A renewable resource.
- (6) Distributed generation.
- (pp) "Utility" means:
 - (1) a public, municipally owned, or cooperatively owned electric utility; or
 - (2) a joint agency created under IC 8-1-2.2;

unless the utility is exempt under IC 8-1-8.5-7.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-1; filed Aug 31, 1995, 9:00 a.m.: 19 IR 16; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 3. 170 IAC 4-7-2 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-2 Integrated Resource Plan Submission

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2. (a) The following utilities, or their successors in interest, shall submit to the commission an IRP consistent with this rule according to the following schedule:

- (1) Hoosier Energy Rural Electric Cooperative shall submit an update of its 2014 IRP by November 1, 2016, consistent with subsection 10(b) of this rule.
- (2) Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company by November 1, 2016, and every three years thereafter.
- (3) Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative and Wabash Valley Power Association by November 1, 2017, and every three years thereafter.
- (4) Duke Energy Indiana, and Indiana Michigan Power Company, by November 1, 2018, and every three years thereafter.

(b) Upon request of a utility, the director may grant an extension of a submission deadline, for good cause shown.

(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:

- (1) The integrated resource plan.
- (2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.
- (3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following:
 - (A) A brief description of the utility's:
 - (i) existing resources;
 - (ii) preferred resource portfolio;

- (iii) key factors influencing the preferred resource portfolio;
- (iv) short term action plan;
- (v) the IRP public advisory process; and
- (vi) any additional details the commission staff may request.

(B) A simplified discussion of resource types and load characteristics.

The utility shall make the IRP summary readily accessible on its website.

(d) Contemporaneously with the submission of an IRP under this section, a utility shall provide to the director the following information:

(1) The name and address of each known individual or entity considered by the utility to be an interested party.

(2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information:

(A) A general description of the subject matter of the submitted IRP.

(B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 120 days of the IRP submittal.

An interested party includes any business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP. A utility is not required to separately notify all of its customers.

(3) A statement that the utility has served a copy of the documents submitted under subsection (d) of this section on the OUCC. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2; filed Aug 31, 1995, 9:00 a.m.: 19 IR 18; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; errata filed Jul 21, 2009, 1:33 p.m.: 20090819-IR-170090571ACA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 4. 170 IAC 4-7-2.1 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.1 Public Comments and Director's Reports

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.1. (a) A customer or interested party may comment on an IRP submitted to the commission. A comment must:

- (1) be in writing;
- (2) be received by the commission within ninety (90) days from the date a utility submits its IRP to the commission;
- (3) be electronically submitted to the director or as otherwise accepted by the directors;
- (4) clearly identify the utility upon which written comments are submitted; and
- (5) be provided to the utility using the utility contact information provided in the IRP.

(b) The director shall issue a draft report on the IRP no later than one hundred and fifty (150) days from the date a utility submits its IRP to the commission.

(c) Supplemental or response comments may be submitted by:

- (1) the utility;

- (2) a customer; or
- (3) an interested party.
- (d) Supplemental or response comments must be:
 - (1) in writing;
 - (2) received by the commission within thirty (30) days from the date the director issues the draft report;
 - (3) electronically submitted to the director or submitted through an electronic filing system if requested by the director; and
 - (4) provided to:
 - (A) the utility;
 - (B) each customer or interested party that submitted written comments; and
 - (C) the OUCC.
- (e) The director may allow additional written comment periods or extend the submission deadline for written comments or supplemental or response comments by notifying the utility and interested parties.
- (f) The director shall issue a final report on the IRP within 30 days following the deadline for supplemental or response comments.
- (g) The draft report and the final report shall:
 - (1) be limited to commenting on the IRP's compliance with the requirements of this rule;
 - (2) list all areas where the director believes the IRP fails to comply with the requirements of this rule; and
 - (3) not comment on:
 - (A) the desirability of the utility's preferred resource portfolio; and
 - (B) a proposed resource action in the IRP.
- (h) The director may extend the deadlines for issuance of the draft report and the final report by notifying the utility and interested parties.
- (i) Failure by the director to issue a draft or final report by the applicable deadline shall result in a presumption that the IRP complies with this rule.
- (j) Subject to IC 5-14-3 and any determination by the commission regarding confidentiality under 170 IAC 1-1.1-4, the commission shall make publicly available on the commission's website or other electronic document system:
 - (1) The utilities' IRPs.
 - (2) Written comments.
 - (3) Supplementary and responsive comments.
 - (4) The director's draft report.
 - (5) The director's final report. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.1*)

SECTION 5. 170 IAC 4-7-2.2 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.2 Resource Adequacy Assessment Report

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.2. (a) Each utility listed in subsection 2(a) of this rule shall provide to the director and the OUCC the resource adequacy assessment reported to a regional transmission organization within 25 days of the date reported or as otherwise agreed by the director. (b) A

utility providing information as required in subsection (a) shall explain any differences in the information provided under subsection (a) with the utility's most recent IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.2*)

SECTION 6. 170 IAC 4-7-2.5 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.5 Effects of Integrated Resource Plans in Docketed Proceedings

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.5. (a) The failure of an interested party to file comments under this rule shall not constitute a waiver of any right to participate as a party or to advance an argument or position in a formally docketed proceeding before the commission. Similarly, the content of comments filed by an interested party under this rule shall not preclude that party from advancing an argument or position in a formally docketed proceeding before the commission, whether or not that argument or position was raised in comments submitted under this rule.

(b) When a utility takes a resource action, it shall be consistent with the most recent IRP submitted under this rule, including its:

- (1) inputs;
- (2) data and assumptions;
- (3) methods;
- (4) models;
- (5) judgment factors; and
- (6) rationales used to determine inputs, methods, and risk metrics;

unless any differences between the most recent IRP and the resource action are fully explained and justified with supporting evidence, including an updated IRP analysis.

(c) Documents submitted to the commission or created pursuant to this rule may be used as follows:

- (1) To assist the commission in the preparation of the commission analysis.
- (2) In the preparation of a commission staff report in formally docketed proceedings before the commission.
- (3) As evidence in a formally docketed proceeding before the commission if admitted.

(*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.5*)

SECTION 7. 170 IAC 4-7-2.6 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.6 Public advisory process

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.6. (a) The following utilities are exempt from this section:

- (1) Indiana Municipal Power Agency;
- (2) Hoosier Energy Rural Electric Cooperative; and
- (3) Wabash Valley Power Association.

(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP.

(c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the OUCC, the commission, and its staff.

(d) The utility retains full responsibility for the content of its IRP.

(e) The utility shall conduct a public advisory process as follows:

(1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:

(A) An introduction to the IRP and public advisory process.

(B) The utility's load forecast.

(C) Evaluation of existing resources.

(D) Evaluation of supply and demand-side resource alternatives, including:

(i) associated costs;

(ii) quantifiable benefits; and

(iii) performance attributes.

(E) Modeling methods.

(F) Modeling inputs.

(G) Treatment of risk and uncertainty.

(H) Discussion seeking input on its candidate resource portfolios.

(I) The utility's scenarios and sensitivities.

(J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.

(2) The utility is encouraged to hold additional meetings as appropriate.

(3) The schedule for meetings shall be determined by the utility and shall:

(A) be consistent with its internal IRP development schedule; and

(B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.

(4) The utility or its designee shall:

(A) chair the participation process;

(B) schedule meetings;

(C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and

(D) develop and publish to its website meeting minutes within fifteen (15) calendar days following each meeting;

(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.

(6) The utility shall take reasonable steps to notify:

(A) its customers;

(B) the commission;

(C) interested parties; and

(D) the OUCC.

of its public advisory process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.6*)

SECTION 8. 170 IAC 4-7-2.7 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.7 Contemporary issues technical conference

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.7. (a) The commission or its staff may host an annual technical conference to facilitate:

- (1) identifying contemporary issues;
- (2) identifying best practices to manage contemporary issues; and
- (3) instituting a standardized IRP format.

(b) The agenda of the technical conference shall be set by the commission staff. Utilities, the OUCC, and interested parties may request commission staff include specific contemporary issues and presenters.

(c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed.

(d) Utilities shall discuss the designated contemporary issues in the next IRP if the contemporary issues were designated by the director at least one (1) year prior to the submittal date of the utility's IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.7*)

SECTION 9. 170 IAC 4-7-3 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-3 Waiver or variance requests

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-2-29; IC 8-1-2.2; IC 8-1-8.5-7; IC 8-1.5

Sec. 3. (a) A utility may request a variance from a provision of this rule for good cause.

(b) A request under this section shall:

- (1) Describe the situation which necessitates the variance.
- (2) Identify the provision of this rule for which the variance is requested.
- (3) Explain the difference between the expected effects of complying with this rule on the utility, its customers, and interested parties in the public advisory process if the variance is denied and the expected effect on the parties if accepted.
- (4) Explanation of how the variance is expected to aid the implementation of this rule.
- (5) A request shall be submitted in sufficient time that the IRP submittal schedule shall not be adversely affected.

(c) The director shall respond in writing regarding acceptance or denial of a request under this section within fifteen (15) calendar days. The request shall not be unreasonably denied, and any denials shall include the reason for the denial. If the director fails to respond within fifteen (15) calendar days, the request shall be deemed accepted.

(d) The request by the utility and the director's acceptance or denial shall be posted on the commission's website or other publically accessible electronic document system.

(e) An interested party may appeal to the full commission the director's acceptance or denial under this section. An appeal to the full commission must be filed with the commission in a docketed proceeding and provided to the utility, the OUCC, and other interested parties within thirty (30) days of the posting of the director's written acceptance or denial of the request.

(*Indiana Utility Regulatory Commission; 170 IAC 4-7-3; filed Aug 31, 1995, 9:00 a.m.: 19 IR*)

19; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 10. 170 IAC 4-7-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-4 Integrated Resource Plan Contents

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1; IC 8-1.5

Sec. 4. An IRP must include the following:

- (1) At least a 20 year future period for a predicted or forecasted analysis.
- (2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.
- (3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with subsection 5(b) of this rule.
- (4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.
- (5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis if performed.
- (6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with subsection 6(b) of this rule.
- (7) The resource screening analysis and resource summary table required in section 7 of this rule.
- (8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.
- (9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(c) of this rule.
- (10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.
- (11) A discussion of the:
 - (A) inputs;
 - (B) methods; and
 - (C) definitionsused by the utility in the IRP.
- (12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 5(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data:
 - (A) source title;
 - (B) author;
 - (C) publishing address;
 - (D) date;
 - (E) page number; and
 - (F) an explanation of any adjustments made to the data.

The data must be submitted within two weeks of submitting the IRP in an editable format, such as a comma separated value file or excel spreadsheet format.

(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following:

- (A) customer class;
- (B) rate class;
- (C) NAICS code;
- (D) DSM program; and
- (E) end-use.

(14) The database in subdivision (13) may be developed using, but not limited to, the following methods:

- (A) Load research developed by the individual utility.
- (B) Load research developed in conjunction with another utility.
- (C) Load research developed by another utility and modified to meet the characteristics of that utility.
- (D) Engineering estimates.
- (E) Load data developed by a non-utility source.

(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.

(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.

(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.

(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.

(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.

(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.

(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.

(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.

(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource portfolio.

(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria:

- (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the

resources required over the planning horizon to reliably and economically satisfy electrical needs.

(B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources.

(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable.

(D) Not include future resources, laws, or policies unless:

- (i) A utility subject to section 2.6 of this rule receives stakeholder input supporting the inclusion;
- (ii) Future resources have obtained all necessary regulatory approvals; and
- (iii) Future laws and policies have a high probability of being enacted.

A base case scenario need not align with the utility's preferred resource portfolio.

(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.

(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:

(A) The most current power flow data models, studies, and sensitivity analysis.

(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).

(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:

- (i) the limits of the utility's transmission use;
- (ii) the utility's assessment practices developed through experience and study; and
- (iii) operating restrictions and limitations particular to the utility.

(27) A list and description of the methods utilized by the utility in developing the IRP, including the following:

(A) For models used in the IRP, the model's structure and reasoning for its use.

(B) The utility's effort to develop and improve the methodology and inputs, including for its:

- (i) load forecast;
- (ii) forecasted impact from demand-side programs;
- (iii) cost estimates; and
- (iv) analysis of risk and uncertainty.

(28) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following:

(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.

- (B) The avoided transmission capacity cost.
- (C) The avoided distribution capacity cost.
- (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, environmental compliance costs, and transmission and distribution operation and maintenance.
- (29) A summary of the utility's most recent public advisory process, including:
 - (A) Key issues discussed.
 - (B) How the utility responded to the issues.
 - (C) A description of how stakeholder input was used in developing the IRP.
- (30) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-4; filed Aug 31, 1995, 9:00 a.m.: 19 IR 20; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 11. 170 IAC 4-7-5 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-5 Energy and demand forecasts

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 5. (a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:

- (1) Historical load shapes, including the following:
 - (A) Annual load shapes.
 - (B) Seasonal load shapes.
 - (C) Monthly load shapes.
 - (D) Selected weekly load shapes.
 - (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.
- (2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.
- (3) Actual and weather normalized energy and demand levels.
- (4) A discussion of methods and processes used to weather normalize.
- (5) A minimum twenty (20) year period for peak demand and energy usage forecasts.
- (6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following:
 - (A) Total system.
 - (B) Customer classes, rate classes, or both.
 - (C) Firm wholesale power sales.
- (7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.
- (8) Justification for the selected forecasting methodology.
- (9) For purposes of subdivisions (1) and (2) of this subsection, a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.

(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as:

- (1) Rate of change in population.
- (2) Economic activity.
- (3) Fuel prices, including competition.
- (4) Price elasticity.
- (5) Penetration of new technology.
- (6) Demographic changes in population.
- (7) Customer usage.
- (8) Changes in technology.
- (9) Behavioral factors affecting customer consumption.
- (10) State and federal energy policies.
- (11) State and federal environmental policies.

(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the on-going efforts to improve the credibility of the load forecasting process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-5; filed Aug 31, 1995, 9:00 a.m.: 19 IR 21; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 12. 170 IAC 4-7-6 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-6 Description of Available Resources

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated:

- (1) The net and gross dependable generating capacity of the system and each generating unit.
- (2) The expected changes to existing generating capacity, including the following:
 - (A) Retirements.
 - (B) Deratings.
 - (C) Plant life extensions.
 - (D) Repowering.
 - (E) Refurbishment.
- (3) A fuel price forecast by generating unit.
- (4) The significant environmental effects, including:
 - (A) air emissions;
 - (B) solid waste disposal;
 - (C) hazardous waste; and
 - (D) subsequent disposal; and
 - (E) water consumption and discharge;

at each existing fossil fueled generating unit.

- (5) An analysis of the existing utility transmission system that includes the following:

(A) An evaluation of the adequacy to support load growth and expected power transfers.

(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs.

(C) An evaluation of the potential impact of demand-side resources on the transmission network.

(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.

The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.

(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:

(1) Rate design as a resource in meeting future electric service requirements.

(2) Demand-side resources.

For potential demand-side resources, the utility shall include the following:

(A) A description of the potential demand-side resource, including its costs, characteristics and parameters..

(B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.

(C) The customer class or end-use, or both, affected by the demand-side resource.

(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings(E)

The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements.

(E) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.

(3) Supply-side resources. For potential supply-side resources, the utility shall include the following:

(A) Identification and description of the supply-side resource considered, including:

(i) Size (MW).

(ii) Utilized technology and fuel type.

(iii) Energy profile of non-dispatchable resources.

(iv) Additional transmission facilities necessitated by the resource.

(B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.

(C) A description of significant environmental effects, including the following:

(i) Air emissions.

(ii) Solid waste disposal.

(iii) Hazardous waste and subsequent disposal.

(iv) Water consumption and discharge.

(4) Transmission facilities as a resource. In analyzing transmission resources, the utility shall include the following:

(A) The type of the transmission resource, including whether the resource consists of one of the following:

(i) new projects

- (ii) upgrades to transmission facilities
- (iii) efficiency improvements; or
- (iv) smart grid technology.

(B) A description of the timing, types of expansion, and alternative options considered.

(C) The approximate cost of expected expansion and alteration of the transmission network.

(D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.

(E) A description of how:

- (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and

- (ii) RTO planning and implementation processes affect the IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-6; filed Aug 31, 1995, 9:00 a.m.: 19 IR 22; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 13. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of resources

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.

(*Indiana Utility Regulatory Commission; 170 IAC 4-7-7; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 14. 170 IAC 4-7-8 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-8 Resource portfolios

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 8. (a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following:

- (1) risk;
- (2) uncertainty;

- (3) regional resources;
 - (4) environmental regulations;
 - (5) projections for fuel costs;
 - (6) load growth uncertainty;
 - (7) economic factors; and
 - (8) technological change.
- (b) With regard to candidate resource portfolios, the IRP must include:
- (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.
 - (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s).
 - (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.
- (c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information:
- (1) A description of the utility's preferred resource portfolio.
 - (2) Identification of the standards of reliability.
 - (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.
 - (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following:
 - (A) safety;
 - (B) reliability
 - (C) risk and uncertainty;
 - (D) cost effectiveness; and
 - (E) customer rate impacts.
 - (5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, cost-effectively, and reliably meets the electric system demand taking cost, risk, and uncertainty into consideration.
 - (6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten (10) years of the planning period.
 - (7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following:
 - (A) Operating and capital costs of the preferred resource portfolio.
 - (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.
 - (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.
 - (D) The utility's ability to finance the preferred resource portfolio.
 - (8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following:

(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to:

- (i) environmental and other regulatory compliance;
- (ii) reasonably anticipated future regulations;
- (iii) public policy;
- (iv) fuel prices;
- (x) operating costs;
- (v) construction costs;
- (vi) resource performance;
- (vii) load requirements;
- (viii) wholesale electricity and transmission prices;
- (ix) RTO requirements; and
- (x) technological progress.

(B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.

(9) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following:

- (A) Demand for electric service.
- (B) Cost of new supply-side resources or demand-side resources.
- (C) Regulatory compliance requirements and costs.
- (D) Wholesale market conditions.
- (E) Fuel costs.
- (F) Environmental compliance costs.
- (G) Technology and associated costs and penetration.
- (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.

(10) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-8; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 15. 170 IAC 4-7-9 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-9 Short term action plan

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 9. (a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9), where the utility must take action or incur expenses during the three (3) year period.

(b) The short term action plan must include, but is not limited to, the following:

(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:

(A) The objective of the preferred resource portfolio.

(B) The criteria for measuring progress toward the objective.

(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq.* and consistent with the utility's longer resource planning objectives.

(3) The implementation schedule for the preferred resource portfolio.

(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.

(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-9; filed Aug 31, 1995, 9:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 16. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 IRP Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide the director an update regarding substantial, unexpected changes that occur between IRP submissions. Copies of an update shall be provided to the OUCC and other interested parties.

(b) Upon the request of the commission or its staff, the utility shall provide updated IRP information to the director, the OUCC and interested parties. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-10*)

ATTACHMENT B. ENTIRETY OF FUEL OUTLOOK IN IRP

- Fuel Commodity and Transportation: The options analysis utilized the correlated fuel commodity forecast for coal and natural gas. Natural gas pricing was assumed at Henry Hub and adjusted for the basis to the Chicago City Gate, plus transportation to burnertip. In order to obtain transportation rates, the pipeline tariff rates, along with storage and balancing rates, were escalated for transportation over time. For coal pricing, coal site specific costs were assumed at the mine mouth, and incorporated transportation costs to account for benefits or detriments associated with location, i.e., rail or barge. *See* Figures 8-3 through 8-5 for the fuel assumptions.

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4.1.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance of coal in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Recent energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower cost and highly efficient natural gas extraction processes (horizontal drilling and fracking) have caused an oversupply resulting in a reduction in natural gas prices. An increase in wet gas production to gather petroleum liquids over the past few years have further increased natural gas

supply. These dynamics are expected to keep natural gas pricing low in the near term. Longer term natural gas prices are expected to recover somewhat with the addition of new combined cycle natural gas generation and increased liquefied natural gas export capacity. This should allow coal pricing to move off of current levels in the long run.

Natural gas is currently displacing a significant amount of coal fired electric generation, driving lower coal prices. Decreased coal demand and higher mining costs driven by stringent government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies. The restructuring of coal companies' debts and other costs should allow them to produce coal in this low energy price environment for a period of time. Supply will likely be rationalized and any significant increase in demand could result in coal price volatility. However, the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal fired electric generation. This dynamic may limit coal demand upside and pricing.

In general, rising coal production costs and low coal prices have resulted in declining Appalachia coal production – a dynamic that has increased market share of the lower cost Illinois Basin (“ILB”) region, which includes locations in Indiana and generally produces a higher sulfur coal than coal mined in other regions. Several new mines have opened up in the ILB, particularly in Illinois. With its higher sulfur content, ILB coal is viewed as being a potential export resource, but also available for domestic use in generating stations that have installed flue gas desulfurization systems which nearly eliminate sulfur dioxide emissions. Southeast utilities are targeting ILB coal on a long-term basis as replacement for Columbian and Central Appalachia coal.

Powder River Basin (“PRB”) coal from Wyoming and Montana has a lower heat content per pound of coal than coal mined in other regions. Domestic utilities that have not traditionally burned PRB coal are now blending or are evaluating blending PRB coal with Central Appalachian, ILB, or Northern Appalachian (“NAPP”) coals to reduce their overall fuel costs. Prior to a softening in Asian economies (China in particular), Asian demand for PRB coal grew as Japan and China were building new, high efficiency coal units, and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad; however, the lack coal demand and the strong dollar have also nearly eliminated this market option for domestic coal producers.

Lastly, low energy prices and current and future environmental regulations will continue to put pressure on coal supply and coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices in subsequent planning activities.

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4.1.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Market demand for all coal, including ILB coal has decreased for reasons stated above; therefore, prices have steadily fallen. NAPP coal used by NIPSCO as a blend fuel in two of its cyclone units was historically heavily exported; however, the international demand for metallurgical and steam coal has been drastically reduced. Although NAPP coal has

had a robust market overseas, lethargic international demand and the stronger US dollar have caused export prices to collapse. NAPP producers have brought that supply back to the domestic market which helped drive prices lower. Pricing for PRB coal has also fallen and is close to the marginal cost of production. All coal pricing is expected to remain soft as long as energy prices stay low and the overhang of natural gas over supply will likely keep energy prices low, which will keep coal prices low for the balance of 2016 into 2017.

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Attachment C. SCENARIOS AND SENSITIVITIES ANALYZED IN NIPSCO IRP

2016 Integrated Resource Plan Scenarios And Sensitivities Variables Descriptions

Scenarios & Sensitivities		NIPSCO Load	CO ₂ Price	Natural Gas Price	Power Price	RPS
Base (B)		Base Load	Base	Base	Base	No
No CO ₂ Price (Bs1)		Base Load	No	Base No CO ₂	Base No CO ₂	No
Low Load (Bs2)		Low Load	Base	Base	Base	No
High Gas Price (Bs3)		Base Load	Base	High	High	No
Loss of Major Industrial Load (Bs4)		Base, Loss Major Industrial	Base	Base	Base	No
Challenged Economy (CE)		Low Load	Base	Low	Low	No
No CO ₂ Price (CEs1)		Low Load	No	Low No CO ₂	Low No CO ₂	No
Loss of Major Industrial Load (CEs2)		Low, Loss Major Industrial	Base	Low	Low	No
Aggressive Environmental Regulation (AE)		Base Load	High	High	High	No
High Renewables & Increasing Load (AEs1)		High Load	High	Very High	Very High	Yes
High Renewables & Decreasing Load (AEs2)		Low Load	High	Very High	Very High	Yes
Booming Economy (BE)		High Load	Base	High	High	No
No CO ₂ Price (BEs1)		High Load	No	Base no CO ₂	Base no CO ₂	No
Major Industrial Load (BEs2)		Base, Loss Major Industrial	Base	High	High	No
Base Delayed Carbon (BDC)		Base Load	Base BDC	Base BDC	Base BDC	No

Attachment D. BRIEF OF INDUSTRY PETITIONERS

No. 15-60821

**IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT**

**SOUTHWESTERN ELECTRIC POWER COMPANY; UTILITY WATER
ACT GROUP; UNION ELECTRIC COMPANY, doing business as Ameren
Missouri; WATERKEEPER ALLIANCE, INCORPORATED;
ENVIRONMENTAL INTEGRITY PROJECT; SIERRA CLUB;
AMERICAN WATER WORKS ASSOCIATION; NATIONAL
ASSOCIATION OF WATER COMPANIES; CITY OF SPRINGFIELD,
MISSOURI, by and through the Board of Public Utilities; DUKE ENERGY
INDIANA, INCORPORATED,**

Petitioners,

v.

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; GINA
MCCARTHY, in her official capacity as Administrator of the United States
Environmental Protection Agency,**

Respondents.

Petitions for Review of an Order of the Environmental Protection Agency

ORIGINAL BRIEF OF INDUSTRY PETITIONERS

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CERTIFICATE OF INTERESTED PERSONS

The undersigned counsel of record certifies that the following listed persons and entities as described in the fourth sentence of Rule 28.2.1 have an interest in the outcome of this case. These representations are made in order that the judges of this Court may evaluate possible disqualification or recusal.

Utility Water Act Group (“UWAG”),¹
Petitioner/Intervenor

Southwestern Electric Power Company (“SWEPCO”),
Petitioner

Union Electric Company (d/b/a Ameren Missouri) (“Ameren”),
Petitioner

Kristy A.N. Bulleit and Harry M. Johnson, III,
Counsel for UWAG, SWEPCO, and Ameren

City of Springfield, Missouri, by and through its Board of Public Utilities (“City Utilities”),
Petitioner

Thomas J. Grever,
Counsel for City Utilities

Duke Energy Indiana, Inc.,
Petitioner

Sean M. Sullivan,
Counsel for Duke Energy Indiana, Inc.

¹ UWAG is an energy utility industry group consisting of 211 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association.

Clean Water Action,
Intervenor

Environmental Integrity Project,
Petitioner/Intervenor

Sierra Club,
Petitioner/Intervenor

Waterkeeper Alliance, Inc.,
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American Water Works Association,
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National Association of Water Companies
Petitioner

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/s/ Harry M. Johnson, III
Counsel for Petitioner/Intervenor UWAG
and Petitioners SWEPCO and Ameren

STATEMENT REGARDING ORAL ARGUMENT

Petitioners Utility Water Act Group (“UWAG”), Southwestern Electric Power Company (“SWEPCO”), Union Electric Company dba Ameren Missouri (“Ameren”), City of Springfield, Missouri, by and through the Board of Public Utilities (“City Utilities”), and Duke Energy Indiana, Inc. (“Duke Energy”) (collectively, “Industry Petitioners”) respectfully request oral argument.

Oral argument is warranted for a number of reasons. This case involves the regulation of the wastewater of the steam electric power generating industry by Respondents United States Environmental Protection Agency and Gina McCarthy, in her official capacity as Administrator of the United States Environmental Protection Agency (collectively, “EPA”). The regulation is expected to cost the industry billions of dollars and impact our society in innumerable ways. Seven separate petitions for review were filed by diverse interests, including industry, environmental organizations, and other affected groups.

Moreover, the procedure by which EPA imposed this regulation is unprecedented and warrants special attention by the Court. Notwithstanding the mandate of the Administrative Procedure Act, 5 U.S.C. §§551-59, 701-06 (“APA”), for transparent and defensible rulemakings, EPA has withheld from the public record critical data, methodologies, and analyses purporting to support the final rule, claiming they are confidential business information. As such, oral

argument is necessary to scrutinize EPA's substantive conclusions underlying the rule, as well as its explanation for its procedural choices here.

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GLOSSARY OF TERMS AND ACRONYMS

AMP	American Municipal Power
APA	Administrative Procedure Act
BAT	Best Available Technology Economically Achievable
BATW	Bottom Ash Transport Water
CBI	Confidential Business Information
CCR	Coal Combustion Residuals
CPP	Clean Power Plan
CWA	Clean Water Act
ELGs	Effluent Limitations Guidelines
EPRI	Electric Power Research Institute
FGD	Flue Gas Desulfurization
FGDW	FGD Wastewater
GWW	Gasification Wastewater
ICPR	Incremental Costs and Pollutant Removals Report
IGCC	Integrated Gasification Combined-Cycle
MDS	Mechanical Drag System
NODA	Notice of Data Availability
NPDES	National Pollutant Discharge Elimination System

NSPS	New Source Performance Standards
O&M	Operation and Maintenance
ORP	Oxidation Reduction Potential
PRB	Powder River Basin
RIA	Regulatory Impact Analysis
RMDS	Remote Mechanical Drag System
TDD	Technical Development Document
TDS	Total Dissolved Solids
VCE	Vapor Compression Evaporation

JURISDICTIONAL STATEMENT

Industry Petitioners seek review of the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule (the “Final Rule” or “Rule”). The Rule was promulgated by EPA pursuant to several Clean Water Act (“CWA”) sections: 33 U.S.C. §§1311, 1314, 1316, 1317, 1318, 1342 and 1361. The Final Rule was published on November 3, 2015.²

This Court has jurisdiction under §509(b)(1)(E) of the CWA, 33 U.S.C. §1369(b)(1)(E) (2015), which provides that review of EPA’s actions in approving or promulgating any effluent limitation or “other limitation” under 33 U.S.C. §§1311, 1312, 1316, or 1345 may be had by any interested person in the Circuit Court of Appeals of the United States for the Federal Judicial District in which the person resides or transacts business that is directly affected by such action.³

Each Industry Petitioner filed in a Circuit Court in which it, or its members, transact business that is directly affected by the Final Rule.

² 80 Fed. Reg. 67,838-903 (Nov. 3, 2015).

³ See *Am. Petroleum Inst. v. EPA*, 661 F.2d 340 (5th Cir. 1981) (Court had jurisdiction under 33 U.S.C. §1369(b) to hear challenge to effluent limitations guidelines for the petroleum refining industry).

STATEMENT OF THE ISSUES PRESENTED FOR REVIEW

1. Did EPA violate the Administrative Procedure Act (“APA”) by withholding essential data, methodologies, and analyses from the public record as confidential business information (“CBI”)?
2. Did EPA violate the APA by relying on CBI materials not in the public record when responding to public comments?
3. Was it arbitrary and capricious for EPA to set limits applicable to plants burning subbituminous coal or lignite without collecting wastewater data or performing analyses necessary to determine whether those plants can achieve those limits?
4. Did EPA violate the APA by failing to provide the public any opportunity to comment on EPA’s analyses of the Clean Power Plan, which EPA relied on in the Final Rule as part of its statutorily-required consideration of cost?
5. Did EPA’s unexplained, differential treatment of the best available technology for gasification wastewater render the resulting limits, and its cost analysis of those limits, arbitrary and capricious?

STATEMENT OF THE CASE

Industry Petitioners seek review of certain provisions of the Final Rule, which was deemed issued for purposes of judicial review on November 17, 2015.⁴ Various petitioners filed seven petitions for judicial review in multiple U.S. Courts of Appeals. The petitions were consolidated in this Court.⁵

The Final Rule revises the technology-based wastewater discharge limits for the steam electric power generating industry. It sets new and stringent “effluent limitations guidelines” (“ELGs”) for hundreds of existing coal-fired power generating facilities, as well as more stringent new source performance standards (“NSPS”) for new sources. The CWA prescribes the factors EPA must consider in developing ELGs and NSPS. As with all rulemakings, EPA also must comply with rulemaking procedures under the APA, 5 U.S.C. §§551-559, 701-06.

EPA has violated both the CWA and the APA in its conduct of this rulemaking. The relevant history and factual context of the Final Rule follow.

I. EPA’s Development of Industry-Specific Effluent Guidelines and Standards

Sections 301 and 304 of the CWA, 33 U.S.C. §§1311, 1314 (2015), require EPA to establish, periodically review and, if appropriate, update ELGs for point source discharges from existing facilities in various industries. CWA §306, 33

⁴ 80 Fed. Reg. at 67,838.

⁵ Judicial Panel on Multidistrict Litigation, Consolidation Order, ECF#00513301255 (Dec. 9, 2015).

U.S.C. §1316 (2015), requires EPA to develop NSPS for new sources. Both ELGs and NSPS are technology-based. EPA sets these technology-based limits by promulgating nationally uniform, primarily numerical regulations for industry categories or subcategories of dischargers.⁶ Those limits and standards must be included in any National Pollutant Discharge Elimination System (“NPDES”) permit issued by EPA or a state permitting authority.

EPA first adopted ELGs for the steam electric point source category in 1974, soon after passage of the CWA.⁷ In 1982, the Agency finalized a major revision of the ELGs.⁸ In 2009, EPA initiated another major revision to the steam electric ELGs, and the resulting Final Rule is the subject of this litigation.

At issue are new ELGs based on the “best available technology economically achievable” (“BAT”) standard in 33 U.S.C. §1314(b)(2)(B). The statute requires EPA to take into account the following factors when establishing BAT limits.⁹

- age of equipment and facilities involved;
- the process employed;
- engineering aspects of the application of various types of control techniques;

⁶ See *E. I. du Pont de Nemours & Co. v. Train*, 430 U.S. 112, 121-22 (1977).

⁷ 39 Fed. Reg. 36,186 (Oct. 8, 1974).

⁸ 47 Fed. Reg. 52,290 (Nov. 19, 1982).

⁹ *Id.* §1314(b)(2)(B).

- process changes;
- cost of achieving effluent reductions;
- non-water quality environmental impact (including energy requirements); and
- “such other factors as the Administrator deems appropriate.”

Section 306 likewise requires consideration of cost and performance for NSPS.¹⁰

This litigation presents fundamental issues regarding the adequacy of EPA’s record support primarily on the performance and cost of technologies it selected for three specific wastestreams discussed below. The same arguments apply equally to the ELGs and the NSPS.

II. Development of the Final Rule

A. EPA Initiates ELG Rulemaking

In October 2009, EPA released a final report on its investigation of the industry for possible ELG revision.¹¹ This rulemaking, conducted pursuant to a schedule EPA negotiated with several environmental groups, ensued.¹² Among other things, the Agency collected wastewater characterization data and technology

¹⁰ See *id.* §§1316(a)(1), (b)(1)(B).

¹¹ Index.47. Documents from EPA’s Certified Administrative Record Index are cited herein as “Index.[ROA DOC.#].[pincite].” An appendix containing those portions of the administrative record cited by the parties will be filed separately in accordance with 5th Cir. R.30.2(a).

¹² See Consent Decree at ¶¶3-4, *Defenders of Wildlife v. Jackson* (D.D.C. Mar. 19, 2012) (No. 10-cv-1915), ECF#15.

performance information through an industry survey and through site visits and sampling events.¹³ On June 7, 2013, EPA published the Proposed Rule.¹⁴

B. EPA's Proposal

The Proposed Rule outlined regulatory options for further regulation of seven wastestreams, assessing each option's performance and cost.¹⁵ Three of those wastestreams—or effluent—are at issue here.

1. The Primary Wastestreams at Issue

The first is flue gas desulfurization (“FGD”) wastewater (“FGDW”). To meet air quality requirements, many coal-fired plants use FGD “scrubbers” to control sulfur dioxide emissions. In a wet scrubber, a slurry containing lime or limestone reacts with the sulfur in the flue gas to form calcium sulfite. Metals and other constituents arriving at the scrubber may end up in the scrubber slurry and intermittently leave the scrubber in the scrubber “blowdown” (*i.e.*, wastewater), which is categorized as FGDW.¹⁶ The characteristics of the resulting FGDW vary widely among plants and even over time at any given plant, according to a variety

¹³ See 78 Fed. Reg. 34,432, 34,444 (June 7, 2013) (“Proposed Rule”) (summarizing EPA’s sampling efforts).

¹⁴ *Id.*

¹⁵ *Id.* at 34,458, Table VIII-1.

¹⁶ *Id.* In addition to scrubber blowdown, EPA includes the following wastestreams in the definition of FGDW: “overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process.” 80 Fed. Reg. at 67,893 (to be codified at 40 C.F.R. §423.11(n)).

of factors, including most prominently the type of coal burned and its constituents, as EPA's record shows.¹⁷

The second wastestream at issue is bottom ash transport water ("BATW"). Plants generate BATW if they use water to sluice bottom ash¹⁸ out of the boiler to a treatment system. BATW generally flows from a hopper underneath the boiler through pipes to a surface impoundment or dewatering bin. In many cases, the system discharges to a surface water.

The third wastestream at issue is gasification wastewater ("GWW") from integrated gasification combined-cycle ("IGCC") units. IGCC is an electric power generation process combining technology that produces synthetic gas from coal with combined cycle systems that generate electricity using that gas.¹⁹ The production, cleaning, combustion, and cooling of synthetic gas can involve a number of processes resulting in GWW.²⁰

¹⁷ See, e.g., EPA, *Variability in Flue Gas Desulfurization Wastewater: Monitoring and Response*, Index.12006.15-16; see also *infra* at 53-54. EPA notes that "coal is the source of the majority of the pollutants that are present in the FGD wastewater (i.e., the pollutants present in the coal are likely to be present in the FGD wastewater)." Index.47.4-17.

¹⁸ EPA defines "bottom ash" in part as "the ash, ... which settles in the furnace or is dislodged from furnace walls." 80 Fed. Reg. at 67,893 (to be codified at 40 C.F.R. §423.11(f)). It defines "transport water" in part as "any wastewater that is used to convey...bottom ash...from the ash collection or storage equipment, or boiler, and has direct contact with the ash." *Id.* at 67,894 (to be codified at 40 C.F.R. §423.11(p)).

¹⁹ 78 Fed. Reg. at 34,448.

²⁰ GWW means "any wastewater generated at an [IGCC] operation from the gasifier or the syngas cleaning, combustion, and cooling processes." 80 Fed. Reg. at 67,894. It includes, but is not limited to: "[s]our/gray water; CO₂/steam stripper wastewater; sulfur recovery unit

2. EPA's Approach To Developing the Proposed ELGs

For each of these wastestreams, EPA assessed the amount of pollutants that candidate technologies were likely to remove and the pollutant limits each could achieve for all coal-fired power plants producing that wastestream.²¹

EPA also conducted a multi-step cost evaluation of the regulatory alternatives. First, EPA identified the universe or “baseline” of coal-fired plants that would incur costs to comply with any or all of the proposed ELGs. EPA excluded plants that EPA believed would retire or convert to gas before the Rule’s anticipated effective date.²² EPA then estimated the cost of the technology in question for each plant in the baseline.²³ Using those cost estimates, EPA evaluated the percentage of each plant’s revenue (and the revenue of any parent entity) that the cost would represent.²⁴ EPA also assessed the market impacts of the proposal. The Agency used various metrics to assess the likelihood that the

blowdown, and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal.” *Id.*

²¹ Index.2920.10-2 (consideration of technology pollutant removals), 13-3–13-4 (calculation of limitations).

²² *Id.* at 9-2 n.74.

²³ *See, e.g., id.* at 9-27–9-28 (presenting EPA’s estimate of “compliance costs for those generating units expected to be subject to the proposed ELGs” for FGDW).

²⁴ Index.2639.4-3,4-9.

Rule would affect generating capacity or cause premature retirements, among other things.²⁵ For this set of analyses, EPA used an “Integrated Planning Model.”²⁶

EPA’s cost analysis at proposal excluded certain elements. It did not include any assessment of the remaining useful life of the plants that were in the baseline and anticipated to bear compliance costs. EPA also did not include the economic impacts of another important rule affecting the same coal-fired plants: the Clean Power Plan (“CPP”) for greenhouse gases, which was under development but had not yet been formally proposed.²⁷

3. FGD Wastewater

EPA focused on a combination of two treatment systems for FGDW: chemical precipitation treatment (for mercury and arsenic) followed by biological treatment (for selenium and nitrate/nitrite).²⁸ These treatment systems are complex, multi-component technologies that must be designed and sized to treat a specific mix of pollutants, in terms of pollutant type, load, and distribution.²⁹ The use of biological treatment for FGDW treatment—and particularly for removal of selenium—is a relatively new innovation. The complexity and variability of

²⁵ *Id.* at 5-7.

²⁶ *Id.* at C-1–C-5.

²⁷ *See* 79 Fed. Reg. 34,830 (June 18, 2014).

²⁸ Proposed Rule, 78 Fed. Reg. at 34,458 (Table VIII-1).

²⁹ Index.2920.7-4–7-13 (EPA’s description of chemical precipitation and biological treatment technologies).

FGDW make it difficult to treat using biological processes, which depend on stable conditions to maintain the microorganisms on which treatment depends. For instance, changes in temperature or in wastewater constituents, such as percentage of solids or an increase in chlorides, can cause system upsets.³⁰

EPA relied on two steam electric plants using biological treatment to remove selenium: Belew's Creek and Allen.³¹ Both plants burn only bituminous coals.³²

EPA also assessed the performance of chemical precipitation treatment at those plants and four others. These included Pleasant Prairie, burning 100% subbituminous coal, and Hatfield's Ferry, burning a blend of bituminous and subbituminous coals.³³ But neither of those plants uses biological treatment, and EPA used no data from plants that burn lignite.³⁴ Thus, EPA lacked any data with which to assess the performance of biological treatment on FGDW produced by the roughly 25% of the industry that burns subbituminous or lignite coals.³⁵

EPA estimated the compliance costs of chemical precipitation and biological treatment for each facility by using cost curves from technology vendors and plant-

³⁰ See, e.g., Index.9123.21-23.

³¹ See Index.2920.13-5.

³² *Id.* at 3-11.

³³ *Id.*

³⁴ *Id.*

³⁵ See *id.* at 6-5 (Table 6-2).

provided wastewater flows data.³⁶ Much of the vendor cost information and some of the flow data were classified as CBI and not released. EPA likewise did not provide any information showing that it had investigated the underlying basis for the vendors' cost information.

Based on this information, EPA estimated that the 116 plants included in the baseline at proposal would incur industry-wide costs of \$2.5 billion in one-time capital expenditures and \$257 million in annual operation and maintenance ("O&M") costs.³⁷

EPA received many comments on the proposed rule, including extensive comments from UWAG.³⁸ Comments showed that EPA overestimated the feasibility and performance of both chemical precipitation treatment and biological treatment, even for the plants for which EPA had performance data.³⁹

With regard to biological treatment, commenters stressed that EPA had failed to account for the full range of variation in FGDW across the industry and at any given plant over time. In particular, comments noted that EPA lacked any information with which to assess the treatability of FGDW produced by plants

³⁶ See Proposed Incremental Costs and Pollutant Removals ("Proposed ICPR"), Index.2292.6-8,6-92.

³⁷ Index.2920.9-28.

³⁸ Index.9778.

³⁹ See *id.*

burning subbituminous or lignite coals, which are likely to have different characteristics from FGDW produced by the plants in EPA's database.⁴⁰

Even for plants burning bituminous coals, commenters explained that (1) EPA's selected technology was not demonstrated to be capable of handling the high nitrate loads typical of FGDW;⁴¹ and (2) EPA failed to consider the capability of biological treatment systems to handle higher chloride levels than occurred at Belews Creek and Allen.⁴²

Besides these concerns about the technologies' performance, commenters also raised significant questions about EPA's cost estimate.⁴³

4. Bottom Ash Transport Water

For BATW, EPA considered two options. The first was the status quo (allowing discharge subject to certain limits). The second was a prohibition against any discharge of BATW through the use of a technology located directly under the boiler (mechanical drag system ("MDS")) or a similar technology

⁴⁰ See, e.g., Index.9753.17-18; Index.8923.3.

⁴¹ See, e.g., Index.9778.203-04.

⁴² *Id.* at 165-67.

⁴³ See, e.g., Index.8689.160 (commenting that capital costs for retrofitting chemical precipitation plus biological treatment for some of Southern's plants would be up to \$1.7 billion, versus EPA's estimated \$253 million for those plants plus others of Southern's).

located away from the boiler (remote mechanical drag system (“RMDS”)).⁴⁴ Only RMDS requires water for bottom ash transport.

EPA calculated the cost of BATW compliance for the plants in its baseline (*i.e.*, those plants that EPA thought were not already complying with the proposed BATW discharge prohibition). EPA estimated that it would cost the industry \$4.47 billion in initial capital and \$494 million annually for O&M.⁴⁵

Commenters demonstrated that EPA had overestimated the feasibility and underestimated the costs of constructing and operating the BATW model technologies. In particular, the Electric Power Research Institute (“EPRI”)⁴⁶ and UWAG showed that EPA ignored engineering overhead, as well as the costs associated with constructing buildings to protect RMDSs from adverse weather events, and adding clarification and reaction tanks to remove fines, which some plants may need.⁴⁷ Also, as commenters pointed out, EPA failed to account for additional BATW storage capacity during major maintenance events.⁴⁸

⁴⁴ Index.12840.7-41–7-42. EPA identified the status quo as “preferred” for plants less than 400 megawatts. 78 Fed. Reg. at 34,435-36.

⁴⁵ Index.2920.9-40(Table 9-6).

⁴⁶ EPRI is an independent, non-profit organization that “conducts research and development on the generation, distribution and use of electricity for the benefit of the public.” <http://www.epri.com/About-Us/Pages/Our-Business.aspx> (last accessed Dec. 2, 2016).

⁴⁷ Index.9778.64 (UWAG); Index.8939.8-3,8-5 (EPRI).

⁴⁸ Index.8689 (Southern Company); *see also* Index.8692.3-4 (City Utilities) (space needs and costs for retrofitting would preclude retrofitting in some cases, particularly where facility housed two or more units).

5. Gasification Wastewater

IGCC facilities use two different types of waste treatment systems for GWW: a one-stage system, known as Vapor Compression Evaporation (“VCE”), and a two-stage system, in which the wastewater produced by VCE is further treated using “forced circulation evaporation” (also known as crystallization).⁴⁹ Two-stage treatment produces far less wastewater, but that wastewater (known as “Crystallizer Effluent”) has higher pollutant concentrations than does the wastewater from one-stage treatment (“VCE Effluent”), as EPA recognized when it evaluated essentially the same technology for FGDW. *Id.*

To develop the proposed GWW limits, EPA considered wastewater treatment data from two IGCC facilities: Wabash River (which uses one-stage treatment), and Polk (which uses two-stage treatment).⁵⁰ But EPA discarded Polk’s Crystallizer Effluent data because the Agency believed Polk’s crystallizer was malfunctioning at the time of sampling.⁵¹ Thus, the record is devoid of any data regarding the pollutant content of Crystallizer Effluent at IGCC facilities.

During EPA’s development of the proposed GWW limits, Duke Energy explained to EPA that its new Edwardsport facility would produce both VCE

⁴⁹ See Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (“Final TDD”), Index.12840.7-14–7-18 (discussion of FGDW treatment technologies equally applicable to GWW).

⁵⁰ Index.2920.13-5,13-20; Index.12840.13-7,13-26.

⁵¹ Index.2920.13-20; Index.12840.13-26–13-27.

Effluent and Crystallizer Effluent, and would combine them for further treatment in a reverse osmosis process before discharge.⁵² In its discussion of Two-Step Treatment at IGCC facilities, EPA had acknowledged that IGCC facilities might choose to reuse VCE Effluent and Crystallizer Effluent onsite, discharge both streams, or manage each stream separately, which is why the Agency sampled the treated effluent from both steps.⁵³

Puzzlingly, though, when EPA proposed the GWW limits, EPA ignored the pollutant contribution of Crystallizer Effluent to a combined GWW discharge and set the proposed limits based solely on VCE Effluent.⁵⁴ Moreover, EPA ignored the only valid data in the record about the relative pollutant content of VCE Effluent versus Crystallizer Effluent, *i.e.*, the data EPA obtained from the Brindisi plant regarding the ability of Two-Step Treatment to treat FGDW, which showed that the pollutant content of Crystallizer Effluent is higher than VCE Effluent.⁵⁵ Despite comments from industry expressing concern about the lack of sufficient IGCC-specific data in the record,⁵⁶ the numerous technical differences between the

⁵² NPDES Permit No. IN0002780, Duke Energy Indiana, Inc. – Edwardsport, Index.123.132.

⁵³ Index.2920.13-20; *see also* Index.12840.13-26.

⁵⁴ Index.2920.13-20; *see also* Index.12840.13-27.

⁵⁵ Index.2920.13-19; *see also* Index.12840.13-25–13-26.

⁵⁶ Index.8684.78-81 (Duke Energy) (discussing inadequacies of data set for setting reliably achievable GWW limits), 86-87 (noting Edwardsport did not begin commercial operation until June 2013 and that additional operational time was needed before reliable

limited number of IGCC facilities in operation,⁵⁷ and EPA's decision to set the GWW limits based solely on VCE Effluent,⁵⁸ EPA finalized the GWW limits as proposed.

C. EPA Develops the Final Rule

After the comment period closed, EPA engaged in extensive discussions and correspondence with vendors marketing technologies for treating FGDW and BATW. One example is reflected in "Post Proposal Questions for GE_for EPA Review," in which EPA asked follow up questions to GE "to clarify whether specific cost elements [identified by commenters] are included or not included in the cost estimates provided in previous correspondence."⁵⁹ In developing the Final Rule and responding to public comments, the record shows EPA relied heavily on the information it collected from those vendors. Yet that critical information was withheld from the record on the grounds that it is CBI.

performance data would be available); Index.9778.289-91 (UWAG) (discussing inadequacies of data set for setting reliably achievable GWW limits).

⁵⁷ Index.8684.77-78; Index.9778.287-89.

⁵⁸ Index.9778.290 ("Apparently EPA based the limits on condensate from a vapor compression evaporator, probably the cleanest wastestream that could be found..."); Index.8684.85-86 ("[T]he sampling events that EPA conducted focused only on effluent consisting of the vapor-compression evaporator condensate from the grey water treatment systems. It is inconsistent to then establish the same effluent limits for all other ancillary wastestreams ... based only on the sampling data from the narrow subset of grey water effluent data associated with the vapor-compression evaporation technology installed.").

⁵⁹ Index.11564.3.

Moreover, EPA doubled-down on its redaction of even basic methodological information. It classified large swaths of the record as CBI, most notably in the Final Sanitized Steam Electric Incremental Costs and Pollutant Loadings Report (“Final ICPR”). EPA removed entire sections from the Final ICPR, even though the same sections were not classified as CBI at proposal.⁶⁰ These included all of Section 5 (“General Methodology, Terminology, and Common Cost Elements”), Section 6 (“FGD Wastewater Cost Methodology”), Section 7 (“Fly Ash Transport Water Cost Methodology”), and Section 8 (“Bottom Ash Transport Water Cost Methodology”).

After the close of the comment period, EPA also undertook a fresh round of analyses that had the effect of removing more plants from the baseline, thereby making the economic impact of the Final Rule look far smaller. Among other things, EPA recognized the significance of the CPP Rule. The Agency re-ran its Integrated Planning Model to assess for the first time the impact of the proposed CPP Rule on the baseline.⁶¹ It also conducted a follow-up analysis on the implications of the final CPP.⁶² Neither of these analyses was made available for public comment. Departing from the practice it followed for other major

⁶⁰ Compare Proposed ICPR, Index.2292.§§5-8 (proposed cost methodologies spanning 217 pages), with Final ICPR, Index.12134.§§5-8 (an estimated 250 pages entirely withheld as CBI).

⁶¹ 80 Fed. Reg. at 67,866-67.

⁶² See Analysis of Potential Effect of Using a Baseline with the CPP Proposal in Lieu of the CPP Final, Index.12360.

environmental rules, EPA did not issue a Notice of Data Availability (“NODA”) for the ELG rulemaking when the CPP was proposed.⁶³ Based on its CPP analyses, EPA took 47 plants fully out of the baseline, and 19 partially out of it.⁶⁴

Besides consulting the vendors and removing more plants from the baseline, EPA obtained some additional information on biological treatment at the Belews Creek and Allen plants.⁶⁵ But EPA obtained no information on the extent to which biological treatment of FGDW from plants burning subbituminous or lignite coals could achieve the final selenium and nitrate/nitrite limits, nor did it evaluate the likely cost. And, EPA says that much of the post-proposal FGDW cost information is CBI.⁶⁶ Thus, the public has no access to the basic facts on which EPA relied and cannot reproduce its calculations.

⁶³ “Federal agencies routinely use NODAs to provide the public with an opportunity to consider and comment on emerging technical issues and data related to an ongoing rulemaking or other important environmental protection program.” EPA, Fact Sheet: Clean Power Plan Notice of Data Availability (Oct. 28, 2014), available at www.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-notice-data-availability (last accessed Dec. 2, 2016). *See, e.g.*, 79 Fed. Reg. 64,543 (Oct. 30, 2014), 79 Fed. Reg. 67,406 (Nov. 13, 2014) (two NODAs for CPP); 78 Fed. Reg. 46,490 (Aug. 2, 2013) (third NODA for Coal Combustion Residuals Rule).

⁶⁴ Index.12840.4-45 (Table 4-18).

⁶⁵ Index.11727 (Belews Creek data submittal of March 28, 2014); Index.11725 (Allen data submittal of March 28, 2014).

⁶⁶ *See, e.g.*, Supplemental Costs and Loadings Documentation Memorandum, Index.12183.7 (describing Index.12268, 12261, and 12262 (all CBI) as methodology to estimate sodium bisulfite O&M costs, derivation of oxidation reduction potential (“ORP”) monitor costing methodology, and correspondence with vendor regarding capital and O&M for ORP monitor, respectively).

For BATW, EPA claims that it added tank rental costs for “surge capacity” during bottom ash maintenance events, and that it updated or adjusted its direct and indirect capital cost factors.⁶⁷ However, it is impossible to see exactly what costs EPA assumed, because much of that information is CBI.⁶⁸

The Final Rule requires all plants discharging FGDW to meet new BAT limits for mercury, arsenic, selenium, and nitrate/nitrite.⁶⁹ The limits are the same across the industry without regard to coal type burned. The Rule also prohibits the discharge of BATW except in very limited circumstances,⁷⁰ and imposes limits on GWW.⁷¹

III. Industry Petitioners’ Motion To Complete the Record

Because EPA withheld so much basic information from the public record as CBI, certain industry petitioners⁷² filed a joint motion to complete the record.⁷³ The motion was filed long before briefing commenced on the merits. It sought to compel EPA to reconsider whether the information withheld as CBI in fact

⁶⁷ See 80 Fed. Reg. at 67,845.

⁶⁸ See, e.g., Index.12183.9 (describing Index.12275, 12281, and 12280 (all CBI) as cost equations and factors for bottom ash conveyance O&M costs, RMDS volume estimate for tank rental costs, and MDS/RMDS drag chain replacement frequency and cost, respectively).

⁶⁹ 80 Fed. Reg. at 67,894-95 (to be codified at 40 C.F.R. §423.13(g)(1)(i)).

⁷⁰ *Id.* at 67,896 (to be codified at 40 C.F.R. §423.13(k)(1)(i)).

⁷¹ *Id.* (to be codified at 40 C.F.R. §423.13(j)(1)(i)).

⁷² It was unnecessary for Duke Energy to join the motion because its separate petition for review does not depend on CBI.

⁷³ ECF# 00513560826.

qualifies as CBI, and to produce its methods and analyses in a non-CBI format for the public and the Court. EPA filed an opposition,⁷⁴ and the motion was initially denied by a single judge order.⁷⁵ Industry Petitioners then filed a motion for reconsideration by the full motions panel.⁷⁶ The panel ordered the motion to complete the record to be “carried with the case.”⁷⁷ Because the motion relates to information that EPA relied on in the Final Rule, but withheld from the public and Court, the motion is integrally related to Industry Petitioners’ arguments on the merits herein.

SUMMARY OF ARGUMENT

This is a case of first impression. Never before has EPA promulgated a rule while shielding such vast amounts of its basic work product from review. Here, EPA has invoked the concept of CBI to withhold facts, methods and analyses on which its conclusions depend. As an initial matter, this Court must decide whether an agency may use CBI as a justification for offering only bare conclusions without explaining how and why it reached its regulatory decisions. This Court must further decide whether an agency may rely heavily on information from equipment vendors with a significant financial stake in the outcome of the rule, but

⁷⁴ ECF# 00513661798.

⁷⁵ ECF# 00513686767.

⁷⁶ ECF# 00513695043.

⁷⁷ ECF# 00513769227.

then remove critical portions of that information from the public record under the guise of CBI.

The Final Rule is not inconsequential. It will force plant closures and have massive impacts on an industry that is vital to our nation's infrastructure. Yet, to an unprecedented extent, the Agency has withheld fundamental information purporting to justify the rule. EPA claims thousands of pages of the record are CBI that cannot be shared with the public or this Court, including the following:

- entire chapters of core documents with titles such as “General Methodology, Terminology, and Common Cost Elements,” and entire sections with titles such as “General Cost Methodology” and “Compliance Cost Methodology”;
- results from pilot and full-scale studies conducted specifically to test the effectiveness of EPA's proposed BAT; and
- basic cost information that the CWA requires EPA to consider.

On the record before the Court, the Final Rule is arbitrary and capricious because it lacks adequate justification and support. The pervasiveness of CBI is so great that the Rule must be vacated in its entirety.⁷⁸

That is not the only defect with the Rule. EPA took other impermissible shortcuts that resulted in an inadequate record or otherwise violated the APA.

EPA's overreliance on CBI also produced legally deficient responses to public comments. For instance, the responses repeatedly cite to information that

⁷⁸ Indeed, EPA has withheld so much information that neither Petitioners nor the Court can know the full extent of potential deficiencies of the Rule.

EPA solicited from vendors to respond to the comments, but EPA then withheld from the public record. Directing commenters to documents that are unavailable is effectively no response at all and violates the APA. Again, given the extent of the violation, vacatur is the appropriate remedy.

EPA also promulgated the Final Rule without gathering necessary data on certain types of plants covered by the Rule. EPA gathered no data whatsoever on the treatability of selenium and nitrates in FGDW produced by plants burning subbituminous coals, such as Powder River Basin coal (“PRB”), or lignite. These plants comprise upwards of 25% of the industry. EPA set stringent limits for selenium and nitrates based on use of biological treatment and applied those limits to all coal plants, regardless of the type of coal they burn. But those limits reflect no consideration of the likely performance and cost of biological treatment at plants burning subbituminous coals or lignite. Lacking data or any other credible evaluation of the likely performance and cost of biological treatment for their FGDW, EPA had no reasonable basis for concluding that those plants can comply with the limits. Consequently, irrespective of the other defects in the Rule, the FGDW limits must be vacated as applied to plants burning subbituminous or lignite coals.

In addition, in its haste to promulgate the Final Rule, EPA deprived the public of notice and opportunity to comment on a key issue. EPA acknowledges

that it relied on the CPP in its cost analysis for the Final Rule, but EPA never allowed the public the opportunity to comment on the CPP's impacts on ELG costs and compliance. Because this error implicates the entire Final Rule, the Rule should be vacated.

Finally, the limits on GWW from IGCC plants are arbitrary and capricious. Without any rational explanation, EPA used a methodology to set limits for GWW that conflicts directly with EPA's indistinguishable methodology for FGDW. This represents an additional reason why the GWW limits must be vacated.

STANDARD OF REVIEW

The Final Rule is an "agency action" subject to review under the APA, which provides for review of "[a]gency action made reviewable by statute and final agency action for which there is no other adequate remedy in a court...."⁷⁹ An agency action, such as the Final Rule, must be held unlawful and set aside if that action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law...."⁸⁰

In reviewing an agency's action, the Court must determine whether the action "bears a rational relationship to the statutory purposes" and whether "there

⁷⁹ 5 U.S.C. §704 (2015); see *ConocoPhillips Co. v. EPA*, 612 F.3d 822, 831 (5th Cir. 2010).

⁸⁰ 5 U.S.C. §706(2)(A) (2015); *Bennett v. Spear*, 520 U.S. 154, 154-55, 174-75 (1997).

is substantial evidence in the record to support it.”⁸¹ The Court must make a “searching and careful” review to determine whether an agency action is arbitrary and capricious.⁸²

ARGUMENT

I. EPA’s Sweeping Use of CBI To Withhold Its Methods and Analyses Has Deprived the Public and the Court of the Required Foundation for the Rule

EPA has withheld its most basic data, methodologies, and analyses from the public record under the guise of CBI. This is unacceptable and unprecedented. EPA has a duty to disclose the whole record of its action and to fully explain its course of inquiry, analysis, and reasoning. EPA has at its disposal tools that allow it to protect CBI, if necessary, yet EPA used none of them here, instead withholding at least 1,194 documents in whole or in part.⁸³

This is not harmless error. The missing documents constitute the facts and analyses EPA conducted both to respond to comments and to arrive at its final assessment of the cost and performance of technologies selected as BAT. EPA’s decision that the economic impacts render its BAT limits “economically

⁸¹ *Texas Oil & Gas Ass’n v. EPA*, 161 F.3d 923, 934 (5th Cir. 1998) (quoting *Mercy Hosp. of Laredo v. Heckler*, 777 F.2d 1028, 1031 (5th Cir. 1985)).

⁸² *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 416 (1971).

⁸³ See Certified Index to the Administrative Record. ECF#00513538746 (June 8, 2016). (CBI column indicating some, but not all, of document withheld as CBI, *see, e.g.*, Index.12136 (Appendix to Final ICPR containing EPA’s estimates of costs not accounting for the CPP, withheld in its entirety although indicated as not containing CBO in the index)).

achievable” depends on those facts and analyses, many of which it has hidden. In place of the details, EPA offers only summary conclusions, or *ipse dixits*.

A. EPA Has a Duty To Disclose the Facts on Which It Relied and To Fully Explain Its Reasoning

Only the record can supply a justification for the Final Rule. The Court may not presume EPA acted with a reliable and adequate foundation: “the grounds upon which the administrative agency acted” [must] be “clearly disclosed and adequately sustained” in the record.⁸⁴ “It is the Agency’s duty to ‘fully explicate its course of inquiry, its analysis, and its reasoning.’”⁸⁵ In *Pacific Fisheries*, the court remanded a portion of ELGs and rejected consideration of a study “vague[ly] referenc[ed]” in the record as support for EPA’s conclusion regarding effectiveness of BAT, where the record did “not disclose the analytic approach utilized” in the study, among other things.⁸⁶ Similarly, in *Tanners’ Council*, the Fourth Circuit set aside ELGs due to the lack of available record evidence to support them, lest the court “would have to trust completely EPA’s conclusions.”⁸⁷

⁸⁴ *SEC v. Chenery Corp.*, 318 U.S. 80, 94 (1943).

⁸⁵ *Ass’n of Pac. Fisheries v. EPA*, 615 F.2d 794, 820 (9th Cir. 1980) (Kennedy, J.) (quoting *Tanners’ Council of Am., Inc. v. Train*, 540 F.2d 1188, 1191 (4th Cir. 1976)).

⁸⁶ *Id.*; see also CBI_GE ABMet Pilot Study Report, Index.11966 (entirely withheld, and discussed nowhere in the public record); *NRDC v. EPA*, 808 F.3d 556, 574 (2d Cir. 2015) (remanding EPA’s issuance of CWA general permit setting effluent limitations based on BAT, where EPA actively worked to keep information about disfavored treatment technology out of record by “exclud[ing] or delet[ing] information” from the final report” of its own scientific advisory board).

⁸⁷ 540 F.2d at 1193.

As this Court has further explained, “[j]udicial review must be based on something more than trust and faith in EPA’s experience.”⁸⁸ “Courts...are no longer content with mere administrative ipse dixits based on supposed administrative expertise.”⁸⁹ Nor is an agency’s “presumption of regularity” a viable substitute for a complete record.⁹⁰

In short, the Court may not presume that EPA’s decision is supported by information withheld from the public record.

B. EPA Has Myriad Tools To Make the Whole Record Available Without Compromising CBI

EPA has available a variety of tools to present facts and analyses on which it relied, while at the same time protecting confidential information. It has used those tools in many other effluent guidelines rulemakings.⁹¹ EPA could, for instance, produce ranges of values, graphs, cost formulas or curves, discussions, or other analyses, as appropriate, to satisfy its obligations to present the “whole record” for review, including its methodologies and analyses, without disclosing

⁸⁸ *Am. Petroleum Inst.*, 661 F.2d at 349 (internal quotation omitted) (remanding ELGs for additional consideration and explanation of cost by EPA).

⁸⁹ *Id.*

⁹⁰ *Id.* at 348 (quoting *Overton Park*, 401 U.S. at 415) (“presumption is not to shield [agency’s] action from a thorough, probing, in-depth review”).

⁹¹ See, e.g., Development Document for Final Effluent Limitations Guidelines and Standards for the Iron and Steel Manufacturing Point Source Category (Apr. 2002), at 1-9, 14-3–14-6 (aggregating certain data in the public record and masking facility identities) (available at www.epa.gov/eg/iron-and-steel-manufacturing-effluent-guidelines-documents) (last accessed Dec. 2, 2016).

CBI.⁹² In *NRDC*, the court found that EPA had adequately explained its decision where it compiled CBI in the rulemaking record into a composite, anonymized non-CBI graph as part of the public record and discussed the graph “at some length.”⁹³

In addition, EPA could have simply taken the time to collect more data that are not CBI. It could have supplemented the CBI information with information from other sources or consultants who would not assert CBI. Likewise, EPA could have conducted or commissioned its own studies to independently verify the information claimed as CBI.

In other words, EPA is not handcuffed by CBI, as it may suggest. Instead, when EPA makes use of CBI, it must still fully explain in the public record both the facts found and its reasoning from those facts. It must support the rulemaking through the use of non-CBI data, methodologies, and analyses that satisfy the standard upon review.⁹⁴

⁹² See *NRDC v. Thomas*, 805 F.2d 410, 418 n.13 (D.C. Cir. 1986).

⁹³ *Id.*

⁹⁴ See *Nat’l Wildlife Fed’n v. EPA*, 286 F.3d 554, 565 (D.C. Cir. 2002) (economic analysis predicting bankruptcies and plant closures was adequate, even though it did not reveal firm-specific CBI, because anonymized non-CBI compilation provided all necessary information).

C. EPA Did Not Adequately Explain the Cost or Performance of BAT for FGD Wastewater or Bottom Ash Transport Water, and Is Hiding Behind CBI

Congress has limited EPA's discretion in the selection of BAT by identifying specific factors the Agency must consider.⁹⁵ Because BAT must be "economically achievable," one such factor EPA *must* consider is cost.⁹⁶ So, too, EPA must consider the performance of the technology at reducing pollutants.⁹⁷ Performance and cost go hand-in-hand, as improving performance may require adding more technology, which then increases cost.

EPA bears the burden of demonstrating that it considered the cost of the technology it chose as BAT and showing that the technology, at the cost EPA projected, will achieve the performance standards it set.⁹⁸ Here, EPA's explanation of its performance and cost estimates for the technologies it chose as BAT for FGDW and BATW are general conclusions with crucial detail missing.

At the proposed rule stage, EPA discussed these technologies and its methodologies and analyses for evaluating their cost. EPA provided significantly

⁹⁵ 33 U.S.C. §1314(b)(2)(B).

⁹⁶ *Id.* ("Factors relating to the assessment of best available technology shall take into account...the cost of achieving such effluent reduction....").

⁹⁷ *Id.* at §1314(b)(2)(A); *see E. I. du Pont de Nemours & Co.*, 430 U.S. at 131.

⁹⁸ *Am. Petroleum Inst.*, 661 F.2d at 356-57 (remanding EPA's promulgation of ELGs for further consideration of cost, where industry and EPA cost data differed significantly and EPA offered "no explanation and no support for [its] conclusions" regarding cost); *Am. Meat Inst. v. EPA*, 526 F.2d 442, 465 (7th Cir. 1975) (concluding that EPA could not rely on a technology as basis for limitation, where it was incapable of meeting the limitation without incurring "impractical and extremely expensive" costs not considered by EPA when selecting BAT).

more detail about its methodologies when it published the proposed ELG rule for public comment.⁹⁹ When EPA then took comments from the public, it learned—and in some instances even acknowledged—that its performance and cost analyses had shortcomings, overstating performance and understating cost.¹⁰⁰ This meant that EPA was required to collect additional information, make changes, and explain the changes in the Final Rule.

EPA's errors at proposal were not trivial. For example, comments showed that, industry-wide, the cost of installing biological treatment alone for FGDW would nearly exceed EPA's estimated costs for adding both biological treatment and chemical precipitation treatment.¹⁰¹ Indeed, one company's comments showed that the cost of installing EPA's selected FGDW treatment technology at its plants would be nearly seven times higher than EPA had estimated for a subset of those same plants.¹⁰² Similarly, EPRI was unable to replicate EPA's conclusions regarding the ability of biological treatment to remove pollutants from FGDW.¹⁰³

⁹⁹ *See, e.g.*, Index.2292.6-88-6-105.

¹⁰⁰ *See, e.g.*, Index.10081.6-665 (EPA agreeing with commenters who indicated that EPA should consider engineering-related costs and construction timelines associated with closed-loop bottom ash handling retrofits).

¹⁰¹ *See* Index.8939.A-25 (finding incremental biological costs of over \$2 billion).

¹⁰² Index.8689.160 (Southern Company).

¹⁰³ Index.8939.4-2.

Based on EPRI's calculations, EPA had overestimated pollutant removals for biological treatment by a factor of eight.¹⁰⁴

EPA's cost estimate for achieving no-discharge of BATW was likewise off by a wide margin. For example, after identifying a host of errors and omissions, EPRI calculated total industry capital costs for conversion from wet to dry ash handling, just for plants with a nameplate generating capacity above 400 megawatts, to be over \$6 billion and \$452 million in annual O&M costs – more than double EPA's estimate.¹⁰⁵

1. EPA Reacts to the Comments by Soliciting CBI from Vendors

EPA responded to these comments by soliciting revised information from financially interested vendors. These are the same vendors whose technology was at issue and who had incentives to tout their systems as effective and reasonably priced. Much of the revised information – *and how EPA incorporated it into the final analyses* – has been withheld from the public and the Court. Thus, neither Industry Petitioners nor the Court can determine whether EPA in fact corrected the original errors or whether the revised analyses are themselves rational. This flies in the face of the APA.

¹⁰⁴ *Id.* at 4-1.

¹⁰⁵ Index.8939.8-2.

EPA’s contacts with vendors demonstrate how EPA consciously chose to conceal the substance of its final cost analysis. EPA prepared follow-up questions for GE “to clarify whether specific cost elements [identified by commenters] are included or not included in the cost estimates provided in previous correspondence,” among other things.¹⁰⁶ GE responded to these questions, but that information has been withheld from the public record.¹⁰⁷

Notes of subsequent meetings and correspondence between EPA and GE are similarly missing from the public record, nearly always in their entirety. Presumably, these pertain directly to the questions identified by the public during the comment period.¹⁰⁸ Other key documents have been withheld in their entirety, such as:

- the updated cost curve supplied to EPA by GE in 2014;¹⁰⁹
- additional follow-up questions and answers between EPA and GE;¹¹⁰
- correspondence with GE regarding ABMet costing information;¹¹¹ and

¹⁰⁶ Post Proposal Questions for GE_for EPA Review, Index.11564.3.

¹⁰⁷ See CBI_GE Response to Post Proposal Questions, Index.11680.

¹⁰⁸ See, e.g., Notes from Call with GE Water on March 4, 2015, Index.11999 (redacted to effectively be of no use, e.g., “GE indicated [Redacted].”).

¹⁰⁹ CBI_Updated ABMet Cost Curve, Index.11888.

¹¹⁰ CBI_Email from Bill Bonkowki; RE: Clarification [sic] on Updated ABMet Costs from June 2014, Index.11906.

¹¹¹ CBI_Supplemental Costs and Loadings Attachment 75, Index.12258 (description found in metadata available at Regulations.gov, see <https://www.regulations.gov/docket?D=EPA-HQ-OW-2009-0819-5681> (last accessed Dec. 2, 2016)).

- summary of correspondence with GE regarding updated ABMet costing information as of 2014.¹¹²

These inaccessible documents go to the heart of how EPA addressed the cost issue.

2. In the Final Rule, EPA Offers Only Conclusions and Hides Its Cost and Effectiveness Data, Methodologies, and Analyses Behind CBI

a. Cost

Using CBI as a pretext, EPA has provided only its bare conclusions in the public record regarding many of its cost analyses. The Agency has not provided supporting detail for those analyses (anonymized or otherwise). Despite comments showing that EPA had omitted or grossly underestimated various costs for the proposed rule, and despite the fact that EPA added new technology requirements, these final costs inexplicably *decreased* on a per-plant basis for FGDW. The average capital cost per plant went from just over \$21.5 million for the Proposed Rule to approximately \$20.5 million for the Final Rule.¹¹³ And the average annual O&M costs went from approximately \$2.2 million to approximately \$1.4 million.¹¹⁴

EPA's revised cost figures cry out for explanation. Yet, EPA offers only its *ipse dixit* as support. EPA suggests that it considered public comments and

¹¹² CBI_Supplemental Costs and Loadings Attachment 76, Index.12259 (same as footnote 111).

¹¹³ Compare Index.2920.9-28 with Index.12840.9-32.

¹¹⁴ *Id.* (averages were calculated by dividing total industry cost by number of plants).

changed its analysis “where appropriate,” but without ever explaining *how*.¹¹⁵

EPA provides no detail that would allow any meaningful review.

Despite the requirement to explain what it did, EPA withheld the underlying data, methodologies, and analyses under the guise of CBI. For example, they are missing from EPA’s Final ICPR, which “describes the methodologies used to estimate plant-specific compliance costs...associated with installing and operating the various technologies and practices that make up the regulatory options considered by EPA to revise the existing ELGs.”¹¹⁶ Unquestionably, this document is central to EPA’s development of the Final Rule.

The Final ICPR is the only document that describes EPA’s consideration of costs and pollutant removals in full. The Final TDD refers directly to it for detailed explanations of EPA’s methodology. For example, the Final TDD summarizes EPA’s final method for estimating indirect capital costs, and cites Section 6.2.6.10 of the Final ICPR “for more details on the methodology.”¹¹⁷ Despite EPA’s express reliance on this key document, the referenced subsection has been redacted *in its entirety*.

¹¹⁵ See, e.g., Index.12840.3-20 (“EPA evaluated public comments to identify plant-specific operation and flow data and, where appropriate, used this information to revise estimates of compliance costs and pollutant removals for those facilities....”).

¹¹⁶ Index.12134.1-1.

¹¹⁷ See Index.12840.9-25. There is no section 6.2.6.10 of the Final ICPR identified in the table of contents in the public record. Presumably, EPA meant to cite to section 6.1.6.10, which the table of contents describes as discussing EPA’s indirect capital costs methodology.

In fact, EPA has withheld entire sections from the Final ICPR as CBI consisting of hundreds of pages of information.¹¹⁸ The table of contents reveals the titles of the missing sections and subsections, and those titles make clear the vital nature of the withheld information.¹¹⁹ In Section 5 alone, one can see that basic subject matter about cost has been redacted.¹²⁰

¹¹⁸ See Index.12134 (un-paginated placeholder between 4-35 and 9-1, noting that Sections 5, 6, 7, and 8 “have been removed from this document”).

¹¹⁹ See *id.* at ii-vii.

¹²⁰ *Id.* at ii-iii.

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According to its title, the missing Section 5 explains EPA’s “General Methodology, Terminology, and Common Cost Elements.” The missing subsections provide the “General Cost Methodology and Terminology” and other more specific cost methodologies. In addition to EPA’s final cost methodologies underlying the Final Rule, these sections identify and describe the technologies evaluated. In short, the titles of Section 5 and its subsections confirm that EPA has withheld basic cost information necessary to evaluate its methods and analyses.

The same is true for Sections 6 through 8. These sections lay out EPA’s methodologies for analyzing costs and technologies for treating FGDW, fly ash transport water, and BATW.¹²¹ As with Section 5, EPA included within these sections basic technology descriptions for multiple wastewater treatment options, as well as capital cost and operation and maintenance cost methodologies for each technology.¹²² EPA redacted *all* of these sections and subsections.

While these sections or subsections might contain some CBI, the underlying methodologies themselves are necessary to understanding what EPA did and why. In fact, the proposed version contains substantially more information than the final. This enabled the public to evaluate EPA’s cost methodologies in the Proposed ICPR, which provided 217 pages of methods and analyses in chapters 5, 6, 7, and 8.¹²³ By withholding these methods and analyses in the Final ICPR, EPA has deprived the public of the same ability to analyze the Final Rule.

These missing pages are critical to determining whether EPA’s promulgation of the Final Rule was reasonable. EPA’s Response to Comments alone cited the redacted portions of the Final ICPR *at least 53 times*—5 times to Section 5

¹²¹ *Id.* at iii-vii (Section 6, 7, and 8 entitled “FGD Wastewater Cost Methodology,” “Fly Ash Transport Water Cost Methodology,” and “Bottom Ash Transport Water Cost Methodology,” respectively).

¹²² *See, e.g., id.* (table of contents identifying redacted subsections entitled “Technology Description” for chemical precipitation for FGDW (Section 6.1.1), vector truck collection for fly ash transport water (Section 7.2.1), and MDS for BATW (Section 8.1.1)).

¹²³ *See* Index.2292.5-1-8-33.

(General Methodology, Terminology, and Common Cost Elements), 30 times to Section 6 (FGD Wastewater Cost Methodology), 4 times to Section 7 (Fly Ash Transport Water Cost Methodology), and 14 times to Section 8 (Bottom Ash Transport Water Cost Methodology).¹²⁴

Under the pretext of CBI, EPA has withheld over 250 pages in the Final ICPR presenting the Agency's cost methodologies for the Final Rule from the public record. No other document presents these methodologies in a way that allows them to be critically reviewed.¹²⁵ For example, the Final TDD is carefully crafted to provide only general narrative descriptions of "EPA's *approach* for estimating costs."¹²⁶ This is no substitute, for instance, for the actual "details on

¹²⁴ See, e.g., Index.10079.4-188 ("EPA disagrees with the commenter's assertion that EPA did not include capital expenditures for plants recycling a majority of their bottom ash transport water. EPA did. As discussed in Section 8.5 of the [Final ICPR], EPA included a one-time bottom ash management cost..."), 4-194 ("EPA disagrees with the commenter's assertion that EPA did not account for costs associated with jurisdictional regulatory approval and that EPA also fails to account for any equipment that may be retired or rendered obsolete. As discussed in Section 5.1 of the [Final ICPR], EPA includes costs associated with indirect capital costs.").

¹²⁵ Complete redaction of large ICPR sections calls into question whether the hidden data satisfies even minimal data reliability. At the proposal stage, EPA chose to use dubious 1980s BATW pollutant loadings data. When commenters objected, EPA removed these values from its loadings database. Index.10081.6-423. There is no reason to believe the hidden data in the Final Rule is any more reliable.

¹²⁶ Index.12840.9-33 (emphasis added); see, e.g., *id.* at 9-38 (describing EPA's cost methodology for converting to dry bottom ash MDS handling merely as "Total MDS Capital Costs = Conveyance and Intermediate Storage Equipment Costs + Direct Capital Costs + Indirect Capital Costs + Bottom Ash Disposal Costs").

the bottom ash cost *methodology*,” which is redacted from the ICPR.¹²⁷

As such, EPA has failed to explain its consideration of the cost of BAT under the CWA.

b. Effectiveness of BAT Technologies

EPA claims that “biological treatment [is] well-demonstrated” technology for the treatment of FGDW.¹²⁸ But the public record hardly supports such an overarching conclusion. Nothing in the public record demonstrates that biological treatment can treat all of the industry’s FGDW effectively.

For example, EPA’s reliance on CBI prevents any demonstration that biological treatment is effective when a plant’s FGDW contains high amounts of chloride. EPA acknowledges that “[c]hemical precipitation systems are typically not able to remove chlorides from FGD wastewater....”¹²⁹ This means that biological treatment systems must be able to handle whatever chloride is present in FGDW.

The public record establishes that chloride levels exceed 25,000 ppm at some plants discharging FGDW.¹³⁰ By comparison, the public record also suggests that biological treatment is not designed for chloride levels that high. At

¹²⁷ *Id.* at 9-37 (emphasis added) (citing to unavailable Final ICPR Section 8 for such details).

¹²⁸ 80 Fed. Reg. at 67,850.

¹²⁹ Index.12840.8-9.

¹³⁰ Index.10080.5-379.

the 2010 International Water Conference, GE described its ABMet biological treatment system—which EPA used as the basis for BAT—as “designed to handle chloride levels up to 20,000 ppm.”¹³¹ EPA’s explanation of the discrepancy is critical because the Agency established the Rule’s limits based only on plants with chloride levels less than 10,000 ppm.¹³²

Despite the evidence in the public record, EPA claims that the *non-public* “record demonstrates that...bioreactor systems can handle chloride levels of up to 30,000 ppm” or even 35,000 ppm.¹³³ But it is impossible for the Court or public to verify whether EPA’s statement has any basis whatsoever. EPA has withheld the document it claims demonstrates the system’s efficacy, even when the claims exceed the vendor’s own public statements. In any event, EPA relies entirely on GE’s unsubstantiated claims, not *EPA’s* analysis of them.¹³⁴

EPA also has withheld correspondence with the vendor that may undermine the claims regarding the general efficacy of biological treatment. In the two-page “Notes from Call with GE Water,” EPA has redacted nearly everything of value as

¹³¹ Index.9778.165-66 (citing Sonstegard, J., J. Harwood, and T. Pickett, “ABMet™: Setting the Standard for Selenium Removal,” 2010 International Water Conference, IWC-10-18, at 5). UWAG also noted that GE had privately advised EPRI that the system could handle up to 25,000 ppm chloride. *Id.* (explaining that 25,000 ppm has not been demonstrated anywhere). But, even if *that* level were demonstrated, nothing in the record demonstrates that the system could handle *higher* than 25,000 ppm.

¹³² *Id.* at 166.

¹³³ Index.12840.8-9 (citing CBI_Additional GE Response to Post Proposal Questions, Index.11781, and Index.10080.5-379).

¹³⁴ *See, e.g.,* Index.12006.8–9.

CBI regarding these issues.¹³⁵ The memorandum is striking. It suggests there are difficulties or, at the very least, important variables affecting the system's capabilities:¹³⁶

- “GE reports [Redacted]. While GE has [Redacted]. GE is [Redacted] to control oxidants and ORP.”
- “GE reports that thus far, any issues related to high oxidants or [Redacted]. GE believes these issues with [Redacted].”
- “The ABMet™ system can process wastewater with [Redacted] nitrate concentrations. [Redacted] with a membrane bioreactor (MBR) or stirred tank system with MBR to [Redacted] prior to treatment with the ABMet™ system. Alternatively, the ABMet™ system can be designed to [Redacted].”
- “EPA inquired about any existing biological treatment systems having operational issues. GE reported [Redacted].”
- “GE indicated [Redacted].”
- “EPA inquired about the mechanism used to remove selenium from the backwash stream. GE noted that [Redacted].”

Given these extreme redactions, the public record simply does not support EPA's conclusions.

D. EPA's Duty To Explain Is at Its Greatest When It Relies on Third-Party Vendors That Have a Financial Stake in the Outcome

As a general matter, EPA's duty to explain its reasoning is heightened when it relies on the expertise of outside parties. As this Court recently reiterated, EPA

¹³⁵ Index.11999.

¹³⁶ *Id.* at 1-2 (all redactions in original).

“is free to rely on outside experts to support its conclusions, [but] the level of deference owed to an agency’s conclusions is substantially diminished when the subject matter in question lies beyond the agency’s expertise.”¹³⁷

If EPA chooses to rely on outside vendors, the record must establish that the Agency critically analyzed the vendors’ information. “As long as [EPA] conducts its own independent and thorough review of the consultants’ report, the agency’s reliance on outside reports is within its discretion and does not change the standard of review.”¹³⁸ “An agency may not...reflexively rubber stamp information prepared by others.”¹³⁹ Because EPA’s verification of vendor-supplied information is not available anywhere in the record, EPA has not satisfied its obligation to establish *reasonable* reliance on the vendor information.

These imperatives should be at their highest when EPA relies on information supplied by *self-interested* vendors. EPA solicited information about the cost and performance of treatment technologies from the very vendors that would benefit financially from EPA’s designation of their technologies as BAT. EPA’s reliance

¹³⁷ *Texas v. EPA*, 829 F.3d 405, 432 (5th Cir. 2016).

¹³⁸ *Avoyelles Sportsmen’s League, Inc. v. Marsh*, 715 F.2d 897, 906 n.17 (5th Cir. 1983) (rejecting lower court’s decision to engage in *de novo* review, but suggesting nevertheless that more probing review is warranted if record does not reveal agency’s independent review of outside reports); *cf. Save Our Wetlands, Inc. v. Sands*, 711 F.2d 634, 642 (5th Cir. 1983) (under NEPA, “the agency was fully authorized to consider or even adopt the [outside report]. It must, however, independently verify the report.”).

¹³⁹ *Coliseum Square Ass’n, Inc. v. Jackson*, 465 F.3d 215, 236 (5th Cir. 2006), *cert. denied*, 552 U.S. 810 (2007) (internal quotation and citations omitted).

on these financially motivated vendors shows that the Agency itself lacks the necessary expertise.¹⁴⁰

As such, any deference owed to EPA's conclusory assertions regarding the cost and performance of BAT is "diminished and the agency must support its arguments more thoroughly than in those areas in which it has considerable expertise and knowledge."¹⁴¹ This is particularly true when confronted with well-supported arguments and studies in public comments.¹⁴² As this Court has held, EPA fails to fulfill "its obligation of...analysis" under the CWA when the Agency relies on studies or data that may "mask an important methodological flaw."¹⁴³ To survive judicial review, EPA must demonstrate—not merely assert—that the vendor information it relied on was accurate and that EPA independently verified the information and any analyses relying upon it.

By concealing the critical information from review as CBI, EPA utterly fails to meet this heightened standard.

¹⁴⁰ *See Texas*, 829 F.3d at 432 (EPA's very "reliance on an outside expert demonstrates" that it lacks the expertise). While EPA certainly has experience establishing effluent limitations based on, for instance, performance capabilities of wastewater treatment technologies as provided by vendors, EPA must provide enough detail to verify the reasonableness of its reliance on such information. This is the minimum that the APA requires.

¹⁴¹ *Id.* at 433.

¹⁴² *Id.* at 422-33 (merely "pointing to the report of [its] outside expert, does not detail why" EPA's regulation overcomes industry's concerns).

¹⁴³ *Am. Petroleum Inst.*, 661 F.2d at 356 (remanding ELGs).

E. EPA’s Failure To Explain Its Rationale Is So Egregious That It Warrants Vacating the Entire Rule

If an agency’s “finding is not sustainable on the administrative record made, then the...decision must be vacated and the matter remanded...for further consideration.”¹⁴⁴ Here, EPA has said *what* it believes, but it has not shown *why* it believes that.¹⁴⁵ Despite EPA’s reassurances in presenting its conclusions, the Agency has pointed to supporting information that has been withheld as CBI. Without access to that information, it is impossible to verify that EPA promulgated a defensible rule.

In light of the *systemic* failings by EPA to support and explain the Final Rule on the public record before the Court, the Court should vacate the Rule.

II. EPA Has Failed To Respond Adequately to Public Comments, Because Many of Its Responses Are Based on Information Withheld from the Public Record

EPA has failed to satisfy its obligations to respond to public comments. In its Response to Comments alone, EPA referenced documents withheld, in whole or part, nearly 300 times under the pretext of CBI.¹⁴⁶ At least 53 of those references are to sections removed from the Final ICPR, which contains EPA’s analysis of costs associated with the various technologies EPA considered and ultimately

¹⁴⁴ *Camp v. Pitts*, 411 U.S. 138, 143 (1973).

¹⁴⁵ See *Sierra Club v. EPA*, 167 F.3d 658, 663 (D.C. Cir. 1999) (“Although EPA said *that* it believed the combination of regulatory and uncontrolled data gave an accurate picture of...performance, it never adequately said *why* it believed this.”) (emphasis in original).

¹⁴⁶ EPA cited documents entirely withheld 165 times and partially withheld 112 times.

selected as BAT. These inaccessible documents, expressly referenced by EPA, are part and parcel of the Agency's Response to Comments.

EPA had the latitude to craft its responses and support them with whatever documentation it chose. It was not required to refer to CBI. EPA could have anonymized or sanitized the CBI, presenting the information in a non-confidential fashion. Instead, EPA forsook this opportunity, without justification or explanation.

Without the underlying documents referenced by EPA itself, the "responses" are reduced to summary conclusions. The responses cannot be verified or fully reviewed and, therefore, are legally inadequate. Referring commenters to unavailable CBI is effectively no response at all.

A. EPA Has a Duty To Respond to Public Comments

EPA must give "reasoned responses to all significant comments."¹⁴⁷ A response to comments is adequate only if it allows the reviewing court to determine whether the agency has "examine[d] the relevant data and articulate[d] a satisfactory explanation for its action including a rational connection between the facts found and the choice made."¹⁴⁸ As this Court has explained, the precise

¹⁴⁷ *PPG Indus., Inc. v. Costle*, 630 F.2d 462, 466 (6th Cir. 1980). See 5 U.S.C. §553(c) (2015); *Nat'l Wildlife Fed'n v. Costle*, 629 F.2d 118, 134-35 (D.C. Cir. 1980) ("*Costle*").

¹⁴⁸ *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal quotation and citation omitted).

“scope and degree of detail required by §553(c) depends on the scope and detail provided in the comments.”¹⁴⁹

Mere conclusions are insufficient.¹⁵⁰ Moreover, the agency must fully explain responses that reject significant comments, particularly where “the magnitude of the difference” between the commenter’s and agency’s figures “should have alerted the EPA to the possibility that the...objections...were well-founded.”¹⁵¹

B. If EPA Chooses To Rely on a Document in Its Response to Comments, EPA Must Defend the Document

An agency has the prerogative to respond to comments in whatever fashion it chooses, so long as it does so adequately.¹⁵² This prerogative extends to the selection of evidence in support of responses to comments. However, when an agency chooses to refer to other documents in its final decision, “the reasoning [in those documents] becomes that of the agency and becomes its responsibility to defend.”¹⁵³ As the Court explained, “the public interest in knowing the reasons for

¹⁴⁹ *Cent. & S. W. Servs., Inc. v. EPA*, 220 F.3d 683, 692 (5th Cir. 2000), *cert. denied sub nom. Util. Solid Waste Activities Group v. EPA*, 532 U.S. 1065 (2001).

¹⁵⁰ *Am. Mining Cong. v. EPA*, 907 F.2d 1179, 1190-91 (D.C. Cir. 1990).

¹⁵¹ *Texas v. EPA*, 499 F.2d 289, 309 (5th Cir. 1974), *cert. denied sub nom. Exxon Corp. v. EPA*, 427 U.S. 905 (1976).

¹⁵² *See United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 252 (2d Cir. 1977) (“The agencies certainly have a good deal of discretion in expressing the basis of a rule, but the agencies do not have quite the prerogative of obscurantism reserved to legislatures.”).

¹⁵³ *NLRB v. Sears, Roebuck & Co.*, 421 U.S. 132, 161 (1975).

a policy actually adopted by an agency supports” disclosure of the information in those documents.¹⁵⁴

C. EPA’s Express Reliance on Unavailable CBI in Its Responses to Comments Fails To Satisfy the APA

EPA cannot justify a rule by relying on reports, studies, or data withheld from the public record, even if referenced in its response to comments.¹⁵⁵ The following sections highlight just a few examples of this, where each “response” pertains to objections raised by the public about issues EPA is required to consider under the CWA. EPA’s consideration of, and response to, these objections is therefore of central significance to the Final Rule. EPA’s responses are plainly inadequate due to reliance on CBI.

1. EPA’s Responses Regarding the Impact of Facility Age on Its Selection of BAT

The CWA requires EPA to consider “the age of equipment and facilities involved” when selecting BAT.¹⁵⁶ In its comments, American Municipal Power, Inc. (“AMP”) questioned EPA’s claim “that the age of a plant or unit ‘by itself does not in general affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this

¹⁵⁴ *Id.*

¹⁵⁵ *Ass’n of Pac. Fisheries*, 615 F.2d at 819-20.

¹⁵⁶ 33 U.S.C. §1314(b)(2)(B).

rulemaking.”¹⁵⁷ AMP went on to note that “the age of a plant or unit *does significantly* impact the cost-effectiveness of any new regulatory controls..., as well as the overarching decision of its owner as to whether to make the retrofit or close the facility instead.”¹⁵⁸ AMP’s concern was “that EPA’s failure to establish subcategories (which could vary applicability based on unit age...) ... could needlessly add to the long list of closed coal units and thus negatively impact regional electric reliability....”¹⁵⁹

EPA publicly offers very little in response to this comment. First, it simply restates its original conclusory statement “that neither age nor location of a plant or generating unit ‘by itself in general affect the wastewater characteristics, the processes in place, or the ability to install and operate the treatment technologies evaluated as part of this rulemaking.”¹⁶⁰ Next, it asserts that “EPA’s analysis shows that all operations covered by the final rule can achieve the final limitations.”¹⁶¹

¹⁵⁷ Index.8765.2 (quoting Proposed Rule, 78 Fed. Reg. at 34,446).

¹⁵⁸ *Id.* (emphasis added).

¹⁵⁹ *Id.*

¹⁶⁰ Index.10078.3-590.

¹⁶¹ *Id.*

EPA supports these assertions entirely by reference to CBI.¹⁶² The response points to a document that has been withheld in its entirety—“CBI Memorandum: Steam Electric Effluent Guidelines – Evaluation of Potential Subcategorization Approaches.”¹⁶³ Because this is the only document EPA offers in its response to comments as containing the full explanation of its required consideration of age, the response is patently inadequate.¹⁶⁴

2. EPA’s Responses Regarding the Effectiveness of Biological Treatment

UWAG questioned in its comments whether biological treatment was demonstrated to effectively treat FGDW with high nitrate or selenium concentrations.¹⁶⁵ EPA again responded by referring to CBI. EPA claims that “GE has conducted a number of pilot and full-scale studies that have demonstrated the effectiveness of the biological treatment system in meeting nitrate-nitrite and selenium limits.”¹⁶⁶ In support of that statement, EPA cites only two documents,

¹⁶² *Id.* at 3-591 (citing DCN-SE05813). In its nearly 6,000-page long Response to Comments, EPA repeatedly refers the reader back to this response as proof of its consideration of age. *See, e.g.*, Index.10080.5-521.

¹⁶³ Index.12128. EPA also cites to Chapter 5 of its Regulatory Impact Analysis (“RIA”), which is irrelevant. *See* Index.10078.3-591. That chapter makes no mention of “age” at all. *See* Index.12842.5-1–5-26. The RIA certainly does not explain *why* or *how* EPA’s economic analysis eliminates age as a determining factor for projecting generating unit retirements, as EPA claims. *See id.* Nor does the RIA provide any reasoning in response to AMP’s comment that age significantly impacts the cost-effectiveness of new regulatory controls.

¹⁶⁴ *See* Index.12840.5-2 (briefly summarizing EPA’s consideration of age, but citing repeatedly to the same withheld memorandum for detailed explanation).

¹⁶⁵ Index.9778.148–50.

¹⁶⁶ Index.10080.5-447.

both of which are entirely withheld as CBI: “CBI_Additional GE Response to Post Proposal Questions,” and “CBI_GE Written Responses to Additional Follow Up Questions.”¹⁶⁷

Apart from CBI, EPA offers nothing to support its belief that “[t]he ability of the biological technology to effectively operate under varying conditions of chlorides, TDS and other characteristics is well-demonstrated by the record for the rule.”¹⁶⁸ EPA cites to recommendations on “how plants can (and should) ensure the proper operation of the treatment system, including steps that should be taken to condition the influent wastewater prior to the bioreactor.”¹⁶⁹ But even assuming that EPA’s recommended steps *might* help biological treatment systems treat high levels of selenium and nitrate, those steps do not *demonstrate* the ability of the system to meet the specific limits.

Given that the only possible demonstration is withheld as CBI, EPA has failed to respond to comments adequately.¹⁷⁰

3. EPA’s Responses Regarding the Costs of BAT

Most striking are EPA’s inadequate responses regarding the costs of BAT, and therefore overall costs of the Final Rule. In one remarkable example, UWAG

¹⁶⁷ *Id.* (citing Index.11781 and Index.11846, respectively).

¹⁶⁸ Index.10080.5-448. “TDS” means total dissolved solids.

¹⁶⁹ *Id.* at 5-447.

¹⁷⁰ Commenters also questioned whether EPA had adequately considered whether high chloride levels impeded biological systems. *See supra* at 38-40. As noted previously, EPA used CBI to withhold the information supporting EPA’s position. *Id.*

identified transcription errors in EPA's economic model that resulted in estimated costs being "*off by a factor of 10*, underestimating the overall capital costs for dry fly ash retrofits for the industry."¹⁷¹

EPA conceded these mistakes in its Response to Comments.¹⁷² EPA's cursory response says that it corrected its equations, but does not reveal the new equations themselves. And EPA does not show that these changes were actually made. Confirmation of this is presumably contained only in the withheld CBI sections of the Final ICPR.

Indeed, EPA frequently referenced withheld sections of the Final ICPR in its Response to Comments. For instance, EPA says that it considered all of the following when finalizing the Rule, yet offers no details as to *how* it did so:

- costs of jurisdictional regulatory approvals, and the impact of equipment retired or rendered obsolete;¹⁷³
- costs for a chemical addition system that will add a chemical reducing agent into the FGDW chemical precipitation system when needed to respond to elevated ORP levels;¹⁷⁴
- costs for the treatment and disposal of the backwash from the biological system in the chemical precipitation component of FGDW BAT;¹⁷⁵

¹⁷¹ Index.9778.96–98 (emphasis added).

¹⁷² Index.10081.6-234 ("EPA acknowledges the errors in the three capital cost equations....").

¹⁷³ Index.10079.4-194 (citing Final ICPR, Index.12134.§5.1).

¹⁷⁴ Index.10080.5-382 (citing §6.2).

¹⁷⁵ *Id.* at 5-384, 5-401 (citing §6.2).

- costs for additional instrumentation to allow for appropriate monitoring and control of FGDW characteristics entering treatment;¹⁷⁶ and
- costs for adequate staffing for O&M of the treatment system, as well as staffing associated with disposal of treatment residuals.¹⁷⁷

Commenters presented specific concerns about specific cost issues, yet

EPA's position is simple: "trust us."¹⁷⁸

Under the APA, EPA must show its work to enable the Court to "engage in a substantial inquiry."¹⁷⁹ EPA's repeated failure to respond adequately to comments is fatal to the Final Rule. Vacatur is the required remedy.¹⁸⁰

III. EPA Failed To Demonstrate That Biological Treatment is Technologically "Available" for Plants Burning Subbituminous or Lignite Coals

None of the plants on which EPA based its biological treatment-based limits burns subbituminous or lignite coal.¹⁸¹ Indeed, not one of the subbituminous- or

¹⁷⁶ *Id.* at 5-513 (citing §§6.1, 6.2).

¹⁷⁷ *Id.* at 5-401 (citing §6.2).

¹⁷⁸ *See also id.* at 5-537 ("The absence of cost curves due to the presence of CBI prevents EPA from comparing the differences between EPA's costs and the commenter's costs for the biological treatment system."). Similar concerns apply to the responses to comments about fly ash transport water. City Utilities warned in comments that EPA's conclusion that retrofitting controls was economically feasible was based on studies performed under vastly different fly ash market conditions that no longer existed. Index.8692.3 ("EPA's final EGU mercury rule and proposed coal combustion residual (CCR) rule have induced a chilling effect on the ash recycling market," such that "the cost-effectiveness of future dry flyash conversion projects should in no way be gauged by comparison to projects completed prior to the mercury MACT and CCR publication."). However, EPA's detailed cost methodology on this issue is withheld as CBI. *See* Index.12134 (entire section titled "Fly Ash Transport Water Cost Methodology" redacted).

¹⁷⁹ *Overton Park*, 401 U.S. at 415.

¹⁸⁰ *See* 5 U.S.C. §706(2); *Cent. & S. W. Servs.*, 220 F.3d at 692 (identifying limited circumstances, which are not present here, when remand without vacatur would be appropriate upon finding an agency's responses to comments inadequate).

lignite-burning coal plants in EPA’s database has biological treatment as part of its FGDW system, nor were any pilot test data for biological treatment available for such facilities in the record. Therefore, based on EPA’s record, *the Agency has not demonstrated—and cannot demonstrate—the feasibility of biological treatment for 16-25% of all plants subject to the new FGD limits.*¹⁸²

As this Court has stated, “EPA bears the burden of producing a reasonable basis on the record for its regulations.”¹⁸³ Here, as in *Chemical Manufacturers*, the decision to regulate FGDW discharged by these plants without any performance data for biological treatment is arbitrary and capricious and in violation of the statutory command that EPA consider those factors.

¹⁸¹ The Rule’s analytical database includes some data from Hatfield’s Ferry, a plant that at the time burned a blend of PRB and Eastern bituminous coal. However, that plant did not have a biological treatment system for its FGD wastewater. *See* Index.1653.1.3-5. It also includes data from We Energies’ Pleasant Prairie Plant which burns PRB coal but which also did not have biological treatment. *See* Index.9778.206.

¹⁸² EPA based its estimates of plants burning subbituminous and lignite coals on EPA survey data. The survey collected information through 2009. But at the final rule stage, EPA asserted that, after accounting for “announced retirements,” there were no lignite-burning plants discharging FGD wastewater. Index.10078.3-525. However, industry comments demonstrate that several lignite-burning plants are authorized to discharge FGD wastewater. *See* Index.9753.5.

¹⁸³ *Chem. Mfrs. Ass’n v. EPA*, 885 F.2d 253, 265 (5th Cir. 1989), *cert. denied sub nom. PPG Indus. v. EPA*, 495 U.S. 910 (1990) (vacating/remanding ELG where lack of performance data in the record for in-plant biological treatment meant EPA’s decision to derive limits for 20 pollutants based on in-plant biological treatment was “no more than an educated guess”).

A. Differences Among Coal Types Have Significant Implications for the Performance and Cost of Biological Treatment

According to EPA, out of 100 plants identified as discharging FGDW in 2009, 15 to 20 plants burn subbituminous coal and 1 to 5 burn lignite.¹⁸⁴ This is important because coals vary greatly not only in their price,¹⁸⁵ availability, and heating value, but also in the air emissions they produce when burned,¹⁸⁶ the applicability and performance of air emissions control technologies,¹⁸⁷ and the characteristics of wastewater resulting from use of those air emissions control technologies.¹⁸⁸ None of these facts is disputable.

Nor can there be any dispute that steam electric units are typically designed to handle a certain coal type or types. A unit designed to burn a subbituminous coal such as PRB coal cannot simply switch to burning bituminous coal. The same is true for lignite plants.

¹⁸⁴ Index.12840.6-5(Table 6-2). EPA also identified 10-15 plants that burn two or more coal types. *Id.* Whether those plants can meet the limits is also in question.

¹⁸⁵ *See, e.g.*, Index.12372.215 (listing coal prices by types—bituminous, subbituminous, lignite, and anthracite—for selected years from 1949-2011).

¹⁸⁶ Different coals contain differing amounts and combinations of pollutants, including sulfur, hydrogen chloride, and mercury, which are important factors for designing and operating air emission technologies and managing the resulting wastewaters. *See* Index.12377.9-12.

¹⁸⁷ EPA has acknowledged differences between electric generating units based on coal types in other rulemakings. In the Mercury and Air Toxics Rule, EPA set different hazardous air pollutant emission standards based on coal ranks. 79 Fed. Reg. 24,073, 24,088 (Apr. 24, 2013).

¹⁸⁸ Index.47.4-17 (noting pollutant concentrations in FGD scrubber purge vary due to, among other factors, “air pollution control systems operated upstream of the FGD system.”).

At no point over the course of this rulemaking did EPA purport to restrict, or consider the feasibility and cost of restricting, the type of coal a plant could burn or the type of air emissions control technology a facility might use in meeting applicable air emissions control requirements. Thus, each affected facility's choice of coal and its air emissions control technology must be taken as a given and not as a collateral factor that can simply be changed in order to achieve the ELGs.

B. FGD Wastewater from Subbituminous Coal is Very Different from FGD Wastewater from Bituminous Coal

EPA claims that subbituminous-burning plants can achieve the FGD limits because biological treatment systems provide “a mechanism to reduce selenium and nitrate/[nitrite]” and because the selenium and nitrate/nitrite present in FGDW, whether derived from bituminous or subbituminous coal, “is not different.”¹⁸⁹ The record refutes this flawed conclusion. The effectiveness and cost of wastewater treatment systems depend on the full pollutant “matrix”—that is, the specific mixture of pollutants as well as their individual characteristics—of the wastewater being treated.

The record demonstrates that FGDW from subbituminous-burning plants is substantially different from FGDW from bituminous-burning plants. The table below summarizes four-day average EPA data for FGDW exiting the chemical precipitation portions of the FGDW treatment systems at Allen and Belew Creek

¹⁸⁹ Index.10080.5-450–5-451.

Stations, which burn Eastern bituminous coal, and at Pleasant Prairie Power Plant, which burns PRB coal.¹⁹⁰ The table uses dissolved values after chemical precipitation, because biological treatment is designed to remove dissolved fractions of constituents.¹⁹¹ Allen and Belews Creek use both chemical precipitation and biological treatment to treat their FGDW,¹⁹² while Pleasant Prairie uses a chemical precipitation system.¹⁹³

For nitrates, the dissolved fraction of Pleasant Prairie's chemical precipitation effluent is more than *8 times* the values for both Allen and Belews Creek. For selenium, Pleasant Prairie's effluent is about *23 times* that of Allen and almost *twice* the Belews Creek value.¹⁹⁴

¹⁹⁰ At Belews Creek and Allen, this is a midpoint sample in the wastewater treatment system, prior to biological treatment. But at Pleasant Prairie, the sampling point is the end of the FGDW treatment system since it has no biological treatment.

¹⁹¹ See Index.1992.4-7–4-10(Table 4-2); Index.1954.4-16–4-18(Tables 4-4,4-5); Index.1966.4-12–4-14(Tables 4-3,4-4).

¹⁹² Index.1992.2-2; Index.1954.2-3.

¹⁹³ Index.1966.2-3.

¹⁹⁴ The record contains additional documentation of the substantial differences in FGD wastewater influent between bituminous and subbituminous plants. See, e.g., EPRI, *Pilot-Scale and Full-Scale Evaluation of Treatment Technologies for the Removal of Mercury and Selenium in Flue Gas Desulphurization Water*, Index.12102.3-4,3-5,3-8,3-23 (showing much higher selenium and nitrate levels for the subbituminous plant).

**Comparison of 4-Day Average FGDW Treatment After Chemical
Precipitation at Allen, Belews Creek, and Pleasant Prairie¹⁹⁵**

Analyte	Unit	4-Day Average Dissolved Effluent, Allen (E. Bituminous)	4-Day Average Dissolved Effluent, Belews Creek (E. Bituminous)	4-Day Average Dissolved Effluent, Pleasant Prairie (PRB)
Aluminum	(ug/l)	NQ ¹⁹⁶	ND	NQ
Arsenic*	(ug/l)	NQ	NQ	4.85
Boron	(ug/l)	58,600	150,000	9,930
Calcium	(ug/l)	1,750,000	3,490,000	639,000
Chloride	(mg/l)	3,300	7,780	1,950
Magnesium	(ug/l)	396,000	738,000	3,560,000
Manganese	(ug/l)	393	NQ	10,800
Mercury	(ng/l)	342	46,200	22.3
Nitrate/Nitrite	(mg/l)	13.3	19.8	160
Selenium	(ug/l)	91.1	1,210	2,080
Sodium	(ug/l)	31,300	48,900	518,000
Sulfate	(mg/l)	1,400	1,380	15,500
TDS	(mg/l)	7,560	20,100	22,400

*The pollutants highlighted are those for which EPA set new BAT limits.

In addition to the pollutants EPA chose to regulate, the values for many pollutants that EPA chose *not* to regulate—but which may affect the efficiency or proper operation of the treatment system—are also quite different. For instance, the 4-day average sulfate level in the Pleasant Prairie influent is more than 11

¹⁹⁵ Index.1992.4-7-4-10; Index.1954.4-16-4-18; Index.1966.4-12-4-14.

¹⁹⁶ “NQ” means the analyte was measured above the detection limit but below the quantitation limit for all four sampling days. “ND” means the analyte was below the detection limit and could not be quantified.

times that of Allen or Belews Creek. Sulfate levels can affect the operation of the system by causing calcium sulfate scaling, in which mineral deposits build up inside the treatment system's piping and equipment.¹⁹⁷ At Pleasant Prairie, even with lime addition as a pretreatment step, the remaining high sulfate levels necessitate weekly cleaning of the secondary clarifier.¹⁹⁸ Without this regular cleaning, "excessive scale would build up and affect the performance of the clarifier."¹⁹⁹ This scaling issue is likely to impact both the denitrification system²⁰⁰ EPA has added to the model technology treatment chain and the biological treatment system meant to target nitrate/nitrite and selenium removal.

The presence of high TDS also can complicate treatment of FGDW. Within the biological treatment system, high TDS may interfere with attachment sites for bacteria, lessening the effectiveness of treatment.²⁰¹ As indicated in the table above, EPA's 4-day average for Pleasant Prairie demonstrates a TDS level that is about 3 times that of Allen and also higher than Belews Creek. Data in the record

¹⁹⁷ Index.12102.4-3.

¹⁹⁸ Index.11876 (response to Question 19).

¹⁹⁹ *Id.*

²⁰⁰ EPA has not demonstrated the use of a denitrification system as part of FGD wastewater treatment at any plant burning subbituminous coal, even though it accounted for denitrification costs at Pleasant Prairie and Hatfield's Ferry (which burns a blend of subbituminous and bituminous coals). Index.12264.Worksheet-List_of_Plants. Nonetheless, EPA simply assumes the additional technology will not be subject to operational issues such as scaling.

²⁰¹ EPRI, Index.12102.4-4.

show that TDS levels can be as high as 50,000 mg/l,²⁰² which is approximately 6 *times* the Allen 4-day average and almost 2.5 *times* the Belews Creek average.

EPA tries to negate the TDS issue by pointing to a pilot study at Petersburg Station in which TDS “ranged as high as 27,000 mg/L.”²⁰³ But Petersburg burns bituminous coal, so its results are irrelevant for subbituminous- and lignite-burning plants. Moreover, since FGDW influent can contain TDS at levels almost double the amount documented at Petersburg,²⁰⁴ the pilot study fails to demonstrate that biological treatment systems can handle high TDS levels from subbituminous fuels equally as well as TDS levels from bituminous fuels.

Without data, it is not reasonable to *assume*—as EPA has done—that biological treatment systems will work for wastewater generated by subbituminous- and lignite-burning plants. The feasibility of biological treatment for subbituminous and lignite-burning plants must be demonstrated through actual data from these types of facilities.

C. Including Pleasant Prairie Data Does Not Remedy the Lack of Biological Treatment Data for Subbituminous Plants

Industry members commented extensively on the viability of biological treatment systems for subbituminous-burning plants. We Energies, the owner of

²⁰² Index.126.2-3.

²⁰³ Index.10080.5-365 (citation omitted).

²⁰⁴ Index.126.2-3.

Pleasant Prairie, commented that “nothing in the rulemaking record demonstrates that facilities burning subbituminous coal can meet the proposed selenium and nitrate/nitrite limitations.”²⁰⁵ The company urged EPA to “recalculate effluent limitations for FGD wastewater using a more robust set of data that represents the variability of FGD wastewater across the industry” and to include data from at least one plant burning solely subbituminous coals.²⁰⁶

In response, EPA explained that, between the proposed and final rules, it decided to include Pleasant Prairie data in the database used to derive FGD limits.²⁰⁷

By including Pleasant Prairie in the dataset, the effluent limitations are based on data that include plants burning bituminous coal, subbituminous coal, and blends of bituminous and subbituminous coals. The record demonstrates that the chemical precipitation plus biological treatment BAT basis is effective at removing the pollutants present in FGD wastewater regardless of the type of coal that is burned, and in particular those pollutants for which EPA is establishing effluent limitations. See, e.g., the pollutant removal performance for arsenic and mercury.

EPA’s response is misleading. The Pleasant Prairie data are relevant only to the mercury and arsenic limits, which are based on chemical precipitation. The facility did not have biological treatment. The performance of Pleasant Prairie’s chemical precipitation system as to arsenic and mercury is irrelevant to the

²⁰⁵ Index.8923.3.

²⁰⁶ *Id.*; see also Index.9778.116 (UWAG).

²⁰⁷ Index.10084.9-368.

performance of the biological treatment portion of the technology. Thus, EPA is wrong that “[t]he record demonstrates that the chemical precipitation plus biological treatment BAT basis is effective at removing the pollutants present in FGD wastewater regardless of the type of coal that is burned.”²⁰⁸

EPA further misleads by claiming: “The data in the record also shows that the biological treatment technology is effective at removing nitrate-nitrite and the different forms of selenium present in FGD wastewater; *that is proven true for every type of coal that has been tested with the technology.*”²⁰⁹ Note EPA’s qualified language: biological treatment is effective for “every type of coal *that has been tested with the technology.*” That is the point. Subbituminous and lignite coal have not been tested with the technology, and thus the *technology is not demonstrated for those coal types.* To set limits without appropriate supporting data is arbitrary and capricious.²¹⁰

²⁰⁸ Contrary to EPA’s assertion, it also has not demonstrated that plants burning a blend of bituminous and subbituminous coals can meet the selenium and nitrate/nitrite limits. The only plant burning a blend of coals during EPA’s sampling was Hatfield’s Ferry, which had no biological treatment system.

²⁰⁹ *Id.* (emphasis added).

²¹⁰ See *Chemical Mfrs.*, 885 F.2d at 265 (EPA failed to demonstrate a “reasonable basis for its conclusion” where it tried to use data from end-of-pipe biological treatment systems to justify in-plant biological treatment systems).

D. EPA’s Theorizing About the Efficacy of Biological Treatment is Nothing More Than an Impermissible “Educated Guess”

Lacking data, EPA nonetheless declares there is no “theoretical reason” why biological treatment would not be effective at plants burning subbituminous coal.²¹¹ It bases its “theoretical” judgment on two specious arguments.

First, EPA says that “[t]here is nothing unique about the form of selenium or nitrate-nitrite that is present in FGD wastewater at plants burning subbituminous (or any other type of coal). . . .”²¹² This statement misses the point. Although the specific types of selenium and nitrate/nitrite in FGDW may generally be the same across coal types, the differences between FGD *wastewater* from bituminous coals and that from subbituminous coals is significant. As shown by EPA’s own data for the Allen, Belews Creek, and Pleasant Prairie plants, the wastewaters differ in material ways.

Nonetheless, EPA simply asserts that “the characteristics of wastewater from subbituminous plants (as evidenced by the data for Pleasant Prairie. . . .) are similar to the characteristics of wastewater from plants burning bituminous coal (i.e., . . . Belews Creek. . . .)”²¹³ It is simply not true that all concentrations and characteristics of FGDW from subbituminous plants are similar to those for

²¹¹ Index.10084.9-368.

²¹² *Id.*

²¹³ *Id.*

bituminous plants.²¹⁴ But even if they were “similar,” comparing pollutant concentrations is not sufficient for demonstrating that biological treatment is feasible and available for subbituminous and lignite plants.

Second, the Agency claims it considered and ruled out whether other pollutants or wastewater characteristics unique to subbituminous coal would potentially interfere with biological treatment.²¹⁵ With this statement, EPA waves away possible operational difficulties from scaling (as can be caused by high sulfate levels) or from high TDS (which can potentially impact biological treatment performance). Yet, these problems occur at facilities burning subbituminous coals, and EPA’s responses on the record are inadequate, as discussed above.

It is telling that EPA urges all plants to perform site-specific pilot studies before installing FGDW equipment.²¹⁶ These studies are necessary, according to EPA, to assess wastewater characteristics and determine the most appropriate technologies and their design (*e.g.*, sufficient capacity and residence time) to handle the variability of the particular FGD wastewater.²¹⁷ EPA specifies that the studies should be conducted “over a long enough period of time that will include

²¹⁴ *See supra* at 54-58.

²¹⁵ Index.10084.9-368.

²¹⁶ Index.12006.14-16.

²¹⁷ *Id.*

variability in plant operations such as shutdowns, fuel switches (preferably for all fuel types burned at the plant), variability in electricity generating loads, periods with high [oxidation reduction potential], etc.”²¹⁸ These pilot studies are necessary because of the unpredictable variability of FGDW.²¹⁹ EPA recommends that a plant “identify the ‘worst case’ scenario and design a sufficient FGDW treatment system that can operate under the worst case conditions and achieve the effluent limits.”²²⁰

In short, EPA acknowledges the uniqueness of each FGDW at each given plant. This acknowledgement demonstrates that EPA could not have taken into account all of the site-specific technologies needed to achieve the final effluent limits for FGD wastewater. Without a full consideration of site-specific design factors, EPA could not have properly derived costs for FGD compliance at all facilities.

For lignite, EPA claims its data are “representative of the plants discharging FGD wastewater.”²²¹ Even though EPA’s survey documented 1-5 lignite plants discharging FGDW, the Agency claims that, once “announced retirements” are

²¹⁸ *Id.* at 15–16.

²¹⁹ GE, a vendor of biological treatment systems, acknowledges the “*extreme variability* in effluent quality [i.e., FGD wastewater influent to the treatment system] due to the variety of coal sources, limestone sources, and scrubber operation....” J. Sonstegard, et al., ABMet: Setting the Standard for Selenium Removal, Index.250.2 (emphasis added).

²²⁰ Index.12006.16.

²²¹ Index.10078.3-525.

accounted for, there are no lignite plants discharging FGDW.²²² But, as Luminant informed EPA, although its lignite plants had not discharged FGDW in some time, the plants are fully authorized to discharge FGDW.²²³ Clearly, the ability to discharge FGDW is important to those plants. Otherwise, they would not retain that flexibility in their permits. Luminant also explained to EPA that lignite “is a basic fuel in the Texas fleet.”²²⁴

EPA also retorts that commenters provided no data demonstrating that subbituminous- or lignite-burning plants would be unable to meet the effluent limitations.²²⁵ Since no subbituminous- or lignite-burning plants have installed the biological treatment system that EPA claims is BAT, it would be difficult indeed to produce such data. But that is beside the point. The burden is on EPA to demonstrate that the BAT technology is technologically “available” for the whole industrial category.

In any event, the law does not tolerate rules based on theoretical possibilities. A strikingly similar issue arose in this Court.²²⁶ There, industry challenged effluent limitations based on biological treatment, just as in this case.

²²² *Id.*

²²³ Index.9753.5.

²²⁴ *Id.* at 18.

²²⁵ Index.10080.5-166, .10078.3-525.

²²⁶ *See Chem. Mfrs.*, 885 F.2d 253 (remanding portions of ELG for the organic chemicals, plastics, and synthetic fibers industries).

EPA designated in-plant biological treatment as the model BAT technology.²²⁷

However, EPA had no data from in-plant biological treatment systems, just as here there is no performance data for biological treatment systems at plants burning subbituminous or lignite coals. Instead, EPA “relied on a data base consisting solely of three end-of-pipe biological treatment plants.”²²⁸ In the case at hand, EPA relies on data from two biological treatment systems located at plants burning *bituminous* coals to set the selenium and nitrate/nitrite limits at issue.²²⁹ In *Chemical Manufacturers*, industry petitioners explained that the detention time for the three end-of-pipe treatment systems used to derive the limits exceeded the maximum time used by EPA to estimate the costs of in-plant treatment systems. Therefore, industry claimed, EPA had not demonstrated that the limits could be achieved since “detention time is a key variable determining the effectiveness of biological treatment....”²³⁰

EPA tried to justify its use of end-of-pipe treatment data by noting that the in-plant and end-of-pipe systems use similar biological processes and treated comparable wastestreams. EPA also claimed that the concentration of biodegrading organisms in the aeration basin would decrease the amount of

²²⁷ *Id.* at 264.

²²⁸ *Id.*

²²⁹ Index.12840.13-39.

²³⁰ *Chem. Mfrs.*, 885 F.2d at 265 (footnote omitted).

detention time necessary to reach the prescribed level of treatment.²³¹ But this Court was unmoved by these factors. It found that “the record contains no performance data for in-plant treatment of the twenty priority pollutants at issue....”²³² The court rejected EPA’s theoretical point about the concentration of biodegrading organisms affecting detention time as “no more than an educated guess.”²³³ EPA failed to “make clear exactly what level of pollution would result from any given combination of shorter detention time and increased [concentration of biodegrading organisms].”²³⁴ The Court thus found that EPA had not demonstrated a reasonable basis for its conclusion that in-plant biological treatment would be as effective as end-of-pipe biological treatment.²³⁵

In the case at hand, EPA is also guessing. It says there is no evidence of possible interferences with biological treatment stemming from FGDW derived from subbituminous coal.²³⁶ But that is a theoretical judgment unsupported by any performance data. It says a “well operated” PRB-burning plant should have no

²³¹ *Id.*

²³² *Id.*

²³³ *Id.*

²³⁴ *Id.*

²³⁵ *Id.*

²³⁶ Index.10084.9-368.

issues meeting the limits.²³⁷ Again, that is all theory, unsupported by any credible analysis.

With as much as 25% of the coal fleet dependent upon subbituminous or lignite coals, EPA's speculation is no small matter. It is certainly not clear "exactly what level of pollution" would result from applying biological treatment at subbituminous- and lignite-burning plants.²³⁸ For these reasons, EPA's FGDW limits must be vacated as to subbituminous- and lignite-burning plants.

IV. EPA's Failure To Solicit Comments Before Stripping Plants from the Baseline Violated the APA and Undermined EPA's Economic Impact Assessment

EPA undertook significant analyses of the CPP's impacts on the Final Rule without notice or public comment.²³⁹ Based on those analyses, it stripped 47 plants out of the baseline entirely, and another 19 partially. This allowed the Agency to substantially reduce its estimate of the number of plants that would close, convert to gas, or change their ash management practices as a result of the Final Rule, which in turn profoundly affected the Agency's assessment of the Rule's economic impact on the industry. It also deprived the Industry Petitioners and the public of any opportunity to raise questions about the accuracy of EPA's assessment, or to understand and address the assumptions EPA made about the remaining useful life

²³⁷ Index.10080.5-148. If, in the absence of data, it is sufficient merely to say that a "well operated" plant should be able to meet a limit, then EPA could justify any conceivable limit.

²³⁸ *Chem. Mfrs.*, 885 F.2d at 265.

²³⁹ Index.12840.4-45.

of facilities that EPA projected would stay open beyond its chosen compliance deadline of December 31, 2023 (but not necessarily very far beyond that date). By failing to provide for public comment on its CPP analyses, EPA violated the APA. The Rule must be vacated and remanded to EPA to consider public comments because EPA's analyses implicate the entire Rule.

A. The APA Requires EPA To Solicit Comments on Significant New Information That Arises After the Close of the Comment Period

Under the APA, EPA must set forth in its notice of proposed rulemaking “either the terms or substance of the proposed rule or a description of the subjects and issues involved.”²⁴⁰ “The notice should be sufficiently descriptive of the ‘subjects and issues involved’ so that interested parties may offer informed criticism and comments.”²⁴¹

As this Court has explained, “fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency.”²⁴² “[I]f new data are considered after the agency receives comments on the data it initially provides, the nature of the change...in the newly-considered data determines whether it must again publish notice and invite

²⁴⁰ 5 U.S.C. §553(b)(3).

²⁴¹ *Ethyl Corp. v. EPA*, 541 F.2d 1, 48 (D.C. Cir. 1976) (en banc), *cert. denied*, 426 U.S. 941 (1976).

²⁴² *Chem. Mfrs. Ass’n v. EPA*, 870 F.2d 177, 200 (5th Cir. 1989), *cert. denied sub nom. PPG Indus. v. EPA*, 495 U.S. 910 (1990).

additional comments.”²⁴³ “A petitioner who objects to an agency’s failure to publish data for comment must indicate with reasonable specificity what portions of the document it objects to and how it might have responded if given the opportunity.”²⁴⁴

B. EPA Was Required To Solicit Comments on the Effect of the CPP on the Rule, and Its Failure To Do So Prejudiced Industry

A major new rule proposed by EPA after the close of the comment period on the proposed ELG rule, which would regulate the same industry as the Final Rule, is significant new data in the Agency’s possession requiring additional notice and comment under the APA.²⁴⁵ The same is true of EPA’s own analysis of the impact of the CPP on the Final Rule. Yet EPA failed to release this analysis for comment before finalizing the Rule.

EPA agrees that the CPP, which sets greenhouse gas emission guidelines for existing power plants, is a major new rule affecting the same plants targeted by the Final Rule; that is why EPA conducted its analysis.²⁴⁶ But EPA should have given the public an opportunity to comment on the impact of this major regulation on the Final Rule. It had plenty of time to do so, given that EPA proposed and finalized

²⁴³ *Id.* at 201.

²⁴⁴ *Id.* at 202 (internal quotations and citation omitted).

²⁴⁵ *See id.* at 201.

²⁴⁶ *See* EPA Fact Sheet: Overview of the Clean Power Plan (CPP is a “historic and important step in reducing carbon pollution from power plants” that generated 4.3 million public comments) (available at www.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan) (last accessed Dec. 2, 2016).

the CPP nearly 17 months and 3 months, respectively, before it published the Final Rule at issue here.²⁴⁷

A recent—and strikingly similar—example demonstrates the critical importance of public comments in this situation. In virtually identical circumstances, the public was given the opportunity to comment on EPA’s analysis of the CPP’s impacts in the recent Cross-State Air Pollution Rule Update. EPA decided to drop the CPP analysis altogether after acknowledging that commenters were correct that the analysis was performed inappropriately.²⁴⁸

If given that opportunity here, the industry would not only have addressed errors in EPA’s analysis, it also would have demonstrated to EPA that the Final Rule’s deadlines should be synchronized with the CPP’s, to avoid unnecessary waste of resources and compliance costs. As issued, the Rule specifies that the new limits become applicable “as soon as possible.”²⁴⁹

Although permitting authorities have discretion to consider the CPP in deciding what constitutes “as soon as possible” for a given facility,²⁵⁰ the Final Rule requires application of the new limits “no later than” December 31, 2023.

²⁴⁷ See 79 Fed. Reg. at 34,830 (June 18, 2014); 80 Fed. Reg. 64,662, 64,941 (Oct. 23, 2015) (noting finalization date of August 3, 2015).

²⁴⁸ 81 Fed. Reg. 74,504, 74,529 (Oct. 26, 2016) (“We agree that the CPP should not be included in the base case modeling for this rule.”).

²⁴⁹ See, e.g., 80 Fed. Reg. at 67,894-95 (to be codified at 40 C.F.R. §423.13(g)(1)(i)) (requiring compliance with the new FGD wastewater limits “as soon as possible beginning November 1, 2018, but no later than December 31, 2023”).

²⁵⁰ See *id.* at 67,894 (to be codified at 40 C.F.R. §423.11(t)(2)(ii)).

Consequently, the Rule’s outer deadline of 2023 is inconsistent with the CPP’s requirements to achieve greenhouse gas performance rates between 2022 and 2030.²⁵¹ Competing deadlines will necessarily have an impact on EPA’s analysis of the respective costs of the rules—and, as noted earlier, cost is a statutory factor EPA is required to consider.

Without the benefit of comments on the impact of the CPP on the proposed ELG rule, EPA did not fully consider the ways in which the Final Rule’s deadlines would lead to unanticipated consequences. And, the failure to solicit comments on this point has deprived the Court of the opportunity to evaluate the reasonableness of EPA’s conclusions.²⁵²

In conclusion, Industry Petitioners have indicated with “reasonable specificity” what information EPA withheld from public comment “and how [they] might have responded if given the opportunity.”²⁵³ EPA’s consideration of the CPP, as well as the Agency’s internal analyses of the impacts on the Final Rule, is significant, “newly-considered data” in the Agency’s possession that required it to

²⁵¹ 80 Fed. Reg. at 64,664.

²⁵² See *Gen. Tel. Co. of the Sw. v. United States*, 449 F.2d 846, 862 (5th Cir. 1971) (quoting *Automotive Parts & Accessories Ass’n v. Boyd*, 407 F.2d 330, 338 (D.C. Cir. 1968)) (responses to comments enable court “to see what major issues of policy were ventilated...and why the agency reacted to them as it did”).

²⁵³ *Chem. Mfrs.*, 870 F.2d at 202 (internal citation omitted).

“again publish notice and invite additional comments.”²⁵⁴ The APA requires vacatur where the agency’s error infects the entire rule.²⁵⁵

V. The Gasification Wastewater Limits Are Arbitrary and Capricious

The absence of any data regarding Crystallizer Effluent at IGCC facilities, and EPA’s failure to explain how it could set the GWW limits without those data, undermines the GWW limits themselves and EPA’s cost analysis of those limits. EPA has not explained why VCE Effluent-based GWW limits are achievable or how it was able to reach that conclusion without any Crystallizer Effluent data from an IGCC facility. Given that Duke Energy’s Edwardsport facility will combine VCE and Crystallizer Effluent for additional treatment before discharge, and that there is insufficient data in the record regarding the performance of Edwardsport’s GWW treatment system to know whether the Edwardsport facility can comply with the GWW limits, EPA’s assumption that there would be no capital costs of compliance due to the GWW limits is arbitrary and capricious.

²⁵⁴ *Id.* at 201. Notably, EPA twice re-opened the public comment period for the CPP when new information became available. *See* 79 Fed. Reg. 64,543 (Oct. 30, 2014); 79 Fed. Reg. 67,406 (Nov. 13, 2014). *See also Gerber v. Norton*, 294 F.3d 173, 184 (D.C. Cir. 2002) (appellants “presented enough to show that on remand they can mount a credible challenge...and were thus prejudiced by the absence of an opportunity to do so before....”).

²⁵⁵ *Chem. Mfrs.*, 870 at 200.

A. When Evaluating Two-Step Treatment for FGD Wastewater, EPA Concluded It Could Not Set Effluent Limits Based Solely on VCE Effluent But Did the Exact Opposite for Gasification Wastewater Without Explanation or Basis in the Record

In the Final Rule, EPA evaluated the ability of Two-Step Treatment to treat two types of wastewater—FGDW and GWW—but adopted starkly different approaches for setting BAT limits based on that technology. For FGDW, EPA explicitly stated the pollutant concentrations in Crystallizer Effluent are greater than the pollutant concentrations in VCE Effluent.²⁵⁶ It also recognized the possibility that a facility might combine the two streams prior to discharge and concluded:²⁵⁷

Setting the limitations [based] on the higher concentration stream [Crystallizer Effluent] is necessary to ensure plants ... can meet the limitations, regardless of whether they sample the effluent streams separately or as a combined stream.

For GWW, EPA discarded the only available data regarding Crystallizer Effluent because the Agency concluded the data reflected an ongoing malfunction of Polk's crystallizer.²⁵⁸ But, in spite of EPA's understanding that Crystallizer Effluent has a higher pollutant concentration than VCE Effluent—as well as the Agency's statement that effluent limits for Two-Step Treatment needed to be based on the “higher concentration stream”—EPA did not go back to Polk to obtain

²⁵⁶ Index.12840.13-25.

²⁵⁷ *Id.* at 13-25–13-26 (emphasis added).

²⁵⁸ *Id.* at 13-27.

additional data regarding Polk’s Crystallizer Effluent after the malfunction was resolved. Instead, and without explanation, EPA simply set the GWW limits based on the pollutant concentration of VCE Effluent—the *lower* concentration stream.²⁵⁹

In doing so, EPA has run afoul of its obligation to provide a reasoned explanation in the record for treating similarly situated matters differently.²⁶⁰ The record contains no evidentiary basis to conclude the chemical content of Crystallizer Effluent is lower than the content of VCE Effluent at IGCC Facilities, and EPA has provided no explanation—even a purely theoretical one—as to why this would be the case.²⁶¹ Nor has EPA explained why it believes the GWW limits (unlike FGDW) do not need to be based on the “higher concentration stream” or why IGCC facilities will be able to reliably meet the GWW limits (based on VCE Effluent) when the Agency determined this was not possible with respect to FGDW. The Court should vacate and remand the GWW limits to EPA to explain

²⁵⁹ *Id.*

²⁶⁰ See *Lilliputian Sys., Inc. v. PHMSA*, 741 F.3d 1309, 1313-14 (D.C. Cir. 2014) (remanding because agency failed to provide “reasoned explanation and substantial evidence in the record” justifying disparate treatment of products regulated by final rule); *Costle*, 629 F.2d at 133 (remanding because agency failed to explain basis for its disparate treatment of dredged and nondredged waste).

²⁶¹ See *Lilliputian Sys.*, 741 F.3d at 1313-14 (noting record demonstrated similar safety hazards existed from articles subject to air transport ban and articles that were not and that agency failed to articulate how or why it chose to treat them differently); *Costle*, 629 F.2d at 135 (“In short, the record is devoid of any statement, concise and general or otherwise, of the basis for the choices made.”).

the basis for its disparate treatment of GWW and FGDW and how EPA was able to proceed in this manner without any data in the record regarding the chemical content of Crystallizer Effluent at IGCC Facilities.

B. The Central Premises Behind EPA's Cost Analysis for the Gasification Wastewater Limits Are Erroneous

In the Final TDD, EPA stated that all three IGCC facilities in existence during the agency's development of the GWW limits already used the treatment technology it selected as BAT and, on that basis, asserted there would be no capital costs of compliance associated with the final GWW limits.²⁶² This assertion ignores the effect of combining VCE and Crystallizer Effluent into a single stream, *i.e.*, that the concentration of pollutants in the combined stream will be higher than the concentration of pollutants in the VCE Effluent alone as well as EPA's own conclusion (regarding FGDW) that Crystallizer Effluent, if kept as a separate stream, will have a higher pollutant concentration than VCE Effluent.²⁶³

Contrary to EPA's unsupported assertion, any facility employing Two-Step Treatment before discharging GWW *will* incur capital costs to comply with the GWW limits because, based on the data and analysis in the record: (i) a combination of VCE and Crystallizer Effluent will not be able to reliably meet effluent limits based on the lower pollutant concentration of VCE Effluent; and

²⁶² Index.12840.9-7.

²⁶³ *Id.* at 13-25–13-26.

(ii) Crystallizer Effluent, if handled separately, will have a higher pollutant concentration that exceeds limits based on the cleaner VCE Effluent. Thus, in either scenario, a facility would need to modify its wastewater treatment process by: (i) installing additional treatment for separate Crystallizer Effluent streams or to counter the effects of combining the streams, (ii) modifying the system to keep the streams separate, and/or (iii) eliminating discharges of Crystallizer Effluent entirely. Each alternative would necessarily involve a capital expense and would produce additional ongoing compliance costs as well. In other words, facilities like Polk or Duke Energy's Edwardsport plant will—as a matter of logic—incur significant compliance costs due to the GWW limits that EPA's cost analysis did not consider.²⁶⁴

As such, with respect to GWW, EPA has failed to satisfy its obligation to make a “serious, careful, and comprehensive study of the costs which compliance will impose on the industry.”²⁶⁵ The Court should vacate and remand the rule to EPA to correct its cost analysis for GWW, including the development of additional data regarding the actual performance of Edwardsport's GWW treatment system. EPA will then be in a position to make a reasoned, data-based analysis of whether

²⁶⁴ NPDES Permit No. IN0002780, Duke Energy Indiana, Inc. – Edwardsport, Index.123.132 (explaining Edwardsport would recombine both streams for additional treatment via reverse osmosis before discharge).

²⁶⁵ *Am. Petroleum Inst.*, 661 F.2d at 355 (internal citation omitted).

the GWW limits will produce capital compliance costs at Edwardsport and whether to proceed in light of those costs.²⁶⁶

CONCLUSION

For the reasons above, Industry Petitioners request that the Court vacate the Final Rule in its entirety. In the alternative, the Court should vacate the FGDW limits as applied to plants burning subbituminous or lignite coals, and vacate the GWW limits.

²⁶⁶ See *id.* at 355-57; *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1030-31 (D.C. Cir. 1978) (refusing to consider post hoc agency analysis suggesting erroneous assumptions included in cost analysis did not affect substance of final rule).

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CERTIFICATE OF SERVICE

I certify that on December 5, 2016, a true and correct copy of the foregoing was filed through the Court's ECF system, and thereby served on all counsel of record in the consolidated cases.

/s/ Harry M. Johnson, III
Harry M. Johnson, III
Counsel for UWAG, SWEPCO, and
Ameren

CERTIFICATE OF COMPLIANCE

Certificate of Compliance With Type-Volume Limitation, Typeface Requirements, and Type Style Requirements

I certify that the foregoing Industry Petitioners' Opening Brief filed through the Court's ECF system, is an exact copy of the paper document, 5th Cir. R.

25.2.1, does not contain any personal identifiers requiring redaction, 5th Cir. R.

25.2.13, and has been scanned for viruses with the most recent version of a commercial virus scanning program and is free of viruses.

I further certify that:

1. this brief complies with the type-volume limitation of this Court's Order dated Sept. 28, 2016, because this brief contains 17,567 words, excluding the parts of the brief exempted by Fed. R. App. P. 32(a)(7)(B)(iii); and

2. this brief complies with the typeface requirements of Fed. R. App. P. 32(a)(5) and the type style requirements of Fed. R. App. P. 32(a)(6) because this brief has been prepared in a proportionally spaced typeface using Microsoft Word in Times New Roman 14-pt font.

Date: December 5, 2016

/s/ Harry M. Johnson, III
*Counsel for Petitioner/Intervenor UWAG
and Petitioners SWEPCO and Ameren*

General Information

Court	US Court of Appeals for the Fifth Circuit; US Court of Appeals for the Fifth Circuit
Docket Number	15-60821

Attachment E. UNCERTAINTY IN IRP: COMMON PITFALLS AND BEST PRACTICES

Uncertainty in IRP: Common Pitfalls and Best Practices

Adam Borison
March 22, 2016



The opinions expressed in this presentation are those of the individual author(s) and do not represent the opinions of BRG or its other employees and affiliates. The information provided is not intended to and does not render legal, accounting, tax, or other professional advice or services, and no client relationship is established with BRG by making any information available in this presentation. None of the information contained herein should be used as a substitute for consultation with competent advisors.

- ✓ **Introduction**
- **Challenges**
 - Inputs: Data Sources
 - Outputs: Risk Metrics
 - Analysis: Optimization Models
- **Recommendations**
- **Next Steps**

What is (an) IRP?

- An integrated resource **plan** (IRP) is “a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period.”
 - Synapse Energy Economics, Best Practices in Electric Utility Integrated Resource Planning, June 2013.
- Integrated resource **planning** (IRP) is “a process of planning to meet users needs for electricity services in a way that satisfies multiple objectives...”
 - The Tellus Institute, Best Practices Guide: Integrated Resource Planning for Electricity, June 2010.

What is a top-quality IRP?

- Better Plan
 - Better Decisions
 - The “What” in IRP
- Better Planning
 - Better Processes
 - The “How” in IRP

The goal of this presentation is to help you deal more effectively with uncertainty both in the plan and in the planning.

- Introduction
- ✓ **Challenges**
 - Inputs: Data Sources
 - Outputs: Risk Metrics
 - Analysis: Optimization Models
- Recommendations
- Next Steps

Data Sources - Demonstration



Data Sources - Demonstration

- The probability depends on what you know (or think you know). There is no objectively-correct probability.

Data Sources - Insights

- Uncertainty is a state of information not a state of nature
- Probability is simply a formal (explicit and precise) way of conveying your state of information
- Historical data, financial markets and forecasting models (“hard data”) are important but judgment cannot be avoided; in some cases, it is all that is available
- A common pitfall in IRP is to limit rigorous analysis to uncertainties where there is hard data; this misses some of the biggest factors
 - Technology change, market disruption, federal/state politics, environmental regulation
- A best practice is to recognize the subjective nature of uncertainty, and adopt rigorous methods for dealing with judgment
- Experts (both internal and external) have a critical role in providing these judgments; stakeholders (including utility executives and regulators) have a critical role in identifying these experts and in evaluating their judgment

CAA Section 111(d) Sensitivity Analysis

██████████ developed multiple sensitivities for the EPA's proposed regulation for regulating CO₂ emissions from existing generating sources under CAA Section 111(d). The multiple sensitivities are a reflection of the considerable uncertainty related to the stipulations of the finalized regulation scheduled to be issued in summer 2015. Each sensitivity, with the exception of a null sensitivity in which no restrictions are assumed, is based on a set of assumptions on compliance stipulations for the final regulation. Analyzing multiple sensitivities allows the estimation of a range of possible cost impacts from CAA Section 111(d). The cost sensitivity analysis could provide information to state-level agencies tasked with the development of state plans for CAA Section 111(d) implementation.

Stochastic Risk Analysis

The stochastic analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and to the degree they can affect the analysis results (i.e., portfolio costs).

██████████ identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Natural gas prices follow a log-normal distribution centered on the planning case forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2014. The serial correlation factor is 0.65.
2. *Customer load*—Customer load follows a normal distribution and is correlated with ██████████ regional load. ██████████ worked with ██████████ as part of research conducted for the 2013 IRP to estimate the correlation between ██████████ customer load and regional customer load. The correlation factor is 0.50.
3. *Hydroelectric variability*—Hydroelectric variability follows a normal distribution. ██████████ owned hydroelectric generation is correlated with the ██████████ regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from 1928 through 2009.

Data Sources - Example

- Identify and create a stochastic model for each key source of portfolio risk which in this analysis were identified:
 - Natural gas prices;
 - Natural gas basis;
 - Coal prices;
 - Load (electricity demand);
 - CO₂ emission prices; and
 - New generation capital cost.

ICC COMMENTS ON NIPSCO IRP

Risk Metrics - Demonstration

- Consider the following two resource plans (assuming all impacts are identical other than PVRR)

Resource Plan	PVRR Mean	PVRR 10-90 range
A	\$10 billion	\$ 3 billion
B	\$9 billion	\$ 5 billion

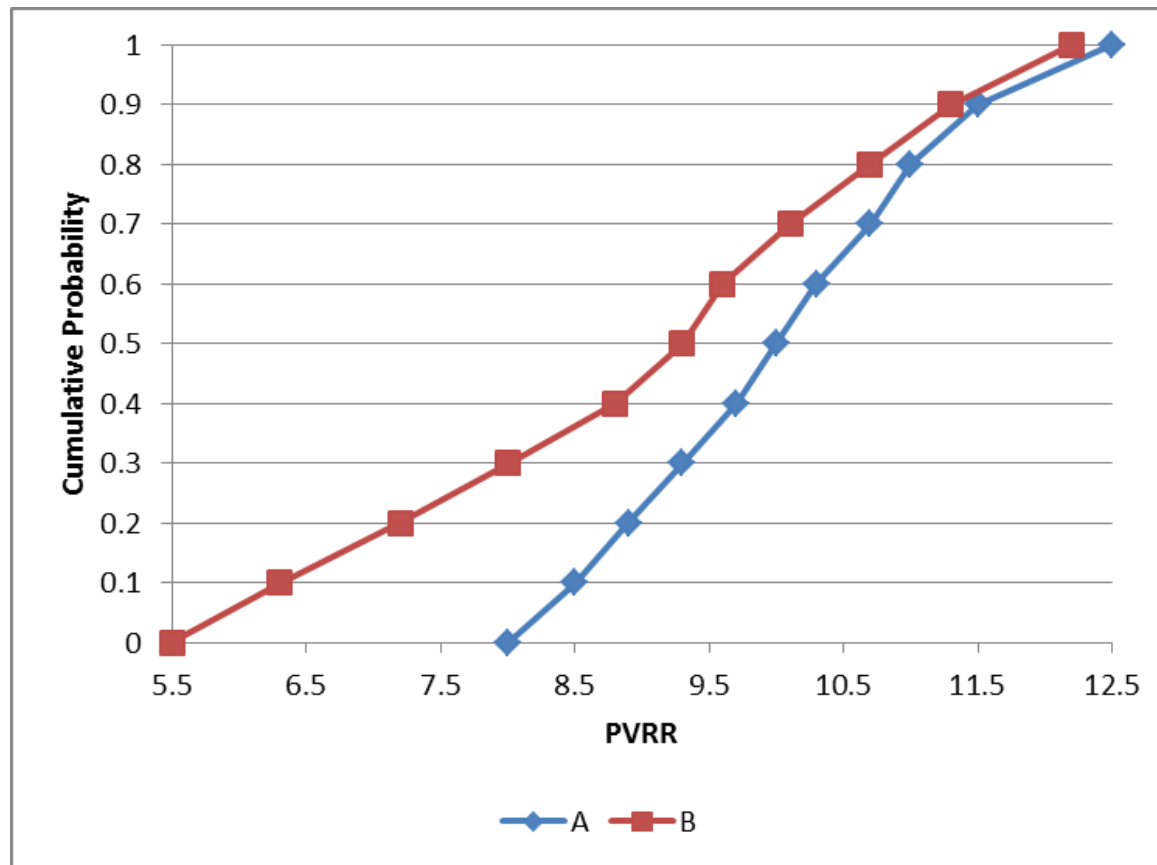
Risk Metrics - Demonstration

ICC COMMENTS ON NIPSCO IRP

PUBLIC VERSION



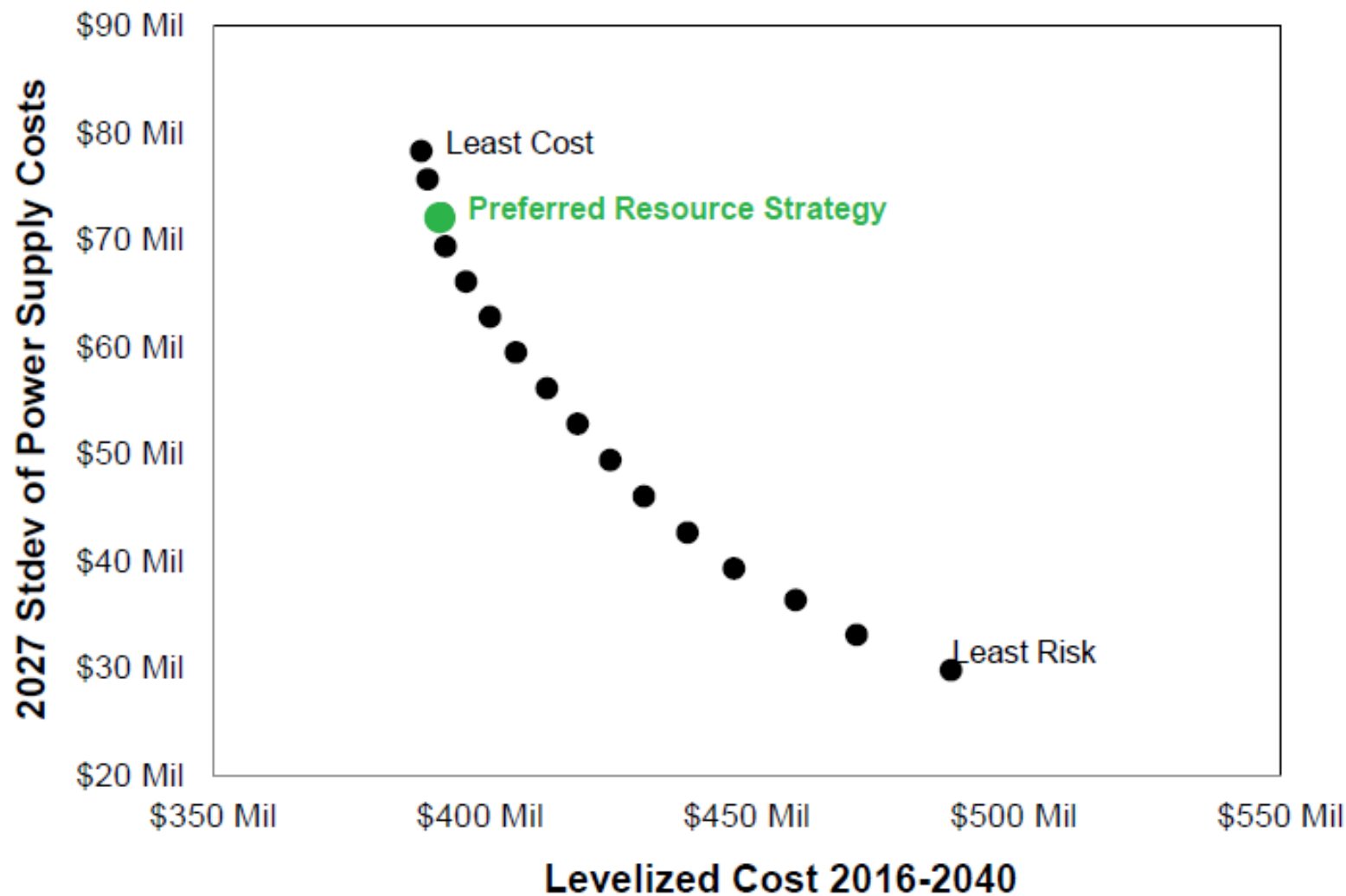
- Plan B dominates Plan A; it has a lower cost in all possible futures. There is no mean/risk tradeoff.



- Risk metrics are critically important in uncertainty analysis but must be selected and used carefully
- Some metrics are better than others; seemingly-reasonable and well-accepted metrics can provide misleading results
- A common pitfall is using standard financial or heuristic measures that may not be suitable for IRP
 - Standard deviation, 10-90 range, 90-mean range, scenario-by-scenario difference (regret)
- A best practice is to use metrics from management science that capture real impacts on stakeholders (ratepayers, shareholders)
 - 90th percentile (tail) value, expected tail value

Risk Metrics - Example

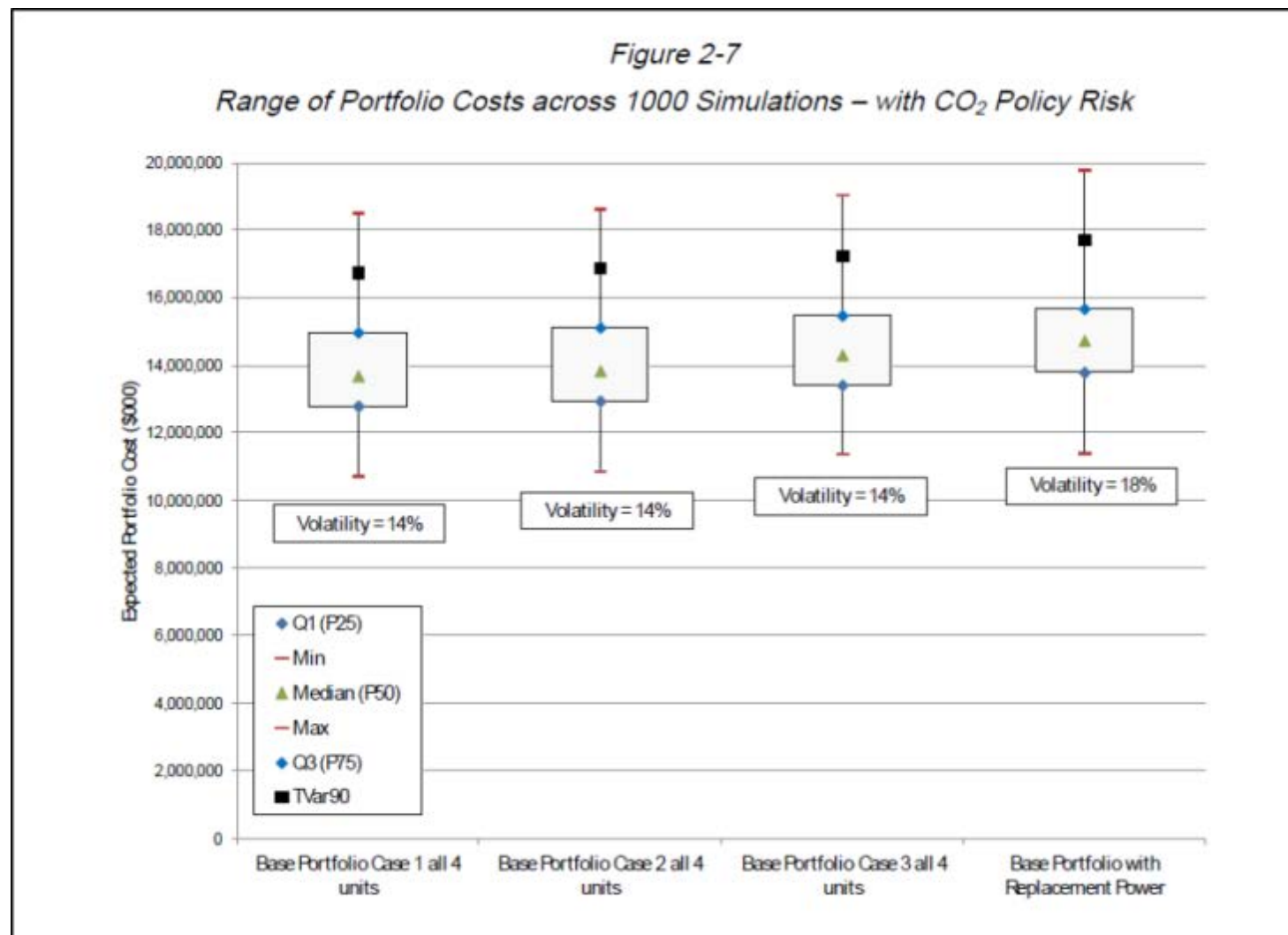
ICC COMMENTS ON NIPSCO IRP



Risk Metrics - Example

ICC COMMENTS ON NIPSCO IRP

PUBLIC VERSION



ICC COMMENTS ON NIPSCO IRP

Optimization Models - Demonstration

PUBLIC VERSION



Optimization Models - Demonstration



- Consider a personal financial investment. Your choices include:
 - Real estate (performed best in 25% of past 20 years)
 - Commodities (20%)
 - Small cap growth (20%)
 - Small cap value (10%)
 - Large cap value (10%)
 - Large cap growth (10%)
 - Bonds (5%)

Optimization Models - Demonstration



- The best choice (S&P) over all years was not best in any given year.

Optimization Models - Insights

- The best decision under uncertainty (across a range of futures) need not look much like the best decision in any given future
- For optimal decision-making under uncertainty, the role of deterministic optimization models should be very limited
 - In an uncertain world, knowing what is best in any given future is of modest value
- A common pitfall is to use detailed deterministic (or operationally stochastic) optimization models to identify the candidate resource plans
 - Aurora, Plexos, Strategist, System Optimizer
- A best practice is to use a wide range of approaches to identify candidate portfolios, and use a decision analysis or real options approach to evaluate them
- Detailed system (production simulation) models are still needed to evaluate impacts of particular portfolios in particular futures

Optimization Models - Example

An optimal, integrated portfolio for each scenario and sensitivity was created using the portfolio optimization model [REDACTED] to combine supply-side resources with the demand-side bundles. The optimization model used the inputs provided to identify the lowest cost portfolio that:

- Meets capacity need
- Meets renewable resources/RECS need
- Includes as much conservation as is cost effective

Once the optimal portfolio for each of the deterministic scenarios was identified, [REDACTED] conducted risk analysis on select portfolios. The [REDACTED] process used to calculate risk measures for each portfolio is briefly discussed below.

Optimization Models - Example

Traditional utility-based resource plans develop deterministic scenarios to minimize the NPV of revenue requirements....

[The model] represents a substantial improvement over traditional planning models by simulating 20 years of physical and market dynamics over 750 futures...

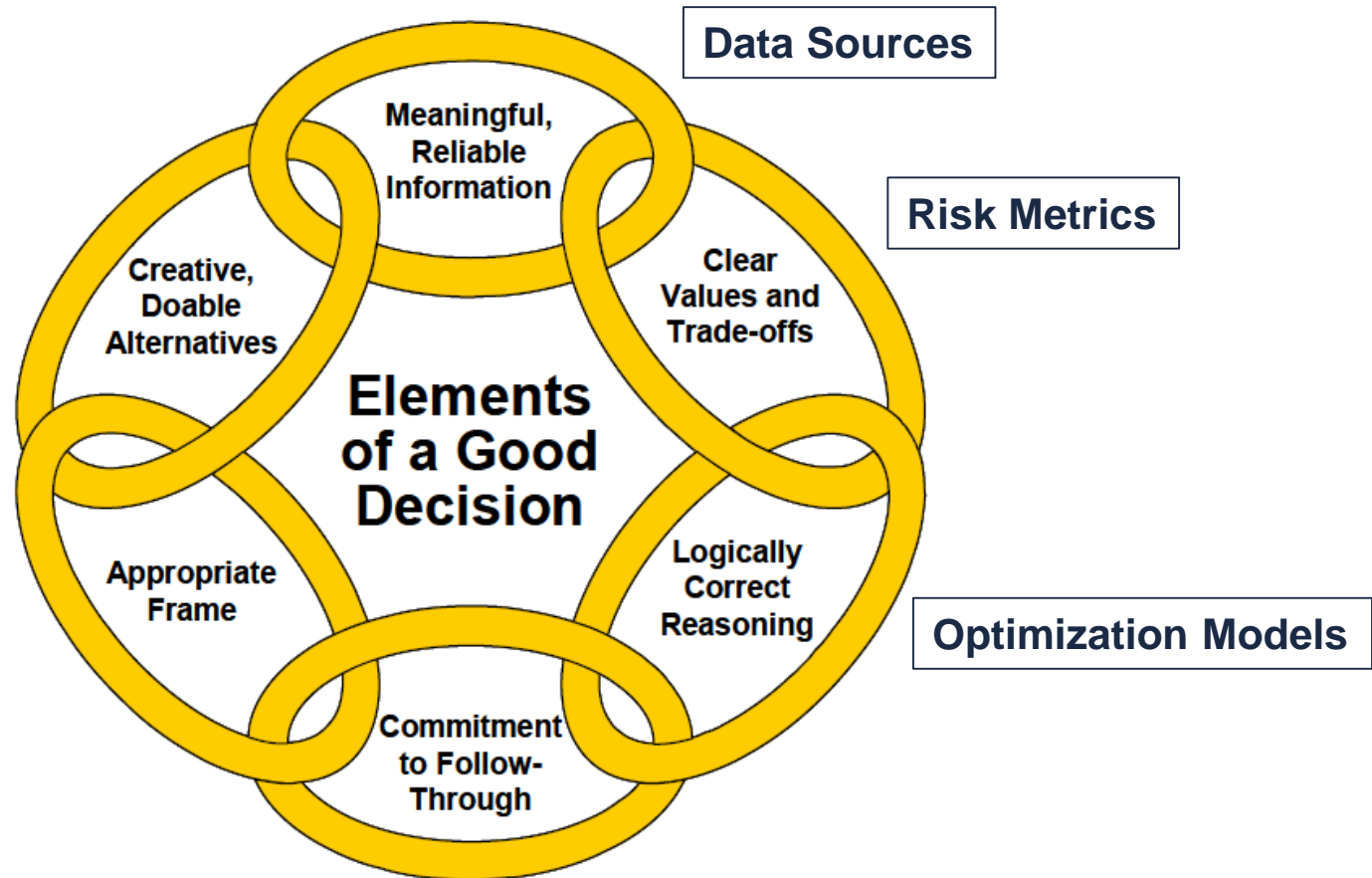
[The model]...distinguishes itself from other software solutions by integrating meaningful uncertainty into...decision-making ...[in] a two-stage process...

- Introduction
- Challenges
 - Inputs: Data Sources
 - Outputs: Risk Metrics
 - Analysis: Optimization Models
- ✓ **Recommendations**
- Next Steps

ICC COMMENTS ON NIPSCO IRP

Better plan = better decisions

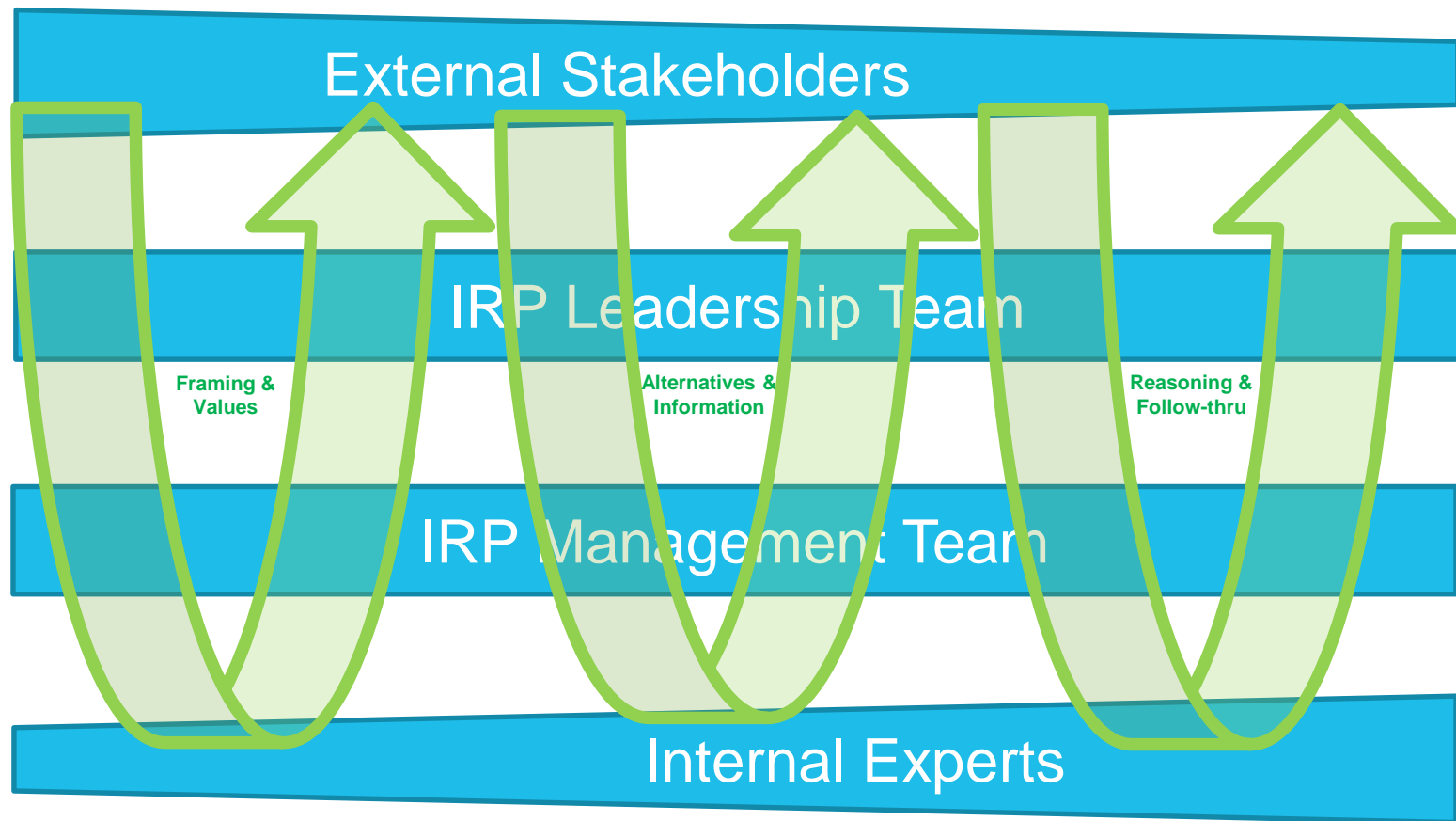
- “Decision Quality” can provide a best practice checklist for an Integrated Resource Plan.



Better planning = more efficient and effective process

2000 COMMENTARIES ON THE IRP PUBLIC VERSION

- The “Dialog Decision Process” can provide a best practice roadmap for Integrated Resource Planning (with appropriate refinements).

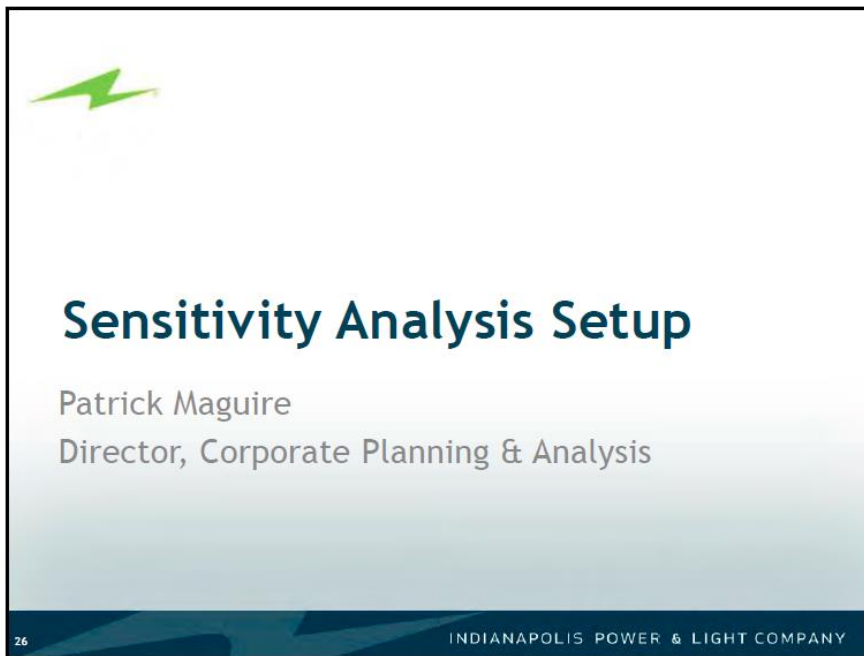


- Introduction
- Challenges
 - Inputs: Data Sources
 - Outputs: Risk Metrics
 - Analysis: Optimization Models
- Recommendations
- ✓ **Next Steps**

- Read
 - Adam Borison, *Electric Power Resource Planning Under Uncertainty, Critical Review and Best Practices*, November 2014
 - Adam Borison, *IRP Best Practices*, May 2015
 - Carl Spetzler et. al., Decision Quality: Value Creation from Better Business Decisions, March 2016

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Attachment F. IPL'S DISCUSSION OF STOCHASTIC MODELING DURING PUBLIC ADVISORY PROCESS





Sensitivity analysis plan

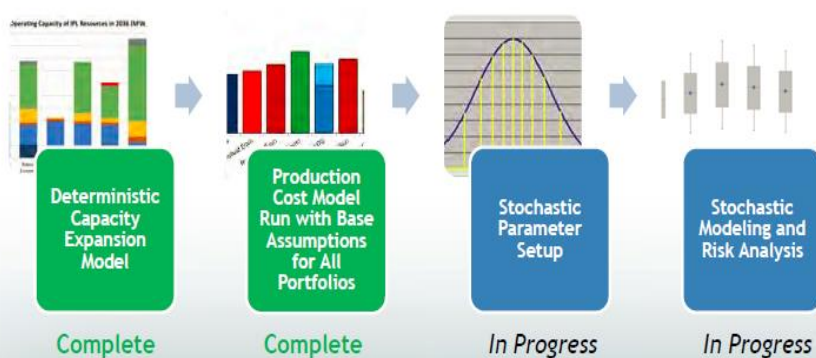
- Two deterministic carbon sensitivities for the base case
 - Delayed CPP from 2022 to 2030
 - High carbon cost for CPP
- Stochastic modeling for all portfolios
 - Multiple inputs varied in each model run
 - Examples: Load (peak and energy), commodity prices, carbon prices, capital costs, forced outage rates

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INDIANAPOLIS POWER & LIGHT COMPANY

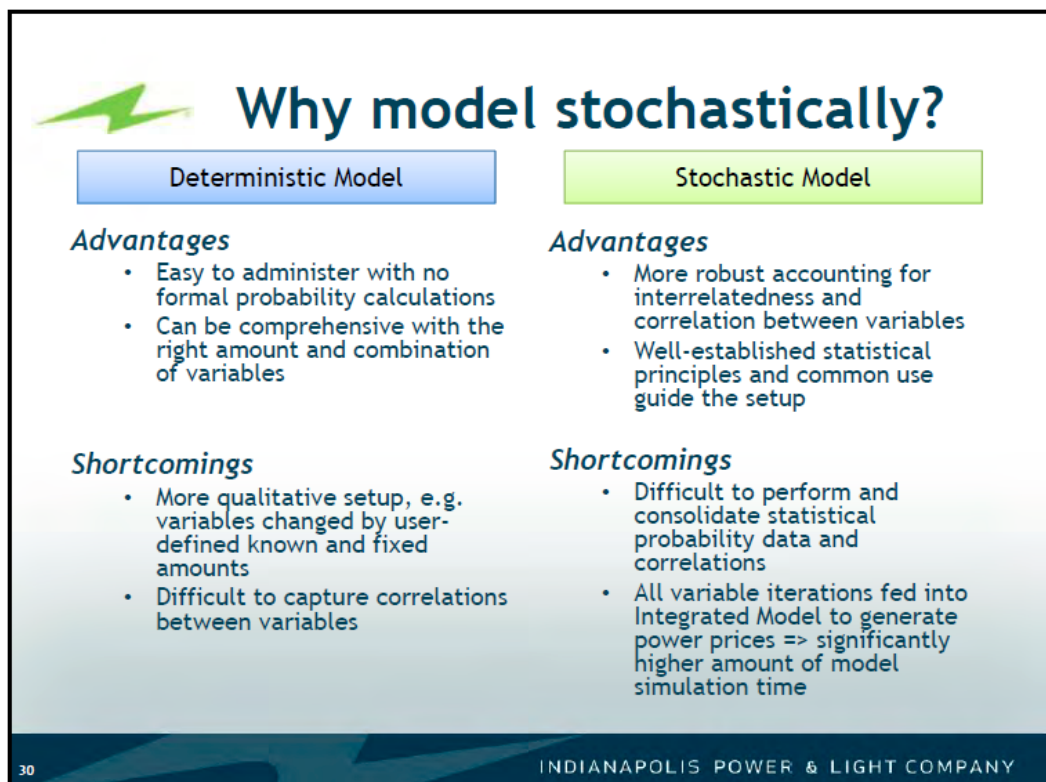
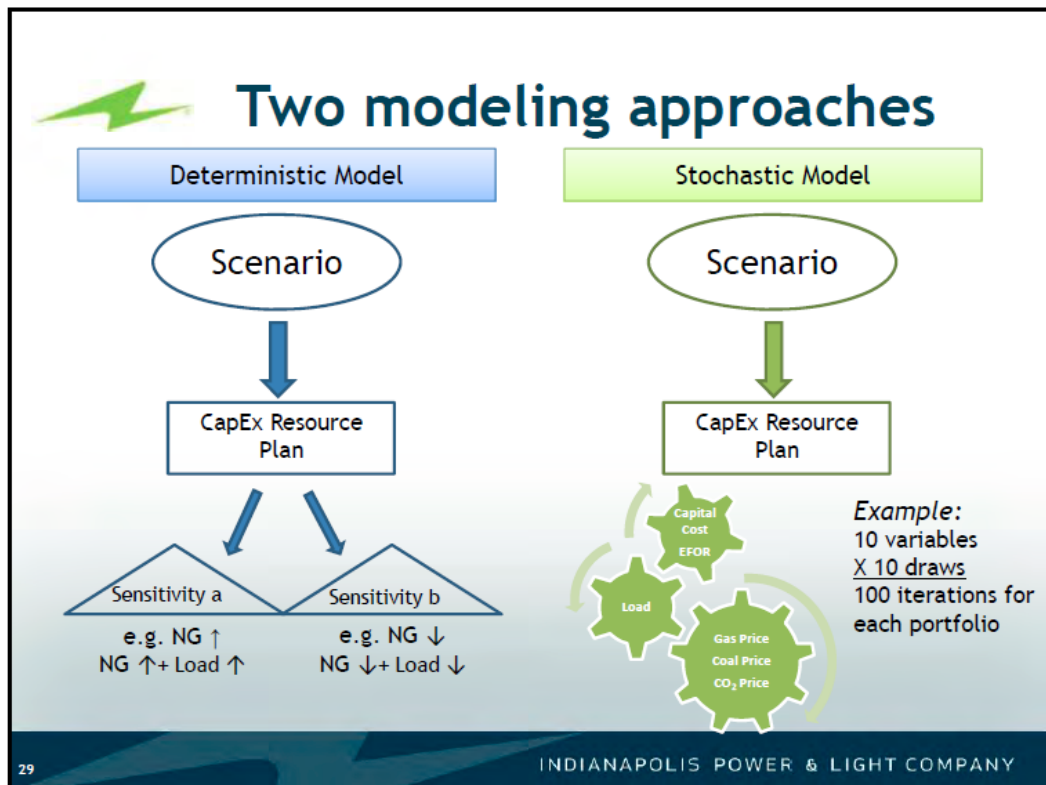


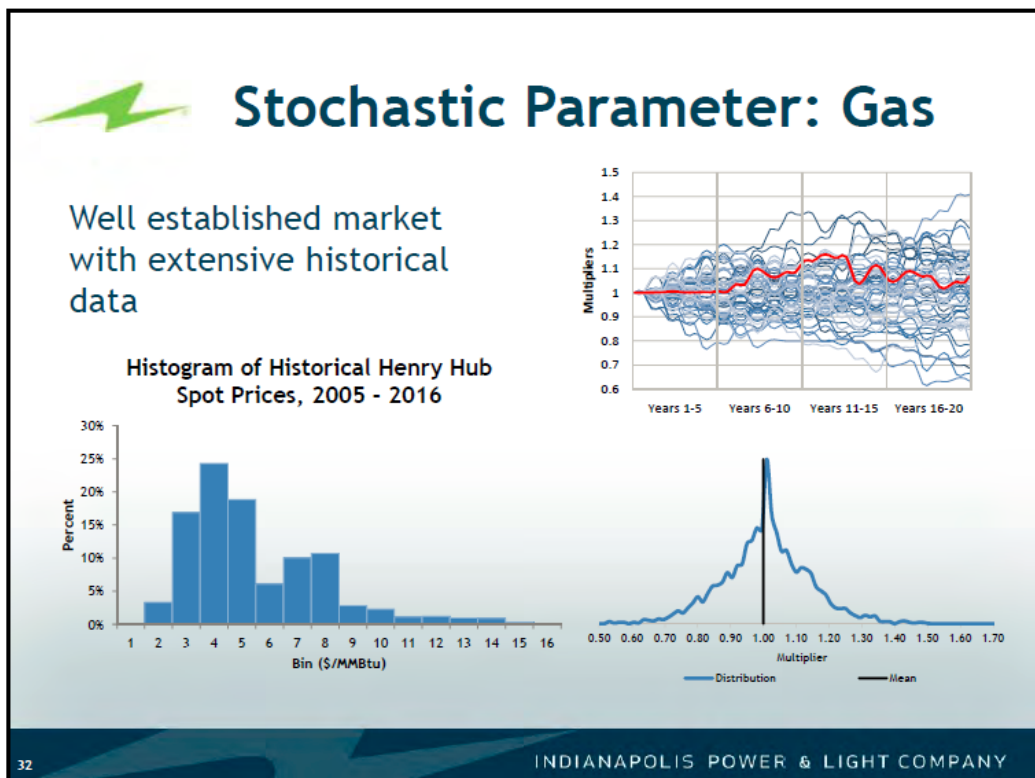
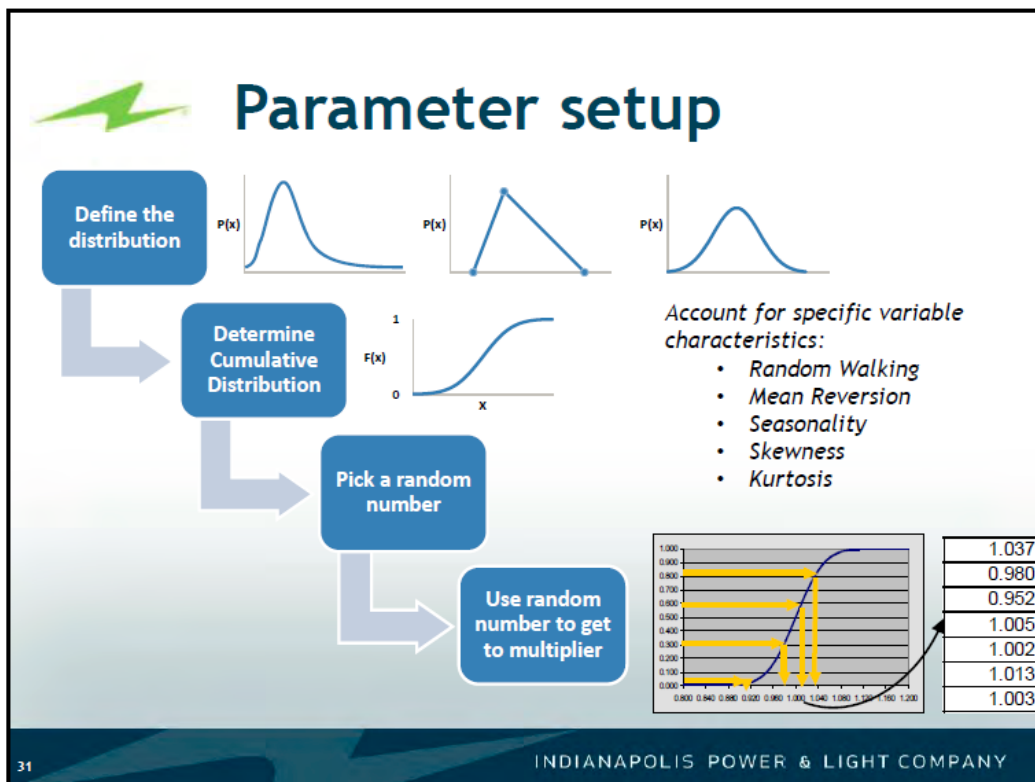
IRP modeling process

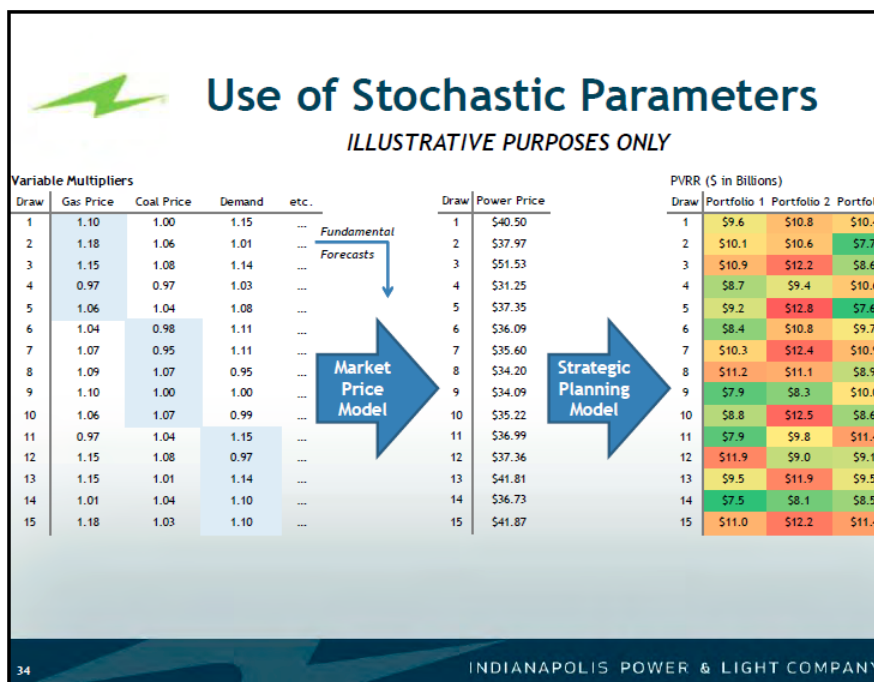
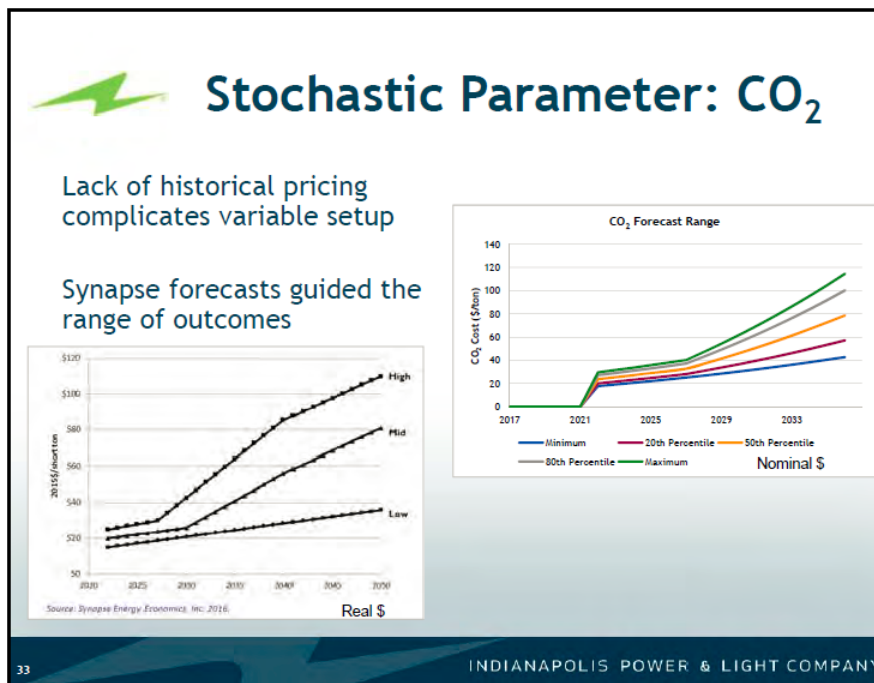


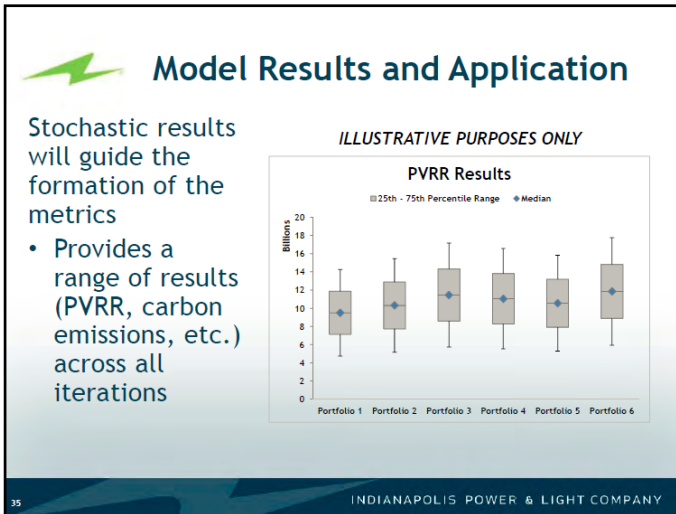
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INDIANAPOLIS POWER & LIGHT COMPANY









Attachment G. DISCUSSION OF IPL'S STOCHASTIC ANALYSIS**7.5.2. Probabilistic Stochastic Analysis**

ABB's Risk Module conducts a probabilistic stochastic analysis of the IRP fundamental modeling inputs

- resource technology cost
- coal prices
- oil prices
- coal unit availability
- gas unit availability
- natural gas prices
- energy load forecast

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- peak load forecast
- carbon prices
- long-term combined cycle capital cost
- long-term wind and solar capital cost
- long-term utility scale and community solar capital cost
- long-term battery storage capital cost

Market prices change as those inputs change. This analysis captures future uncertainties by allowing those inputs to vary over a range of possible values. For each scenario, ABB does 50 random draws for a range of input values by using a stratified Monte Carlo sampling program, called Latin Hypercube. The program uses these random draws to generate forward price curves and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e., Short-Term hourly, Mid-Term monthly, and Long-Term annual).

Through the stochastic modeling process, ABB develops 50 PVRR values, and the mean of those PVRR is the "Expected" PVRR for each scenario. The difference between the "Deterministic PVRR" and the "Expected PVRR" is called "The Value at Risk." The greater the Expected PVRR is than the Deterministic PVRR, the greater the risk that the scenario's portfolio will cost more than the Deterministic PVRR developed through the Production Cost Model.

**Attachment H. NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
REQUEST FOR PROPOSAL**

**STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION**

21.S. Fruit Street Suite 10
Concord, NH 03301-2429
July 15, 2016

**NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
REQUEST FOR PROPOSAL**

**Auction Advisor for Divestiture of Public Service Company of New Hampshire's
Generation Fleet**

**Applicants may submit written inquiries about this Request for Proposal ('RFP')
by email to [RFP@puc.nh.gov] no later than July 19, 2016.**

**Inquiries and their responses will be posted on the NHPUC's website as they are
received.**

**Electronic Proposals must be received by the NHPUC prior to
4.30 p.m. Eastern prevailing time on July 29, 2016
Proposal should be submitted electronically to:**

**Ms. Eunice A. Landry, Business Administrator
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429
RFP@puc.nh.gov**

**In addition to the electronic submission, Applicants must submit ten (10) hard copies
of their proposal for arrival the next business day, to the address above.**

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APPENDIX A – Relevant Documents

APPENDIX B – Scoring Criteria

I. Project Overview/Scope of Services

A. Introduction/Statement of Purpose

The New Hampshire Public Utilities Commission (“the Commission” or “NHPUC”) is soliciting proposals (“Proposals”) from qualified firms (“Applicants”) to serve as its Auction Advisor (“Advisor”) to advise on any work needed to prepare the assets for auction, to manage the transaction-related aspects of a potential sale (“Potential Transaction” or “divestiture”) of the fossil and hydro generating assets and other related properties (“the Portfolio” or the “generating assets”) of Public Service Company of New Hampshire d/b/a Eversource (“Eversource,” “PSNH,” or “the Company.”) Managing the sale process (“Auction”) includes working with the Commission to design the Auction process, selecting Portfolio asset groupings, determining qualified Bidders (“Potential Bidders”), accommodating the participation of municipalities in the Auction, assisting in the preparation of marketing materials including the finalization of a draft Confidential Information Memorandum (“CIM”), managing a formal bid process for the Auction, and negotiating and structuring the Potential Transaction. The Auction Advisor will work with the Commission, PSNH and their respective advisors to determine which bids maximize the net Total Transaction Value (“TTV”) as described in the 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement (“Settlement Agreement”)¹. More specific details on the Scope of Work being requested are included in Section II of this RFP.

Finalization and execution of any contract are subject to a variety of contingencies listed herein, including, contract ratification by the New Hampshire Executive Council.

Nothing in this Request for Proposals or in the retention of an Advisor selected through this RFP process shall require the Commission to take any action with respect to the sale of the Generating Assets.

B. Overview and Project Background

The Commission is an administrative agency with broad supervisory and regulatory authority over public utility matters, including such areas as public utility rates, financing, terms and conditions of utility service, quality of service, safety and reliability, eminent domain matters, public utility exemptions from local zoning ordinances, public utility franchises, utility crossings of public lands and waters, wholesale relationships between utilities, rulemakings, oversight of competitive electricity markets and marketers, certification of renewable energy providers, and consumer complaints.

¹ The Settlement Agreement as filed on June 10, 2015 can be found at http://www.puc.nh.gov/Regulatory/Docketbk/2014/14-238/MOTIONS-OBJECTIONS/14-238_2015-06-10_PSNH_DBA_EVERSOURCE_SETTLEMENT_AGREEMENT.PDF. An amendment to the Settlement Agreement was filed January 26, 2016 and can be found at http://www.puc.nh.gov/Regulatory/Docketbk/2014/14-238/LETTERS-MEMOS-TARIFFS/14-238_2016-01-26_EVERSOURCE_EXECUTED_AMEND_2015_PSNH_SETTLEMENT.PDF.

This RFP is intended to implement State policy favoring the restructuring of the electric utility industry from a traditional vertically-integrated model to one where the generation and energy supply functions are controlled by competitive market forces.

Highlights of the restructuring activities in New Hampshire include the following:

- In 1996, New Hampshire passed legislation to open up its retail electricity supply markets to competition. RSA Chapter 374-F, Electric Utility Restructuring², states that “[T]he most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets.” RSA 374-F:1 Purpose. Broad regulatory guidance was provided in RSA 374-F:3. Restructuring Policy Principles included maintaining system reliability, customer choice, unbundling rates, open access, universal service for all customers, full and fair competition, the recovery of stranded costs, and a commitment to renewable energy and energy efficiency. The Legislature expressly found that it was in the best interests of all citizens of New Hampshire, “to establish a competitive market for retail access to electric power as soon as is practicable....” 1996 N.H. Laws, 129:1, V.
- In May, 1996, the NHPUC opened a proceeding to implement the electric restructuring law, Docket No. DR 96-150. After a detailed proceeding, on February 28, 1997, the Commission issued its “Restructuring New Hampshire’s Electric Utility Industry: Final Plan” (the “Final Plan”). The Final Plan included details on implementation of electric restructuring for each New Hampshire electric utility, including the recovery of stranded costs based on the policy directives contained in RSA 374-F. Litigation followed issuance of the Final Plan and New Hampshire restructured its electric utilities on a case-by-case basis over the ensuing years. After significant litigation with PSNH, a multiparty comprehensive settlement was reached and filed with the Commission in August 1999 (“Agreement to Settle PSNH Restructuring”). That agreement was approved by the NHPUC on April 19, 2000 in Docket No. DE 99-099, and was conformed to that approval and dated June 23, 2000 (the “2000 PSNH Settlement”).
- Pursuant to the 2000 PSNH Settlement, the Commission initiated and directed an auction process to divest the state’s utilities ownership interests in the Seabrook Nuclear Power Station. The state’s utilities similarly divested their ownership interests in other regional nuclear power stations.
- Prior to initiating an auction process for PSNH’s fossil and hydro generating assets, however, the Legislature twice delayed such divestiture as a result of instability in the California electricity markets caused in great part by the activities of Enron Corporation.³
- On January 18, 2013, the NHPUC opened its Docket IR 13-020, “Investigation into Market Conditions Affecting PSNH and its Default Service Customers and the Impact of PSNH’s Ownership of Generation on the Competitive Electric Market”. In the Order of Notice

² <http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-mrg.htm>

³ See: 2001 NH Laws, Chapter 29, <http://www.gencourt.state.nh.us/legislation/2001/HB0489.html>; 2002 NH Laws, Chapter 130, <http://www.gencourt.state.nh.us/legislation/2003/SB0170.html>

opening this investigation, the NHPUC described the history of electric restructuring in New Hampshire, the current “hybrid” system in effect for PSNH in which PSNH’s default service rates are reviewed annually by the NHPUC and set based on PSNH’s actual cost of service, and the changes in market conditions that are affecting PSNH’s costs of providing default energy service to a decreasing customer base as customers continue to migrate to competitive electric suppliers.

- On June 7, 2013, the Staff of the NHPUC and the Liberty Consulting Group issued “Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market” (the “Report”).⁴ The Report analyzed the current conditions affecting PSNH’s default energy service rates and the factors affecting the substantial amount of load that has migrated to competitive electric suppliers over the prior two years. The NHPUC accepted the Report and issued Order No. 25,545 on July 15, 2013.⁵ In Order No. 25,545, the Commission stated that a threshold question for future discussions will be the value of PSNH’s generation assets and the rate impacts if those assets were retired or sold. The Commission directed engagement of expert consultants to determine the value of PSNH’s generation assets and entitlements.
- On April 1, 2014, La Capra Associates, Inc. (“La Capra”) and ESS Group, Inc. (“ESS”) issued their preliminary status report along with Commission staff addressing the value of PSNH’s generation assets and entitlements per Order No. 25,545.⁶ The valuation analysis, based primarily on a discounted cash flow (“DCF”) model, provided an assessment of PSNH’s generating assets and the Burgess BioPower and Lempster Wind Power Purchase Agreements (“PPAs”) held by PSNH. The purpose of the DCF analysis and use of comparable sales was to provide estimates of what a hypothetical third party buyer could be expected to pay for the PSNH generation assets. La Capra concluded that the overall value was substantially less than the net plant value of \$660 million on PSNH’s books as of December 31, 2013.
- In 2014, the Legislature enacted 2014 NH Laws, Chapter 310, “an act relative to the divestiture of PSNH assets and relative to the siting of wind turbines.”⁷ The new law amended RSA 369-B:3-a to require the Commission to “commence and expedite a proceeding to determine whether all or some of PSNH’s generation assets should be divested.” Under the new law the Commission “may order PSNH to divest all or some of its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture.” Per this legislation, the Commission

⁴ <https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020/LETTERS-MEMOS-TARIFFS/13-020%202013-06-07%20STAFF%20REPORT%20ON%20INVESTIGATION%20INTO%20MARKET%20CONDITIONS.PDF>

⁵ <https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020/ORDERS/13-020%202013-07-15%20ORDER%20NO.%2025,545%20ACCEPTING%20STAFF%20REPORT%20AND%20SEEKING%20VALUATION%20ANALYSIS.PDF>

⁶ Staff Report: https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020/LETTERS-MEMOS-TARIFFS/13-020%202014-04-01%20STAFF%20PRELIMINARY%20STATUS%20RPT_PSNH%20GENERATING%20PLANTS.PDF, La Capra Analysis: https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020/LETTERS-MEMOS-TARIFFS/13-020%202014-04-01%20STAFF%20PSNH%20ASSET%20VALUATION%20RPT_LA%20CAPRA%20ASSOCIATES.PDF, ESS Group Report: https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020/LETTERS-MEMOS-TARIFFS/13-020%202014-04-01%20STAFF%20PSNH%20ASSET%20ENVIRONMENTAL%20REVIEW_ESS%20GROUP.PDF.

⁷ <http://www.gencourt.state.nh.us/legislation/2014/HB1602.html>

opened its Docket DE 14-238⁸ to determine whether some or all of PSNH's generating assets should be divested or retired.

- In 2015, the Legislature enacted 2015 NH Laws, Chapter 221, "An ACT relative to electric rate reduction financing," which allowed the NHPUC to authorize the issuance of securitized bonds for recovery by PSNH of any stranded costs related to the sale of its generation assets if such divestment was approved by the Commission.⁹ The 2015 Legislation makes specific reference to the "'2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement' reached by and between PSNH, the New Hampshire Office of Energy and Planning, the New Hampshire Consumer Advocate, and any other settling parties." (The "Settlement Agreement").¹⁰
- On June 10, 2015, the Settlement Agreement was filed with the Commission.¹¹ An amendment to the Settlement Agreement dealing with the proposed asset divestiture process was filed on January 26, 2016.¹² Per the 2015 legislation, the Commission entertained a proceeding to review that Settlement Agreement. Hearings on the merits of the Settlement Agreement were held February 2 through 4, 2016.
- On July 1, 2016, the Commission approved the terms of the Settlement Agreement as amended.¹³ Under the approved settlement, the Commission and PSNH are to expeditiously pursue divestiture of PSNH's generation assets, thereby completing the restructuring of the New Hampshire competitive energy market. Divestiture will take place primarily through the sale of existing power generation assets via auction.

Per the Settlement Agreement, the Commission is to select and supervise an Auction Advisor to conduct the divestiture auction process. The Commission shall have administrative oversight, direction, and control of the present RFP for selection of an auction expert, the auction process, and bid selection.

The primary objective of the Auction Advisor will be to conduct an auction process which maximizes the realized value of the generation assets, (i.e., maximizing the TTV). Such value maximization would minimize any remaining stranded costs as required by law.¹⁴

Additionally the Auction Advisor will:

- Understand the key provisions of the Settlement Agreement;

⁸ <http://www.puc.state.nh.us/Regulatory/Docketbk/2014/14-238.html>

⁹ <http://www.gencourt.state.nh.us/legislation/2015/SB0221.html>

¹⁰ See, RSA 369-B:2, XVIII, <http://www.gencourt.state.nh.us/rsa/html/XXXIV/369-B/369-B-2.htm>

¹¹ <http://www.puc.state.nh.us/Regulatory/Docketbk/2014/14-238/MOTIONS-OBJECTIONS/14-238%202015-06-10%20PSNH%20DBA%20EVERSOURCE%20SETTLEMENT%20AGREEMENT.PDF>

¹² http://www.puc.state.nh.us/Regulatory/Docketbk/2014/14-238/LETTERS-MEMOS-TARIFFS/14-238_2016-01-26_EVERSOURCE_EXECUTED_AMEND_2015_PSNH_SETTLEMENT.PDF

¹³ See NHPUC Order No. 25,920 at <https://www.puc.nh.gov/Regulatory/Orders/2016orders/25920e.pdf>

¹⁴ RSA 374-F:3, XII, <http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-3.htm>

- Work with the Commission, Commission Staff and advisors, PSNH, PSNH's Legal and Subject Matter consultants, and other Parties to Docket No. DE 14-238 throughout the auction process.
- Provide expert services as required to oversee the structure and details of an auction process, including but not limited to activities to organize, initiate, conduct, review, and finalize a divestiture auction of PSNH's generation assets.
- Seek to build consensus amongst Commission Staff, PSNH, and other Parties to Docket No. DE 14-238 and any successor docket relating to the divestiture of PSNH's generating assets regarding auction process, in order to eliminate or minimize the need for an adjudicative decision-making proceeding by the Commission.
- Ensure prospective bidders incorporate necessary terms, conditions, and provisions into their bids, including but not limited to:
 - Acceptance and Provision of employee protections as required by law¹⁵ and as set forth in the 2015 PSNH Settlement Agreement, such as:
 - Provisions of the existing Collective Bargaining Agreement ("CBA") between PSNH and Local 1837 of The International Brotherhood of Electrical Workers shall be binding for the term of the CBA;
 - Provisions of the employee protections for non-bargaining unit employees;
 - Agreement to keep each generating asset in-service for a minimum of 18 months from the date of the financial close of an Asset Sale Transaction;
- Accommodate participation in the Auction by municipalities that host generation assets, to the extent doing so is not in opposition with the overall goal of maximizing TTV;
- Provide an analysis of bids received to describe their relative benefits and weaknesses;
- Fairly allocate the purchase price of the transaction among individual assets of the PSNH Portfolio when more than one asset is included in a single bid from a potential buyer.
- Provide support and expert testimony to facilitate the review and approval of winning bids by the Commission and other federal, state, and local agencies as necessary.

Unresolved resolutions on issues relating to the auction process may be subject to an expedited, adjudicated Commission review. Ultimately, winning bids will need final approval from the Commission through an expedited, adjudicated process, as well as receipt of other federal and state approvals.

The PSNH fossil/hydro generation assets to be divested via auction are listed below. Detailed descriptions of the assets will be provided as part of the divestiture process.

¹⁵ <http://www.gencourt.state.nh.us/rsa/html/XXXIV/369-B/369-B-3-b.htm>

1. Thermal Facilities:**a. Merrimack Station**

Merrimack Station is located south of the Garvins Falls Hydroelectric Project, along the Merrimack River in Bow, New Hampshire. Generating units include coal fired Units 1 and 2 and peaking units CT1 and CT2.

b. Newington Station

Newington Station is located on a site of more than 50 acres, along the banks of the Piscataqua River in Newington, New Hampshire. Generation includes oil or gas fueled Unit 1.

c. Schiller Station

Schiller Station is located east of Newington Station, on the southerly shore of the Piscataqua River in Portsmouth, New Hampshire. Generating units include coal or oil fired Units 4 and 6, biomass or coal fired Unit 5, and peaking unit CT1.

2. Hydro Facilities:**a. Smith Station**

Smith Station is located on the Androscoggin River in Berlin, Coos County, New Hampshire near the confluence of the Dead River and the Androscoggin River.

b. Gorham Station

Gorham Station is located on the Androscoggin River in the Town of Gorham, Coos County, New Hampshire, near the confluence of the Peabody River and the Androscoggin River.

b. Androscoggin Reservoir Company (ARCO)

Hydroelectric stations on the Androscoggin River receive headwater benefits from ARCO. PSNH is a 12.5 percent owner in ARCO.

c. Canaan Station

Canaan Station is located on the northern Connecticut River in the towns of Canaan, Vermont and Stewartstown (West Stewartstown Village), New Hampshire.

d. Ayers Island Station

Ayers Island Station is located on the Pemigewasset River approximately 12 miles upstream from the U.S. Army Corps of Engineers' Franklin Falls Flood Control Dam in the Towns of Bristol, Bridgewater, Ashland and New Hampton, New Hampshire.

e. Eastman Falls Station

Eastman Falls Station is on the Pemigewasset River in Franklin, New Hampshire.

f. Amoskeag Station

Amoskeag Station is located on the Merrimack River in Manchester, New Hampshire, downstream from Hooksett Station.

g. Hooksett Station

Hooksett Station is located on the east side of the Merrimack River in Hooksett, New Hampshire, downstream from the Garvins Falls Station and Merrimack Station, and upstream from Amoskeag Station.

h. Garvins Falls Station

Garvins Falls is located on the Merrimack River in Bow, New Hampshire.

i. Jackman Station

Jackman Station consists of a dam, located on Franklin Pierce Lake, and a penstock, surge tank and powerhouse, located in Hillsborough, New Hampshire.

3. Remote Combustion Turbines:**a. Lost Nation Combustion Turbine**

The Lost Nation Combustion Turbine is located in the town of Northumberland, New Hampshire.

b. White Lake Combustion Turbine

The White Lake Combustion Turbine is located in the town of Tamworth, New Hampshire.

PSNH, with the assistance of its auction and legal consultants¹⁶ has already completed significant work in anticipation of an asset auction in order to expedite the divestiture process. The Company has: prepared a substantial draft of the Confidential Information Memorandum (“CIM”) under the direction of a consultant with experience in generation asset marketing; completed Phase I site assessments of each asset; completed ALTA surveys; and collected and organized over 2,000 documents that are expected to be of interest to prospective Bidders.

Compiled documents include:

- Environmental permits, reports and documents (air, waste, water, soil, etc.)
- Operational documents, including manuals, maintenance reports and one-line diagrams
- Legal documents, including fuel related contracts and interconnection agreements
- HR documents, including the collective bargaining agreement in effect with the IBEW (“CBA”) and benefit documents
- Real estate documents, including ALTA Survey, easement plans, deeds, and title reports.

The auction is expected to be conducted, reviewed, and finalized within the context of a formalized docketed Commission proceeding.

C. General Disclaimer of the Commission

This RFP does not commit the Commission to award a contract or to proceed with a process that could lead to the sale of the Generating Assets. This RFP and the process it describes are proprietary to the Commission. No other party, including any Applicant, is intended to be granted any rights hereunder. Any response, including written documents and verbal

¹⁶ <http://www.balch.com/> and Concentric Energy Advisors

communication, by any Applicant to this RFP, shall become the property of the Commission and may be subject to public disclosure by the Commission, or any authorized agent of the Commission. In order to access confidential information held by PSNH, Applicants may be required to sign a Confidentiality Agreement (CA) provided by PSNH. Applicants should contact Mr. Eric Chung of PSNH at: Eric.Chung@Eversource.com for a CA.

Any contract awarded under this RFP is expressly contingent upon review and ratification of such contract by the Executive Council of the State of New Hampshire.

II. Scope of Work

A. Scope of Services

The Advisor will work closely with the Commission and its advisors, the Company, the Company's consultants and legal advisors, to design, structure, prepare, and conduct an Auction of PSNH's generation assets, and subsequently to assist with bid evaluations, selection of the most advantageous bids, negotiation of final sale documents, support for all governmental reviews required to accept such bids, and financial closings on the sales of the Assets. The Advisor will report to the Commission on a regular basis, as requested, on the progress and status of key deliverables.

Potential bidders will be provided information regarding the assets subject to auction via a secure virtual data room or other means as deemed necessary and appropriate. The Auction Advisor will serve as the intermediary for communications from bidders throughout the Auction.

Key responsibilities of the Advisor include the following:

I. Auction Design and Preparation

- 1) Reviewing and becoming familiar with relevant New Hampshire laws, NHPUC regulatory dockets, recent sales of electric generating assets, PSNH's generating assets, prevailing market conditions, and the like;
- 2) Describing various Auction structures and discussing the merits and considerations of each structure;
- 3) Recommending an Auction structure;
- 4) Recommending asset portfolio bid groupings
- 5) Identifying Potential Bidders, including municipalities, and determining appropriate outreach strategy;
- 6) Recommending Auction timeline;
- 7) Preparing a detailed marketing and communication strategy including an overview of the Portfolio and Potential Transaction ("Opportunity Overview");
- 8) Reviewing the proposed Confidentiality Agreement ("CA") to be distributed to Potential Bidders;
- 9) Assisting in hiring of consultants, if deemed necessary;

- 10) Preparing marketing materials, including developing financial analysis and finalizing the draft CIM in coordination with the Commission, PSNH, and their respective advisors; and
- 11) Assisting in finalization of the set of documents for a virtual data room including upload to an industry-standard platform suitable for due diligence.
- 12) Identify opportunities to further maximize the sale price of the Assets.

II. Auction

- 1) Contacting Potential Bidders and disseminating Opportunity Overview / Confidentiality Agreement;
- 2) Managing Confidentiality Agreement negotiation and execution in conjunction with PSNH's legal advisors;
- 3) Preparing the initial solicitation document for indications of interest from prospective bidders and qualifying Potential Bidders with regard to financial capability;
- 4) Providing the CIM and financial data to Potential Bidders;
- 5) Granting Potential Bidders access to the virtual data room;
- 6) Managing a formal due diligence process, including the dissemination of questions and delivery of responses to applicable Potential Bidders;
- 7) Assisting PSNH management and the Commission in the preparation and delivery of management presentations to qualified potential bidders and managing the prequalification process;
- 8) Coordinating site visits and management presentations with the Commission, PSNH, and Potential Bidders;
- 9) Soliciting ongoing (formal and/or informal) feedback from potential bidders and reporting relevant feedback to the Commission and PSNH;
- 10) Reviewing transaction documents, including the Purchase and Sale Agreement ("PSA") as provided by the Commission and PSNH's legal advisors;
- 11) Inviting Potential Bidders to submit Phase II binding offers, including comments on the draft PSA ("Bids");
- 12) Interpreting Bids and providing recommendations on the financial and qualitative merits of each Bid;
- 13) After discussing recommendation with the Commission and PSNH and based on the Commission's decision, negotiating the PSA with preferred Potential Bidder in coordination with the Commission's and PSNH's legal advisors;
- 14) Reporting to the Commission and PSNH on a regular basis, and as requested, on the progress and status of the process (at a minimum, assume one weekly update meeting/conference call, although this could vary depending on the stage of the project); and
- 15) Providing materials and testimony to support review and approval of winning bids by federal, state, and local agencies as required for closing on the financial transaction.

Please note that should generation assets be left unsold as a result of the auction process or as a result of the Commission not approving a sale, the Commission may direct the Auction Advisor to initiate a new divestiture process for such unsold assets no later than ninety days from the date of the

Commission's order approving the sale of the other generating assets, or direct PSNH to pursue retirement of such unsold assets in an economic manner.

This Section II, Scope of Services (above), states anticipated requirements for the Potential Transaction and the tasks identified as likely necessary to meet those requirements. The Commission reserves the right, however, to modify specific requirements, based on changed circumstances (such as a change in business or technical environments), the proposal selection process, and contract negotiations with the Applicant(s) selected for negotiations, and to do so with or without issuing a revised RFP. The Applicant must provide in its proposal a detailed proposed scope of services showing how it will meet the project requirements stated in this Section II.

B. Additional Scope per Commission Contracting Requirements

Applicants will be required to provide the following certificates prior to entering into a contract:

Secretary of State's Office Certificate of Good Standing ("CGS")	Individuals contracting in their own name do not need a CGS. Business organizations and trade names need a CGS, except for nonresident nonprofit corporations.
Certificate of Vote /Authority ("CVA")	Individuals contracting in their own name do not need a CVA. Business entities and trade names need a CVA.
Certificate of Insurance	Certificate of Insurance form attached with insurance coverage required under the contract. Modifications of insurance coverage required will be specified in the contract.
Workers' Compensation	Contractor must demonstrate compliance with or exception from RSA 281-A (and if applicable, RSA 228:4-b and RSA 21-I:80, and any other applicable laws or rules).

C. Form Of Contract

The terms and conditions set forth in Form P-37 (v. 1/09) General Provisions Agreement (available at: <http://www.puc.nh.gov/Home/requestforproposal.htm>) are hereby incorporated as

part of this RFP and will apply to any contract awarded the Applicant. While the Commission will consider minor modifications of this form during negotiations, the Commission disfavors substantial material changes from this form agreement. To the extent that an Applicant believes that exceptions to the standard form contract will be necessary for the Applicant to enter into a Contract, the Applicant should note those issues during the Applicant question period. The Commission will review requested exceptions and accept or reject the same at its sole discretion. In no event is an Applicant to submit its own standard contract terms and conditions in response to this solicitation.

III. Proposal Format, Content, and Submission Requirements; Selection Process

A. Required Proposal Format

The official copy of a proposal must be filed electronically on or before the bid deadline set forth above. Applicants must also furnish at least ten (10) hard copies, of their proposal by the next business day following submission of their electronic proposal to the address set forth above. Such written copies should include tabbed indexes separating the following sections in the following order:

Table of Contents

1. Team Page (including contact information)
2. Summary of Proposal
 - a. Summary of project team
 - b. Understanding of the scope of work and expected deliverables

Please include the following:

Applicant's business identification information, including name, business address, telephone number, website address, and federal taxpayer identification number or federal employer identification number; a primary contact for the Applicant, including name, job title, address, telephone and fax numbers, and email address; a description of Applicant's business background, including, Applicant's business organization (corporation, partnership, LLC, for profit or not for profit, etc.), whether registered to do business in New Hampshire, state of business formation, number of years in business, primary mission of business, significant business experience, whether registered as a minority-, woman-, or disabled-owned business or as a disadvantaged business and with which certifying agency, and any other information about Applicant's business organization that Applicant deems pertinent to this RFP.

3. Portfolio Positioning
 - a. Description of key investment highlights you would use to position the Portfolio

in the market

- b. Description of primary areas of potential bidders' concerns, options to mitigate those concerns and approach used to maximize the TTV
- c. Key drivers of value for the Portfolio and how these compare and contrast to other hydroelectric and thermal generation portfolios that have come to market

4. Market Update

- a. Generation merger & acquisition ("M&A") market update
- b. Key lessons learned from recent M&A process

5. Auction Design and Process

- a. Benefits and considerations of various Auction structures and approaches
- b. Recommended Portfolio asset groupings
- c. Recommended Auction approach
- d. Recommended list of Potential Bidders

6. Qualifications and Experience

- a. Power generation financing and advisory experience for both hydroelectric and thermal generation
- b. Detailed example of advisory experience for similar engagement on the buy and sell side
- c. A statement that indicates why your company is uniquely qualified to perform this Work. At a minimum, reference local knowledge/experience, available resources and any other differentiators.

This section should include the following:

The organization's experience in advising private sector companies and public sector entities over the last 10 years in transactions similar to those anticipated in this RFP. Include the size of the companies or public sector entities and the types of transactions evaluated and executed;

Experience with managing the sale of other similar utility assets; coordination with regulatory bodies on such sales, including preparation of related pre-filed and oral witness testimony in regulated utility proceedings;

At least three detailed examples of a similar client engagement where you describe the process of reviewing asset sales, making recommendations, and the final results;

Any prior experience your firm has had working with the New Hampshire Public Utilities Commission;

Any and all engagements your firm has had with PSNH and any PSNH subsidiaries or affiliates.

Any additional services not identified in this RFP that you could provide from which the Commission would benefit.

7. Summary of References

Applicant should provide at least three references for projects that are similar in scope, size and/or value to the work sought by this RFP and on which the staff who will be assigned to this project worked. For each reference, include the name, address, and telephone number of a contact person, dates of engagement and brief description of the project, including the specific role that Applicant played in the assignment.

8. Identification of Project Staffing and Organization

The selected Applicant shall provide a team of seasoned professionals with significant prior experience. Identify the lead and supporting project staff to be assigned to this project, their proposed roles on this project, and summary of prior experience, with particular emphasis on experience with engagements of comparable size and scope to that of this RFP. Applicant should provide an organizational chart, including work titles and brief job descriptions for the scope of work of this engagement, as well as a statement describing which team members will be committed to the project and available to participate in regular (e.g., weekly) meetings. As an appendix to your proposal, include resumes for all staff assigned to the project.

9. Proposed Scope of Work

- a. Description of approach
- b. Detailed proposed scope of work in accordance with Section IV
 - i. Detailed description of how each objective will be addressed
 - ii. Deliverables and due dates

10. Estimate work to be performed by in-house experts and by sub-contractors and identify potential sub-contractors

11. Proposed Schedule

Applicant should provide a schedule of anticipated tasks, assuming a start date of September 6, 2016 (date subject to change).

12. Fee Proposal

The Commission anticipates paying the Advisor *solely* from sale proceeds, subject to a successful transaction closing. Applicants should include proposals for cost containment including but not limited to cost caps. Fee proposals must include details for handling transaction costs (such as materials, copying, postage, travel,

etc.). Fee proposals must also discuss payment in the event of a “failed auction” regarding some or all of PSNH’s generating assets.

As noted earlier, fee proposals must reflect the considerable preliminary work already accomplished by PSNH in preparation for the auction process.

13. Statement of Requested Exceptions to Contract Terms

State exceptions, if any, to Commission Contract Terms that Applicant requests, including the reasons for the request and any proposed alternative language. (*See* Section III.B for more information.)

14. Tax and Regulatory Status and Clearance Statement

Include a statement, in the form requested in Appendix C, attesting to Applicant’s tax and regulatory compliance with the Commission. (*See* Section III.D for more information.)

15. Disclosure of Litigation; Disclosure of Administrative Proceedings

State, for the 5-year period preceding the date of this RFP, a description of any judicial or administrative proceeding that is material to Applicant’s business or financial capability or to the subject matter of this RFP, or that could interfere with Applicant’s performance of the work requested by this RFP, including, but not limited to, any civil, criminal or bankruptcy litigation; any debarment or suspension proceeding; any criminal conviction or indictment; and any order or agreement with or issued by a court or local, state or federal agency. For each such proceeding, state the name of the case or proceeding, the parties involved, the nature of the claims involved, its current status and the final disposition, if any. Provide the same information for any officer, director, principal, or partner of Applicant’s organization, and for any subcontractor Applicant plans to use to perform the services described in this RFP.

16. Statement of Financial Capacity

Provide documentation demonstrating fiscal solvency and financial capability to perform the work sought by this RFP, including but not limited to audited financials.

17. Defaults:

Provide a description, in detail, of any situation occurring within the past five (5) years in which the Applicant, or a joint venture or partnership of which Applicant was a part, defaulted or was deemed to be in noncompliance of any contractual obligations, explaining the issues involved in the default, the outcome, the actions taken by Applicant to resolve the matter. Also provide the name, title and telephone number of the party to the contract who asserted the event of default or noncompliance or the individual who managed the contract for that party.

18. Potential Conflicts of Interest

Applicant shall state any past or current engagements which are related in any way to this Portfolio and/or that could present a conflict of interest in performing the engagement, and propose specific measures to address any conflicts in a manner sufficient to avoid undermining the propriety or appearance of propriety of any sale or related transaction or decision by the Commission. Applicant shall represent that it has not provided or agreed to provide any confidential information related to the Portfolio or to the Auction process to any other person, and will not do so in the future, except as may ultimately be authorized by the Commission in connection with the contemplated sale process. Applicant shall further commit that, if chosen as Auction Advisor, Applicant nor shall any affiliate of Applicant enter into any other contract related to a sale of the Generating Assets, or accept any compensation relating to such sale, except pursuant to the terms of its contract with the Commission. Applicant also commits that it shall accept no future engagement that could present a conflict of interest during the term of this engagement.

If the Commission determines after reviewing the information provided under Section 18, or through any other source, that an Applicant would have a conflict of interest that cannot be reasonably addressed in a manner to ensure the propriety of the services performed pursuant to this RFP, the Commission shall disqualify the Applicant from further consideration.

B. Selection Process

The Commission will base its selection on criteria on the following factors with weighting and ranking done in accordance with Appendix B.:

1. Ability to meet particular requirements of the contracting needs of the Commission;
2. Ability to meet prequalification requirements and to rapidly negotiate and come to agreement on the Commission Contract Terms with the fewest exceptions;
3. Prior experience of Applicant and staff with the scope of work described;
4. Quality of proposed services for the Commission;
5. Overall firm quality, including reputation, breadth of expertise, and depth of relevant resources;
6. Ability to effectively market the generation assets to a broad network of qualified bidders, as reflected by a demonstration of knowledge of the relevant asset markets and the broad network of potential asset bidders;
7. Demonstrated prior experience providing expert witness testimony before utility regulators, especially in the context of generation asset sale transactions;
8. Administrative and operational efficiency, which optimizes time and resources spent by the Commission on oversight and administration, and includes an ability to work with the Commission, PSNH, and other retained advisors cooperatively and productively;
9. Anticipated cost-effectiveness, based on relationship between total overall expected costs and anticipated quality of the Applicant's service, as well as any proposed cost containment

mechanisms; and

10. Assessment based on performance during in-person or telephone interviews.

IV. Proposal Administration

A. Procurement Schedule

(1) RFP release	(expected July 15, 2016)
(2) Questions regarding the RFP due	July 19, 2016
(3) Responses provided	July 25, 2016
(4) Proposal submission due date	July 29, 2016
(5) Applicant interviews and/or presentations	August 1-5, 2016
(6) Applicant selection/Conditional Award posted	August 12, 2016
(7) Contract start date	Upon contract ratification by the New Hampshire Executive Council

The above dates are estimates only and the Commission reserves the right, in its sole discretion, to change the above schedule. Notice of changes in the due date for Applicant questions and the date for proposal submission will be provided by the Commission. The other dates/times listed may be changed without notice to prospective Applicants.

B. Questions Relating to the RFP

Applicants are encouraged to submit questions regarding this request via RFP@puc.nh.gov

Questions are due per the schedule in Section IV.A. Questions received later than the conclusion of the Question Period shall not be considered properly submitted and may not be considered.

The Commission intends to issue official responses to properly submitted inquiries via posting to the Commission web site per the schedule in Section IV.A; however, this date is subject to change at the Commission's discretion. The Commission may consolidate and/or paraphrase questions for clarity. The Commission may, at its discretion, amend this RFP on its own initiative or in response to issues raised by inquiries, as it deems appropriate. Oral statements, representations, clarifications, or modifications concerning the RFP shall not be binding upon the Commission. Official responses by the Commission will be made only in writing by the process described above.

C. Interviews/Presentations

Applicants may be selected for either a phone interview or an in-person presentation. Interviews and presentations will be conducted per the schedule contained in Section IV.A.

D. Term of Contract

It is anticipated that the initial term of the Contract with the Auction Advisor shall commence upon the approval of the Contract by the New Hampshire Executive Council and, unless sooner terminated by the Commission pursuant to the terms of the Contract, shall expire twenty-four (24) months thereafter. The Commission may, at its sole option, amend the Contract to add up to two (2) additional successive one-year terms ("Additional Terms"). Except as may be stated otherwise in such amendment, the terms and conditions of this Contract shall apply throughout each Additional Term.

E. Contract /Proposals and Confidential Information

Pursuant to the relevant statutes and regulations, all responses to this RFP shall be considered confidential until the award of a contract. At the time of receipt of proposals, the Commission will post the number of responses received with no further information. No later than five (5) business days prior to submission of a contract to Governor & Executive Council pursuant to this RFP, the Commission will post the name, rank or score of each proposer.

The content of each Applicant's Proposal shall become public information upon the Effective Date of any resulting Contract. Any information submitted as part of a response to this request for proposal (RFP) may be subject to public disclosure under RSA 91-A. In addition, in accordance with RSA 9-F:1, any contract entered into as a result of this RFP will be made accessible to the public online via the website Transparent NH (<http://www.nh.gov/transparentnh/>). Any Applicant providing information which is exempt from disclosure pursuant to RSA 91-A:5 shall submit a motion for confidential treatment with its proposal. The Commission shall review such motions and determine in writing whether the information shall be held confidential and exempt from disclosure pursuant to RSA 91-A:5. Material for which a motion for confidential treatment is filed shall be kept confidential by the Commission until a written determination is made. *See* N.H. Code of Admin. Rule Puc 201.04 and 203.08.

F. Restriction of Contact with State Employees

From the date of release of this RFP until an award is made and announced regarding the selection of a Proposer, all communication with personnel employed by or under contract with the Commission regarding this RFP is forbidden unless first approved by the RFP Point(s) of Contact listed on Page 1 of this RFP. Commission employees have been directed not to hold conferences and/or discussions concerning this RFP with any Contractor during the selection process, unless otherwise authorized by the RFP Point(s) of Contact.

G. RFP Addendum

The Commission reserves the right to amend this RFP at its discretion, prior to the Proposal submission deadline. In the event of an addendum to this RFP, the Commission, at its sole discretion, may extend the Proposal submission deadline, as it deems appropriate.

H. Validity of Proposal

Proposals must be valid for one hundred and eighty (180) days following the deadline for submission of Proposals in Schedule of Events, or until the Effective Date of any resulting Contract, whichever is later.

I. Proposal Preparation Cost

By submitting a Proposal, an Applicant agrees that in no event shall the Commission be either responsible for or held liable for any costs incurred by an Applicant in the preparation of or in connection with the Proposal, or for Work performed prior to the Effective Date of a resulting Contract.

J. Oral Presentations/Interviews and Discussion

The Commission reserves the right to require Applicants to make oral presentations of their Proposals. Any and all costs associated with oral presentations/interviews/demos shall be borne entirely by the Proposer.

K. Ethical Requirements

From the time this RFP is published until a contract is awarded, no bidder shall offer or give, directly or indirectly, any gift, expense reimbursement, or honorarium, as defined by RSA 15-B, to any elected official, public official, public employee, constitutional official, or family member of any such official or employee who will select, evaluate, or award an RFP, or similar submission. Any bidder that violates RSA 21-G:38 shall be subject to prosecution for an offense under RSA 640:2. Any bidder who has been convicted of an offense based on conduct in violation of this section, which has not been annulled, or who is subject to a pending criminal charge for such an offense, shall be disqualified from bidding on the RFP, or similar request for submission and every such bidder shall be disqualified from bidding on any RFP or similar request for submission issued by any state agency. A bidder that was disqualified under this section because of a pending criminal charge which is subsequently dismissed, results in an acquittal, or is annulled, may notify the department of administrative services, which shall note that information on the list maintained on the state's internal intranet system, except in the case of annulment, the information, shall be deleted from the list.

L. Right of the Commission in Evaluating Proposals

The Agency reserves the right to:

- Make independent investigations in evaluating Proposals;
- Request additional information to clarify elements of a Proposal;
- Waive minor or immaterial deviations from the RFP requirements, if determined to be in the best interest of the State;
- Omit any planned evaluation step if, in the Commission's view, the step is not needed;
- At its sole discretion, reject any and all Proposals at any time; and
- Open contract discussions with the second highest scoring Proposer and so on, if the Commission is unable to reach an agreement on Contract terms with the higher scoring Proposer(s).

M. Procedure After Selection

Pursuant to RSA 21-G:37, Applicants that question the Commission's identification of the selected proposal may request that the agency review its selection process. Such request shall be made in writing and be received by the Commission within 5 business days after the rank or score is posted on the agency website. The request shall specify all points on which the proposer believes the Commission erred in its process and shall contain such argument in support of its position as the bidder seeks to present. In response, the Commission shall review the process it followed for evaluating responses and, within 5 business days of receiving the request for review, issue a written response either affirming its initial selection of a proposer or canceling the RFP. In its request for review, a proposer shall not submit, and an agency shall not accept nor consider, any substantive information that was not included by the proposer in its original RFP response. No hearing shall be held in conjunction with a review. The outcome of the agency's review shall not be subject to appeal.

APPENDIX A **RELEVANT DOCUMENTS**

This listing of relevant documents is intended to be an aid to prospective Applicants and not an exhaustive listing of matters that an Applicant may deem relevant. Each Applicant is expected to have reviewed and become familiar with the materials set forth herein, as well as with other materials deemed necessary and appropriate by each such Applicant.

New Hampshire Laws:

Electric Industry Restructuring:

Session Law: 1996 NH Laws, Chapter 129

<http://www.gencourt.state.nh.us/legislation/1996/HB1392.htm>

Codified Law: RSA Chapter 374-F

<http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-mrg.htm>

2001 Divestiture Delay:

Session Law: 2001 NH Laws, Chapter 29, <http://www.gencourt.state.nh.us/legislation/2001/HB0489.html>

2002 Divestiture Delay

Session Law: 2002 NH Laws, Chapter 130,

<http://www.gencourt.state.nh.us/legislation/2002/HB0284.html>

2005 Mercury Emissions Reduction Law

Session Law: 1996 NH Laws, Chapter 105

<http://www.gencourt.state.nh.us/legislation/2006/HB1673.html>

2014 Law Relative to PSNH's Generation Assets

Session Law: 2014 NH Laws, Chapter 310

<http://www.gencourt.state.nh.us/legislation/2014/HB1602.html>

2015 Securitization Law

Session Law: 2015 NH Laws, Chapter 221

<http://www.gencourt.state.nh.us/legislation/2015/SB0221.html>

NHPUC Dockets and Orders:

Docket No. IR 13-020, “Investigation into Market Conditions Affecting PSNH and its Default Service Customers and the Impact of PSNH's Ownership of Generation on the Competitive Electric Market”

<https://www.puc.nh.gov/Regulatory/Docketbk/2013/13-020.html>

(This docket includes reports from PUC Staff, Liberty Consulting Group, La Capra Associates, and ESS Group referenced herein.)

Docket No. DE 11-250, “Investigation of Scrubber Costs and Cost Recovery”

<https://www.puc.nh.gov/Regulatory/Docketbk/2011/11-250.html>

Docket No. DE 14-238, “Determination Regarding PSNH's Generation Assets”

<http://www.puc.state.nh.us/Regulatory/Docketbk/2014/14-238.html>

(This docket includes the 2015 PSNH Settlement Agreement and the Amendment thereto, as well as detailed testimony from PSNH describing the 2015 Settlement Agreement, the generating assets to be sold, and the anticipated divestiture auction process.)

Eversource Corporate Documents:

Form 10-K dated February 25, 2015

<http://www.sec.gov/Archives/edgar/data/13372/000007274115000013/f2014form10kedgar.htm>

Form 10-Q dated May 6, 2016

<https://www.sec.gov/Archives/edgar/data/13372/000007274116000075/march312016form10q.htm>

2016 Proxy Statement

<https://www.eversource.com/Content/docs/default-source/investors/proxy-statement.pdf>

2015 Eversource Annual Report

<https://www.eversource.com/Content/docs/default-source/Investors/2015-annual-report.pdf>

NH Department of Environmental Services:

Phase I Environmental Assessments and DES documents regarding Eversource's generating assets
http://www.puc.state.nh.us/Regulatory/Docketbk/2014/14-238/LETTERS-MEMOS-TARIFFS/14-238_2015-11-30_PSNH_DBA_EVERSOURCE_ATT_ENVIRONMENTAL_ASSESSMENTS.PDF

APPENDIX B

SCORING CRITERIA

RFP Response Evaluation Matrix - Eversource Generation Divestiture Auction Manager

Scoring Methodology - The Selection Committee will evaluate each Proposal in accordance with the criteria set forth in 1-10, below. Sections 1 and 2 are yes/no Evaluations. If the Committee determines that No is the answer to section 1 or 2, the Proposal will not receive further evaluation. The remaining categories will be graded on a score of 1 to 5, with 1 being the least desirable, 3 being average or moderate desirability and 5 being ideal/maximum desirability. The score in each category will be multiplied by the percentage weight given to each category and then added together to get an overall score. The highest overall score will denote the best/most ideal proposal.

Scoring Criteria

1. Ability or capacity to meet particular requirements of the contract and needs of the Commission (Yes or No) If No, Proposal will Receive No further consideration;
2. Ability to meet prequalification requirements, with fewest exceptions (Yes or No) If No, Proposal will Receive No further consideration;
3. Prior experience of Applicant and staff with the scope of work described (20% of Overall Score);
4. Quality of proposed service and solutions for Commission (10% of Overall Score);
5. Overall firm quality, including reputation, breadth of expertise, and depth of relevant resources (15% of Overall Score);
6. Ability to effectively market the generation assets to a broad network of qualified bidders, as reflected by a demonstration of knowledge of the relevant asset markets and the broad network of potential asset buyers (20 % of Overall Score);
7. Demonstrated prior experience providing expert witness testimony before utility regulators, especially in the context of generation asset sale transactions (5% of Overall Score);
8. Administrative and operational efficiency, which optimizes time and resources spent by Commission on oversight and administration, and including an ability to work with the Commission, Eversource, and other retained advisors (if any) cooperatively and productively (10 % of Overall Score);
9. Anticipated cost-effectiveness, based on relationship between total overall expected costs and anticipated quality of the Applicant's service, as well as any proposed cost containment mechanisms (10% of Overall Score);
10. Assessment based on performance during in-person and/or phone interviews (10% of Overall Score).

Below is a sample of the Scoring Matrix to be used by the Committee:

	FIRM	1. Ability to meet contracting requirements (must be "YES")	2. Pre-qualification requirements with fewest exceptions (must be "YES")	3. Prior experience with scope of work	4. Quality of proposed services and solution	5. Firm quality (reputation, breadth of expertise, resources)
		N/A	N/A	20%	10%	15%
1	Respondent 1					
2	Respondent 2					
3	Respondent 3					
4	Respondent 4					
5	Respondent 5					
6	Respondent 6					

	FIRM	6. Ability to market generation assets	7. Expert witness testimony experience	8. Administrative and operational efficiency	9. Cost-effectiveness and cost containment	10. Assessment based on interview performance	WEIGHTED SCORE	RANK
		20%	5%	10%	10%	10%		
1	Respondent 1							
2	Respondent 2							
3	Respondent 3							
4	Respondent 4							
5	Respondent 5							
6	Respondent 6							

Attachment I. SECTIONS 7-10 FROM DRAFT RULES**Draft Date: August 4, 2012****SECTION 13. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:****170 IAC 4-7-10 Updates**

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide an update regarding substantial unexpected changes that occur between IRP filings.

(b) Upon the request of the commission or its staff, the utility shall provide the requested updated IRP information.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-10)

Draft Date: October 4, 2012**SECTION 13. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:****170 IAC 4-7-10 Updates**

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide an update regarding substantial unexpected changes that occur between IRP filings.

(b) Upon the request of the commission or its staff, the utility shall provide the requested updated IRP information.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-10)

Draft Date: October 22, 2015**SECTION 13. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:****170 IAC 4-7-10 Updates**Authority: IC 8-1-1-3; **IC 8-1-8.5-3**

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide an update regarding substantial unexpected changes that occur between IRP filings.

(b) Upon the request of the commission or its staff, the utility shall provide the requested updated IRP information.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-10)

Draft Date: March 4, 2016

SECTION 16. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 IRP Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility shall provide an update regarding substantial unexpected changes that occur between IRP submissions.

(b) Upon the request of the commission or its staff, the utility shall provide updated IRP information. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-10*)

Draft Date: July 5, 2016

SECTION 16. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 IRP Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide the director an update regarding substantial, unexpected changes that occur between IRP submissions. Copies of an update shall be provided to the OUCC and other interested parties.

(b) Upon the request of the commission or its staff, the utility shall provide updated IRP information to the director, the OUCC and interested parties. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-10*)