FILED
September 18, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	**))))))))))))**	**CAUSE NO. 38707-FAC125**

<u>SUBMISSION OF APPLICANT'S PROPOSED FORM OF ORDER</u>

Duke Energy Indiana, LLC ("Duke Energy Indiana"), by counsel, respectfully submits its Proposed Form of Order in the above-captioned Cause to the Indiana Utility Regulatory Commission ("Commission").

Respectfully submitted,

DUKE ENERGY INDIANA, LLC

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing electronically this 18th day of September 2020 to the following:

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PROPOSED FORM OF ORDER

Presiding Officers:
David E. Ziegner, Commissioner
David Veleta, Senior Administrative Law Judge

On July 31, 2020, Duke Energy Indiana, LLC ("Applicant") filed its Verified Application and direct testimony and exhibits for approval by the Indiana Utility Regulatory Commission ("Commission") of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of October, November and December 2020 for electric and steam service and to update monthly benchmarks for purchased power costs. On August 3, 2020, Sierra Club and Citizens Action Coalition of Indiana, Inc. ("CAC") filed Petitions to Intervene, which were subsequently granted on August 12, 2020. On September 4, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony, and CAC and Sierra Club filed its direct testimony. Applicant filed rebuttal testimony on September 14, 2020.

Pursuant to the Commission's June 12, 2020, Docket Entry, a public evidentiary hearing was held in this Cause on September 17, 2020, at 1:30 p.m. via WebEx. Counsel for Applicant, Sierra Club, CAC and the OUCC participated in the hearing. Applicant, the OUCC, CAC and Sierra Club offered their respective prefiled testimony and exhibits into the evidentiary record without objection. At the hearing, Sierra Club moved to make any fuel adjustment factor approved for Duke Energy Indiana in Cause No. 38707 FAC 124 interim and subject to refund pending the outcome of the investigation in Cause No. 38707 FAC 123 S1 insofar as Cause No. 38707 FAC 123 S1 is reviewing the reasonableness of Duke Energy's self-commitment practices, issues which also affect Cause No. 38707 FAC 124. CAC joined Sierra Club's motion. Duke Energy Indiana opposed the motion, citing the narrow scope the Commission established for 38707 FAC 123 S1.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's rates and charges related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Applicant's Characteristics.** Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant also renders steam service to one customer, International Paper.

3. **Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income.** On June 29, 2020, the Commission issued an Order in Cause No. 45253 ("June 29 Order") approving base retail electric rates and charges for Applicant. The Commission's June 29 Order found that Applicant's base cost of fuel should be 26.955 mills per kWh. The Applicant's jurisdictional operating income level authorized in the June 29 Order is not applicable to this proceeding and will be phased in over time in future proceedings. The Applicant should reflect an authorized jurisdictional net operating income of $267,500,000 based on the Commission's Order in Cause No. 42359 issued May 18, 2004 ("May 18 Order"), prior to any additional return on (1) qualified pollution control property; (2) property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC"); (3) federally mandated compliance projects; (4) transmission, distribution and storage system improvement projects; and (5) company-owned renewable energy projects approved by the Commission in various rate proceedings not taken into account in the May 18 Order.

Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of May 2020, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.022601 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2020, to be $464,533,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. **Fuel Purchases.** Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of May 31, 2020, coal inventories were approximately 3,646,554 tons (or 67 days of coal supply), which is an increase over what was reported in FAC124 due to a combination of decreased demand during the spring months due to COVID-19, and low gas and power prices. He testified that coal inventories are projected to remain flat over the next quarter. Mr. Phipps added that Applicant continues to evaluate a host of options in order to effectively manage its coal inventory. Mr. Phipps stated that as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. Due to continued weak coal market conditions, resale opportunities will continue to be

extremely difficult in the near term. Given the continued decline in coal burns due to falling power prices, the Company began a coal decrement in March. Mr. Phipps further testified as to Applicant's successful contract reopener activities and the extension of a transportation contract. Mr. Phipps testified that it was his opinion that Applicant is purchasing coal and oil at prices as low as reasonably possible.

Mr. Phipps testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from March through May 2020 the price Applicant paid for delivered natural gas at its gas burning stations was between $1.43 per million BTU and $2.15 per million BTU. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness, Mr. Michael D. Eckert, testified regarding Applicant's coal inventory. He testified that Petitioner's forecasted 2020 coal burn has increased since its last FAC, it is still less than the 2020 forecasted amount from the 2019 4th quarter forecast, which was the basis for its 2020 coal purchase plan. He recommended Applicant continue to update the Commission on its coal inventory and how it proposes to address its increased inventory. He also recommended Applicant update the Commission on its 2020 and 2021 projected coal burn and coal purchases.

Mr. Swez testified that Applicant continues to submit an incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in FAC 113.

Mr. Swez testified that the Edwardsport IGCC Generating Station continued to run at a high rate, producing over 300,000 MWhrs in each month of March through May 2020, and performing at 74.2% net capacity factor. He testified the major planned outage schedule to begin in April was moved to the end of May due to the COVID-19 pandemic. He testified that when the unit's gasifiers are available or operating, Edwardsport IGCC is being offered with a commitment status of must-run. Mr. Swez stated that Edwardsport IGCC has followed MISO's dispatch direction between the minimum and maximum capability of the unit during this time. Mr. Swez also testified that during times when syngas is not available and the station is available on natural gas operation, the unit will typically be offered to MISO with a commitment status of economic and can be committed and dispatched at MISO's discretion.

Sierra Club's witness, Ms. Devi Glick, testified that the Commission should disallow losses Applicant incurred at Edwardsport and Cayuga Stations based on its uneconomic self-commit and operational decisions. She testified that Applicant uses an economic assessment to determine whether to commit a unit to operate in MISO. Applicant reviews forecasted market prices and projected variable startup, shutdown, and operational costs for the next seven days to project net operational revenues for each unit. The process is repeated three times for a total of 21 days. All revenue projections and commitment decisions for the following day are recorded in a "Daily Generating Unit P&L Analysis". Therefore, Applicant should elect to self-commit its units on a forward-looking basis only if it expects to make positive energy market margins, and should keep a unit offline if projected to operate at a loss. She testified that although Applicant decreased the frequency with which it self-committed many of its coal-fired power plants during this FAC period, it still self-committed a significant portion of the time which led to unnecessary net operational losses passed to ratepayers. Ms. Glick testified Applicant's commitment-decision process is not aligned with or guaranteed to serve the best interest of ratepayers. Ms. Glick testified that her review of the Profit & Loss analysis finds Applicant self-commits units when it knows it will lose money on a variable basis by operating the unit. She testified that Applicant provided three dates of Profit & Loss Sheets which showed multiple instances where Applicant self-committed despite the analysis indicating it would save money be either operating the unit on a different fuel or allowing the unit to be economically committed through MISO. She testified that she reviewed Applicant's Profit & Loss analysis for most of the three-month FAC period and found at least four instances where Applicant brought online, or left online, a unit despite its commitment analysis showing that net losses would be lower if the unit was not brought online or was taken offline. Ms. Glick testified that during March 2020 through May 2020, Petitioner knowingly decided to uneconomically self-commit Edwardsport on coal, despite its own analysis showing that self-committing and operating on syngas/coal would result in $6.8 million in projected net losses for ratepayers relative to operating the unit on gas. She testified that she calculated this value by summing the daily projected net revenues or losses for Edwardsport from the Profit & Loss analysis for each day for operation of the plant both on syngas/coal and on natural gas. She then calculated the difference between the projected operational losses or revenues from the unit when operating on each fuel source.

Ms. Glick testified that there were operational losses during March 2020 through May 2020 for the Cayuga units. She testified that in order to serve its steam customer, one of the Cayuga units is generally self-committed and self-scheduled above its normal minimum operating level regardless of economics. She testified that Applicant's steam contract likely did not contemplate the scenario where the plant was no longer able to economically run full time as a baseload resource and cannot economically operate during many hours of the year. Ms. Glick testified that Applicant should be modeling its electricity system with and without the requirement to provide steam to the industrial customer in order to understand the cost of operating to serve the steam customer. She also noted losses at Gibson Units 2 and 3 during this FAC period, which Ms. Glick explained were due to offering the units as Must Run. Ms. Glick testified that she also reviewed Applicant's data on performance of its coal fleet during March 2020 through May 2020 and found losses from operating its coal fleet during extended periods while they were otherwise non-economic to operate. She explained how she calculated these values and testified the unit's actual net revenues or losses were very close to Applicant's values projected by its Profits & Losses analysis sheets. Ms. Glick testified that commissions and public utilities in Minnesota and Missouri have begun to explore and address the issue of unit self-commitment, with some utilities switching to seasonal operation at specific plants and only running units during summer months when energy prices are highest.

Ms. Glick also offered testimony regarding the Company's use of the coal price decrement during this FAC period. She stated that the reason Duke Energy Indiana needed to use a coal price decrement was due to its coal purchasing practices, specifically its use of long-term coal contracts and imprudent spot coal purchases.

Ms. Glick testified that the reasonableness of fuel costs depends on the reasonableness of unit commitment decisions, among other factors, and the existing FAC proceeding process does not allow for sufficient review of unit-commitment decisions. She recommended the Commission create a sub-docket or other process to: 1) establish an annual process for review of unit commitment and dispatch practices over the prior year, which allows for customer refunds if warranted; 2) have Applicant file its “Profits & Losses” spreadsheets and make them available to intervenors; and 3) to the extent Applicant’s commitment decisions have been guided by must-take or minimum-take provisions in medium or long-term contracts, examine the prudency of such contracts.

CAC’s witness, Mr. Edward Burgess, provided testimony regarding the Company’s use of a coal price decrement during this FAC period. Mr. Burgess stated that this practice distorts the unit commitment and dispatch of its five coal plants at the expense of its customers and amounts to an indirect subsidy for imprudent coal fuel purchase decisions made by the Company. Mr. Burgess also testified that even with decrement pricing imputed into costs, the Company’s Daily P&L Analysis projected economic losses at some coal plants that were subsequently committed as Must Run. He explained that this is particularly true at Edwardsport and Cayuga, specifying that Edwardsport’s total losses were comprised of both economic losses from operating the plant on coal, and the opportunity cost from not running the plant on natural gas. Mr. Burgess also testified that the Cayuga plant created economic losses due to the requirement to commit the unit as Must Run even when it is uneconomic to do so.

Mr. Burgess recommended that the Commission: 1) reduce the amount that Duke Energy Indiana can collect from its customers by the amount equal to the decrement pricing that it applied to the fuel burned at its coal plants; 2) deny cost recovery for any long-term future coal fuel purchases until the Company has achieved an inventory level of 45 full load burn days; 3) reduce the amount that Duke Energy Indiana can collect from its customers by an amount equal to the net economic losses due to uneconomic unit commitment at Edwardsport and Cayuga; and 4) require the Company to provide two sets of Daily P&L Analysis data sheets for the period: one with and one without decrement pricing reflected.

In rebuttal, Mr. John Swez disagreed with Ms. Glick that Applicant’s generating unit commitment and operation practices are concerning in any way. He testified that Applicant commits its generating units on an economic basis, after including specific operational considerations and taking into account the amount of purchase energy and ability to hedge customer risk in the forward market. He testified the daily commitment decisions for each unit are designed to minimize total customer cost by maximizing each unit’s economic value. Units committed by MISO are committed on an economic basis using MISO’s security constrained economic dispatch. Mr. Swez also testified that units are dispatched on an economic basis between their minimum and maximum capability when not required to run at a specific output as would be necessary for unit testing or an operational requirement. He explained the five different commitment status offers allowed by MISO, stating that utilizing a commitment status of Must-Run in MISO does not necessarily mean that a generating unit was not economically committed.

Mr. Swez explained Duke Energy Indiana’s commitment process. He testified Applicant performs an economic review (Daily Profit and Loss Analysis) each business day to inform the commitment status decision for each unit. The analysis projects expected operating margins from operation of each coal unit for the next 7-14 days based on unit operating parameters and expected market prices. The unit is offered with a commit status of Must-Run if it is expected to have a positive margin or is “in the money”, meaning revenues received are projected to be greater than variable production costs. If a unit’s projected revenues are less than the variable production costs ("out of the Money") and the unit can come off-line, it is offered with a commit status of Economic. Mr. Swez testified a commit status of Must-Run may be utilized to prevent uneconomic cycling of on-line generating units across lower priced energy periods such as over a weekend, which reduces the overall cost to supply energy to customers by reducing additional costs and risks. He testified that if a unit is expected to have revenues approximately equal to its variable costs, it is "at the money" and offered as Must-Run or Economic, depending on the particular situation. Small changes in energy prices or unit cost can swing a unit from being in the money to out of the money, so often a designation of Must-Run makes sense to provide certainty to plant operators. Mr. Swez testified that when Applicant forecasts that a unit will be out of the money over a period where it makes sense to decommit the unit, a commit status of Economic is utilized, which defers to MISO to decide whether a unit will continue running or not. If MISO commits the unit to be online, it guarantees customers at least break even economically through the Revenue Sufficiency Guarantee Make Whole Payment. If MISO does not commit the unit, it will then come off-line.

Mr. Swez testified there are many types of operational constraints considered in making commitment decisions, such as 1) contractual obligations, such as the Cayuga steam supply contract; 2) joint ownership arrangements at Gibson Unit 5; 3) unit testing; 4) start-up times and costs; 5) impact of MISO charges and credits; 6) a unit's fuel supply; and 7) transmission congestion and loss impact on a unit's operation. Also, after a planned or forced maintenance outage a unit may be committed as Must-Run to ensure repairs were appropriately made and the unit is available to run.

Mr. Swez testified that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. For units with longer start-up times or higher start-up costs the MISO Day-Ahead Market will not typically result in a commitment of these generating units from an off-line state when being offered with a commitment status of Economic, even though they may be the most economic choice over a multi-day period. As a result, always using an Economic commitment status could at times cause either the lowest cost unit to remain off-line or uneconomic cycling of certain units across multiple days. He testified that each time a power plant is cycled, its major and minor auxiliary components experience significant thermal and pressure stresses, which cause damage. Over time and repeated cycles, component life can be shortened, impacting maintenance and capital costs and increasing forced outages. A risk adjusted unit commitment process adjusts for the risk associated with cycling a unit off and then back on.

Mr. Swez testified that the Daily Profit & Loss Analysis informs the commitment decision, it does not determine the commitment decision, as suggested by Ms. Glick. The realities and risks of operating actual generating units in the real world must be considered. He testified that Applicant does not have the luxury of after-the-fact academic calculations when deciding in real-time whether to commit a unit. In addition, Ms. Glick's analysis does not look at the opposite scenario – all times the Company didn't run or turned off its generation when it would have been more economic (in hindsight) to run the units. In addition, as Ms. Glick's own comparison shows, the Daily Profit & Loss Analysis tends to be slightly conservative, meaning that units tend to fair slightly more profitable than forecast. Mr. Swez testified that this occurs due to the Company's inability to model the MISO Ancillary Services Market ("ASM") in the Daily Profit & Loss Analysis.

In response to Ms. Glick's arguing against operating Edwardsport on syngas in favor of natural gas, against operating at least one Cayuga unit to serve the steam customers, and against bringing Gibson 2 online as Must-Run during freezing weather, Mr. Swez explained there were operational reasons for operating these units during this FAC period. Mr. Swez testified that such a large amount of purchase energy could expose the customer to unnecessary additional price risk. Mr. Swez also testified that the additional generation during this FAC period due to the use of the coal price decrement avoided larger future losses.

Mr. Swez disagreed with Ms. Glick and Mr. Burgess that uneconomic commitment of a Cayuga unit to supply steam to its customer caused losses of $6.5 Million and $3.7 Million, respectively, during the FAC period. He explained the contractual obligations involved with serving the steam customer, and that there was required environmental testimony. In addition, Mr. Swez explained that shutting down both Cayuga units during the winter would result in a significant extension to the amount of time to return a unit to service. Mr. Swez also explained that the relationship between the steam customer and the electric customer can be complimentary, as there are other fixed costs that would have been charged to the electric customers had the steam customer not existed due to economies of scale.

Mr. Swez testified that Ms. Glick's and Mr. Burgess's analyses failed to account for the impacts of required unit testing that took place during the FAC period. He testified that even though a test may only last a short period of time, the unit may need to be brought on prior to the test to reach a steady state condition.

In response to Ms. Glick and Mr. Burgess, Mr. Swez also explained the various reasons for offering Edwardsport with a commitment status of Must-Run, including 1) cycling would cause the station's equivalent forced outage rate to increase causing lower capacity and energy value in the MISO energy markets; 2) while gasifiers are brought off-line, the unit would be unavailable on coal for the approximate 14-day cycle time; 3) de-committing the gasifiers for long periods would cause loss of essential personnel; 4) the continued use of auxiliary energy when switched over to natural gas, so the gasifiers are not totally shutdown; 5) increased cost of firm natural gas transportation; 6) natural gas volatility; and 7) the existing Edwardsport permits do not contemplate it operating on natural gas as a primary fuel over extended durations. Mr. Swez also estimated quantitative values to go with these qualitative factors. He then testified that operating Edwardsport solely on natural gas is shortsighted as it only considers the short-term impact as opposed to a long-term viewpoint, and concluded by stating his belief that the longer-term analysis needed to make decisions on the Company's generation make up are better suited to an IRP process – not in a docket ostensibly on fuel purchasing and generation dispatch.

Mr. Swez next explained the coal price decrement being used by the Company in this FAC period. He stated that including the coal price decrement into the Company's offers to MISO was appropriate because not doing so would be the same as ignoring any other variable cost, such as the cost of emissions or variable operations and maintenance expense. All variable costs should be included in a unit's offer and ignoring any of them could result in an inaccurate offer that does not correctly reflect the economics of generation. Mr. Swez stated that customers are benefiting from the use of the coal price decrement since higher costs are avoided that more than offset any current losses. He also explained how Mr. Burgess's analysis supporting his recommendation for a disallowance related to the coal price decrement was incorrect.

In rebuttal, Mr. Phipps testified that the Company's use of the coal price decrement is not related to the Company's coal purchasing strategy. The Company's coal contracts are entered into prudently with the best information available at the time the contracts are entered into. Its procurement strategy balances the costs associated with transacting longer-term coal contracts with the need to provide reliable generation supply, especially during periods of high demand and extreme weather. He testified the Company uses methods and strategies to ensure reasonable costs, including the use of staggered terms on long-term contracts, maintaining a diversified mix of suppliers, and using indices, at times, in the determination of adjustment of prices. His team conducts a thorough evaluation of supplier proposals including quality, quantity, volume flexibility, transportation alternatives and price. He testified many long-term contracts contain provisions for periodic price reopener negotiations, some type of price escalations and de-escalations, or a mechanism to adjust prices based upon a published market price index. The Company's procurement contracts are subject to external review quarterly through the FAC process with the OUCC auditors.

Ms. Sieferman rebutted Ms. Glick's position that the Cayuga units should be offered to MISO without consideration of its obligation to provide steam to its steam customer. She described the 45-year business and contractual relationship with its steam customer, International Paper. Ms. Sieferman testified that as part of Applicant's jurisdictional separation study, the costs and revenues associated with the sale of steam are removed from the remainder of the costs and revenues assigned to retail electric customers. Thereby, retail electric customers are receiving less fixed costs assigned to them than they otherwise would have had the steam supply contract not existed, thereby lowering their base rates. Ms. Sieferman testified that International Paper was assigned approximately $2.5 million in revenue requirement to cover variable and fixed costs in the last retail rate case, which costs were removed from the cost of service for electric customers. Ms. Sieferman testified the contractual arrangement is complementary to both International Paper and the Company's retail electric customers, and allows the State of Indiana and Vermillion County to retain one of its largest employers. Ms. Sieferman also testified in opposition to Mr. Burgess's argument that the Company perform calculations to identify any economic losses associated with running at least one Cayuga unit to provide steam under the contract, explaining that the Company will be initiating discussions in the near term with the steam customer in order to negotiate modifications to the contract to reflect the most recent cost of service study. Ms. Sieferman explained, that would be an appropriate time for the Company and steam customer to begin discussions regarding any future changes to commitment of the Cayuga units into the MISO market.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during March through May 2020. With regard to its coal inventory levels, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC. We do not find it reasonable or necessary to seek additional information from Duke Energy Indiana in its quarterly FAC filings. Similarly, we do not agree with Sierra Club and the CAC that disallowances are warranted based on how the

Company is dispatching its coal units, particularly Edwardsport and Cayuga. We agree with Mr. Swez that the longer-term analysis needed to make decisions on the Company's generation make up are better suited to an IRP process particular in concerns with operating Edwardsport on coal or gas. Similarly, we agree with the Company that the Cayuga Steam contract is a Commission approved special contract and it is appropriate for Duke Energy Indiana to take that into account in its dispatch process.

As to the Company's use of the decrement, which was challenged by CAC and Sierra Club, but not by the OUCC, this is not a new issue to the Commission and as such, we stand by our finding in Cause No. 38707 FAC 96, in which the Commission found:

> We find that Duke Energy Indiana has laid a reasonable foundation for the mechanics of its coal decrement pricing impacts and that examination of the inputs to the calculation is the appropriate initial review point in regards to the submission of detailed testimony and analysis of the coal decrement cost impacts as recommended by the Industrial Group. Accordingly, we find that Duke Energy Indiana should conduct and present as support for the reasonableness of its pricing the changes in inputs to the calculations in each applicable future FAC filing.[1]

We agree with Petitioner that the decrement is a reasonable, appropriate and low cost method to handle coal inventory issues and that the Company's application of the decrement in this proceeding was reasonable. Accordingly, Petitioner shall continue to file its support for the reasonableness of its decrement costs and any adjustments to the inputs to the decrement calculations in each applicable future FAC filing. We will address the request for a subocket on the decrement and coal procurement practices below.

As to intervenor concerns related to coal procurement practices, we also note that Duke Energy Indiana has kept the Commission informed adequately on these issues in each FAC. As we found in response to similar arguments in a prior Duke Energy Indiana FAC:

> With regard to the submission of detailed testimony and analysis demonstrating the reasonableness of entering into any new long-term contract as recommended by the Industrial Group, we decline to make such a requirement explicit. Duke Energy Indiana has reasonably presented detailed discussion in the past, for example its testimony filed in Cause No. 38707 FAC 80 concerning the coal contract with Bear Run mine, for significant long-term commitments. As Duke Energy Indiana is required to show the reasonableness of its actions as a working of the FAC summary proceeding, we will afford it the opportunity to do so absent a showing that it has failed to do so thus far.[2]

We agree with Mr. Phipps that Duke Energy Indiana's procurement strategy balances the costs associated with transacting longer-term coal contracts with the need to provide reliable generation supply, especially during periods of high demand and extreme weather. We also agree that Duke Energy Indiana uses adequate methods and strategies to ensure reasonable costs. As

[1] Cause No. 38707 FAC 96. p. 6 (October 30, 2013)
[2] *Id.*

such we find that Petitioner's coal procurement practices are reasonable and prudent, and we encourage Petitioner to continue to inform the Commission in the quarterly FAC process.

In this proceeding, Sierra Club moved to make any fuel adjustment factor approved for Applicant interim and subject to refund pending the outcome of the investigation in Cause No. 38707 FAC 123 S1 insofar as Cause No. 38707 FAC 123 S1 is reviewing the reasonableness of Applicant's self-commitment practices. Duke Energy Indiana objected to the request noting that the subdocket was limited to decisions made in the FAC 123 quarterly period. We agree and deny the Motion to keep this fuel clause subject to refund.

5. Hedging Activities. Applicant's witness Mr. Wenbin (Michael) Chen testified the Company takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that Applicant realized a loss of $149,200 from natural gas hedges purchased for March through May 2020. He testified that market price for gas realized lower values than the hedged prices, attributable to lower power generation demand and lower gas heating demand caused by the COVID-19 pandemic. He testified Applicant experienced net realized power hedging losses for the period of $455,954 primarily attributable to COVID-19 pandemic impact on load as well as mild weather which drove natural gas prices into a sustained downward trend reaching the lowest level in the last twenty years. Power prices followed the gas price lower in these months. Ms. Sieferman testified that Applicant realized a total net hedging loss of $622,719 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. Chen explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave the Company with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated Applicant never speculates on future prices, and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets. Mr. Chen testified that, as mentioned in the FAC100 proceeding, Applicant restarted using virtual trades as a hedging tool for expected forced outages in the Real-Time market because of heightened LMP price volatility caused by gas supply issues and extremely cold weather experienced in the past winter.

No evidence was offered in this Cause noting issues with the realized net amounts for power and gas hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net amounts. In addition, Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Applicant to include $622,719 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. Energy and ASM. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Swez testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; and (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and Schedule 27-A.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO to Applicant. She also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Applicant to MISO, net of any credits, are proper and that such amounts billed to customers through the FAC are proper.

In its Phase II Order in Cause No. 43426 ("Phase II Order") the Commission authorized Applicant and the other Joint Petitioners to recover costs and credit revenues related to the ASM. Mr. Swez explained that Applicant has included various ASM charges and credits in this proceeding incurred for March through May 2020, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	Mar-20	Apr-20	May-20
Regulation Cost Dist.	0.0449	0.0507	0.0495
Spinning Cost Dist.	0.0182	0.0288	0.0320
Supplemental Cost Dist.	0.0034	0.0036	0.0037

OUCC witness Mr. Eckert testified that Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented and incorporating our previous discussion on coal decrement pricing above, we find Duke Energy Indiana's participation in the Energy and Ancillary Services Markets and utilization of the coal price decrement constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 F AC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

7. <u>Participation in the Energy and ASM Markets and MISO-Directed Dispatch</u>. As previously noted, the June 1 Order approved certain changes in the operations of Applicant as a result of the implementation of the Energy Markets. Specifically, we found that Applicant (and the other electric utilities participating in Cause No. 42685) should be granted authority to participate in the MISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. Mr. Swez generally described Applicant's participation in the MISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed in his filed testimony the offer process and noted there are a variety of reasons that Applicant will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible.

Mr. Swez testified that beginning in early March 2020 a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Cayuga Units 1-2, and Edwardsport (syngas only) to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He stated that, to the extent that the price decrement results in units being dispatched that otherwise would not be, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost alternatives to manage the inventory are avoided. Mr. Swez testified the price decrement is working as designed as Applicant initially saw an increase in generation output from these units. As the level of the coal price decrement decreases over time as inventories decrease, the economic need to burn excess coal decreases. In the October 30, 2013 Order in Cause No. 38707 FAC 96, the Commission ordered Applicant to present the inputs to its calculation of the coal price decrement applicable to each FAC filing as support for the reasonableness of its pricing. Mr. Swez provided the confidential coal stacks for the time period March through May. Mr. Swez testified that Applicant continues to forecast its coal inventory position as part of the normal course of business.

Based upon the evidence presented, we find Applicant's participation in the energy and ancillary services markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

8. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified during this FAC period there were five outages that met these criteria. The first outage occurred at Gibson Unit 4 on February 12 due to a feedwater heater valve pressure seal failure during startup. Repairs were made and the unit returned to available status on March 7. At that time the unit went into a reserve shutdown status. Upon unit startup after the reserve shutdown period on March 12, a second outage occurred due to a boiler tube failure. Repairs were made and the unit returned on March 18. The third outage occurred at Gibson Unit 1 on March 20 when, in order to protect personnel, the unit's ongoing planned outage was paused due to the COVID-19 pandemic. The unit remained in this forced outage until May 16 when it returned to its planned outage status. The fourth outage occurred at Cayuga Unit 2 on April 29 when the unit transitioned to a forced outage to repair a tube leak. Repairs were made and the unit returned to available status on May 10. The fifth outage occurred at Gibson Unit 4 on May 10 due to a boiler tube leak. Repairs were made and the unit returned on May 17. Mr. Swez testified that no Root Cause Analysis ("RCA") was performed for any of these outages.

9. Operating Expenses. Ind. Code § 8-1-2-42(d) (2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Applicant filed operating cost data for the 12 months ended May 31, 2020. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $758,530,000. For the 12-month period ended May 31, 2020, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,365,056,000. Accordingly, Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

10. Return Earned. Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in regulated utilities earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with Applicant's June 27, 2012 order in Cause No. 42736-RTO 30, the proposal for Schedule 26-A treatment of costs or revenues associated with the Applicant's Company-owned Multi-Value Projects (MVPs) should be addressed at the time any such projects have been completed and are included for recovery. Applicant's witness Ms. Sieferman testified that the first of such projects were included for the first time in MISO billing effective June 2019. Applicant proposed that the costs and revenues associated with Company-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test which is consistent with the treatment of its Company-owned RECB projects beginning in Cause No. 38707 FAC86. Applicant will provide more detail as it relates to the RTO rider in its next filing in Cause No. 42736. Based upon the evidence presented, the Commission finds the Applicant's exclusion of revenues and expenses associated with Company-owned MVPs should be approved on an interim basis, subject to refund, pending the outcome of Applicant's next RTO filing as recommended by the OUCC's witness Mr. Guerrettaz.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $486,441,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $464,533,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended May 31, 2020.

11. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of October through December 2020, will be $56,192,653 or $0.023395 per kWh. Applicant previously made the following estimates of its fuel costs for the period March through May 2020, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
Mar 2020	24.827	24.574	1.03
Apr 2020	23.371	25.837	(9.54)
May 2020	22.540	24.455	(7.83)
Weighted Average	23.639	24.935	(5.20)

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of (5.20). Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for October through November 2020 should be accepted.

12. Purchased Power Benchmark. Applicant has calculated monthly purchased power benchmarks in accordance with the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of this Commission in Cause Nos. 38706 FAC 45, 38708 FAC 45, 38707 FAC 56, and 38707 FAC 59. The benchmarks are as follows:

Month / Year	**Benchmark $/MWh**	**Facility**
Mar 2020	24.26	Cayuga 1
Apr 2020	26.00	Madison 7
May 2020	39.82	Gallagher 2

Mr. Burnside testified that Applicant did not exceed the benchmarks for the reconciliation period at issue in this FAC proceeding.

The OUCC's witness Mr. Michael Eckert testified that Applicant did not purchase any power that was non-recoverable.

Based on the evidence of record, the Commission finds that Applicant has met the requirements necessary to establish monthly benchmarks for power purchases that occurred during the March through May 2020 reconciliation period.

13. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to October through December 2020 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.023395
Net Reconciliation Factor	(0.001150)
Adjusted Fuel Cost Factor	0.022245
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	(0.004710)

Ms. Sieferman testified that the net variance factor shown above reflects $7,384,940 of under-billed fuel costs applicable to retail customers that occurred during the period March through May 2020.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended May 2020 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed.

14. Effect on Residential Customers. The approved factor represents a decrease of $0.000905 per kWh from the factor approved in Cause No. 45253. The typical residential customer using 1,000 kWhs per month will experience a decrease of $0.90 or 0.7% on his or her total electric bill compared to the factor approved in Cause No. 45253 (excluding sales tax).

15. Interim Rates. Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved herein should be approved on an interim basis, subject to refund, in the event an excess return is earned.

16. Fuel Adjustment for Steam Service. On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $0.8179135 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the October through December 2020 billing cycles. Exhibit B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $20,792 credit to International Paper for the months of March through May 2020.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $0.8179135 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Applicant's reconciliation amount of $20,792 credit to International Paper has been properly determined and should be approved.

17. Shared Return Revenue Credit Adjustment for International Paper. In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 10, Applicant did not have excess earnings for the 12 months ended May 2020. Therefore, we find International Paper is not due a shared return revenue credit.

18. <u>Request for a Subdocket.</u> CAC and Sierra Club filed a Joint Motion for Subdocket to Investigate Duke Energy Indiana's Coal Decrement Pricing and Fuel Procurement Practices, in which they argued that "A subdocket would also allow for further record development with respect to these procurement and projection issues, which the short FAC timeline has inhibited." In response, Duke Energy Indiana stated the Commission recently reviewed the Company's proposed level of fuel inventory in its most recent base rate case, Cause No. 45253, and demonstrated its understanding of fuel procurement by finding that "inventory levels can and do fluctuate based on circumstances that are largely outside the control of the Company, such as weather driven demand, plant availability, and commodity price fluctuations."[3] Duke Energy Indiana further noted the Commission has previously reviewed decrement pricing and fuel procurement practices, approving their usage and determining that the Company should present information related to decrement pricing "in each applicable future FAC filing".[4] Duke Energy Indiana asserted that yet another subdocket is unnecessary as this Commission has proved that it is fully capable of reasonably reviewing decrement pricing and fuel procurement impacts for Duke Energy Indiana and other investor-owned electric utilities in the state.

As discussed in Section 4 above, the Commission has found the use of the decrement to be an appropriate mechanism to address a coal surplus situation.[5] As Mr. Phipps explained in his direct testimony, a combination of decreased demand during the spring months due to COVID-19, as well as low gas and power prices have contributed to Duke Energy Indiana's coal surplus. We note that Duke Energy Indiana is not the only electric utility to face a coal surplus and use the decrement to manage its coal surplus.

We see no basis to abandon our finding in Cause No. 38707 FAC 96, quoted above in which the Commission found that the Company laid a reasonable foundation for the decrement in the FAC proceeding. Further, we agree with Duke Energy Indiana that the decrement is not a new process and has been and can continue to be reviewed in the quarterly FAC processes for Duke Energy Indiana and the other electric utilities.

As to the CAC and Sierra Club's request that a subdocket be commenced to investigate Duke Energy Indiana's fuel procurement practices, we decline to do so. In each FAC proceeding, Mr. Phipps provides an update on the Company's procurement strategy as well as an update on activity with existing contracts. In this proceeding, Mr. Phipps testified that Duke Energy Indiana entered into a price reopener for an existing contract for 1 million tons to be shipped in 2019 and 1 million tons to be shipped in 2020. The Company is reasonably handling its coal procurement and we see no basis to open a further investigation. Rather, we encourage Duke Energy Indiana to continue to present a discussion of its decrement pricing practices, coal procurement strategy, and significant coal contracts in subsequent FAC filings. CAC and Sierra Club's Motion for a Subdocket is therefore denied.

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[3] Duke Energy Indiana, IURC Cause No. 45253 (June 29, 2020), p. 24.
[4] Cause No. 38707 FAC 96, Final Order at p. 6.
[5] *Id.*

19. **Confidential Information.** On July 31, 2020, and September 11, 2020 Applicant filed motions requesting protection of confidential and proprietary information along with supporting affidavits. On August 12, 2020 and September 15, 2020, the Presiding Officers made preliminary determinations and/or clarifications that trade secret information should be subject to confidential procedures, as supported by Applicant's affidavits, including (i) its coal stack for every decrement update between March and May 1010, including fuel, storage and transportation pricing, and pricing projections; and (ii) pricing, commercial terms, and supplier information related to its coal contracts (including interim coal storage contracts), as well as its coal positions. The Commission finds such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and should be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Finding No. 13, and the fuel cost adjustment for steam service as set forth in Finding No. 16 of this Order are hereby approved on an interim basis, subject to refund.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this order, is hereby approved.

3. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the date of approval for all bills rendered.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories in its next FAC filing, as described in Finding No. 4 of this Order.

5. The material submitted to the Commission under seal shall be and hereby is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code §8-1-2-29.

6. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, OBER AND ZIEGNER CONCUR:

APPROVED:

I hereby certify that the above is a true and correct copy of the Order as approved.

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Mary M. Becerra
Secretary to the Commission