STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR FEDERALLY MANDATED REQUIREMENTS; APPROVAL OF CLEAN COAL TECHNOLOGY, ENERGY AND COMPLIANCE PROJECTS; FOR ONGOING REVIEW; FOR APPROVAL OF FINANCIAL INCENTIVES INCLUDING (1) THE RECORDING OF A REGULATORY ASSET FOR COSTS INCURRED DURING TESTING AND OPERATION OF SUCH PROJECTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE AND DEPRECIATION, TAX AND FINANCING COSTS, UNTIL SUCH COSTS ARE REFLECTED IN RATES AND (2) ALTERNATIVELY, THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH A PERIODIC RATE ADJUSTMENT MECHANISM; ALL UNDER IND. CODE §§ 8-1-2-23, 8-1-8.4-1 ET SEQ, 8-1-8.7-1 ET SEQ., AND 8-1-8.8 -1 ET SEQ.	)	**CAUSE NO. 44446**

Direct Testimony of
Jeremy I. Fisher, PhD

REDACTED VERSION

On Behalf of
Sierra Club, Citizens Action Coalition, and Valley Watch.

May 28, 2014

Table of Contents

Table of Figures

Table of Tables

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and six years of working within the energy planning sector, including work on integrated resource plans, long-term planning for utilities, states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities.

I have provided consulting services for various clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the California Energy Commission ("CEC"), the California Division of Ratepayer Advocates ("CA DRA"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the State of Utah Energy Office, the State of Alaska, the State of Arkansas, the Regulatory Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), Environmental Defense Fund ("EDF"), Stockholm Environment Institute ("SEI"), Civil Society Institute, and Clean Wisconsin. I developed a regulatory tool for EPA and state air quality agencies, released by EPA in 2014 as the Avoided Emissions and Generation Tool ("AVERT"), and have provided technical support to EPA regarding electric utility planning practices.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oregon, Nevada, Utah, Wisconsin, and Wyoming. I have reviewed and evaluated the energy planning practice of utilities in dockets involving integrated resource plans ("IRP") and certificates of public convenience and necessity ("CPCN").

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and a Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as Exhibit JIF-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club, Citizens Action Coalition, and Valley Watch (collectively "Joint Intervenors").

Q Have you testified in front of the Indiana Utility Regulatory Commission previously?

A Yes. In 2013, I provided testimony on Indianapolis Power and Light's ("IPL") application for a certificate of public convenience and necessity ("CPCN") for various environmental retrofits at their "big five" coal-fired generating units in Cause No. 44242, as well as on a subsequent IPL CPCN application for a replacement natural gas unit in Cause No. 44439. I also gave a presentation regarding IRP best practices before the IURC and Indiana utilities at the 2013 IRP Contemporary Issues Technical Conference.

Q What is the purpose of your testimony?

A My testimony evaluates the economic modeling performed on behalf of Vectren South ("the Company") in support of this application for certificate of public convenience and necessity for various retrofits at Brown 1 & 2, Culley 3 and Culley plant, and Warrick 4.

Q How much is the Company proposing to invest as part of this application?

A The Company "estimates the total projects cost to be in the range of $75-$95 million;" for the purposes of economic modeling, the Company assumes total costs of $89.3 million, with roughly [redacted]

Q What are your findings regarding the Company's application?

A The Company limited the scope of its economic analysis in ways that skewed the outcome, and committed several errors in the economic analysis it did conduct.

- The Company failed to present a 20-year analysis it conducted on the economics of Brown 1 & 2 and Culley 3 that shows that Brown 1 & 2 are non-economic choices for retrofit;
- The Company's analysis fails to account for capacity sales in scenarios where excess capacity is procured;
- The Company's analysis uses a coal price forecast well below that of regional forecasts and that does not reflect the very high prices paid by the Company for coal in recent years;
- The Company's analysis incorrectly accounts for revenue sharing provisions of off-systems sales;
- The Company considered replacing its existing units with only new facilities; the Company did not consider the economics or replacing its units by purchasing an existing facility or entering into a power purchase agreement ("PPA");
- Even though the Company seeks approval to install controls at Warrick 4 and the Culley plant, the Company did not even attempt to analyze

[1] Exhibit WDG-3, Table 1.

whether the least-cost option is to install controls at Culley 2 and Warrick 4;

- Finally, an assessment of Brown and Culley's operations from 2010 to 2013 reveals that these units have likely operated non-economically, losing [redacted] relative to the market, causing consumers to pay above-market costs for the last four years.

Overall, these findings indicate that Vectren's proposal to retrofit and continue the operation of Brown and Culley are non-economic decisions and not in the best interests of ratepayers.

Q What does the Company's 20-year economic analysis show?

Over a 20-year period, retiring and replacing Brown 1 and 2 with a new combined cycle gas turbine ("CCGT") is a lower-cost option than retrofitting both units. The analysis indicates a moderate decrease in the economic viability of Brown 1 & 2 individually (relative to a CCGT) in the base case, but a significant decrease in the benefit of retrofitting these two units together, dropping from a net benefit of [redacted] o a liability of [redacted] These are the results from Company's own 20-year analysis, without any adjustments.

Q Did you adjust the Company's 20-year economic analysis to correct the additional errors you identified above?

A Yes. After reviewing the Company's 20-year modeling, I corrected the analysis such that:

- excess capacity is valued similarly to capacity shortfalls;
- the Company's coal price projection matches regional forecasts; and
- the analysis reflects the ratepayer benefits of net off-system sales.

Confidential Table 1, below, shows the net benefit of the retrofits in the Company's base case over a 20-year period,[2] the "downside" (a scenario in which

[2] Net benefits are calculated as the difference between the case in which all units are retrofit and cases in which one or more units are not retrofit.

gas prices are low and carbon prices are high), and "upside" (a scenario opposite that of the downside) for various replacement scenarios relative to the retrofits. In two out of three scenarios, retiring and replacing Brown 1 and 2 and Culley 3 is the least-cost option.

Confidential Table 1.
20-yr Net Benefit of Retrofits, after adjustments (million 2014$)[3]

Unit(s)	*Base*	*Downside*	*Upside*
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

In addition, my analysis shows that Brown 1 and 2, and Culley 2 and 3 have had effectively negative net revenues relative to the MISO market for 2010-2013.A review of Culley 2, not analyzed by the Company, indicates that it is unlikely to make reasonable revenues in the foreseeable future, and should be considered for expedient retirement as well.

Q What are your recommendations to the Commission regarding the Company's application for a CPCN at Culley 2 & 3, AB Brown 1 & 2, and Warrick 4?

A Based on my assessment of the evidence provided by the Company with regards to Brown 1 & 2 and Culley 3, I recommend the following:

- The Commission should deny the CPCN for these units. Based on a review of recent and likely forward-looking net revenues for Culley 2, I recommend that the Commission deny the CPCN for this unit as well.

[3] Source: JI 1-15 (2014-2033), with adjustments for capacity market sales, off-system sales, and regional coal price forecast.

- The Commission should direct the Company to issue all-source RFPs for replacement capacity and/or energy that seek both self-build as well as contract options to meet requirements.
- The Commission should establish an investigation into whether Culley and Brown have operated non-economically from 2010-2013, and if so, the extent to which ratepayers have been harmed by Vectren's actions.

The Company has not presented an economic assessment of Warrick 4. I have not completed an assessment of this unit and I have no recommendation regarding Warrick 4.

2. OVERVIEW OF THE COMPANY'S ECONOMIC ANALYSIS

Q Please describe the analysis conducted on behalf of the Company in this case to justify the proposed controls at Culley, Brown and Warrick.

A The Company contracted with Black and Veatch Management Consulting Division ("B&V") to perform an economic analysis comparing retrofitting the units to retiring and replacing them.[4] The analysis reviewed the cost of retrofitting and maintaining Brown 1, Brown 2, the combination of Brown 1 & 2 together, and Culley 3, as well as the costs of retiring those units in December 2015 and replacing those units (or combination of units) with combustion turbines ("CTs") or natural gas combined cycle units in 2018. B&V used PROMOD-IV, a simulation dispatch model,[5] to estimate the dispatch and production cost of their existing and possible replacement units against the MISO market, as well as market purchases and sales. B&V reviewed a baseline scenario, as well as two scenarios termed "upside" and "downside" in which they examined favorable and non-favorable conditions for maintaining their own coal units.

[4] Direct Testimony of Wayne D. Games, p20 line 23 through p21, line 2. The B&V analysis is attached to Games's testimony as Confidential Exhibit WDG-3.
[5] *See* Exhibit WDG-3, page 6.

Q **Did Black & Veatch analyze the economics of retrofitting or replacing Culley 2 or Warrick 4?**

A No. Culley 2 and Warrick 4 were excluded from the B&V analysis. As a result, the B&V analysis could not, by design "confirm . . . that retrofitting Brown 1 and 2, Culley 2 and 3, and Warrick 4 with the proposed pollution control equipment offers the lowest cost option."[6]

Q **Did the Company present any other economic analysis demonstrating that retrofitting Culley 2 and Warrick 4 are the least-cost options?**

A No, not that I am aware of. The Black & Veatch analysis does not consider the economics of retrofitting versus replacing Culley 2 and Warrick 4. The Company has not presented any other, comparable analysis of the economics of retrofitting Culley 2 and Warrick 4.

Q **Have you reviewed all of the Company's economic analyses that support this application?**

A Yes, I have thoroughly reviewed all of the Company's analyses provided to me, including the B&V economic analysis and a Burns & McDonnell ("B&Mc") report commissioned by the Company. Mr. Games states that "Vectren South also hired Burns & McDonnell to conduct an economic analysis of alternative options to retrofitting the Units. B&Mc provided pricing for natural gas, coal, waste to energy, nuclear, renewables including wind and solar, and energy storage generation resources." [7] The B&Mc analysis established capital and maintenance costs and operating characteristics of the options that could have been evaluated by Vectren as new-build replacement options in the B&V analysis. To be clear, the B&Mc analysis did not evaluate forward fuel pricing or recommend for or against specific technologies.[8]

[6] Direct Testimony of Wayne D. Games, p21 lines 2-4.
[7] Direct Testimony of Wayne D. Games, p20 line 20 through p23.
[8] JI DR 2.11 Burns and McDonnell 2013 Vectren TA Report Draft.

Q What was the outcome of B&V's analysis?

A B&V presents the outcome of their analysis in Table 3 of WDG-3. This table indicates the total net present value of revenue requirements ("PVRR") of the base retrofit scenario and alternatives, but not the net benefit of the retrofit – i.e., the difference between the base case and the alternatives. In Confidential Table 2, below, I present the net benefit of the retrofits as found by B&V in the base, downside and upside cases. These costs are derived from workpapers provided in JI 1-15. Differences between the values presented here and in WDG-3 are due to rounding.

Confidential Table 2.
10-yr Net Benefit of Retrofits (million 2014$)[9]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

Q What is notable about these results?

A First, based on my experience in similar cases, the net benefit of retrofitting and maintaining these 245-275 MW units in the base case is fairly small on an absolute scale [redacted] indicating that a particularly careful review is warranted. In particular, for Brown 1 & 2, the [redacted] net benefit found by the Company equates to a quite low value of roughly [redacted][10]

Second, the fact that the benefit of retrofitting Brown 1 & 2 individually, relative to a CC replacement [redacted]) is more beneficial than retrofitting both Brown 1 & 2 together [redacted], suggests an analytical error. B&V models these units as market participants. Therefore, I would expect that if Brown

[9] Source: JI 1-15 (2014-2023), and Games Workpapers
[10] The Company assumes a 481 MW combined capacity for Brown 1 & 2.*See* JI 1-15.

1 is beneficial, and Brown 2 is also beneficial then the benefit of a combined Brown 1 & 2 would be roughly the same as the sum of the benefit of Brown 1 plus Brown 2 – or around [redacted] Instead, the benefit of retrofitting both is smaller than the benefit of retrofitting either individually. This discrepancy is even more pronounced in the downside scenario, where the net benefit of retrofitting either Brown 1 or Brown 2 are both positive ([redacted], but the benefit of retrofitting both is negative [redacted]). I will discuss this issue in more depth later in my testimony.[11]

Third, and most problematically, the Company hid critical results from this Commission that were significantly less favorable than the ones presented by Mr. Games. Mr. Games's testimony and Exhibit WDG-3 (the B&V analysis) only report favorable results from a 10-year analysis period (2014-2023) and fail to report results from a 20-year analysis (2014-2033) that clearly indicate that Brown 1 & 2 are non-economic. The Company's 10-year analysis over-represents near-term impacts, underrepresents long-term costs, fails to even cover the recovery period of the retrofits or the replacement units, and does not account for the Company's estimated costs at their coal units past 2023. The more reasonable 20-year results show that Brown 1 & 2 are non-economic in both the base and downside scenarios examined by the Company.

3. <u>THE COMPANY'S SHORTENED ANALYSIS PERIOD IS CONTRADICTED BY THE 20-YEAR ANALYSIS SHOWING THAT BROWN 1 & 2 ARE UNECONOMIC</u>

Q You described the Company's 10-year net present value as "problematic." Why?

A There are several problems with the Company's use of a 10-year period for the economic analysis. Overall, ten years is a very short analysis window that does not capture important costs after 2023. The short analysis period:

- Excludes important capital expenditures that occur after 2023;
- Obscures the poor performance of the coal units after 2020;

[11] *See infra* pp. 21-26.

- Fails to capture the anticipated 20-year economic life of the retrofits,[12] or the Company's stipulation that the "units will remain generating electricity for the next twenty (20) years;"[13]
- Does not include the period over which the Company will actually recover costs for the retrofits, starting in 2020;[14]
- Is inconsistent with the Company's 20-year analysis period in the 2011 IRP,[15] or proposed for the 2014 IRP; and
- Does not capture the full depreciation period of the Company's previously invested controls.[16]

Q **In Exhibit WDG-3, did B&V present only the values for the 10-year NPVs under the three scenarios they analyzed?**

A Yes.

Q **Did B&V analyze the economics of retrofitting versus replacing the units on any other time scale other than 10 years?**

A Yes, a review of workbooks provided to Joint Intervenors in response to JI DR 1.15, but not included as part of Mr. Games' filed workpapers, indicates that either the Company or their consultants reviewed the outcome of this PVRR analysis over 20 years but chose to withdraw those results from the B&V report and specifically truncated important results and data from filed workpapers.

The more reasonable 20-year analysis yields a completely different answer than the limited 10-year analysis. The Company appears to have been aware of this

---

[12] *See* Direct Testimony of Diane M. Fischer, page 17, line 2.
[13] Response to OUCC 3-14(b).
[14] *See* Direct Testimony of Carl C. Chapman, page 6, lines 15-17.
[15] *See* Vectren 2011 IRP (DR JI 1-6), p161 "For the purposes of this discussion, the planning period PVRR is defined as the present value of revenue requirements for the 20 year period, 2012 – 2031, over which the optimization analysis was performed. "End effects", estimates of revenue requirements beyond the twenty year planning period, were also considered when selecting the optimal plan."
[16] Direct Testimony of Carl C. Chapman, page 7, lines 11-13. "The $400 million previously invested in emission controls will be fully depreciated in 9-13 years, depending on the installation date of the equipment at each plant."

discrepancy at the time of this filing, yet did not disclose the unfavorable results to this Commission.

Q What is the outcome of the Company's analysis over a 20-year period?

A Over a 20-year period, retiring and replacing Brown 1 and 2 with a new CCGT is a lower-cost option than retrofitting both units. The analysis indicates a moderate decrease in the economic viability of Brown 1 & 2 individually (relative to a CCGT) in the base case, but a significant decrease in the benefit of retrofitting these two units together, dropping from a net benefit of [redacted] o a liability of [redacted]

The Company's 20-year analysis results are shown in Confidential Table 3, below.

Confidential Table 3.
B&V 20-yr net benefit of retrofits (million 2014$)[17]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

Q What is the source of this 20-year analysis?

A The 20-year analysis was performed by B&V, but provided only in response to discovery request JI 1-15. The spreadsheet, as provided, included a drop-down toggle to switch between a 10-year and 20-year analysis, as shown in Confidential Figure 1, below.

[17] Source: JI 1-15 (2014-2033)

Confidential Figure 1.
Screenshot of JI-1.15 analysis page for "base" scenario, highlighting dropdown for "10yr" or "20yr" analysis.

[redacted]

Formulas were erased in this version of the Company's workbooks, despite a request that formulas remain intact for examination.[18] Nonetheless, it was fairly straightforward to re-create the Company's analysis and produce identical results in the 10 year analysis period. The Company's spreadsheet included model output results through 2033 (rather than 2023). Therefore, it simply required examining the full span of the available data rather than the truncated version reviewed in Exhibit WDG-3.

[18] Joint Intervenor's definitions included with their discovery requests note that "'Workpapers' are defined as original, electronic, machine-readable, unlocked, Excel format (where possible) with formulas in-tact." *See* General Instructions to Joint Intervenor's First, Second, and Third Data Requests to Vectren South §1.(p). Vectren subsequently provided a different version of this workbook, in which the toggle switch for the 20-year results had been removed, but which had the formulas intact.

Q Was the Company aware of the 20-year analysis results?

A I assume so. The original version of the spreadsheet provided in JI 1-15 clearly had the capacity to review both 10-year and 20-year results. The Company and/or B&V made the decision to present only the 10-year results in Exhibit WDG-3.

Q Did the Company explain why it ignored or withdrew the 20-year results?

No. Joint Intervenors asked if "B&V-MCD [Management Consulting Division] had performed the economic analysis for a period other than 2014-2023," or if they "examined the outcome of this analysis if extended through 2034 or any other date beyond 2023."[19] Vectren claimed that B&V had not conducted an extended analysis, despite the presence of the workpapers provided in JI DR 1.15 that clearly indicate that the analysis was set up through 2033. When pressed to reconcile its original response with the workpapers provided to Joint Intervenors, Vectren stated that:

> B&V conducted a 10-year analysis. The original work book was set-up to include additional years and some of the information for the years 11-20 were populated, but no analysis for this period was conducted.[20]

This response cannot be reconciled with the facts. The workbook provided in response to JI DR 1.15 contains a mechanism by which B&V and/or Vectren could review either 10 or 20 year NPV results, as shown in Confidential Figure 1. Moreover, the entire analysis is populated with data through 2033, with the exception of "Recovery", which is truncated in 2026. I would consider it imprudent if the Company and/or B&V had populated the entire dataset through 2033, but simply decided not to change a single formulation in their workbooks to look at the full span of data, rather than the truncated set.[21]

---

[19] *See* JI DR 3.19(a) and (b)

[20] *See* Supplemental Responses to JI DR 3.19, email from Jason Stephenson on May 23, 2014 to Jennifer Washburn, Counsel for CAC.

[21] In the confidential workpapers provided by Mr. Games (Confidential Vectren Output Format_13May2014.xlsb), a single column is used to provide a reference for the time-span that should be

In addition, Vectren provided a supplemental response to JI DR 1.12, which requested any analyses performed for Brown and Culley that had not been presented in this testimony. The Company provided a contemporary study (November 2013) of Culley 2 that seemed to use a similar analysis structure, and in which all analyses were presented over a 20-year time horizon.[22]

Q What is the outcome of the 20-year analysis?

A The value of Brown 1 & 2 relative to a 2x1 NGCC replacement is positive in the Company's assessment only through 2026. Confidential Figure 2, below, shows the cumulative present value of Brown 1 & 2 through the end of the analysis period – i.e. what would happen if the assessment is only reviewed through a certain end date. The Company's selection of 2023 as an end date in this analysis belies the poor long-term recovery anticipated for Brown 1 & 2.

used for the NPV function. Using Mr. Games formulas in the JI DR 1.15 workbooks, and changing the reference cell structures (in "Base Comparison" tab) to look through column "W" (2033) instead of column "M" (2023) results in the 20 year analysis instead of a 10-year analysis. In the first version of workpapers provided by Mr. Games (Confidential Vectren Workpaper.xlsb), the workbook even has blank spaces from columns N-W where data from 2024-2033 previously populated the analysis (see tab "Base", for example).

[22] *See* Exhibit JI DR 3 12.pdf, slide 12 titled "Initial 20 Year NPV Comparison Across Alternative Portfolio's – Generation Total Costs to Serve."

Confidential Figure 2.
Cumulative present value benefit of retrofit at Brown 1 & 2 (replacement with 2x1 NGCC)

[redacted]

According to the Company's analysis, Brown 1 & 2 only have a positive value if viewed through 2026 – i.e. they are a net drain on ratepayers if assessed past 2026. In fact, the analysis indicates that the net annual benefit of these units becomes negative in 2020 – i.e. they start losing money in 2020 on an annual basis. Since the recovery of the capital costs requested in this case carry well beyond 2020, or even 2026 (the Company does not even propose to begin recovery until 2020), it is likely that the Company would be left with attempting to recover stranded costs on a money-losing unit.

To be clear, these 20-year values and outcomes are from the Company's analysis with no changes aside from looking at the net present value from 2014 to 2033 instead of 2014-2023.

The 10-year results misrepresent the actual economic outlook for Brown 1 & 2, and conveniently ignore the likely stranded costs that the Company will incur with these units.

Q How does a 20-year analysis change the assessment of the Company's units?

A The 20-year analysis captures the impact of an expected carbon price on the Company's existing fleet and the subsequent poor performance of Culley and Brown, the capital investments required at Brown and Culley through 2026, and the full extent of capital required for the CCGT or CT replacements.

Ultimately, the difference between the 10-year and 20-year analyses, from a net present value perspective, is small for Brown 1 & 2, individually, with differences from a reduction in benefit of [redacted] to an increase in benefit [redacted] *See infra* **Confidential Table 4**. Culley 3 benefits from the extended analysis period (presumably by capturing more capital costs for the CCGT). However, the economics of replacing Brown 1 & 2 with a CCGT changes markedly, switching from a benefit of [redacted] over a 10-year period to a liability of [redacted] over a 20-year period, a change of over [redacted]

Confidential Table 4.
10-yr and 20-yr net benefit of retrofits in base scenario[23]

[redacted]

The values in Confidential Table 4 come directly from the Company's own analysis. I have not made any adjustments to these values.

Q Why shouldn't the Company retrofit Brown 1 & 2 now and then retire the units in 2020?

A The analysis here indicates that the Company would be unable to recover the costs of the retrofits if the units ceased operations in 2020.

[23] JI DR 1.15 (million 2014$). These numbers are based only on Vectren's data, with no assumption changes or other corrections aside from reviewing data through 2033

Q Is a 10-year analysis period consistent with reasonable utility planning practice?

A No. In this case, the Company is not making short-term resource investment decisions. Instead, the Company is planning on spending substantial capital at Culley and Brown and has proposed to defer recovery of the investments until 2020 - three years prior to the end of the 10-year analysis period reported by Vectren.[24] Vectren would presumably seek to recover the costs of the equipment over a 20-year period, consistent with the prior installed equipment.[25] I would thus expect that Vectren would not complete recovery of these retrofits until 2040. Similarly, any replacement capacity would likely not be recovered over the short period covered by this 10-year analysis.

By choosing a 10-year analysis period, the Company ends its analysis only three years after Brown and Culley begin to perform poorly in Vectren's base case forecast. After 2020, the capacity factor of Brown 1 & 2 plunge from 70% to about [redacted] in the base case, Culley 3 drops from near 70% to less than [redacted] nd the already low Culley 2 (at less than 40%) drops to about [redacted] see Confidential Figure 3, below). Revenues from these units would be significantly diminished with such a dramatic drop in output. However, by ending the analysis in 2023, the Company's presentation to the Commission obscures ten subsequent years of lagging performance in the Company's own base case forecast as compared with the replacement alternative.

---

[24] *See* Direct Testimony of Carl C. Chapman, page 6, lines 4-18.

[25] *See* response to OUCC 3-14(a). "The $400 million Vectren South emission control equipment referred to by Mr. Chapman which has already been installed will be fully depreciation *[sic]* in 9-13 years pursuant to Vectren South's Commission approved depreciation rates." SCRs and baghouses were installed at Culley and Brown between 2003-2006, implying a 20-year depreciation period. See also response to OUCC 3-14(c). "The new equipment Vectren South is proposing to install in this proceeding will be depreciated in accordance with Vectren South's approved depreciation rates."

Confidential Figure 3.
Capacity factors for Culley and Brown (base case), CCGT 1x1 (Brown 1 CC replacement case), and CCGT 1x2 (Brown 1 & 2 CC replacement case)

[redacted]

Q Does the 10-year analysis period exclude capital costs the Company expects to incur after 2023?

Yes, the Company's short analysis period also appears to exclude important capital expenditures that the Company expects will occur after 2023. Workpapers provided by Mr. Games show annual capital expenditures, including MATS controls, at Brown 1 & 2, and Culley 3, and the translation from these values and the existing plant balance to the expected recovery at Brown and Culley each year through 2023.[26] Brown 1 & 2, and Culley 3, incur significant capital expenditures from 2014 through 2023 as indicated in Confidential Figure 4, below.

[26] *See* Games workpapers, Confidential Vectren Output Format_13May2014.xlsb, tab "Existing Unit Data."

Confidential Figure 4.
Annual CapEx recovery on evaluated units, difference between retrofit (base) and retire cases. Million nominal $.

[redacted]

In total, additional capital spending at the units amounts to $314 million (nominal) from 2014 through 2023. Only a fraction of these costs are due directly to the proposed retrofits. While the Company does not explain the remaining capital expenses, it is not uncommon for large fossil units to incur ongoing capital expenses for upgrades to equipment.

Q Is there a problem with the way that the Company has portrayed capital spending at Brown and Culley in this analysis?

A Yes. There are three significant problems with the way that the Company has structured this analysis with regards to capital expenses.

First, I would expect that ongoing capital expenditures would be incurred through the end of a full 20-year analysis period (i.e. 2033, and beyond), not ceasing in 2023 as portrayed here. The capital treatment excludes known future capital costs that should be part of this assessment. The 10-year analysis ignores a large fraction of capital costs that would be incurred for the coal units and the gas replacement units, and thus is simply non-representative of the actual costs that the Company would expect to recover over the next thirty years.

Second, in the analysis conducted by B&V, the proposed retrofits appear to be depreciated over a 30-year period at Brown, and a 22-year period at Culley,[27] but the analysis cuts off after 10 years. This means that both Brown and Culley incur avoidable capital expenses that should be part of this assessment, but are excluded by the short analysis period. In the workpapers provided with JI DR 1.15, the capital recovery plan for Brown and Culley only extends to 2026 and then cuts off promptly,[28] despite the significant non-recovered plant balance – including the extended recovery of the retrofits.

Third, depreciation expenses on the gas-fired units extend through 2033, and thus are inconsistent with the treatment of retrofit costs, which end in 2026. According to the Company's analysis, ratepayers would fund the natural gas replacement continuously, but cease paying for retrofits in 2026. This is a clear analysis error and bias.

Q Have you corrected this analysis error?

A No. I have not corrected this error, in part because I do not have a schedule of capital spending at the Company's coal units from 2026 to 2033. Correction of this error would favor replacing the coal units.

Q Is the Company's 10-year analysis period consistent with Vectren's 2011 IRP or the forthcoming 2014 IRP?

A No. The short analysis period is inconsistent with the Company's 2011 IRP, [29] which explains that the planning period used in the IRP is a "20 year period, 2012-2031." The 2011 IRP not only reviewed a longer window, but also discussed the importance of "end effects", impacts on the net present value of revenue requirements due to ongoing and late-year capital expenditures (i.e.

[27] *See* Games workpapers, Confidential Vectren Output Format_13May2014.xlsb, tab "Existing Unit Data." Annual straight line depreciation rate of 3.348% at Brown equates to a 30-yr depreciation; 4.533% at Culley equates to a 22-yr depreciation period. It is not clear if this depreciation assumption comports with the Company's expected depreciation rates for the retrofit equipment.
[28] In Mr. Games's workpapers, capital recovery extends through 2023 and then is cut off.
[29] *See* Vectren 2011 IRP (DR JI 1-6), p161 "For the purposes of this discussion, the planning period PVRR is defined as the present value of revenue requirements for the 20 year period, 2012 – 2031, over which the optimization analysis was performed."

expenditures for which depreciation would reasonably occur after the end of the analysis).[30] End effects were not considered in this CPCN, but can have significant impacts on analysis results as recognized and discussed in the Company's 2011 IRP.

Q Does this Commission value consistency between IRP and resource decisions?

A Yes. The Commission's proposed IRP rule provides that "[a]ny resource action shall be consistent with the most recent IRP submitted under this rule . . . unless any discrepancies between the most recent IRP and the resource action are fully explained and justified with supporting evidence."[31] Clearly, the Company's most recent IRP in 2011 and forthcoming IRP for 2014/2015 use an assessment mechanisms that is inconsistent with the resource action contemplated here.

4. OVERSIZED REPLACEMENT UNITS EARN MISO CAPACITY CREDIT

Q In your introduction, you stated that the fact that the replacement of Brown 1 & 2 together was not comparable to the sum of the replacement of Brown 1 and 2 individually indicated an analytical error. Please elaborate.

A As I stated in the introduction, I would expect that if retrofitting Brown 1 is beneficial, and retrofitting Brown 2 is also beneficial, then the benefit of retrofitting both Brown 1 & 2 would be roughly the same as the sum of the benefit of Brown 1 plus Brown 2; instead, the benefit of retrofitting both is smaller than the benefit of retrofitting either individually.

Q Did you ask the Company about this discrepancy?

A Yes. Joint Intervenors asked that Vectren "please explain, in detail, why, in the base scenario, the delta net present value of retrofitting Brown 1 & 2 ($53

[30] *See* Vectren 2011 IRP (DR JI 1-6), "'End effects,' estimates of revenue requirements beyond the twenty year planning period, were also considered when selecting the optimal plan. 'End effects' are important due to their full consideration of the impact of resource additions that occur toward the end of the discrete 20 year planning period. The study period PVRR is defined as the planning period PVRR plus the end effects. The optimal resource plans as presented in this study were selected on a study period basis."
[31] 170 IAC 4-7-2(q) (proposed).

million) is substantially smaller than the value of retrofitting either Brown 1 ($88 million) or Brown 2 ($76 million), or the sum of both Brown 1 and Brown 2, respectively."[32] This data request asked for the Company to identify the absence of about $111 million of value theoretically held by the Brown coal units.[33]

The Company objected that responding to this inquiry would require an analysis, which they had not completed and which they objected to performing.[34] They subsequently hypothesized that the discrepancy was due to the replacement of Brown 1 & 2 with a larger and more efficient CCGT than the smaller CCGT that would replace either Brown 1 or 2, separately. Specifically, the Company states that "the two Brown units are replaced by a larger, lower-emitting, natural gas-fired unit. This is a different technology and has different operating costs, which affects the amount of emissions, market sales and purchases, and variable production costs."[35]

Do you have an alternate explanation as to why the value of Brown 1 and 2, separately, appears to be so much higher than the value of Brown 1 & 2, together?

A Yes. In the B&V analysis, the Company or B&V neglected to account for market sales of excess capacity available from purchasing oversized CCGT units.

B&V explicitly accounts for capacity market <u>purchases</u> and energy market purchases and sales, but does not include any category of capacity market sales. Joint Intervenors requested that the Company "please explain why there are no credits for surplus capacity in 'Market Capacity Cost,' [and if] these credits [were] captured in 'Market Sales.'" The Company indicated that "market sales" accounts for energy sales only, and did not indicate that capacity sales were accounted for elsewhere.[36]

---

[32] *See* JI 3.17
[3333] $88 + $76 - $53 = $111.
[34] *See* objection to JI 3.17
[35] See Response to JI 3.17
[36] See response to JI 3.24(a).

Q Are the replacement units contemplated by the Company in this case the same capacity as the potentially retiring fossil units?

A No. Vectren modeled CCGTs that are generally larger in capacity than the fossil units that they would replace, and CTs that are generally smaller in capacity (see Table 5, below). The CCGT units are 40-60 MW larger than their coal analogs, and in the case of Brown 1 & 2 (combined), 138 MW larger.

Table 5.
Unforced capacity (UCAP) of coal and replacement units (MW).

Unit(s)	***Fossil Units (after retrofits)***	***CCGT replacement***	***CT Replacement***
Brown 1 / 2	240 / 242	306	202
Culley 3	269	306	202
Brown 1 & 2	481	620	*(not modeled)*

This mismatch between the size of the retiring units and the potential replacement units results in an analysis problem – in the case of the CCGTs, the Company would be investing additional short-term capital to procure more capacity than necessary to replace their coal units. The Company's valuation of the coal units should minimize capacity differences (i.e. compare against an equally sized CCGT share).[37]

Having failed to review replacement capacity of the same size as their evaluated coal units, the Company should at least recognize the value of excess capacity.

Q May Vectren participate in MISO's capacity market?

A Yes. Vectren is a member of MISO and as such is held to MISO's Resource Adequacy construct, and has access to MISO's voluntary annual capacity auction.

[37] The assessment that the Company would perform from a requirements basis (i.e., if it requires additional capacity) is a different and separate analysis than the valuation of the existing coal units.

Q Does the Company's economic analysis incorporate the capacity market?

A Yes. The B&V analysis uses the amount of capacity available to the Company in 2014 as a benchmark or reference, and assumes that any amount of capacity missing relative to its 2014 holdings must be met with capacity purchases.

However, the B&V analysis does <u>not</u> assume any benefit for the Company if it holds more capacity than it did in 2014.

Q Are the Company's 2014 capacity holdings the benchmark against which the Company will actually procure or sell capacity?

A No. The Company will be required to hold an appropriate amount of capacity each year to meet its reserve requirements as set by MISO, regardless of its holdings in 2014.

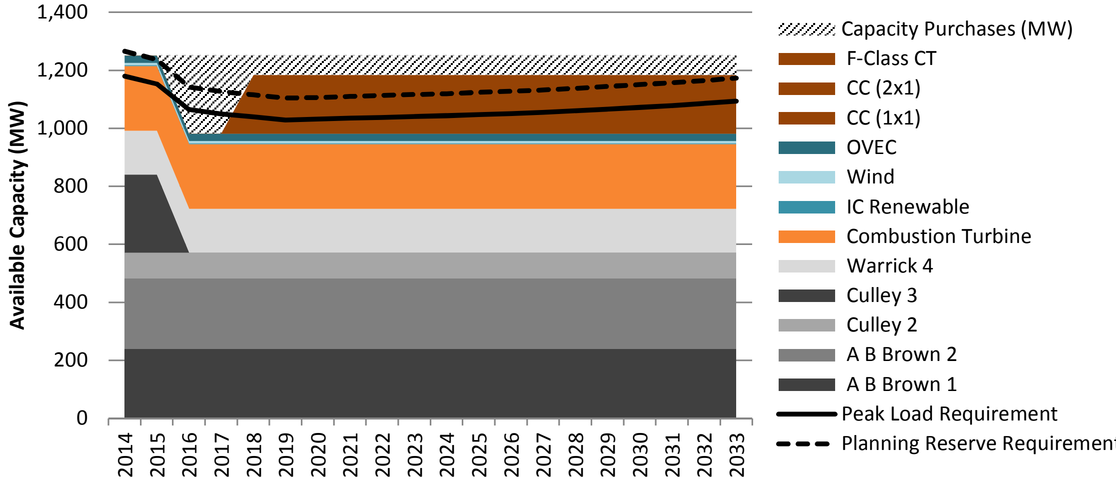
Nonetheless, for the purposes of a comparative analysis, as long as the Company assumes an equivalent price for the purchase and sale of capacity, it actually does not matter which years or conditions are used as a benchmark or reference. In absolute terms, the Company's analysis will be incorrect, but the difference between scenarios is indifferent to the assumption of a 2014 benchmark year.

However, this is true only if the Company assumes an equivalent price for the purchase and sale of capacity. In the B&V analysis, the Company assumes a rising price for purchase of capacity, and a <u>zero</u> price for the sale of capacity.

For example, in the scenario where Culley 3 is replaced with a 202 MW CT that comes online in 2018, the analysis assumes that Vectren has to acquire 269 MW of market capacity in 2016 & 2017 to fill the gap left by Culley 3; the analysis also assumes an acquisition of 67 MW of market capacity (the difference between the 269MW Culley 3 unit and the 202 MW CT replacement) from 2018-2033 despite the fact that this market capacity is not necessary to meet the Company's reserve requirements (see Figure 5, below).[38]

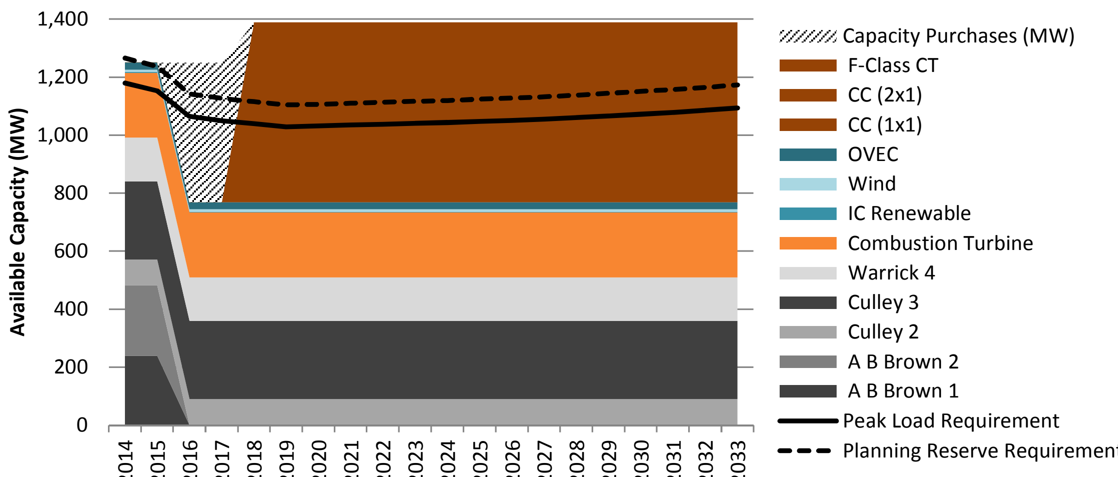
[38] Capacity purchase amounts (in MW) derived from market capacity purchases (in $) divided by capacity price, through 2023 (last available year of data). Capacity price after 2023 increases at 2.7% inflation, back-derived from capacity purchase costs and capacity shortfall position. MISO UCAP planning reserve margin set at 7.3% based on "Planning Year 2014-2015 MISO Planning Reserve Margin Results."

Figure 5.
Capacity from Vectren units and market-based capacity purchases (MW),
Culley 3 replaced with 202 MW CT scenario (UCAP).



However, when a replacement unit larger than the retiring unit is brought online, the Company does not assume equivalent capacity market sales for excess capacity. Instead, Vectren assumes no monetary benefit for maintaining excess capacity, despite the reserve margin being well in excess of requirements, as shown in Figure 6 below.

Figure 6.
Capacity from Vectren units and market-based capacity purchases (MW).
Brown 1 & 2 replaced with 620 MW CC (UCAP).



Q **Is including capacity purchases but not capacity sales an error in this analysis?**

A Yes.

Q **Were you able to adjust the Company's analysis to account for this error?**

A Yes. First, I required a continuous capacity price forecast for the full extent of the Company's assessment (2014-20133). In the workpapers to Exhibit WDG-3, the Company provided capacity prices from 2014-2023, but not from 2024-2033.[39] In the absence of these long-term prices, I determined the long-term capacity price forecast (2014-2033) used by the Company from the estimated capacity purchases in the Culley 3 replacement scenario (with a CT). Confidential Figure 7, below, compares the short-term capacity price from the Company's inputs, and the long-term capacity price pulled from the Culley 3 replacement scenario.

Confidential Figure 7.
Capacity price forecast through 2033 from Vectren analysis, as input and derived ($/kw-yr).

[redacted]

I multiplied this price forecast by the capacity acquired in any given scenario above and beyond the capacity of the Vectren system in 2014, retaining an identical assumption set to that used by the Company. I then added the additional

[39] In DR 1-23, Joint Interveners requested that the Company "Please provide the natural gas prices, electricity prices, and capacity prices used by Black & Veatch in the PROMOD modeling for each year of the analysis." The Company referred to WDG-3 for gas prices (provided for 2014-2023), and did not respond to the remainder of the request, including electricity and capacity prices.

capacity benefit in the CCGT replacement cases to the stream of revenues available in any given scenario.

Q How did this correction impact the outcome of the Company's analysis?

A Correcting the analysis to properly include sales of excess capacity has several important impacts on the relative economics of maintaining Brown 1 & 2 and Culley 3 (see Confidential Table 6, below).

Confidential Table 6.
B&V 20-yr net benefit of retrofits, with capacity market correction[40]

	Base	*Downside*	*Upside*
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

The correction impacts the scenarios in which the Company's coal resources were replaced with natural gas combined cycle units. In these scenarios, the replacement capacity is consistently larger than the retiring coal units; the CCGTs replacements are benefited by market capacity values that were excluded in the B&V analysis. Overall, the capacity market correction with the 20-year analysis period indicates that neither Brown 1, Brown 2, nor Culley 3 are economic in the Company's established base case.

5. <u>Coal Costs do not Reflect Past Trends or Regional Forecasts</u>

Q Do the upside and downside scenarios account for potential uncertainties in the Company's coal price forecast?

A No. The upside and downside scenarios examine only a single coal price scenario each for Brown 1 & 2, and Culley 2 and Culley 3, respectively. This projection starts at approximately [redacted]

[40] Source: JI 1-15 (2014-2033) (million 2014$), with capacity market correction.

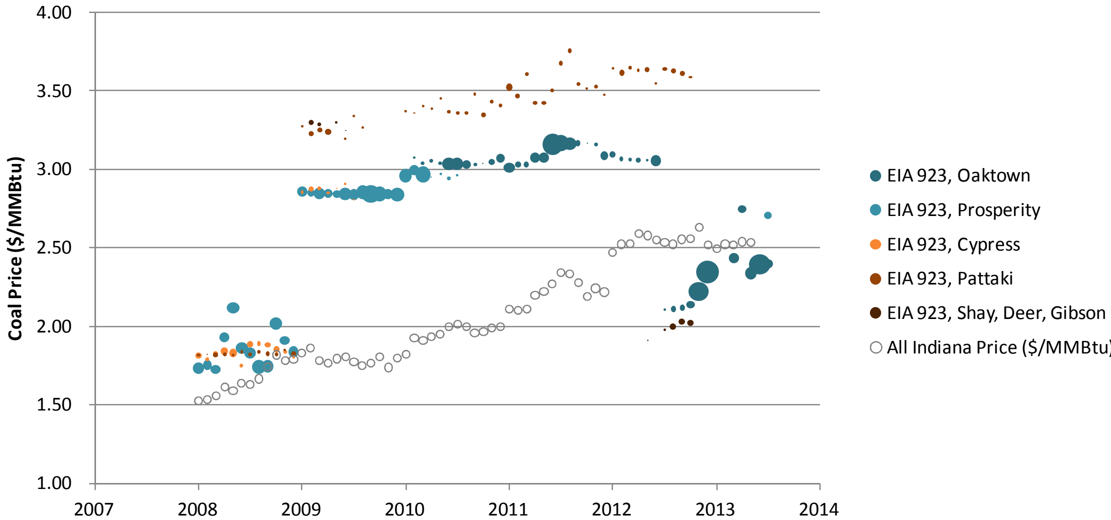
[redacted] implying a steady long-term procurement of very low cost coal.

Q Do Brown and Culley have a history of low and steady coal prices?

A No. A review of coal procured at Brown and Culley from 2008 through 2013 shows that, in fact, Vectren's delivered prices have fluctuated tremendously.[41] At Brown, the Company has received coal costing between $1.7 to $3.8/MMMbtu per month between 2008 and 2013. At the Company's affiliate-owned mine ,Prosperity, prices jumped 64% in 2009 from $1.7 to $2.8/MMbtu, and as recently as mid-2012 Vectren was obtaining coal from the Pattaki mine at above $3.5/MMbtu[42] – by far some of the most expensive coal obtained by any coal unit in the state of Indiana in 2012.[43] Figure 8, below, shows prices of coal received at Brown as reported to the US Energy Information Administration ("EIA") in Form 923 from 2008-2013, as well as reported prices received by Indiana coal plants from Indiana coal mines. Circle sizes in this graphic are proportional to tonnage received at Brown with each shipment.

[41] Data from US Department of Energy, Energy Information Administration (EIA) Form 923, delivered fuel prices.
[42] Data EIA Form 923 for 2008-2014.
[43] Data from 505 coal purchases recorded for Indiana electric power plants in EIA Form 923 for 2012, representing 27.9 million tons of coal. Average price of coal received at Brown from Pattaki in 2012 was $3.62/MMBtu, in the 97th percentile of all coal received by coal units in Indiana in 2012.

Figure 8.
Prices for coal received at AB Brown 2008-2013 (nominal $/MMBtu), and all Indiana coal delivered to Indiana coal units.



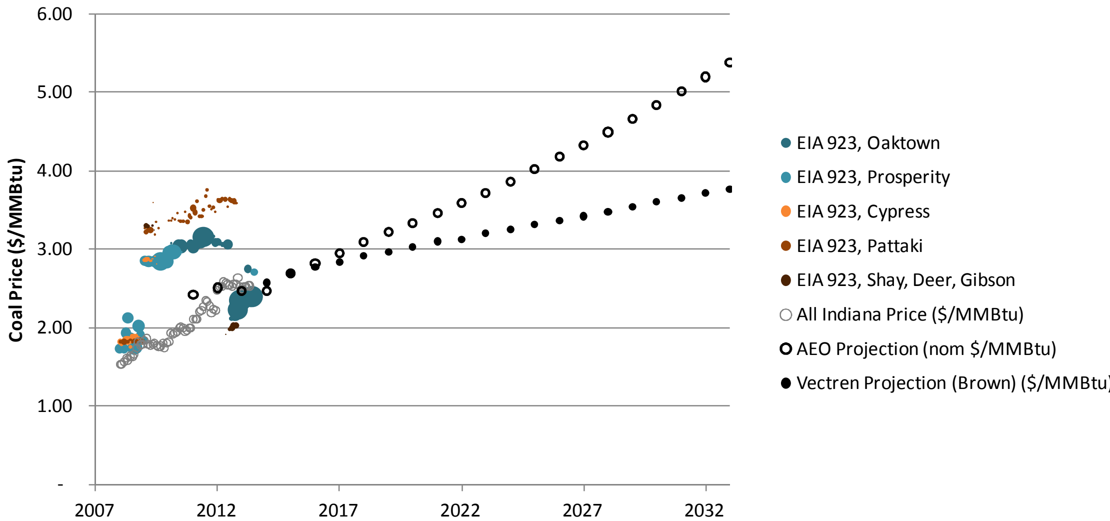
Q What is the Company projecting for the future of coal prices at Brown?

A The Company projects that prices will start at around [redacted] in 2014, and grow at roughly [redacted] per year,[44] [redacted] This trajectory is shown in Confidential Figure 9, below.

Confidential Figure 9.
Prices for coal received at AB Brown, 2008-2013 (nominal $/MMBtu), all Indiana coal delivered to Indiana coal units; coal price projection for

[44] Provided in DR JI 1-15, tab "base", section entitled "Fuel Costs ($/MMBtu)"

Brown from Vectren and regional coal price projection from EIA AEO 2014.



Q Does this growth rate comport with regional projections?

A No. The EIA, in the most recent Annual Energy Outlook, released May 7, 2014, suggests that while Vectren's current (2013-2014) coal prices are consistent with regional prices, the Company's assumed low costs through 2033 are not consistent with regional price projections.[45] AEO 2014 projects a 1% growth rate in real terms, or [redacted] faster than Vectren's prices. This means that AEO 2014 projects coal prices will be about [redacted] higher than Vectren's prices at Brown by 2023 and [redacted] higher in 2033.

This same disparity is present in the Culley analysis, where the Company projects a [redacted] cumulative average growth rate (nominal) in coal prices, which is again [redacted] than the 1% per year real growth rate projected in AEO 2014.

While coal prices may be quite specific to long and short-term contracts signed by specific utilities and generating units with coal suppliers, over the long term I would expect prices received at Brown and Culley (and charged by their affiliate producers) to roughly track regional price projections. The significant disparity between Vectren's projections and the AEO projections, as well as the historically

[45] Projections from AEO 2014, East North Central region coal prices delivered to electric generation.

unstable pricing for coal at Brown and Culley indicate that the Company's optimistic projections should be viewed skeptically.

Q Did you review how the analysis changes if the AEO regional delivered coal price projection is substituted for the Company's projection?

A Yes. I simply scaled the Company's fuel costs at Brown and Culley by a multiplier that shifted costs from Vectren's projections (2014-2033) to those in AEO 2014 for the East North Central region. On net, this made coal prices slightly less expensive in near-term years (through [redacted] at Culley) and increased coal prices at Brown and Culley in 2033 by about [redacted]

In tandem with the 20-year analysis and the capacity market correction, there is a significant net liability for the retrofits at both Brown units and at Culley in the base case, regardless of whether the units are reviewed individually or in concert (see Confidential Table 7, below).

Confidential Table 7.
B&V 20-yr net benefit of retrofits (million 2014$), with capacity market correction and coal price projection adjustment to AEO 2014.[46]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

6. <u>THE COMPANY'S ANALYSIS DOES NOT ACCOUNT FOR REVENUE SHARING FROM OFF-SYSTEM SALES</u>

Q When Indianapolis Power and Light ("IPL") applied for a CPCN for retrofits at their Big Five coal units (Cause No. 44242), you expressed a concern about appropriately capturing the benefit of off-system sales. Is that concern at issue in this docket as well?

A Yes. In Cause No. 44242, I expressed a concern that IPL had modeled their system as if ratepayers received 100% of the benefit of off-system sales, although

[46] Source: JI 1-15 (2014-2033)

IPL currently keeps 100% of off-system sales net revenues. In IPL's case, this inaccurate assumption benefited the proposed retrofits. In Vectren's case, the Company currently shares 50% of net off-system sales with consumers,[47] but also models their system as if ratepayers receive 100% of the benefit of off-system sales. In the case of Brown 1 & 2, the Company's assumption benefits the retirement scenarios where a CCGT is built as a replacement unit. Regardless of how it impacts the outcome, the Company's analysis should accurately capture the actual mechanism for sharing off-system sales revenues when reviewing benefits (or liabilities) to ratepayers.

Q Were you able to adjust off-system sales revenues for the Company?

A Yes, albeit roughly and with significant caveats. I presume that when the Company produces off-system sales, it charges retail customers for the cost of the lowest cost generation and prices off-system sales at the cost of generation in excess of what is produced for customers. To allocate retail sales costs versus the production cost of off-system sales, I assumed that all off-system energy sales were produced by the most expensive units (on a variable cost basis). Effectively, I created a virtual annual bid stack (i.e. ordered the units by cost) and allocated off-system sales to the most expensive units until all sales were allocated.[48] I deducted the variable production cost of these units for MWh produced for off-system sales from the off-system sales revenue to arrive at a net revenue from off-system sales figure. I then took half of this figure (on an annual basis) and allocated it to customers, instead of total off-system sales revenues as done by the Company. I also removed from the analysis the production cost of those marginal units that contributed to off-system sales. An example of this adjustment is shown in Confidential Figure 10, below.

---

[47] JI DR 1.31(a), (b).

[48] Based on data provided in DR JI 1-15.

Confidential Figure 10.
Schematic of adjustment for net off-system sales revenue

[redacted]

The left-most column shows the output of units in the Company's analysis for the Brown 1 & 2 CCGT replacement in the year 2020, stacked by variable cost. The center column indicates the total off-system sales estimated by the Company for this year, and the right-most column shows the contribution of the marginal units to those off-system sales, conservatively assuming that sales are provided by the highest cost units, exclusively. In this particular scenario and year, the Company grosses [redacted] rom off-system sales, but spends [redacted] producing those sales. It nets [redacted] of which half [redacted] are allocated back to ratepayers. In the Company's analysis, I include this [redacted] as a benefit to ratepayers, remove the [redacted] from the ratepayer benefit column, and remove th [redacted] from the Company's production costs.

On net, this adjustment reduces the benefit of the CCGT replacement scenario at Brown 1 & 2 by abou [redacted] NPV, and increases the benefit of the CT replacement scenarios by [redacted] It has a lesser impact on the CC replacement scenarios, increasing the benefit of the replacement only by about [redacted]

[redacted] In combination with the other corrections and adjustments discussed here, this adjustment has a fairly small impact, and does not change the fact that retrofitting Brown 1 & 2 and Culley would be a net liability (see Confidential Table 8, below).

Confidential Table 8.
B&V 20-yr net benefit of retrofits (million 2014$), with capacity market correction, coal price projection adjustment to AEO 2014, and adjustment for off-system sales revenues.[49]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

7. <u>VECTREN RATEPAYERS ARE LOSING MONEY NOW ON BROWN AND CULLEY</u>

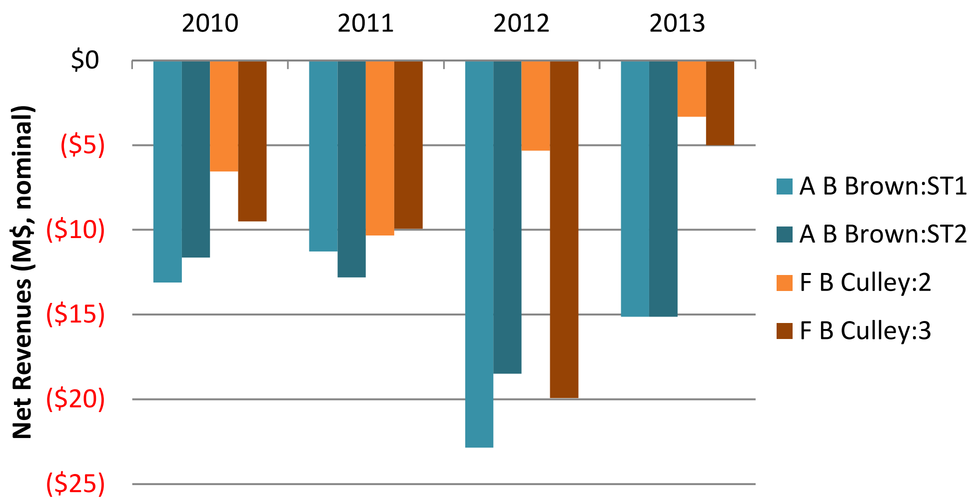
Q Your review of the Company's analysis indicates that both Brown and Culley are non-economic choices relative to replacement options. Are these units high value units in the MISO market today?

A No. I reviewed how Brown 1 & 2 and Culley 2 & 3 have dispatched from 2010 to 2013, the locational marginal prices (LMP) for those units, and the fixed and variable costs of running those units over the last four years. Based on my review, I believe that Vectren has lost [redacted] from 2010 through 2013 (inclusive) by operating these units relative to procuring market-based energy.

My estimate of the Company's net revenues at these units is shown in Figure 11, below. This figure shows that across the last four years, if Brown and Culley had operated as merchant plants, they would have taken significant losses – from $5 to $20 million per year, every year – or a total of $190 million.

[49] Source: JI 1-15 (2014-2033)

Figure 11.
Net revenues at Brown and Culley, 2010-2013, inclusive.



Q Please explain how you determined that Brown and Culley were losing money in MISO.

A I compiled several pieces of information to arrive at this answer.

- LMP: The Company provided LMPs for each of these units for 2010-2013 in response to JI 3.21(a).[50]
- Hourly dispatch: I extracted the reported hourly gross generation for each of these units from EPA's Clean Air Markets Division (CAMD) hourly Air Markets Program Dataset (AMPD), reported as part of EPA's continuous emissions monitoring.
- Variable O&M: The Company provided annual VOM costs ($/MWh) in JI 3.21(b).[51] The Company also provided total VOM costs in JI 2.3(a);[52] I used these to validate the VOM estimates from 3.21(b).
- Fuel costs: I extracted annual weighted average delivered coal prices ($/MMbtu) for Brown and Culley from EIA form 923, and used heat rates from JI 2.3(b)[53] to estimate fuel costs ($/MWh).

[50] Petitioner's Exhibit JI DR 3.21-A - RT Coal Unit LMPs for Jan 2010 - Apr 2014.xlsx
[51] Petitioner's Exhibit JI DR 3.21-B - DR VPC per MWh 2010-2014 Q1.xlsx
[52] Supplemental Exhibit JI DR 2.3-A.xlsx
[53] Supplemental Exhibit JI DR 2.3-B - 2005 through 2014 gen heat rate CF (e f g).xlsx

- Fixed O&M: The Company provided annual historical fixed O&M expenses in JI 2.3(a).[54]

For each year, I multiplied hourly LMP by hourly dispatch to arrive at a gross revenue, and then deducted fuel and variable and fixed O&M costs to arrive at a net revenue. These are the net costs shown in Figure 11, above. Importantly, these net costs do not include annual capital expenditures made by the Company for environmental or long-term maintenance at the units. Incorporating those costs as expenses would just increase the losses of these units.

Unless the Company has a large additional stream of revenues to those units, I see no feasible way that Brown and Culley could have provided a net benefit to ratepayers versus the acquisition of market energy from 2010 to 2013.

Q What conclusions can you draw from your review of historical net revenues at Brown and Culley?

A First, the substantial losses incurred at these units from 2010 to 2013 support the conclusion that maintaining Brown and Culley is not in the best interests of ratepayers. While a finding that a unit is non-economic on a forward-looking basis does not require that the unit actively be losing money on the energy market, the fact that these units both fail the long-term economic viability test <u>and</u> are in the red today indicates that they do not benefit Vectren's ratepayers.

Second, while these units may be currently "used" to produce energy and provide capacity for Vectren's customers, they are not economically "useful" to the Company's ratepayers. The Company's ratepayers do not derive a benefit from the use of these units, and would be better served by alternative resources.

Q The Company did not review the economics of Culley 2. Can you draw conclusions specific to this unit based on your assessment of net revenues?

A I suspect that a separate analysis of Culley 2 would show that this unit is non-economic regardless of its need for substantive capital investments. Culley 2

[54] Supplemental Exhibit JI DR 2.3-A.xlsx

dispatched at a 36% capacity factor in 2013,[55] indicating that it did not have many operational hours in which it could operate economically; indeed, it produced generation in less than half of the year. However, it is not clear that Culley 2 will not be incurring significant capital costs. In this case, there may be avoidable costs at Culley 2 that are independent of Culley 3; the impact of any such costs have been completely ignored in the Company's analysis. More specifically, the B&V analysis shows that Culley 2 will incur over [redacted] in capital from 2014-2018, and an additional [redacted] in 2023.[56] It is difficult to imagine a circumstance in which a unit that has been operating with significant losses could recover those capital costs.

Q Were you able to perform this same analysis on a going-forward basis?

A Yes, but I was able to perform only a rough analysis. In Mr. Games's workpapers and the Company's response to JI DR 1.15, the Company provides insufficient information to estimate the market value of Culley 2 on a stand-alone basis. The analysis provides estimated annual generation and costs for fuel, VOM, FOM, emissions. However, the analysis does not provide estimated market prices except from the price of purchased and sold energy. In response to JI DR 3.21, the Company provided energy prices through 2023 for "on-peak," "off-peak," and "all-hours" periods. These prices are not necessarily representative of the prices available at the hours that Culley 2 might dispatch, but they provide a bounding box on high and low energy prices, as well as the prices that might be commanded by Culley 2 if it were dispatching at all hours. Using the Company's capacity prices to estimate capacity revenues, the high and low energy prices to estimate energy revenues, and the costs listed above, I estimated Culley 2's annual net revenues <u>before capital expenses</u> through 2023 to match the historic net revenue calculation. These are graphed in Confidential Figure 12, below.

[55] Hourly gross generation from US EPA Clean Air Markets Division (CAMD) Air Markets Program Dataset (AMPD).

[56] See JI 1.15, tab "Base", cells D231:H231, M231

Confidential Figure 12.
Annual net revenues for Culley 2 under peak, offpeak, and all hours prices, and historical net revenues.

[redacted]

Under even the best of circumstances, Culley 2 is not estimated to break into the black until 2016; under less favorable circumstances, it may continue to lose money beyond 2023. On a present value basis, the best circumstance is a [redacted] benefit for Culley 2 relative to the market, and at worst a [redacted] loss.

It is notable that these revenues are highly dependent on the Company's assumption of capacity prices; by the numbers provided by the Company, more than one third (33%) of Culley's gross revenues are attributable to the capacity market by 2020 and in all subsequent years.[57]

These revenues do <u>not</u> include the Company's estimated capital expenditures at Culley 2, provided in response to JI DR 1.15. The net present value of capital retrofits required at Culley 2 are estimated at [redacted] Therefore, even in the best circumstance, Culley 2 has [redacted] 2014-2023).

[57] These analyses assume that Culley 2 does not have a significant alternate stream of revenue.

Q What are your recommendations in light of Culley 2's poor historical and projected performance?

A I would recommend that Vectren be required to formulate a plan for the phase out and retirement of Culley 2, and be restricted from incurring significant additional expense at Culley 2 if such expenses do not comport with the expedient phase out and retirement of that unit.

8. Additional Concerns

Q Do you have additional concerns with the Company's analysis as presented here?

A Yes. I have concerns with several other, key aspects of the Company's analysis, but I have not explicitly quantified the impact of these errors. These additional concerns include:

- The failure to use an optimization model to examine least-cost alternative plans;
- The failure to analyze non-gas resources as replacement resources;
- The failure to assess reasonably sized resources from those deemed acceptable by the Company;
- The failure of the Company to issue an RFP for replacement capacity and/or energy resources; and
- The incorrect characterization of Brown 2's deadline for complying with MATS in 2016;

I address each of these issues below.

Q Did the Company use an optimization model to select least-cost alternative resources in its economic analysis?

A No.

Q Why should the Company have used an optimization model in this economic analysis?

A An optimization model would have allowed the Company to review a wide range of resources simultaneously, and possibly would have chosen a lower cost resource portfolio rather than the oversized CCGTs at the core of this analysis. Such selections could have included the procurement of select fossil resources as well as market resources, and depending on the resources made available in the model, a variety of renewable energy options as well. It is by no means clear that the alternative resources selected by the Company—the new CT and CCGT facilities—are the least-cost alternatives to retrofitting the Company's five units.

Q Did the Company review a wide variety of replacement resources in the economic analysis?

A No. The Company limited the selection of alternative resources to oversized CCGT units, and slightly undersized single cycle GT units. In a technology assessment preceding the B&V analysis, Vectren hired Burns and McDonnell to review a range of potential supply-side resources and their incumbent costs. Of all of the technologies reviewed, only the CCGT and GT units were left available for analysis, although the rationale for eliminating the other alternative resources is unclear.

B&Mc explicitly did not recommend the elimination of particular technology types, and appears to have encouraged the Company to model a variety of options. The B&Mc report states that:

> Information provided in this assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. Burns & McDonnell recommends that Vectren utilize the information presented in this technology assessment as input into its production costs models for comparison of generation alternatives to confirm the future economic viability of each generation option and its application in long-term power supply plans. [58]

[58] JI DR 2.11 Burns and McDonnell 2013 Vectren TA Report Draft, page 10-1

To Joint Intervenors, Vectren confirmed that "Black and Veatch eliminated wind and solar resources from consideration prior to any modeling of the resources,"[59] but to OUCC, Vectren took credit for this decision, stating that "Vectren South considered 20 technologies to replace a retired coal unit. Many of the resources are intermittent in nature and therefore can only be counted on for small amounts of capacity during the peak hour of the year."[60] It does not appear that the Company or B&V reviewed opportunities to acquire wind energy and procure relatively low cost capacity resources (i.e. GTs) for capacity as a mechanism of meeting MATS and NOV limits, reducing emissions, and reducing ratepayer costs.

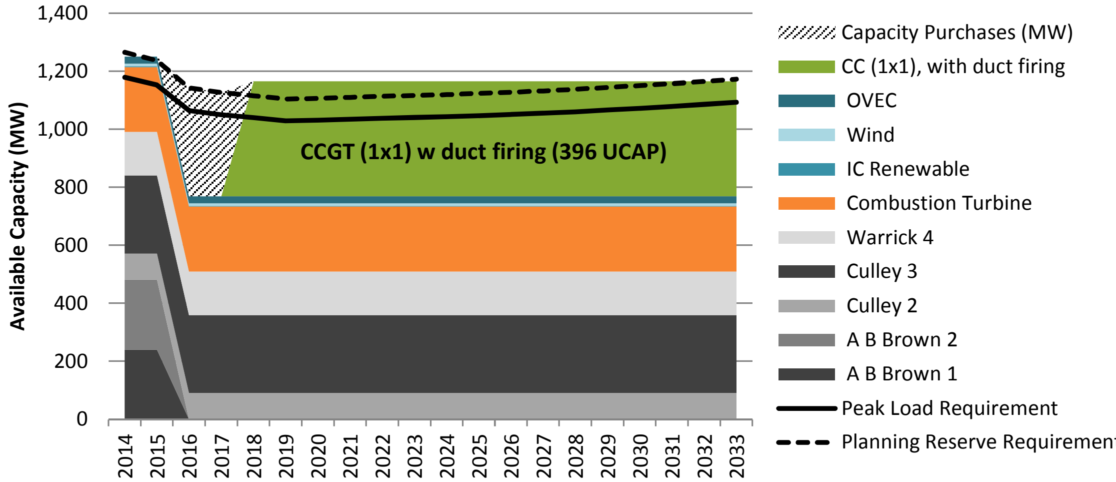
Q Does the Company require the large 2x1 CCGT as a replacement if Brown 1 & 2 were to both retire?

A No. The Company's 1x1 CCGT replacement was modeled without the benefit of duct-fired burners, although this option was laid out by B&Mc in their 2013 technology assessment.[61] If the Company retired Brown 1 & 2, it would lose 481 MW of unforced capacity (UCAP), rendering it short by 373 MW in 2016 (relative to planning reserve requirements). The 1x1 CCGT examined by B&Mc has an installed capacity (ICAP) of 317.5 MW, and a duct-fired option of 91 MW. At a forced outage rate of 3%, this would result in 396 MW of UCAP. With the Company's falling load requirements, I anticipate that this replacement would meet the Company's requirements through 2032.

---

[59] JI DR 1.18(a)
[60] OUCC 2.9
[61] JI DR 2.11 Burns and McDonnell 2013 Vectren TA Report Draft, Appendix A-2

Figure 13.
Capacity from Vectren units and market-based capacity purchases (MW), Brown 1 & 2 replaced with a 396 MW CCGT (duct fired, UCAP).



Overall, the replacement of Brown 1 & 2 with a smaller sized CCGT would be a lower cost and smaller capital investment than replacing those units with a larger 2x1 CCGT.

Q Did you perform this alternate analysis?

A No. I did not have access to the Company's model, and did not assess the economics of this option. I believe that, because of the lower capital burden to build this 1x1 CCGT, this analysis would have likely resulted in a lower cost resource plan.

Q Did the Company issue a request for proposals ("RFP") for energy or capacity resources prior to conducting this analysis or issuing this request for CPCN?

A No, the Company did not issue an RFP. An RFP is a mechanism for testing the market waters to determine the resources that would be available for purchase – often at lower cost than new resource equivalents. Responses to RFPs may be existing resources that are available for sale in whole or in part, long-term power and/or capacity purchase agreements, or offers to build new resources at a fixed cost.

In response to a discovery request from Joint Intervenors, the Company explained that it did not issue an RFP for "several reasons," namely, that Vectren's analysis found that "it was more cost effective to retrofit the existing units;" "there is insufficient time to replace the existing units with replacement capacity;" and the Company "is not certain it could acquire sufficient capacity in 2015 and 2016 to meet its needs if its existing facilities are retired."[62]

This answer does not justify the Company's failure to issue an RFP.

First, the Company explains that the analysis presented here found that it was cost effective to retrofit the units, thus eliminating any requirement for an RFP. This logic is backwards. In this case, an RFP would be issued to seek lower-cost options than those that might be considered in a self-build analysis. Failing to consider RFP options simply means that the Company arbitrarily restricted its assessment of reasonable alternatives, some of which may have been cheaper than the alternative the Company considered.

The Company's second explanation is that there is allegedly insufficient time to replace the units. But the Company, like other electric utilities, has on long been aware of their MATS compliance obligations since 2011, and thus had ample opportunities to consider market directions, review options, and issue RFPs. Moreover, the Company's assessment of the Brown and Culley retrofits assumes that Vectren would acquire market energy and capacity in 2016 and 2017, consistent with a 2018 in-service date for replacement self-build units. If the Company has eliminated this option from consideration, then the whole of Mr. Games's analysis (Exhibit WDG-3) is a meaningless and fruitless exercise.

The third reason put forth by the Company is that it "is not certain that it could acquire sufficient capacity in 2015 and 2016…" The purpose of an RFP is to alleviate that uncertainty, and seek options and opportunities to acquire reasonable resources. This is a reason to issue an RFP.

[62] JI DR 1.25(a)

Q Does the Company's analysis reflect the appropriate and expected retirement dates for Vectren's coal units with a MATS requirement?

A No. The analysis, presented with annual numbers, shows Brown 1 & 2 and Culley 3 operating through 2015, apparently providing a full year of service. In reality Brown 1 and Culley 3 would be able to operate only through April 2015, the MATS compliance deadline. Brown 2 would be available to operate through April 2016, as it has received a compliance extension from IDEM.[63]

9. <u>Conclusions and Recommendations</u>

Q Please summarize your findings in this case.

A This case provides an opportunity for Vectren South to carefully review its existing fleet and determine if ratepayers benefit from the continued use and long-term maintenance of its existing units or if the units should be retired and replaced. The Company retained Black and Veatch to conduct an economic assessment on their behalf of Brown 1 & 2, and Culley 3, examining the option of replacing those units with natural gas combined cycle units.

I evaluated the analysis conducted by B&V, and found a series of problems that significantly impact the outcome of the economic assessment. Most importantly, there is ample evidence that the Company and/or B&V was aware of at least one of these inconsistencies and withheld critical evidence from this Commission that counters the testimony of the witnesses in this case. Evidence from the Company's modeling and the current operation of the units indicates that four of the units at issue in this case, Brown 1 & 2 and Culley 2 & 3, have lost money over the last four years, and cannot reasonably be expected to provide a lower cost of service than replacement capacity from 2014 through 2033.

The analysis conducted by the Company would have indicated to either Vectren or B&V (or both) that at least Brown 1 & 2 were more economically replaced with a CCGT when considered over a reasonable analysis window (20 years); and

[63] OUCC 1.30 Vectren South requested and received a one year extension for MATS compliance at the Brown Unit #2. The approval letter from IDEM is attached as Petitioner's OUCC DR Exhibit 1-30.

that these units would likely have a negative value if offered on the open market. Components of this 20-year analysis, provided to Joint Intervenors in a discovery response, were deleted and removed from the version of Mr. Games's workpapers filed with the Commission. The Company's exclusion of important information does not comport with reasonable utility practice, and denies this Commission the opportunity to fully evaluate the Company's proposal.

Even without making any adjustments, the Company's own 20-year analysis shows that retiring and replacing Brown 1 and 2 is less expensive than retrofitting both units.

Confidential Table 10.
B&V 20-yr net benefit of retrofits (million 2014$)[64]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]		
Brown 1 CC			
Brown 2 CT			
Brown 2 CC			
Culley 3 CT			
Culley 3 CC			
Brown 1 & 2 CC 2x1			

After reviewing the Company's full 20-year analysis, I made adjustments to correct for several errors. I corrected for a failure to include capacity market sales, adjusted the Company's coal price forecast to reflect regional trends, and accounted for the Company's treatment of off-system sales. As the table below indicates, Brown 1 & 2 and Culley 3 are non-economic from a forward-looking perspective.

[64] Source: JI 1-15 (2014-2033)

Confidential Table 9.
B&V 20-yr net benefit of retrofits (million 2014$), with capacity market correction, coal price projection adjustment to AEO 2014, and adjustment for off-system sales revenues.[65]

	Base	***Downside***	***Upside***
Brown 1 CT	[redacted]	[redacted]	[redacted]
Brown 1 CC	[redacted]	[redacted]	[redacted]
Brown 2 CT	[redacted]	[redacted]	[redacted]
Brown 2 CC	[redacted]	[redacted]	[redacted]
Culley 3 CT	[redacted]	[redacted]	[redacted]
Culley 3 CC	[redacted]	[redacted]	[redacted]
Brown 1 & 2 CC 2x1	[redacted]	[redacted]	[redacted]

In addition, I found that Culley 2 is rarely operational (less than half of all hours in 2013) and over the last four years has incurred fixed expenses that it cannot recover on the energy or capacity market. Without a robust capacity market or high energy prices in the future, Culley 2 will continue to lose significant revenue, and represents a risk to Vectren ratepayers.

Q What are your recommendations to this Commission?

My primary recommendation is to deny the CPCN for Brown units 1 and 2 and Culley units 3 and 4.

In addition, the Commission should direct Vectren to begin assessing a reasonable closure, retirement, and replacement process for these units. Such a docket should explicitly address both the stranded costs remaining once these units are removed from service, and the credit risk to Vectren from the loss of revenue. While a financially sound Company may be in ratepayers' interests, such an outcome should not come at the expense of ratepayers today, or in the future.

Second, the Commission should direct the Company to issue all-source RFPs for replacement capacity and/or energy that seek both self-build as well as contract options to meet requirements.

[65] Source: JI 1-15 (2014-2033)

Finally, the Commission should establish an investigation into whether Culley and Brown have operated non-economically from 2010-2013, and if so, the extent to which ratepayers have been harmed by Vectren's actions.

Overall, Vectren's application and evidence do not support the continued maintenance and investment in Brown units 1 and 2 and Culley units 3 and 4.

Q **Does this conclude your testimony?**

A Yes.