STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF DUKE ENERGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	))))	**CAUSE NO. 38707 – FAC 123 S1**

SIERRA CLUB'S SUBMISSION OF PROPOSED ORDER

Sierra Club hereby submits a Proposed Order in both clean and "redlined" form, working from the proposed order submitted by Duke Energy Indiana, LLC in this Cause.

Dated: December 21, 2020

Respectfully submitted,

__/s/ Kathryn A. Watson____________

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that foregoing Sierra Club's Submission of Proposed Order was served upon the following counsel of record via electronic mail on December 21, 2020.

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STATE OF INDIANA

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SUBDOCKET FOR REVIEW OF DUKE ENERGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	**)))**	**CAUSE NO. 38707 FAC123 S1**

<u>SIERRA CLUB'S PROPOSED ORDER</u>

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

On January 31, 2020, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") filed with the Indiana Utility Regulatory Commission ("Commission") an Application in Cause No. 38707 FAC 123 for approval of a change in its fuel cost adjustment for electric service, approval of a change in its fuel cost adjustment for steam service, and an update of monthly benchmarks. The Commission granted the interventions of Sierra Club, Citizens Action Coalition of Indiana, Inc. ("CAC"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), and Steel Dynamics, Inc. ("SDI"). On March 6, 2020, Sierra Club and CAC filed a *Joint Motion for Subdocket to Investigate Duke's Generation Commitment and Fuel Procurement Practices* ("Joint Motion"). The Commission issued a docket entry on March 12, 2020, granting the Joint Motion and opening this subdocket limited to unit commitment decisions during the reconciliation period of September through November 2019. Although Duke Energy Indiana appealed the docket entry to the full Commission, the March 12, 2020 Docket Entry was upheld in the Commission's March 31, 2020 Final Order.

Counsel for CAC, Sierra Club, Nucor and SDI entered Appearances in this subdocketed proceeding. On March 18, 2020 the Indiana Coal Council, Inc. ("ICC") filed a Petition to Intervene, which was subsequently granted on August 31, 2020.

On April 29, 2020, the Company prefiled its case-in-chief, which included the direct testimony and exhibits of the following witnesses:

- John D. Swez, Managing Director, Trading and Dispatch at Duke Energy Carolinas;
- Cecil T. Gurganus, Vice President of Midwest Generation at Duke Energy Business Services, LLC; and
- Maria T. Diaz, Director, Rates and Regulatory Planning at Duke Energy Indiana.

Also, on April 29, 2020, the Company filed a motion for protection of confidential and proprietary information, which was preliminarily granted on May 13, 2020. Second and third motions for protection of confidential and proprietary information were filed by Duke Energy Indiana and preliminarily granted on May 27 and October 29, 2020, respectively. On June 25, 2020, Advanced Energy Economy, Inc. ("AEE") filed its Petition to Intervene. Over the objection of Duke Energy Indiana, AEE's intervention was granted by the Commission on July 15, 2020. On July 30, 2020 Better Jobs Coalition Indiana, Inc. ("Better Jobs") filed a Petition to Intervene.

On July 31, 2020, the OUCC and intervenors pre-filed testimony and exhibits of the following witnesses:

- OUCC - Peter M. Boerger, Ph.D, Senior Utility Analyst
- CAC – Ed Burgess, Senior Director, Strategen Consulting
- Sierra Club - Devi Glick, Senior Associate, Synapse Energy Economics, Inc.
- AEE – Sarah Steinberg, Principal of AEE; Robert B. Stoddard, Director, Berkley Research Group, LLC ("BRG"); Charles J. Cicchetti, Managing Director and Member of BRG; and Michael Jonagan.
- Better Jobs – Simon R. Lomax[1]

On August 5, 2020, Duke Energy Indiana filed an objection to Better Jobs' Petition to Intervene and, in the alternative, a motion to strike the prefiled testimony of Simon R. Lomax. On August 13, 2020, the Commission granted the intervention of Better Jobs, but struck the prefiled testimony of Better Jobs' witness Simon Lomax in its entirety as the testimony was filed prior to its intervention being granted. On August 14, 2020, Better Jobs filed a Motion to Accept Testimony Submitted While Petition to Intervene Was Pending. Duke Energy Indiana filed its objection to said Motion and on August 27, 2020, the Commission denied Better Jobs' Motion to accept the testimony.

On August 28, 2020, Duke Energy Indiana prefiled the rebuttal testimony of John Swez, Cecil Gurganus, Maria Diaz, and Brett Phipps. Also on August 28, 2020, ICC filed cross-answering testimony of Robert DiDona and Better Jobs filed cross-answering testimony of Simon R. Lomax. Petitioner filed a Motion to Strike Better Jobs' cross-answering testimony on September 4, 2020, as not properly responsive to the OUCC's testimony, and Better Jobs filed its Response on September 9, 2020. On September 25, 2020, the Commission granted the Motion to Strike, in part, admitting only the properly responsive testimony. On October 2, 2020, Better Jobs appealed the ruling to the full Commission. By docket entry dated October 30, 2020, the Commissioners approved the decision reached by the Presiding Officers.

On September 10, 2020, Duke Energy Indiana filed motions to strike portions of the CAC's direct testimony of Mr. Burgess and portions of Sierra Club's direct testimony of Ms. Glick on the basis of being outside the limited scope of this proceeding and beyond the case-in-chief testimony of Duke Energy Indiana. Sierra Club and CAC filed their respective responses on September 21, 2020. On October 5, 2020, the Commission granted Duke Energy Indiana's motions, in part, striking the CAC and Sierra Club's references to the FAC 124 and 125 reconciliation periods, and the CAC's references to coal decrement pricing and its impact on the commitment process, as not relevant to this proceeding. The Commission further ruled that the Cayuga contract is approved and not subject to review in the FAC; however, the impact of the contract on unit commitment decisions is relevant to this proceeding. Revised testimony was filed by CAC and Sierra Club. On

[1] Better Job's Intervention had not been granted at the time it filed this testimony.

October 26, 2020 Duke Energy Indiana filed its revised rebuttal testimony to reflect the relevant changes made by CAC and Sierra Club, and to substitute Mr. John Verderame for Mr. Brett Phipps.

On October 5, 2020, the Commission issued a docket entry setting the evidentiary hearing via WebEx due to the ongoing COVID-19 pandemic and the need for several parties to the proceeding to travel across the country for the evidentiary hearing.

Duke Energy Indiana responded to three separate docket entry requests from the Commission received on September 22, October 21, and October 27, 2020, as well as a request made orally during the October 30, 2020 hearing.

A two-day public evidentiary hearing was held in this Cause via WebEx on October 30, 2020, at 9:30 a.m., and on November 9, 2020. Duke Energy Indiana, Sierra Club, CAC, Nucor, AEE, ICC, Better Jobs, and the OUCC appeared at the hearing by counsel. Applicant, Sierra Club, CAC, AEE, ICC, Better Jobs, and the OUCC offered their respective prefiled testimony, exhibits, and stipulations into the evidentiary record.

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

1. <u>Notice and Commission Jurisdiction</u>. 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 Duke Energy Indiana'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. <u>Duke Energy Indiana's Characteristics</u>. Duke Energy Indiana 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. The Company 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. Duke Energy Indiana also renders steam service to one customer, International Paper.

3. <u>Duke Energy Indiana's Case-in-Chief</u>. Mr. Swez testified that the Company commits its generating units on an economic basis, except as required for unit testing, operational requirements, or other "infrequent" reasons. According to Mr. Swez, Duke's commitment process is designed to minimize total customer cost by maximizing each unit's value. He explained the different types of commitment status offers and the meaning of Economic and Must-Run offers. An Economic commit status is used when the Company doesn't self-commit the unit, but the unit is available for commitment by MISO if the unit's costs are favorable compared to all resources available to MISO that day. Must-Run is used when the Company desires to commit the unit itself. He testified the Company performs an economic review each business day (Daily Profit and Loss Analysis) to inform the commitment status decision for each coal unit. The analysis projects expected operating margins from operation of each coal and combined cycle unit for the next 7-14 days based on a unit's operating costs and parameters and expected market prices. He testified that the 7-14 day timeframe is important in order to account for factors beyond just the operating margin that are not apparent within a short time horizon of one or two days, such as cycling cost and time. Mr. Swez testified that operating parameters include the generator's minimum load, maximum load, and variable costs. Market prices are based on forecasted or observed trades for Indiana.Hub LMP prices, adjusted for congestion and losses at each generator's node. Mr. Swez explained that generally if a unit is expected to have a positive margin ("in the money") the unit is offered as Must-Run, which eliminates any uncertainty over the Economic commit status offer and thus the generating unit can take action earlier and plan for operating for the next day, such as ensuring there is enough coal bunkered. He stated that if a unit is expected to have a negative margin ("out of the money") and the unit can come off-line, it makes economic sense to offer with a commit status of Economic. To prevent uneconomic cycling of on-line generating units across lower priced energy periods such as a weekend, a generation unit commit status of Must-Run may be utilized. Mr. Swez testified that when a unit is expected to have revenues approximately equal to its variable costs ("at the money" or marginal) it could be offered using either a Must-Run or Economic commit status, depending on the situation. Given that small changes in energy prices or unit cost can swing a unit to out of the money, Mr. Swez testified that a designation of Must-Run often makes sense to provide certainty to the plant operators. He testified that during the FAC 123 reporting period, the Company's coal-fired generators were frequently marginal units. Mr. Swez explained that the Company uses a commitment status of Economic when a unit is out of the money because it is in the best interests of the customer. The Company is deferring to MISO to decide whether a unit will continue running or not. If MISO commits the unit to be online, it will guarantee that 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 that there are additional considerations in making commitment decisions, including the Company's contractual obligations, such as its steam supply contract at Cayuga Station and the joint ownership arrangement of Gibson Unit 5. At least one unit at Cayuga must be on-line at an output of 300 MW (net) or greater to supply steam to the customer. For Gibson Unit 5, there are three different owners with three energy offers made to two different RTOs. Mr. Swez stated that if any share of the unit is committed in either MISO or PJM, or if any of the three owners desire to run the unit, the unit is committed as Must Run. He testified that unit testing, operational constraints, and multiple unit startups are also considered and may determine a unit's commit status offer. When a unit is committed by the Company or MISO, it must meet its minimum run time. Mr. Swez testified that the impact of MISO charges and credits as they relate to the unit's offer must also be understood, as well as consideration of a unit's fuel supply. In addition, after a unit undergoes a planned or forced maintenance outage, it may be committed as Must Run to ensure the repairs were appropriately made and unit is available to run.

Mr. Swez testified that it is not appropriate for the units at Gibson, Cayuga and Edwardsport to be offered to MISO using a commitment status offer of "Economic" at all times. He testified that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. It is designed to minimize the cost to reliably and economically serve the demand for the next 24-hour period. He testified that 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. Mr. Swez also noted that all available Duke Energy Indiana generating units can be committed by MISO through the Reliability Assessment Commitment ("RAC") process, as it can look out further than the next day period. Mr. Swez testified that using an Economic commit status offer into the MISO Day-Ahead Market for an off-line unit that was economic to run, could result in higher costs for customers. He testified it is not practical nor economic for a large coal unit to be committed by MISO in the Day-Ahead Market if starting from an off-line state. He explained that if an off-line, but in the money, unit is available and submitted with a commit status of Economic, the number of hours available for the Day-Ahead market to commit a unit shrinks to the point that MISO commitment is not practical and almost impossible. Using Cayuga Unit 1 as an example, which has a 32-hour combined cold startup/notification time, the unit would only be available for full output for the last approximate 1 hour of the 24-hour day, making it almost impossible for MISO to commit in the Day-Ahead Market. In fact, the margin produced by the unit during the last few hours of the day would have to overcome the unit's startup cost.

Mr. Swez testified that MISO energy markets are a resource used to Duke Energy Indiana's customers' advantage when power prices are below the cost of the Company's generation cost. As power prices generally fell during the period of 2015 through 2019, the Company's purchased power increased to over 30%. Mr. Swez testified that as energy prices have been at a sustained low level during the Winter of 2019-2020, the percentage of time the Company's units were offered with a commit status of Economic has increased, as expected.

Mr. Swez testified that the Company makes commitment decisions that look to the best interest of the customer and described his team's process in making those decisions. Mr. Swez provided the daily commitment status of each unit during the FAC 123 reconciliation period of September through November 2019. He also described the Company's unique operating issues during this period, including 1) longer planned outages at Gibson Units 4 and 5, Edwardsport (partial unit outages), and Noblesville; 2) marginal unit conditions in September; 3) above normal temperatures in early October leading to higher energy market prices; 4) Cayuga forced outage and derate of another unit in October due to river temperatures; and 5) unusually cold weather in November requiring one unit at Cayuga to be on to serve the steam customer and to avoid issues related to freezing temperatures. Mr. Swez provided an overview of the Company's commitment decisions during the FAC 123 period. He testified that because September was marked by generally marginal unit conditions, the Company's coal units were offered with a commit status of both Must Run and Economic. In October, after the higher ambient temperatures passed, LMPs returned to where units were marginal once again, much like September, and units were offered with commit status of both Economic and Must Run. He testified that colder weather in November brought higher market prices, and the Company's coal units were more in the money than in September and October. Mr. Swez testified that as many of the large coal units tended to be marginal in nature during September through November, those that were on-line tended to stay on-line and those off-line tended to stay off-line due to start-up costs.

Mr. Swez testified that the Company commits its generating units on an economic basis, including considerations made for required unit testing, operational requirements, external customer steam supply, risk of cycling a unit off-line and back on-line, plant heating at Gibson and Cayuga Stations, avoidance of uneconomic cycling, management of Gibson Unit 5 within multiple RTOs and multiple joint owners, consideration of multiple unit startups, MISO charges and credits, congestion and loss impact, coal considerations, and the supply of steam to another generating unit in startup. The daily process to inform its commitment status decision for each unit is designed to minimize the total customer cost by maximizing each unit's economic value. He testified that market participants do not have clear means of informing MISO the cost to shut down a unit. Over time and repeated cycles, component life can be shortened. He testified that the impact on maintenance and capital costs from shortened component life, component failure and increased forced outages can be significant. Mr. Swez testified that although the forecasted energy margin (Daily Profit and Loss Analysis) is an important step in the commit status offer decision, it is not the only input. It informs the decision but does not determine the decision.

Mr. Swez testified that environmental compliance testing occurred at Cayuga Unit 1 and Edwardsport during this FAC reporting period. In addition, there was an unplanned boiler tube leak on Cayuga Unit 1. If the single day's Real-Time impact from the forced outage was eliminated, Cayuga Unit 1 would have had a positive margin for the entire three-month period. Mr. Swez described the commitment status offer for Edwardsport Station. When Edwardsport's gasifiers are available or operating, the station is being offered as Must Run. He testified the reasons for this include: 1) cycling the station on and off would likely increase the station's equivalent forced outage rate, resulting in lower capacity value and less energy value in the MISO energy markets; 2) due to the gasifiers approximate 14-day cycle time, the unit would be unavailable on coal for this period if the gasifiers were brought off-line and forecasting weather and market prices this far int the future is an imperfect science; 3) de-committing Edwardsport gasifiers for long periods of time would cause loss of essential personnel; 4) cycling the station to natural gas for short periods of time is not economic since the gasification system cannot be turned off for short periods of time if the unit is switched over to natural gas, continuing to consume auxiliary energy and not allowing for anticipated savings; 5) natural gas volatility and loss of diversity value of coal; 6) Edwardsport permitting does not contemplate operating on natural gas as a primary fuel over extended durations; and 7) operating solely on natural gas is shortsighted and does not consider a long-term viewpoint. Mr. Swez testified that during the FAC period Edwardsport ran at a high rate, but for a period of planned de-rates in September.

Mr. Swez testified the Company's commitment practices are appropriate and serve to minimize customer costs, while providing operational flexibility. As long as the Company explains its MISO dispatch and commitment process and why such practices are reasonable given the realities of operating generating plants, and the Commission reviews it on a quarterly basis, fuel costs should be approved and not be subject to refund later based on hindsight analysis.

Mr. Gurganus testified that Edwardsport Station provides benefits to Duke Energy Indiana's system and its customers. Since it began operating in 2013, plant performance has continuously improved. According to Mr. Gurganus, the ability to run on both natural gas and coal provides diversity and reliability to Duke Energy Indiana's customers. Edwardsport was built as a long-term asset for customers. He testified that today's risks of single-fuel-source energy reliance are increasing, and it is in customers' best interests to diversify. As the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit –

particularly one with advanced emission controls (Edwardsport IGCC), so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come. Mr. Gurganus testified that Edwardsport was designed to produce its maximum performance when operating on 100% syngas produced from coal. There is reliability and resiliency value in fuel inventory maintained at coal plants, relative to natural gas. He testified that the Company benefits from the ability to run Edwardsport on natural gas, which can be used as a secondary fuel to operate the combustion turbines when the gasifiers are undergoing planned maintenance or in the event of gasification forced outages or derates. This is important as it allows the Company to maintain service of at least one combustion turbine and the steam turbine so the plant is always maximizing its output as needed by MISO.

Mr. Gurganus testified that offering Edwardsport into MISO with a commit status of "Economic" could result in Edwardsport never being selected to run by MISO due to its long startup and shut down processes, which is not what was intended when the plant was approved. Completely shutting the station's auxiliary systems down and turning them back on is a multi-week-long process. It can take up to fourteen days if all of the gasification systems are allowed to reach ambient conditions, requiring a complete re-start of the plant. He testified regarding the importance to reliability and efficiency of Edwardsport to place the gasifiers in service and leave them in service. Cycling the gasifiers for short periods would decrease the efficiency of the plant through continued use of gasification auxiliary power, as well as impart significant thermal stresses that cause equipment wear and tear and increased maintenance costs. He testified that these practical considerations must be taken into account when deciding how to offer Edwardsport for operation to MISO.

Mr. Gurganus testified that Duke Energy Indiana has been supplying a large industrial customer, International Paper, located adjacent to Cayuga Generating Station, with both electricity and high-pressure steam for forty-five (45) years. The steam customer currently employs 180 employees and produces gypsum paper, brown containerboard and other related products. In addition to being a steam customer, it is also one of the Company's larger energy customers. Mr. Gurganus testified that Cayuga Station goes to great lengths to ensure no interruption to the customer's steam supply by avoiding forced dual unit outages and coordinating planned dual unit outages, as well as avoiding periods of peak energy prices when Cayuga's output is needed the most. Mr. Gurganus explained that Cayuga's delivery of steam to International Paper results in (at most) an approximate 4 MW derate to the unit. It does, however impact the quantity of makeup water required by the station. Because of this, Cayuga maintains a robust water treatment system, for which International Paper pays 80% of the cost. He testified that one of Cayuga's units is offered into MISO with a minimum load of 300 MW (net output) to also ensure consistent steam supply to the customer.

Mr. Gurganus testified that load cycling causes accelerated damage to many unit components, causing increased equipment failures with resulting higher EFOR, higher non-routine maintenance and capital replacement costs. Increased cycling puts the Company's assets at increased risk of increased forced outages and events, which is a main reason why large coal-fired and nuclear power plants are offered into MISO as "Must Run." He testified that most coal-fired units, not just Duke Energy Indiana's units, were not designed for frequent cycling. Frequent cycling is also detrimental to the efficient operation of post-combustion emission controls, as it impacts the ability of such equipment to achieve optimized temperatures and/or chemistry for efficient removal of emissions. This results in higher average emission rates and increased air emissions. He testified that increased cycling is also reasonably expected to result in increased turbine fouling, a leading cause of unit derates which can cost several million dollars during a two to three-month long outage period to correct. In addition, the number of tube leaks by a unit is also expected to increase with frequent cycling. Another expected result of frequent cycling is a shortening of inspection intervals for generator field windings from approximately 10 years to approximately every 5 years. In addition, components which are more vulnerable to damage as a result of more frequent cycling would be expected to fail or otherwise require service at more frequent intervals. Mr. Gurganus testified that frequent cycling results in higher net and operating heat rates on the units, as the units consume more startup fuel and more off-line auxiliary power. Frequently cycled units also generally operate at lower average loads, which are less efficient than operating at higher average loads which results in higher CO_2 emission intensity which could be detrimental to future greenhouse gas emission Affordable Clean Energy ("ACE") rule compliance. Mr. Gurganus testified that the Company's generating units were constructed and have been operated for many years to benefit its customers. The Company's long history of serving customers should not be overlooked or minimized through a focus on short-term losses.

Ms. Diaz described the Company's business relationship and regulatory history with International Paper. Most recently, in 2012, the Commission approved in its entirety the updated pricing and provisions in the Fourth Amendment as agreed to by Duke Energy Indiana and International Paper (Cause No. 44087). Ms. Diaz described the key terms of the current contract for steam service to International Paper, which is a firm obligation to serve by Duke Energy Indiana with no interruptible service options. There is also no expected termination date specified in the contract, which continues unless either party gives notice.

Ms. Diaz testified that this steam customer is "carved out" in the setting of retail electric rate base rates as part of the Company's jurisdictional separation study. She testified that by carving out International Paper and treating it as an individual customer, the costs and revenues associated with the sale of steam to this single customer 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. Diaz testified that because the steam service to International Paper reduces the MW output of the two coal-fired units at Cayuga Station by up to approximately 20 MW of the approximate 1000 MW available, some of the costs of the generator and step-up at the station are included in the cost allocation to the steam customer along with other rate base and expense items. She testified that the steam supply to International Paper was assigned approximately $2.5 million in revenue requirement to cover variable and fixed costs in the Company's last retail rate case (Cause No. 42359). Ms. Diaz testified that International Paper is charged its pro-rata share each month of operation and maintenance costs associated with the water treatment facilities and explained how their share is calculated, since it benefits both Duke Energy Indiana and International Paper. She testified that demand revenues are also shared with retail electric customers under the current contract through Standard Contract Rider No. 71 based on the level of demand charge revenues received under the new contract as compared to the amount previously assumed when base rates were established. The portion returned to retail electric customers is based on the application of the incremental demand revenues multiplied by the ratio of the environmental rider rates set forth in Rider 62 plus Rider 71 as a portion of the total electric rate for International Paper. She testified that this sharing mechanism provides a benefit to retail electric customers each 6-month rider period of generally more than $100,000 and will continue until the base rates are set in the Company's currently pending retail base rate case (Cause No. 45253), at which time retail electric customers will benefit instead from the allocation of the full current levels of costs assigned to the steam supply. She explained that the sharing construct will end because all costs and revenues will be reset and reflected in base rates using the forecasted 2020 test period. Ms. Diaz testified that International Paper is also charged its share of fuel costs for its electric service via base rates and using the retail electric FAC rates approved in the Company's FAC filings times its electric usage. In addition, it is also charged its share of fuel costs associated with its steam service using rates also developed and approved in the Company's FAC filings, but with calculations specific to steam service. She explained the calculations and testified that the differences between the estimated fuel cost billed and the fuel cost actually incurred are reconciled quarterly and charged or credited directly to International Paper's monthly electric bills and steam invoices. Ms. Diaz testified that having this steam customer in place provides benefits that have existed for decades and that need to be taken into consideration when evaluating unit commitment decisions at Cayuga over a three-month period. Benefits include: fixed cost contribution from International Paper that reduces overall recovery from retail electric customers; sharing of a portion of incremental demand revenues with retail electric customers between rate cases; and the benefit of the Company diversifying its portfolio of customer offerings by providing steam service and allowing the mill to continue to operate and employ Indiana workers.

4. <u>OUCC and Intervenors' Testimony</u>.

A. <u>OUCC Testimony</u>. Mr. Boerger testified that the primary tool Duke Energy Indiana uses to make unit commitment decisions is its Profit and Loss Analysis ("P&L Analysis"), which is performed each weekday. He testified that the P&L Analysis reviews each coal and gas combined cycle unit to identify whether it is expected to earn a profit or lose money each day over a rolling three-week horizon on sales made in the daily energy market operated by MISO. He testified that MISO's commitment process, which is conducted day-ahead and during the operation day, looks at its set of committed units and seeks to decommit units not operating profitably when taking into account both incremental and no-load costs. However, MISO cannot decommit self-committed Must Run units operating unprofitably and will continue to dispatch them based upon their incremental cost. Mr. Boerger testified that no-load costs can lead to a high level of dispatch but unprofitable operation, therefore dispatching a unit above its minimum does not necessarily indicate a self-committed unit was committed in an economic fashion. Mr. Boerger testified that there are costs inherent in using a Must-Run designation that must be recognized and evaluated in determining whether the Company self-committing its units is appropriate in a given situation.

Mr. Boerger testified that the Company's P&L Analysis lacks any support tools used in arriving at unit commitment decisions. The OUCC recommended the Company have a standard approach when using its profit and loss data and technical constraints for unit commitment. Such a tool would allow input from plant personnel regarding the engineering constraints on commitments and be maintained in an information management system. Mr. Boerger testified that in addition to wear and tear costs related to frequent shutdowns and startups, Duke Energy Indiana should also consider wear and tear that could be avoided through commitment decisions that would keep units from running. He testified that the Company should also consider such running-related costs as part of its determinations of the economics of making Must Run unit commitment decisions. Mr. Boerger recommended the Company evaluate such costs and incorporate a reasonable reflection of them in its unit commitment methodology.

Mr. Boerger agreed that the Company must commit its Cayuga units in a manner to accommodate the steam contract, however he testified that it does not appear the Company is being compensated adequately for the provision of steam at Cayuga. He testified that unit commitment-related costs for serving the steam customer are no more hypothetical than the costs Duke Energy Indiana forecasts in its Integrated Resource Plan ("IRP") every three years or the costs it forecasted in the future test year it used in its recent base rate case. He testified that a forecast of such costs should have been incorporated into the Company's contract-related calculations to ensure other customers are not subsidizing this steam customer. Mr. Boerger recommended an annual review by the Company to determine whether all of the costs incurred in serving the steam load under the contract, including unit commitment costs being imposed on other customers, are being properly reflected. Such annual analyses would be reviewed in the Company's next base rate case or other proceedings to evaluate the prudency of the decision to continue or modify the contract.

Mr. Boerger testified that the Company's approach to committing Edwardsport is not the same approach it uses to commit its coal-fired units and its reasons for the difference are not all related to providing electricity to retail customers at the lowest fuel cost reasonably possible. He stated that the Company does not consider offering the Edwardsport unit as economic when the gasifiers are available. Mr. Boerger recommended a determination by the Commission as to whether the Company is committing the Edwardsport Station in a manner consistent with I.C. § 8-1-2-42.3(d)(1). Mr. Boerger also recommended Duke Energy Indiana and its parent company work to encourage MISO to improve its unit commitment system to better handle long-startup-time units.

B. <u>CAC Testimony</u>. Mr. Burgess' key findings were as follows: (1) the Company commits its coal generation units as Must Run even when they are forecasted to yield economic losses, which is most common at Edwardsport Station that operated with a Must Run designation with coal as the primary fuel source; (2) the Company's steam contract has led to Must Run designations at one of the Cayuga generators resulting in higher costs to customers; (3) the Company routinely under-forecasts the economic losses that actually occur from plants that are given a Must Run commitment status, leading to a greater number of Must Run designations and higher costs to customers; and (4) in its modeled forecasts to determine the amount of coal it will burn, the Company presumes Must Run status at several plants, which overestimates the amount of coal it will need. Mr. Burgess recommended the following: (1) a reduction in the amount collected from customers equal to the economic losses due to operating Edwardsport with coal when the Company predicts losses to occur but commits the unit as Must Run. Further reductions should be made for the amount collected by any foregone economic benefits the Company predicts from operating the plant on coal syngas instead; (2) assign economic losses associated with Must Run designations at Cayuga to Duke Energy Indiana or the steam customer; (3) require the Company to provide additional reporting on its unit commitment decisions going forward as part of future FAC applications; and (4) require the removal of Must Run designations from the medium-term generation forecast models used in the FAC as these designations increase the likelihood of coal oversupply.

Mr. Burgess testified regarding his understanding of the Company's decision-making tools and processes influencing its unit commitment status. Mr. Burgess testified that the Company makes a large share of unit commitment decisions outside of the MISO market optimization process and without regard for its own forecast of the value in the MISO market, which constrains the value of its market participation for its customers. He also testified that regular unplanned outages should be anticipated and factored in to the Company's unit commitment process by including an outage risk premium in its P&L Analysis. Mr. Burgess testified that since the Company estimated in its 1998 EPRI study few instances of shutdown costs at Cayuga and none at Edwardsport, it would have made more economic sense to offer these units as Economic rather than Must Run. He testified that committing them as Must Run without properly accounting for the magnitude of any avoidable or non-avoidable costs is not appropriate and sacrifices the added value of full participation in the MISO market optimization process. He testified that Duke Energy Indiana's use of the 1998 EPRI study to estimate its shutdown costs is somewhat outdated. Mr. Burgess testified that if a unit does not fully recover its startup costs through energy market revenue, it will be made whole via MISO Day-Ahead Make Whole Payments. However, units designated as Must Run are not granted any Make Whole Payments if startup costs are not fully recovered, so it is actually in the best interest of the Company's customers to offer the units as Economic as there is less risk that startup costs will go unrecovered.

Mr. Burgess testified that the Company designates Edwardsport as Must Run any time the gasifiers are available, regardless of what may be in the best interest of its customers, and has no economically-based decision-making process for determining the unit commitment status. He testified that the Company is routinely underestimating the economic losses, or overestimating the economic benefits, that occur at units that are designated as Must Run. To the extent the P&L forecasts reveal that the Company has been operating its plants imprudently, the ultimate harm to customers is even greater than these forecasts would suggest. He testified that this means the Company's unit commitment decisions are biased in favor of Must Run designations as its forecasts are overly optimistic. Mr. Burgess testified that when the Company commits a unit as Must Run despite its own forecast that such commitment would lead to an economic loss, it is reasonable to require Duke Energy Indiana to shoulder the entire economic loss that was actually experienced. Mr. Burgess recommended the Company adjust its P&L analysis to account for the general outage rates of each unit, realizing that forcing units with high outage rates to operate as Must Run could also increase the frequency of unplanned outages and therefore costs for customers. Mr. Burgess testified that the most logical unit commitment status for marginal units is Economic due to MISO Make Whole payments. He testified that the Company's operations at Edwardsport were imprudent as it used coal as the primary fuel source rather than natural gas that would have avoided economic losses and realized economic benefits for customers. He estimated that Duke Energy Indiana's customers could pay an additional $700-800 million more than necessary if it continues to operate in the same way going forward, despite the Company's P&L Forecasts clearly demonstrating that it would be more profitable on natural gas.

Mr. Burgess testified that the Company's steam contract creates ratepayer losses from uneconomic unit commitment. Given that at least one Cayuga unit is committed as Must Run

100% of the time, regardless of its economic competitiveness, it may cost the Company more to generate power for steam than it will earn for that power in the MISO market, putting electric customers at a higher risk. He testified that the steam customer is not responsible or held accountable for the unit's economic losses, which means the Company's retail electric customers are effectively subsidizing the steam supply for International Paper. Mr. Burgess recommended losses caused by the steam contract be removed from the FAC 123 collection from retail electric customers.

Mr. Burgess testified that the Company's coal contracting practices are leading to coal oversupply, distorting commitment practices and leading to higher costs for customers. He testified that coal oversupply has been a persistent problem for many years. Mr. Burgess testified that he does not believe a concern about supplier diversity was a valid basis for purchasing new coal.

Mr. Burgess recommended the Company be required to provide a report for each FAC with the following for each generating unit: (1) hourly unit commitment designation; (2) rationale for each hour with a Must Run designation: (3) Daily P&L Analyses conducted in the week prior to any hour with a Must Run designation; (4) actual Daily P&L results for each hour with a Must Run designation. He testified that if the reporting reveals unreasonable Must Run decisions resulting in economic losses, the Commission should reduce the authorized FAC charge accordingly. In cases where the Must Run designation is related to providing steam to the steam customer, the Commission should require economic losses be assigned to the steam customer or borne by the Company. Mr. Burgess recommended that each coal burn forecast be conducted without the presumption that any units be committed as Must Run and that they follow forecasted MISO market price signals. If fuel burns exceed forecast those amounts can be accounted for in a subsequent FAC via the reconciliation factor.

C. Sierra Club Testimony. Ms. Glick testified that (1) all but one of the Company's coal-fired power plants reported net operational losses during the FAC 123 time period; (2) the Company self-committed at least half of the Company's units as must run approximately 50 percent or more of the time during the FAC 123 period; (3) Duke Energy Indiana's commitment and operational practices led to fleet-wide net operational revenues of less than half a million, based on actual revenues and costs reported by the Company; (4) the Company's imprudent, uneconomic commitment and operations practices incurred total actual net losses of $5.2 million during FAC 123 at Edwardsport and Cayuga; (5) contemporaneous data shows Duke projected energy market losses at Edwardsport and Cayuga of $3.7 million and $0.4 million during the periods in which the Company committed each plant as must run, meaning that Duke knowingly self-committed these units even though it expected to incur negative energy margins; (6) the Company did not substantiate or quantify its claims that the Edwardsport air permits do not allow the plant to run on natural gas full time, that Edwardsport would lose essential personnel by switching to natural gas operation, or that natural gas prices would increase as a result of converting to natural gas operation at Edwardsport; (7) the Company ignored its own P&L Analysis and relied on no tools to inform Edwardsport's unit commitment practices; (8) the Company's contemporaneous P&L Analysis sheets do not support its self-commitment decisions at Cayuga; and (9) Duke has failed to demonstrate that the uneconomic operation of Cayuga to serve a steam customer is in the best interests of electricity retail ratepayers.

Ms. Glick testified that Duke relies heavily on self-commitment at its coal units, that is, the use of must run commitment status; all but Cayuga unit 2 and the two Gallagher units were committed as must run well over half the FAC 123 period and Edwardsport and Gibson 1 were committed as must run for 100% of the time both gasifiers were available. While there is nothing inherently unreasonable about self-commitment (*i.e.*, the use of must run commitment to take control of commitment decisions from MISO where a utility validly expects to incur positive net energy margins), uneconomic self-commitment like that practiced by Duke during the FAC 123 period can result in millions of dollars of unnecessary fuel costs for customers. Ms. Glick explained that when an operator commits a unit as must run into the MISO market, the unit may incur losses if the market price of energy falls below the operational cost of the unit. When a unit incurs losses, these unnecessary fuel costs are passed onto Duke customers through the fuel charge.

Ms. Glick testified that the Company's plants are generally uncompetitive with other market resources in the energy market and customers would have been better served had the Company committed its plants economically and purchased energy from the market when prevailing energy prices are expected to be lower than the cost of operating a Duke unit. She testified the Company's market revenue is not covering the fuel and variable costs to operate and are therefore making no contribution towards the fixed and capital costs incurred at its plants. Specifically, Ms. Glick testified that the Company ignores its own P&L Analyses at Edwardsport and Cayuga and regularly makes imprudent unit commitment decisions that foreseeably result in net revenue losses imposed on ratepayers through higher fuel charges. The Company maintained Edwardsport as must run on syngas for all non-outage hours during FAC 123 despite projections showing weekly net operational losses in 50 of the 57 Profit and Loss Analysis sheets produced during the period. As a result of these uneconomic commitment decisions, Duke incurred $3.7 million in losses from operating Edwardsport on coal. Ms. Glick also testified that Duke projected $2.7 million in net revenue from gas operation at Edwardsport, for a total projected difference of $6.5 million between coal-syngas and natural gas operation. Ms. Glick testified that Duke self-committed at least one Cayuga unit as must run for almost the entire FAC 123 period, likely to serve its steam customer, and that these decisions were projected to incur $0.4 million in losses on the MISO energy market and in fact the Cayuga units incurred a total of $1.9 million in losses. Ms. Glick testified that the Company is operating Cayuga when it is not economic in order to provide steam to an industrial customer and these costs are being subsidized by its electric ratepayers.

Ms. Glick testified that the Company should be self-committing its units as must run on a forward-looking basis if it expects to make positive energy market margins and use the economic commitment status when the unit is projected by Duke to operate at a loss. Ms. Glick testified that the Commission should disallow recovery of losses incurred through the imprudent operation of Duke's coal units if Duke does not follow market price signals or the results of its own price-based process and thereby fails to generate or purchase power at the lowest reasonable cost.

As a result of these findings, Ms. Glick recommended the Commission: (1) disallow $3 million of Edwardsport fuel costs for FAC 123, equivalent to the proportion of total variable losses attributable to fuel; (2) disallow $1.7 million in Cayuga fuel costs for FAC 123; (3) require the Company to conduct a cost of service study or alternative analysis to evaluate whether the currently operative steam contract at Cayuga appropriately allocates the costs of uneconomic operation there to serve the steam customer; (4) require the Company to develop a new, price-based profit and loss analysis process for Edwardsport to facilitate the choice between coal-syngas and natural gas operation on a quarterly basis by producing a three-month forecast to assess the projected net revenues associated with coal-based syngas and natural gas, then making commitment decisions with the more economically efficient fuel using either the daily Profit and Loss Analysis (natural gas) or 14-day projections to accommodate cycling times (coal-syngas); (5) require the Company to follow price-based signals at Edwardsport and all other plants in making unit commitment and dispatch decisions, and provide a description of any deviation between the results of its forward-looking P&L Analysis and its actual commitment decision; (6) establish a presumption of disallowance of recovery of fuel costs associated with energy market losses incurred at Edwardsport or any plant as a result of not following the results of the Company's own price-based process; and (7) require the Company to publish in every FAC a public accounting for Edwardsport showing total net revenue, monthly gas and coal consumption, hours of gasifier outages, and total net revenue it would have incurred from operating only on natural gas during all hours.

D. AEE Testimony. Ms. Steinberg testified that the Company's uneconomic self-scheduling of coal generation with guaranteed cost recovery disrupts the market's ability to appropriately price and signal resource characteristics to meet wholesale electric service needs. She testified that seasonal operations of coal plants is becoming standard practice in the industry during periods of the year with lower energy demand and energy prices, and is a more efficient way to operate its coal plants. She testified that the Company should begin planning to implement an accelerated retirement schedule for all of its coal units and develop a substitute portfolio of more cost effective advanced energy technologies. Ms. Steinberg recommended (1) the Commission cease cost recovery for instances where generation is committed to MISO at an economic loss, with the burden of proof on the Company to demonstrate best practices in its commitment decision-making; (2) the Company reduce its coal plant usage in favor of seasonal operations and commit to an accelerated retirement schedule for all units; and (3) plan to build out advanced energy resources to replace retiring generation.

Mr. Stoddard testified that he used a state-of-the-art power systems model, ENELYTIC™, to simulate commitment and dispatch in MISO. He testified that the Company's coal-fired generators operated at a significant financial loss during the FAC 123 and 124 periods, demonstrating that its self-commitment decisions harm the Company's ratepayers and have long-lasting effects. He testified the Commission should not grant recovery of the losses attributable to uneconomic dispatch, which was about 8% of the total energy costs to serve load in FAC 123. He testified that further savings could have been achieved by using selective, seasonal reserve shutdowns that would have lowered costs to serve load by $9.37M. Mr. Stoddard testified that the Company could have retired some or all of its coal units and replaced them with advanced energy resources to further mitigate losses. The Company's failure to accelerate coal unit retirements will continue to be a costly omission in its planning. Mr. Stoddard explained his modeling data and methods. He testified that the results of his model show Duke Energy Indiana's coal units operated at much higher levels than they would have run solely on their economics. This uneconomic dispatch accounts for 93% of the operating losses, principally fuel costs, and is not limited to FAC 123 but is a consistent pattern throughout June 2020. He concluded that the Company has not made every reasonable effort to acquire fuel and generate or purchase power to provide electricity to its retail customers at the lowest fuel cost reasonably possible in the FAC 123 and 124 periods. If the Company's self-commitment decisions are not corrected, his modeling shows this trend continuing and ratepayers charged hundreds of millions of dollars in fuel costs that could have been avoided by greater reliance on economic commitment and dispatch and an accelerated transition to advanced energy resources.

Mr. Cichetti testified that self-commitment bias increases the amount of fuel and purchase power costs recovered in the FAC, and it is not reasonable to approve the pass-through of uneconomic dispatch decisions. He urged the Commission to determine whether the Company has been reasonable and prudent in its efforts to include energy efficiency, renewable energy and demand side management to reduce fuel and purchase power expenses recovered in the FAC. He recommended the Commission deny cost recovery for any amounts that reflect uneconomic dispatch choices and direct the Company to eliminate self-selection commitment bias. He also recommended the Commission determine the extent that increased demand side efficiency could reduce fuel and purchase power expenses recovered using the FAC and take steps to require the Company resume and expand its energy efficiency efforts. Mr. Cichetti recommended the Company include the prospect of future carbon fees in its operations and investment decisions even if they are included on a virtual basis. Finally, he recommended requiring the Company to justify its current unit availability status to determine the net benefits from converting some of its older resources to some form of partial shuttering on a seasonally restricted basis.

Mr. Jonagan recommended the Commission direct the Company to (1) evaluate the potential benefits of seasonal operation of some units; (2) document the cost savings and avoided maintenance that can result by shifting operations to focus more on peak demand periods; (3) conduct an evaluation of the value of the steam contract to its customers relative to reduced operations of the Cayuga plant, or accelerated retirement; and (4) evaluate the economic viability of the operation of the syngas plant at Edwardsport. Mr. Jonagan testified there is an opportunity for the Company to reduce the operations at negative margins and thereby reduce costs to its customers, but there is little or no incentive for the Company to explore these opportunities. He explained how the Company could improve its units' operational flexibility through seasonal operations, a more aggressive cycling strategy during the on-peak season, by reducing the minimum operating load, and by operating Edwardsport as a gas-fired only combined cycle plant.

5. Duke Energy Indiana's Rebuttal. Mr. Swez testified in rebuttal that intervenors focused mostly on the commitment and operation of Edwardsport Station on coal and the supply of steam to an external customer at Cayuga Station. They failed to focus on long-term benefits to the Company's customers and ignored risks associated with procurement of large volumes of energy from MISO and the realities of the resulting short position. He testified the Company 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. A daily risk adjusted process is performed to inform the commitment status decision for each unit designed to minimize the total customer cost by maximizing each unit's economic value within operational constraints, while not exposing the customer to undue risk of price volatility. Unique operational conditions associated with Edwardsport and Cayuga make these units a target of intervenors' analysis.

Mr. Swez further explained how the Company determines a unit's commitment status and its use of a P&L Analysis to understand the financial impact of operating its units in the energy market and deal with consequences of the different time horizons that typically exist between the next day, 24-hour MISO Day-Ahead market and a unit's minimum up time, which is typically at least 72 hours for larger coal units. He explained that the P&L Analysis projects expected operating margins from operation of each coal and combined cycle unit for the next 21 days based on a unit's operating parameters and expected market prices, which is important to account for factors other than daily operating margin, such as cycling cost, that are not apparent or obvious within a short time horizon of one or two days. Generally, if an on-line unit is expected to have a positive margin or is "in the money," the unit is offered with a commit status of Must Run. If off-line, a unit's margin over the multi-day commitment period is generally at least equal to its startup cost in order to be committed. He testified there are times when a unit is out of the money and the Company commits it as Must Run, such as to avoid an uneconomic cycle, to meet a contract constraint such as supplying steam at Cayuga, for unit testing, or due to additional factors and consideration of a longer time horizon such as Edwardsport Station. Mr. Swez testified that the P&L Analysis is not the primary tool the Company uses to make its commitment decisions, as suggested by Dr. Boerger. It is one of the tools to inform generating unit commitment status offers, other factors including operating constraints, the impact of MISO charges and credits, startup and cycling costs along with risk associate with cycling a unit, and the ability to hedge the customers' supply position (market liquidity) are all considered. The P&L statement is not meant to provide an optimal commitment decision. It is a short-term view of, at the most, the next 21 days. It is meant to inform the commitment decision, but does not determine the commitment decision. Mr. Swez testified that further analysis beyond the P&L analysis is needed to get to the best overall result for customers, namely the realities and risks of operating actual generating units in the real world and the liquidity and ability to hedge the Company's customer energy position.

In response to Dr. Boerger's concern that the Company does not have additional support tools that include technical constraints, Mr. Swez testified the Company has a variety of tools to assist in making dispatch decisions including the short-term GenTrader model that is run each day. Although the purpose of this tool is to assist in forecasting the Company's position, the model does perform an economic commitment of all available generating units. Mr. Swez testified that Dr. Boerger's suggestion to develop a new tool to incorporate a standard approach to technical constraints on unit commitment is almost impossible to create to be useful to analyze each potential situation due to the number of possibilities. Mr. Swez testified that this type of analysis is accomplished by the Company on a situational basis when necessary and a new or different tool is unnecessary.

Mr. Swez responded to Ms. Glick's claim that there were instances that units were imprudently brought back or remained on-line, providing a reason for the Company's decision, namely, that the Company's "strategy for operation" at Edwardsport is to operate the unit as must run whenever the gasifiers are available, and that Cayuga 1 was required to be on-line beginning on October 3 to "supply steam to the external steam customer." In response to Dr. Boerger's recommendation that the Company consider the wear and tear that could be avoided through commitment decisions that would keep units from running, Mr. Swez testified that these types of costs are included within the Company's maintenance costs and the real issue is how to apportion those costs into defined variable O&M rate metrics. In addition, nearly every aspect of operation likely affects cost in some way, but not everything is granular enough, nor sufficiently studied by industry, to be reasonably separately defined, such as load-following cycling costs.

Mr. Swez testified that he is not aware of any Company analysis regarding seasonal operation for the Midwest generating units, but fixed costs, commitments in the MISO capacity market, and contractual obligations to supply steam at Cayuga Station would all need to be considered. The MISO capacity construct is an annual commitment and there is no current provision that would allow a utility to seasonally operate a generator that has been committed into the MISO auction. He testified that he believed any attempt to purposefully remove a committed generator from service may be seen by the MISO independent market monitor as physically withholding capacity. In addition, MISO has planned outage approval authority and may not approve frequent, extended, and overlapping outages, as suggested by Mr. Jonagan. Mr. Swez testified that the Company commits its generators into the MISO market and is obligated to make them available due to its must offer obligation, 24x7x365, and to the benefit of customers.

Mr. Swez testified that Mr. Stoddard's analysis of the Company's commitment decisions contains errors and is a theoretical backward-looking analysis, employs perfect foresight, and ignores such things as actual unit outages that occurred, physical constraints, joint ownership arrangements, and steam constraint, among other faults. Mr. Stoddard's analysis basically shuts down all generation from Cayuga and Edwardsport stations and ignores implications from the contractual obligation to supply steam to the steam customer at Cayuga. Mr. Swez testified that the many errors in Mr. Stoddard's model render the results untrustworthy. He also testified that at no point has the Company ever engaged in behavior to purposely mandate or distort MISO operators' commitment and dispatch decision, as suggested by Mr. Stoddard.

Mr. Swez testified that offering all coal-fired units with an Economic commitment status at all times would not be in the best interest of customers and could cost customers significant benefits in the MISO market due to the fact that the unit may not be committed even when economic to run the unit. The outcome would be dependent on factors such as initial state of the unit, startup cost, startup time, incremental and no-load cost of the unit, and LMP present at the time. He testified that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. It is designed to minimize the cost to reliably and economically serve the demand for the next 24-hour period. He testified that 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 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. Mr. Swez also noted that all available units can be committed by MISO through the RAC process, since this process can look out further than the next day. However, the purpose of the RAC is not to maximize a generator's margin, but to maintain reliability. In response to Ms. Glick's argument that the Company's plants are generally uncompetitive in the MISO market and should instead be committed as Economic with purchased energy from the market, Mr. Swez testified that this is not a discussion of unit commitment practices but rather a longer-term decision related to shutting down Edwardsport gasifiers or refusing to run a unit at Cayuga to supply a steam customer. He testified that Intervenors' criticism of unit commitment are the result of (1) the need to keep at least one Cayuga unit on-line to serve steam to an external customer; and (2) the fact that

Edwardsport is being committed when the gasifiers are available and not operated exclusively on natural gas. In response to Mr. Burgess' concern regarding the Company's use of a 1998 EPRI study to estimate shutdown costs, Mr. Swez testified that this study was selected as it was the only study with predictive cycle cost models that utilized actual O&M costs from a significant sample set. He testified that the 1998 cost estimates were escalated to current year costs using Handy Whitman indices, thus the 2001 published date is not significant.

Mr. Swez testified that the current MISO Day-Ahead market is not a multi-day commitment. For units that have commitment costs that wouldn't be recovered for a longer period of time (greater than a day), or for units where the startup time makes the unit physically unable or not practical to be committed by MISO, offering the units as Economic is detrimental to the Company's customers as an off-line unit could go multiple days without being switched on and that this "is not in the customers' best interest." Mr. Swez noted that other generation owners besides Duke Energy Indiana continue to commit generating units as Must Run in MISO. Mr. Swez argued that Ms. Glick's recommendations fail to account for the unique operational conditions associated with Edwardsport and Cayuga, additional costs that would have resulted from gas hedges had Edwardsport operated exclusively on natural gas, the Gibson 5 joint ownership and multiple RTO configuration impacts, unit testing, operational requirements during winter months, multiple startups, and the impact of additional purchase energy and resulting exposure to additional price risk. Mr. Swez testified that although the Company entered into financial hedges during FAC 123, it was not enough to mitigate all exposure to purchase power. Decommiting additional units, as suggested by intervenors, would only increase risk to the Company's customer and cause the Company to enter into additional hedges at a higher price or remain unhedged and subject to the volatility of the market.

Mr. Swez described the multiple motivations the Company had for offering Edwardsport with a commitment status of Must Run when its gasifiers are available or operating, and offered quantified values for some of these reasons. He testified that operating Edwardsport on natural gas is a complicated longer-term analysis, of which the Daily P&L statements showing market margins is only one component. Mr. Swez testified that in this period of very low market prices, the limited times when multiple Cayuga units were operated shows the Company is economically committing units at Cayuga to the extent possible considering the implications of the steam supply contract. Mr. Swez testified that the results of adding an adjustment to the Daily P&L Analysis for unplanned outages, as suggested by Mr. Burgess, would be minimal since the Company is already including known information related to a forced outage at the time the Daily P&L Analysis is completed, except for derates or forced outages that occurred after the offer deadline and lasted until the end of the next day. He testified that the use of a Must Run commitment status prevents unnecessary cycling and extra startups, which results in decreased forced outages.

Mr. Swez testified that imposing additional reporting requirements in each FAC as suggested by Intervenors, would be cumbersome and provide no added value. He testified that Company personnel engage in research, analysis, and discussion each day to determine the optimum generating unit offer for each unit within the constraints given for the benefit of customers. There is no reasonable basis to require a disallowance of fuel costs or require major changes to the Company's dispatch process.

Mr. Gurganus testified in rebuttal that due to recent historic low power prices the Company is running its generation less often and purchasing an increasing amount of its supply from MISO to the benefit of customers, which is what the Company can do when the market so indicates without immediately making the sorts of longer-term decisions Intervenors suggest. He testified that offering its Edwardsport, Cayuga and Gibson units with a commitment status of “economic”, largely means they will never run due to their longer start up times and inability to respond to MISO signals with the speed and flexibility of an “advanced energy resource.” Mr. Gurganus testified that, contrary to a few intervenors’ testimony, the Company does not need to perform an analysis to know that Edwardsport has a 14-day cycling time, would take fewer employees to run a natural gas-fired generating station, and that switching to natural gas all of the time could result in higher market prices for natural gas, especially for the Company’s Wheatland and Vermillion Stations. He testified that switching Edwardsport to run on natural gas and “mothballing” the coal-related equipment is a near permanent decision that must be made after extensive modeling and the weighing of risks, costs and benefits, which the Company intends to do as part of its 2021 IRP. Mr. Gurganus testified that the risks of single-fuel-source energy reliance are increasing and believes the best course is one of moderate change over time, as described in the Company’s most recent rate case. Mr. Gurganus disagreed with Mr. Jonagan’s contention that units with near-term retirement dates should be capable of significant cycling operations because we don’t need to worry about end-of-life performance and maintenance. Cycling wear and tear is not a perfectly linear and predictable process, as suggested by Mr. Jonagan and, in fact, cycling-induced equipment failure often occurs suddenly and without pre-indication from the generating unit. Mr. Gurganus testified that the Company’s large coal-fired generating units were not designed for significant cycling operations and he has no intention of allowing the performance and reliability of the generating fleet to materially degrade as generating unit retirement dates approach.

Ms. Diaz testified in rebuttal that Mr. Burgess’ testimony is an attempt to relitigate the steam contract, which is not an issue within the narrow focus of this proceeding. She testified that Dr. Boerger’s recommendations to review the steam contract for cost recovery on a frequent basis, such as annually, is also not warranted in this proceeding. There is no requirement in the current steam contract or the Commission’s order approving it to perform cost of service studies outside the context of a retail base case or subsequent steam contract amendment proceeding. She testified that the Company will be re-examining the appropriate steam rates in the very near future now that its base electric rates have been updated. Ms. Diaz testified that the Commission has approved the existing steam contract and recently approved allocation of costs to that steam agreement in the retail base rate case.

Mr. Verderame testified in rebuttal that the Company does not over-forecast its coal consumption as Mr. Burgess suggests. The Company reviews its coal position on a monthly basis by looking at its projected coal burns, coal inventory levels, the amount of coal under contract and the quality characteristics needed for a particular generating station. Upon determining a need for additional coal, the Company determines whether it is prudent to purchase on the spot market or to look to a longer-term solution. The Company uses modeling outputs to assist in evaluating its coal procurement needs, including incorporating a stochastic model that gives the Company expected fuel burns, the range of fuel burns, and probability associated with each range. Mr. Verderame described how the Company ensures it is buying coal at the lowest price reasonably possible, including the use of staggered contract terms, diversified mix of suppliers, and use of indices. He testified that its coal forecasts are made using information available at the time as to fuel supply, load forecast, and commodity pricing, but that there are unforeseen circumstances including weather, unplanned outages, and economic downturns, which may alter the Company's coal needs. Mr. Verderame testified that the Company takes every action available to cost-effectively control coal inventories in the least cost-impact manner for customers. Mr. Verderame disagreed with Mr. Burgess' characterization that the Company has a significant oversupply of coal. He explained that it is typical to increase coal supply going into the winter months to ensure reliable coal supply. The Company's 60 days of coal supply during FAC 123 can be attributed to a combination of lower demand during the autumn months and low gas and power prices. He testified the Company had contractual obligations to schedule and receive its coal supply and that it utilized offsite storage with no additional cost to the customer. Mr. Verderame disagreed that the Company is procuring more coal than it needs. He explained that the Company managed to its burn projection as of November 2019 at the time the Company's last purchasing decisions were made. Mr. Verderame disagreed that the Company's projections for coal burn far exceeded actual coal burn during FAC 123. He testified that the Company's over-forecast was approximately 10%, which is in line with normal expected fluctuations. Mr. Verderame explained the steps the Company is undertaking to actively manage its coal inventory levels. He also testified that coal supplier diversity is important in providing a reliable supply of reasonably priced coal to customers. There are only approximately five suppliers for the Duke Energy Indiana jurisdiction that provide low-cost reliable supply offers of coal for 2020 and beyond.

6. <u>Cross-Answering Testimony.</u> ICC's witness Mr. Robert DiDona testified that the intervening parties are using the FAC process to attack Duke Energy Indiana's coal plants because of their often-stated agenda to see all the coal plants retired. Mr. DiDona testified that looking at only FAC data to conclude which plant is the most economic, a natural gas plant or a coal plant, would be misleading as all fuel-related costs may not be included in an FAC (i.e., natural gas firm transportation and interruptible transportation costs). This means you are not making an apples-to-apples comparison of fuel costs. He further testified that a utility should not purchase all of its coal on a spot basis if it wants to be a reliable power supply and realize steady pricing. Mr. DiDona testified that much of the intervenors' testimony focuses on the relative dispatch costs as identified in the FAC but ignore the justifications for the resource decisions made in the Company's IRP and how it needs to operate its plants consistent with those decisions. He testified that the intervenors are dismissive of the cost of cycling and/or seasonal use of coal plants, including the potential negative impact to machinery. Mr. DiDona testified that AEE witness Stoddard's modeling analysis is problematic at many levels and misstates the impact on ratepayers by ignoring the impact of reduced capacity on energy and capacity prices. In addition, none of the intervenors address the adverse economic costs to the state, locality, and ratepayers from premature shutdowns of existing coal plants as well as the impact on reliability and fuel diversity.

Mr. Lomax testified that OUCC witness Dr. Boerger did not independently analyze and compare wholesale electricity prices from MISO with the costs of generating electricity at Duke Energy Indiana's Edwardsport plant. Further, the OUCC did not specify which reasons for the "must run" commitment of Edwardsport are not consistent with providing electricity to retail customers at the lowest fuel cost reasonably possible.

7. Commission Discussion and Findings.

This subdocket was opened for the purpose of investigating Duke Energy Indiana's unit commitment decisions during the FAC 123 reconciliation period of September through November 2019, in recognition of this Commission's statutory obligation to assure that Duke's customers receive electric energy service at "lowest fuel cost reasonably possible."[2] As the Commission noted in its Order in Cause No. 38707 FAC 123 (p.7), "[t]he unit commitment decision is clearly not a simple or non-consequential exercise." We also observe that these decisions have significant consequences for customers, as the large negative energy margins Duke incurred during this three-month period at Edwardsport and Cayuga show. Furthermore, the time constraints of the summary FAC process makes the review of commitment and other consequential fuel cost decisions very challenging. This subdocket has allowed the Commission, OUCC, and Intervenors to review and analyze in more detail Duke Energy Indiana's unit commitment decisions for the FAC 123 reconciliation period.

In their motion for the instant subdocket, both CAC and Sierra Club challenged Duke Energy Indiana's commitment decisions. Specifically, they state that there were "serious issues related to Duke's commitment decisions and fuel purchasing practices underlying Duke's requested fuel costs".[3] CAC and Sierra Club further claim, "Duke knowingly made energy market commitment decisions at the Edwardsport, Cayuga, and Gibson generating facilities that the Company's own projections showed would result in unreasonably incurred fuel costs and (if reimbursed) higher rates for customers during the September to November 2019 period at issue in IURC Cause No. 38707 FAC 123."[4] CAC and Sierra Club contend Duke Energy Indiana's "own economic forecasts reveal that it routinely chose to burn fuel to generate power rather than purchase energy even when it projected that such choice would result in significant operational losses".[5] Through its testimony of Dr. Boerger, the OUCC generally agreed with CAC and Sierra Club finding specifically that Duke is not receiving adequate compensation from its steam customer at Cayuga and that the Duke's commitment of Edwardsport as must run "appears to be inconsistent with the requirements of I.C. § 8-1-2-42.3(d)(1)."[6]

Based on the additional investigation facilitated by the subdocket proceedings, the Commission agrees with CAC and Sierra Club that Duke failed to "ma[k]e every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible."[7] Duke's own Profit and Loss Analyses showed Duke could have obtained energy for its customers at lower fuel costs had it purchased energy from the MISO market or operated Edwardsport on natural gas rather than burning coal at the Edwardsport and Cayuga units for weeks during the FAC 123 period. Although Duke offered various explanations for its reliance on must run commitment at Cayuga and Edwardsport despite contemporaneous analysis indicating operation of the plants would result in losses in the MISO

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[2] Ind. Code §8-1-2-42(d)(1).
[3] Joint Motion for Subdocket to Investigate Duke's Generation Commitment and Fuel Procurement Decision, IURC Docket No. 38707-FAC123, dated March 6, 2020.
[4] Id.
[5] Id.
[6] Id.
[7] Ind. Code §8-1-2-42(d)(1).

energy market, none of these explanations withstand scrutiny or justify increased fuel charges for Duke's electricity retail customers.

Duke does not credibly contest Sierra Club expert Glick's analysis showing a comparison of Duke's *actual* cost and revenue data which shows Duke spent $3.3 million *more* in variable operational costs (fuel and variable O&M costs) at Edwardsport than it would have spent to purchase an equivalent amount of energy on the MISO energy market. These losses were knowingly incurred and therefore imprudently incurred. For the FAC 123 time period, we credit Sierra Club expert Glick's analysis (which, again, Duke does not credibly contest) that Duke's contemporaneous "Profit & Loss" forecasts projected that the use of must run commitment at Edwardsport during the FAC 123 period would cost customers $3.7 million in unnecessary variable operational costs. We observe that the actual losses at Edwardsport during these months were similar to the losses projected by Duke. We agree with OUCC witness Boerger that this pattern of knowingly incurring higher costs for customers at Edwardsport "appears to be inconsistent" and in fact is inconsistent with the requirements of I.C. § 8-1-2-42.3(d)(1).

Although Mr. Swez testified that Duke Energy Indiana commits its generating units on an economic basis, except as required for unit testing, operational requirements, or other infrequent reasons, Mr. Swez's own testimony (both pre-filed and on cross-examination) established that two other motivations, *not* economics, dictate Duke's operational practices at Edwardsport and Cayuga. Mr. Swez testified that there can be a broad range of theoretical factors that might impact commitment decisions at Edwardsport and Cayuga, but the record is clear that in FAC 123 Edwardsport was committed as must run whenever the gasifiers are available, rendering the other theoretical constraints irrelevant. Similarly, at Cayuga, the only factor that appeared pertinent to the must run decisions during the FAC 123 time period, was the need to provide steam service to a single customer. As Mr. Swez admitted, Edwardsport is committed as must run whenever the gasifiers are online due to the 14-day start-up time for the gasifiers and because Duke has committed to the position that long-term coal operation at Edwardsport is beneficial notwithstanding any energy market losses in the foreseeable short-to-medium term. Similarly, at least one Cayuga unit is committed as must run at all times (except when both units are in outage) to ensure Duke meets its contractual commitments to a steam customer.

We find that Duke cannot recoup the imprudent expenditure of fuel costs in service of these operational preferences from retail ratepayers under Indiana law as a knowing decision to incur higher costs—as Duke repeatedly did during this FAC 123 period at Edwardsport— because doing so cannot satisfy the "lowest fuel cost reasonably possible" standard. Duke's defenses for its decisions to incur higher costs with respect to Edwardsport amount to a repudiation of the statements it has made to this Commission that Edwardsport is a "flexible" resource, and we do not credit them on this record as a reason to excuse knowingly incurring millions of dollars in negative energy margins, especially because Duke does not appear to have studied the possibility of switching to gas-only operations for the medium-term, making its arguments against such switch are speculation. For example, while Duke's witnesses worry that switching to gas-only operations might cause a loss of essential personnel, the Company admits that it has not studied that issue or identified which personnel might be lost. In sum, we find that Duke acted imprudently by committing the Edwardsport unit as Must Run during extended periods in which its own analysis showed customers would benefit from either the purchase of energy or a switch to natural gas operation (at a positive energy market margin) instead. By persisting in its use of must run commitment for coal/syngas operation at Edwardsport when the Company's internal estimates show gas *or no* operation will incur millions of dollars less in fuel costs for its retail electric customers, Duke has failed to show that it has "provide[d] electricity to its retail customers at the lowest fuel cost reasonably possible" at Edwardsport.[8] We hold that to adhere to the "lowest fuel cost reasonably possible" standard Duke must monitor and reasonably respond to conditions energy market. The Commission disallows as part of the fuel adjustment charge the fuel-attributable portion of the negative market revenues due to the imprudent operation of Edwardsport on coal/syngas during the FAC 123 period, or $3 million.

We acknowledge, as Mr. Gurganus explained in his testimony, that the operational constraints of the Edwardsport gasifiers make it impractical for Duke to respond to market signals on a daily or even weekly basis. However, as Intervenors' testimony showed, FAC 123 included multi-week periods in which Duke forecast losses as a result of coal operation at Edwardsport. Fortunately, as Mr. Gurganus observed, Edwardsport is capable of operating on both natural gas and coal, providing some measure of fuel diversity. Duke customers may now benefit from this feature in light of energy market trends by switching Edwardsport to natural gas operation during month-long periods in which coal operation is predicted to be more expensive than LMPs. It is unreasonable for the Company to continue to limit Edwardsport's operation to a single, more expensive fuel source, when the unit is capable of generating electricity at lower costs for customers on natural gas and when the continued operation of Edwardsport on coal and syngas results in market losses and unnecessary fuel costs to customers as compared to reserve shutdown and energy purchases.

Although Duke offered a number of reasons for its position that the use of natural gas at Edwardsport is impractical, we do not find any of these explanations convincing. First, Duke claims that de-committing the Edwardsport gasifiers will result in the loss of essential personnel, but has failed to identify what positions would be lost or demonstrate that these individuals could not be transferred to other roles within the unit. Second, Duke asserts that a long-term switch to natural gas at Edwardsport would increase gas prices at the Vermillion and Wheatland Station, but this appears to be nothing more than speculation, as the Company provided no evidence for this assertion. Third, Duke suggests that Edwardsport's current Title V permit is incompatible with long-term natural gas operation, but we find this claim unconvincing given that the plant was designed to operate on duel fuels and Duke has not identified what provisions in that permit are inconsistent with natural gas operation or explained why it is able to operate Edwardsport on natural gas *currently* when the gasifiers are offline despite this purported inconsistency. Fourth, Duke points to longer-term concerns with fuel diversity as a reason to maintain coal operation at Edwardsport. Although resource decisions are beyond the scope of this FAC proceeding, we note that Duke primarily relies on its coal-fired units and that the unique benefit of Edwardsport is its flexibility with respect to gas versus coal operation as the relative prices of those two fuels change. Whatever the resource profile of Duke's fleet, it maintains a statutory obligation to generate or purchase electricity at the lowest reasonable fuel cost to customers, and its current operational practices at Edwardsport do not justify the fuel costs the Company is seeking to pass along to customers during the FAC 123 period.

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[8] Ind. Code §8-1-2-42(d)(1).

With respect to Cayuga, we find that passing on the increased fuel costs associated with otherwise imprudent operation of the Cayuga units to retail electricity customers would constitute a cross-subsidization of Duke's steam customer that is inconsistent with ratemaking principles and the fuel adjustment charge statute. Duke proffered testimony that it anticipates filing revisions to the steam contract in light of the most recent rate case decision, IURC Cause No. 45253. At this time we offer no opinion as to how Duke and its steam customer should allocate the marginal fuel costs associated with the uneconomic self-commitment of Cayuga to ensure uninterrupted service, however, we hold that these costs cannot be recouped from electricity customers through the FAC mechanism.

As we have discussed before, the Commission does not engage in a hindsight analysis. Rather, in determining whether a utility acted prudently we must review the circumstances as they existed considering what was known or should reasonably have been known by the utility at the time of its actions. *See Duke Energy Ind., Inc.*, Cause No. 38707 FAC 76 S1, 2009 WL 3455937 at 17 (IURC Oct. 21 2009). We observe that Duke already has a reasonable process in place for energy market forecasts, and that when Duke followed its own P&L Analyses in making commitment decisions at the Gibson and Gallagher units, those units did not produce the millions of dollars in losses that Duke acknowledged were accrued at Edwardsport and Cayuga. In fact, Duke's process predicted losses at Edwardsport that were very close to the actual losses that occurred, highlighting that while the P&L analyses process could be improved, the larger problem seems to be Duke's reluctance to follow its own analyses. Indeed, contrary to Duke's witnesses' allegations that Intervenors offered "hindsight" analysis of Duke's losses during the FAC 123 period, we note that expert witnesses for CAC and Sierra Club relied primarily on Duke's *own* contemporaneous market forecasts to demonstrate that the Company's use of Must Run commitment was imprudent. Far from hindsight analysis, Intervenors' testimony emphasized commitment choices for which there was ample evidence that Duke knew at the time would result in losses, and where actual losses closely resembled what the Company itself predicted, as in the case of Ms. Glick's analysis of Edwardsport (showing Duke projected $3.7 million in losses over the FAC period and realized $3.3 million in losses).

In conclusion, we find Duke Energy Indiana's unit commitment decisions, specifically its consistent use of must run commitment status at Edwardsport and Cayuga despite contemporaneous market forecasts showing extended periods of losses during the reconciliation period of September through November 2019, were unreasonable. Accordingly, we will disallow a total of $4.7 million in fuel costs we find were imprudently expended at those two units during the FAC period. This amount is equal to the proportion attributable to fuel of total negative energy margin accrued during periods in which Duke forecast market losses and nevertheless committed a coal-fired unit as Must Run (which, based on Ms. Glick's testimony, we find was equal to $3.3 million at Edwardsport and $1.9 million at Cayuga). These negative energy margins are equal to the difference between the fuel portion of the variable cost of operation of the units during those periods and the relevant Locational Marginal Price, or the cost of energy purchases, on the MISO market during those same periods.

Given these findings with respect to the FAC 123 period, we believe it is appropriate to provide some guidance on recovery of fuel costs in future FAC proceedings. Future cases should be decided, as the one has been, based on the information that Duke had at the time it makes its energy market decisions. To aid the Commission's efficient review of Duke's fuel costs and decisions, Duke should include in its Application for all future FAC proceedings: 1) the Profit & Loss Analyses created by Duke during the applicable FAC period; 2) documentation of the commitment decisions made during the FAC period for each Duke unit whenever those decisions anticipate incurring a loss based on the Profit & Loss Analyses; and 3) net revenue (or losses) from running Edwardsport in the FAC period, defined as energy and ancillary service market revenue less fuel and variable O&M and other related information as described below. In addition, to be filed in the last FAC proceeding of calendar year 2021 or other appropriate proceeding, Duke shall perform a cost of service study, or other robust analysis, for a retrospective period of at least one year, to determine the total fuel costs attributable to uneconomic operation at Cayuga. In future cases, Duke's fuel would be most likely to meet the "lowest fuel cost reasonably possible" standard if Duke documents its commitment decisions at all its coal-fired units more extensively to allow the Commission to evaluate the prudence of those decisions more effectively in future FAC proceedings.

8. Interim Rates. We find that refunds are appropriate as a result of this subdocket. The potential refund obligation imposed by the Commission's Orders in Cause Nos. 38707 FAC 123 is now fixed at $4.7 million, equivalent to the fuel cost portion of negative energy market margins (variable operational costs minus energy market prices) for generation at Edwardsport and Cayuga during periods in which the Company committed units as those plants as Must Run despite P&L Analyses forecasting losses.

9. Confidential Information. On April 29, 2020, May 15, 2020, and October 29, 2020, Duke Energy Indiana filed motions requesting protection of confidential and proprietary information along with supporting affidavits. On May 11, 2017, May 27, 2020, and October 29, 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) sensitive contract terms, revenues and load data information involving certain special contracts approved by the Commission; (ii) generation variable cost data; (iii) Day-Ahead awards; (iv) dispatch information; (v) pricing, commercial terms, and supplier information related to Duke Energy Indiana's coal contracts; and (vi) information identifying generating resource outages, including information regarding the reason and duration of the outage as reported to and held confidential by the North American Electric Reliability Corporation in the Generating Availability data system, as well as generating unit operational characteristics, which is used to calculate a unit's energy or ancillary services supply offer, and confidential indicative capacity and energy prices provided to Duke Energy Indiana by a third party. 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. This subdocket should be, and hereby is, closed.

2. Duke Energy Indiana's unit commitment decisions during the reconciliation period of September through November 2019 were unreasonable. Specifically for Edwardsport and Cayuga, the commitment decisions throughout the three-month period did not comply with the "lowest fuel cost reasonably possible" standard of Ind. Code §8-1-2-42(d)(1).

3. Duke incurred actual net negative operational margins of $3.3 million at Edwardsport and $1.9 million at Cayuga. These negative margins were predicted by Duke and were due to Duke's imprudent, uneconomic use of the must run commitment decisions during periods in which Duke's market forecasts showed that variable costs at these units would exceed market energy prices.

4. Duke ignored the results of its own price-based P&L Analysis, and in fact relied on no tools or analysis at any point during FAC 123 to inform or assess Edwardsport's unit commitment practices.

5. Duke uneconomically self-committed its Cayuga units notwithstanding its own P&L projections of negative margins to fulfill a contractual obligation to a single steam customer that requires it to maintain at least one of the Cayuga units as online and at a 300MW net output (70MW above the operational minimum).

6. Duke's proposed fuel adjustment charge would allocate the energy market losses it accrues at Cayuga to meet its operational obligations under the steam contract to its retail electricity customers. Duke has not performed a cost of service study to determine the net system impact to customers of operating Cayuga to serve the steam customer, and has failed to demonstrate that uneconomic operations of the unit to serve the steam customer is in the best interests of retail customers.

7. Duke shall refund retail customers $4.7 million in fuel costs that had previously been imposed "subject to refund" in Cause No. 38707 FAC 123. These refunds shall be allocated in the same manner as the fuel adjustment charge and shall commence with the first billing cycle following approval of this Order by the Commission.

8. To be filed in the last FAC proceeding of calendar year 2021 or other appropriate proceeding, Duke shall perform a cost of service study, or other robust analysis, for a retrospective period of at least one year, to determine the total fuel costs attributable to uneconomic operation at Cayuga for the purpose of serving the steam customer there, and to evaluate whether the economic benefits of the steam contract appropriately cover these additional variable costs.

9. For future FAC cases, and to provide guidance to Duke, we observe that fuel costs are most likely to meet the lowest cost standard if: Duke develops a new, price-based commitment

decision analysis process for Edwardsport, commencing with the first complete FAC period following approval of this Order by the Commission, as follows:

a. At the outset of the FAC period, Duke performs a 3-month look-ahead analysis projecting net energy market revenues for the plant on both syngas and natural gas operation.
b. If the results of the 3-month forecast indicate that net revenues are highest when the plant is operating on natural gas, the Company should continue to produce and utilize the daily Profit and Loss Analysis.
c. If the results of the 3-month forecast indicate that net revenues are highest when the plant is operating on coal/syngas, the Company should produce projections for every 14-day period to assess whether operating on coal continues to be the most economic option for ratepayers during that FAC period.

10. Beginning with its next FAC filing, Duke is ordered to produce, under seal, its P&L Analyses for each of its coal-fired units as part of its FAC Application. If Duke's commitment or dispatch decisions at any of its coal-fired units deviate from the results of its forward-looking price analysis, including the process for Edwardsport set forth above, Duke should document the contemporaneous reason(s) for such a divergence. The Commission will presume imprudence and disallow recovery of that portion of marginal market energy losses attributable to fuel costs for any losses incurred as a result of such deviation from the Company's own price-based process. This presumption is rebuttable.

11. Duke is ordered, beginning with the next full FAC period, to include as part of its FAC Application the following information:

a. All Profit & Loss Analyses conducted during the FAC period;
b. The specific commitment decisions made during the FAC period for each Duke unit;
c. Total net revenue (or losses) from running Edwardsport in the FAC period, defined as energy and ancillary service market revenue less fuel and variable O&M;
d. Monthly gas and coal consumption at Edwardsport in the FAC period;
e. Hours when the gasifiers were in outage in the FAC; and
f. Total net revenue (or losses) that the Company would have incurred/earned from operating Edwardsport on natural gas for all hours in the FAC period (applicable only if Edwardsport operated on coal during the FAC period).

12. As part of its Application for the next complete FAC period, Duke shall perform and file an analysis where each of its coal-fired units are modeled with economic commitment for the entire FAC period. The model shall incorporate startup and shutdown costs. Duke shall also model, with the same constraints, all coal-fired units as must run throughout the same period. Duke shall report the estimated fuel costs associated with the respective economic and must run models.

13. The Commission previously imposed "subject to refund" obligations in Cause Nos. 38707 FAC 124 and FAC 125 contingent on the outcome of this proceeding. The

evidentiary record in this subdocket proceeding was limited to the FAC 123 period. However, given the Commission's findings with respect to the FAC 123, the Commission finds that similar disallowances are warranted for the FAC 124 and FAC 125 period. The Commission will issue additional Orders in those dockets directing Duke to issue refunds equal to that portion of fuel costs attributable to uneconomic commitment at times when Duke's contemporaneous forecasts anticipated negative energy market margins. The total amount of those refunds will be determined based on evidence already in the record in the FAC 124 and FAC 125 proceedings.

14. The information described in the Confidential Information submitted in this Cause are hereby exempt from the public access requirements of Ind. Code § 5-14-3-4 and shall continue to be held as confidential by the Commission.

15. 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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Secretary to the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF DUKE ENERGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	**)))**	**CAUSE NO. 38707 FAC123 S1**

SIERRA CLUB'S PROPOSED ~~FORM OF~~ ORDER

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

On January 31, 2020, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") filed with the Indiana Utility Regulatory Commission ("Commission") an Application in Cause No. 38707 FAC 123 for approval of a change in its fuel cost adjustment for electric service, approval of a change in its fuel cost adjustment for steam service, and an update of monthly benchmarks. The Commission granted the interventions of Sierra Club, Citizens Action Coalition of Indiana, Inc. ("CAC"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), and Steel Dynamics, Inc. ("SDI"). On March 6, 2020, Sierra Club and CAC filed a *Joint Motion for Subdocket to Investigate Duke's Generation Commitment and Fuel Procurement Practices* ("Joint Motion"). The Commission issued a docket entry on March 12, 2020, granting the Joint Motion and opening this subdocket limited to unit commitment decisions during the reconciliation period of September through November 2019. Although Duke Energy Indiana appealed the docket entry to the full Commission, the March 12, 2020 Docket Entry was upheld in the Commission's March 31, 2020 Final Order.

Counsel for CAC, Sierra Club, Nucor and SDI entered Appearances in this subdocketed proceeding. On March 18, 2020 the Indiana Coal Council, Inc. ("ICC") filed a Petition to Intervene, which was subsequently granted on August 31, 2020.

On April 29, 2020, the Company prefiled its case-in-chief, which included the direct testimony and exhibits of the following witnesses:

- John D. Swez, Managing Director, Trading and Dispatch at Duke Energy Carolinas;
- Cecil T. Gurganus, Vice President of Midwest Generation at Duke Energy Business Services, LLC; and
- Maria T. Diaz, Director, Rates and Regulatory Planning at Duke Energy Indiana.

Also, on April 29, 2020, the Company filed a motion for protection of confidential and proprietary information, which was preliminarily granted on May 13, 2020. Second and third motions for protection of confidential and proprietary information were filed by Duke Energy Indiana and preliminarily granted on May 27 and October 29, 2020, respectively. On June 25, 2020, Advanced Energy Economy, Inc. ("AEE") filed its Petition to Intervene. Over the objection of Duke Energy Indiana, AEE's intervention was granted by the Commission on July 15, 2020. On July 30, 2020 Better Jobs Coalition Indiana, Inc. ("Better Jobs") filed a Petition to Intervene.

On July 31, 2020, the OUCC and intervenors pre-filed testimony and exhibits of the following witnesses:

- OUCC - Peter M. Boerger, Ph.D, Senior Utility Analyst
- CAC – Ed Burgess, Senior Director, Strategen Consulting
- Sierra Club - Devi Glick, Senior Associate, Synapse Energy Economics, Inc.
- AEE – Sarah Steinberg, Principal of AEE; Robert B. Stoddard, Director, Berkley Research Group, LLC ("BRG"); Charles J. Cicchetti, Managing Director and Member of BRG; and Michael Jonagan.
- Better Jobs – Simon R. Lomax[1]

On August 5, 2020, Duke Energy Indiana filed an objection to Better Jobs' Petition to Intervene and, in the alternative, a motion to strike the prefiled testimony of Simon R. Lomax. On August 13, 2020, the Commission granted the intervention of Better Jobs, but struck the prefiled testimony of Better Jobs' witness Simon Lomax in its entirety as the testimony was filed prior to its intervention being granted. On August 14, 2020, Better Jobs filed a Motion to Accept Testimony Submitted While Petition to Intervene Was Pending. Duke Energy Indiana filed its objection to said Motion and on August 27, 2020, the Commission denied Better Jobs' Motion to accept the testimony.

On August 28, 2020, Duke Energy Indiana prefiled the rebuttal testimony of John Swez, Cecil Gurganus, Maria Diaz, and Brett Phipps. Also on August 28, 2020, ICC filed cross-answering testimony of Robert DiDona and Better Jobs filed cross-answering testimony of Simon R. Lomax. Petitioner filed a Motion to Strike Better Jobs' cross-answering testimony on September 4, 2020, as not properly responsive to the OUCC's testimony, and Better ~~Job's~~Jobs filed its Response on September 9, 2020. On September 25, 2020, the Commission granted the Motion to Strike, in part, admitting only the properly responsive testimony. On October 2, 2020, Better Jobs appealed the ruling to the full Commission. By docket entry dated October 30, 2020, the Commissioners approved the decision reached by the Presiding Officers.

On September 10, 2020, Duke Energy Indiana filed motions to strike portions of the CAC's direct testimony of Mr. Burgess and portions of Sierra Club's direct testimony of Ms. Glick on the basis of being outside the limited scope of this proceeding and beyond the case-in-chief testimony of Duke Energy Indiana. ~~The~~ Sierra Club and CAC filed their respective responses on September 21, 2020. On October 5, 2020, the Commission granted Duke Energy Indiana's motions, in part, striking the CAC and Sierra Club's references to the FAC 124 and 125 reconciliation periods, and the CAC's references to coal decrement pricing and its impact on the commitment process, as not relevant to this proceeding. The Commission further ruled that the Cayuga contract is approved and not subject to review in the FAC; however, ~~how~~the impact of the contract ~~impacts~~on unit commitment decisions is relevant to this proceeding. Revised testimony was filed by CAC and Sierra Club. On October 26, 2020 Duke Energy Indiana filed its revised

[1] Better Job's Intervention had not been granted at the time it filed this testimony.

rebuttal testimony to reflect the relevant changes made by CAC and Sierra Club, and to substitute Mr. John Verderame for Mr. Brett Phipps.

On October 5, 2020, the Commission issued a docket entry setting the evidentiary hearing via WebEx due to the ongoing COVID-19 pandemic and the need for several parties to the proceeding to travel across the country for the evidentiary hearing.

Duke Energy Indiana responded to three separate docket entry requests from the Commission received on September 22, October 21, and October 27, 2020, as well as a request made orally during the October 30, 2020 hearing.

A two-day public evidentiary hearing was held in this Cause via WebEx on October 30, 2020, at 9:30 a.m~~,~~., and on November 9, 2020. Duke Energy Indiana, Sierra Club, CAC, Nucor, AEE, ICC, Better Jobs, and the OUCC appeared at the hearing by counsel. Applicant, Sierra Club, CAC, AEE, ICC, Better Jobs, and the OUCC offered their respective prefiled testimony, exhibits, and stipulations into the evidentiary record.

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 Duke Energy Indiana'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. Duke Energy Indiana's Characteristics. Duke Energy Indiana 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. The Company 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. Duke Energy Indiana also renders steam service to one customer, International Paper.

3. Duke Energy Indiana's Case-in-Chief. Mr. Swez testified that the Company commits its generating units on an economic basis, except as required for unit testing, operational requirements, or other "infrequent" reasons. ~~Its~~According to Mr. Swez, Duke's commitment process is designed to minimize total customer cost by maximizing each unit's value. He explained the different types of commitment status offers and the meaning of Economic and Must-Run offers. An Economic commit status is used when the Company doesn't self-commit the unit, but the unit is available for commitment by MISO if the unit's costs are favorable compared to all resources available to MISO that day. Must-Run is used when the Company desires to commit the unit itself. He testified the Company performs an economic review each business day (Daily Profit and Loss Analysis) to inform the commitment status decision for each coal unit. The analysis projects expected operating margins from operation of each coal and combined cycle unit for the next 7-14 days based on a unit's operating costs and parameters and expected market prices. He testified that the 7-14 day timeframe is important in order to account for factors beyond just the operating margin that are not apparent within a short time horizon of one or two days, such as cycling cost and time. Mr. Swez testified that operating parameters include the generator's minimum load, maximum load, and variable costs. Market prices are based on forecasted or observed trades for Indiana.Hub LMP prices, adjusted for congestion and losses at each generator's node. Mr. Swez explained that generally if a unit is expected to have a positive margin ("in the money") the unit is offered as Must-Run, which eliminates any uncertainty over the Economic commit status offer and thus the generating unit can take action earlier and plan for operating for the next day, such as ensuring there is enough coal bunkered. He stated that if a unit is expected to have a negative margin ("out of the money") and the unit can come off-line, it makes economic sense to offer with a commit status of Economic. To prevent uneconomic cycling of on-line generating units across lower priced energy periods such as a weekend, a generation unit commit status of Must-Run may be utilized. Mr. Swez testified that when a unit is expected to have revenues approximately equal to its variable costs ("at the money" or marginal) it could be offered using either a Must-Run or Economic commit status, depending on the situation. Given that small changes in energy prices or unit cost can swing a unit to out of the money, Mr. Swez testified that a designation of Must-Run often makes sense to provide certainty to the plant operators. He testified that during the FAC 123 reporting period, the Company's coal-fired generators were frequently marginal units. Mr. Swez explained that the Company uses a commitment status of Economic when a unit is out of the money because it is in the best interests of the customer. The Company is deferring to MISO to decide whether a unit will continue running or not. If MISO commits the unit to be online, it will guarantee that 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 that there are additional considerations in making commitment decisions, including the Company's contractual obligations, such as its steam supply contract at Cayuga Station and the joint ownership arrangement of Gibson Unit 5. At least one unit at Cayuga must be on-line at an output of 300 MW (net) or greater to supply steam to the customer. For Gibson Unit 5, there are three different owners with three energy offers made to two different RTOs. Mr. Swez stated that if any share of the unit is committed in either MISO or PJM, or if any of the three owners desire to run the unit, the unit is committed as Must Run. He testified that unit testing, operational constraints, and multiple unit startups are also considered and may determine a unit's commit status offer. When a unit is committed by the Company or MISO, it must meet its minimum run time. Mr. Swez testified that the impact of MISO charges and credits as they relate to the unit's offer must also be understood, as well as consideration of a unit's fuel supply. In addition, after a unit undergoes a planned or forced maintenance outage, it may be committed as Must Run to ensure the repairs were appropriately made and unit is available to run.

Mr. Swez testified that it is not appropriate for the units at Gibson, Cayuga and Edwardsport to be offered to MISO using a commitment status offer of "Economic" at all times. He testified that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. It is designed to minimize the cost to reliably and economically serve the demand for the next 24-hour period. He testified that 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. Mr. Swez also noted that all available Duke Energy Indiana generating units can be committed by MISO through the Reliability Assessment Commitment ("RAC") process, as it can look out further than the next day period. Mr. Swez testified that using an Economic commit status offer into the MISO Day-Ahead Market for an off-line unit that was economic to run, could result in higher costs for customers. He testified it is not practical nor economic for a large coal unit to be committed by MISO in the Day-Ahead Market if starting from an off-line state. He explained that if an off-line, but in the money, unit is available and submitted with a commit status of Economic, the number of hours available for the Day-Ahead market to commit a unit shrinks to the point that MISO commitment is not practical and almost impossible. Using Cayuga Unit 1 as an example, which has a 32-hour combined cold startup/notification time, the unit would only be available for full output for the last approximate 1 hour of the 24-hour day, making it almost impossible for MISO to commit in the Day-Ahead Market. In fact, the margin produced by the unit during the last few hours of the day would have to overcome the unit's startup cost.

Mr. Swez testified that MISO energy markets are a resource used to Duke Energy Indiana's customers' advantage when power prices are below the cost of the Company's generation cost. As power prices generally fell during the period of 2015 through 2019, the Company's purchased power increased to over 30%. Mr. Swez testified that as energy prices have been at a sustained low level during the Winter of 2019-2020, the percentage of time the Company's units were offered with a commit status of Economic has increased, as expected.

~~Mr. Swez, referencing a recent MISO published paper[2], testified that MISO found almost 76% of all coal-fired energy generated in MISO from early 2017 to late 2019 came from self-committed coal units (*i.e.*, Must Run) that were economically dispatched above their minimum load, and an additional 12% of coal-fired generation came from units that were both economically committed and economically dispatched. Thus, 88% of the MISO coal-fired energy in the last three years was economically dispatched in some manner. The article also recognized the valid reasons for resource owners to self-commit.~~

Mr. Swez testified that the Company makes commitment decisions that look to the best interest of the customer and described his team's process in making those decisions. Mr. Swez provided the daily commitment status of each unit during the FAC 123 reconciliation period of September through November 2019. He also described the Company's unique operating issues during this period, including 1) longer planned outages at Gibson Units 4 and 5, Edwardsport (partial unit outages), and Noblesville; 2) marginal unit conditions in September; 3) above normal temperatures in early October leading to higher energy market prices; 4) Cayuga forced outage and derate of another unit in October due to river temperatures; and 5) unusually cold weather in November requiring one unit at Cayuga to be on to serve the steam customer and to avoid issues related to freezing temperatures. Mr. Swez provided an overview of the Company's commitment decisions during the FAC 123 period. He testified that because September was marked by generally marginal unit conditions, the Company's coal units were offered with a commit status

~~[2] Provided as Attachment 8 to Response to October 21, 2020 Docket Entry, filed on October 26, 2020.~~

of both Must Run and Economic. In October, after the higher ambient temperatures passed, LMPs returned to where units were marginal once again, much like September, and units were offered with commit status of both Economic and Must Run. He testified that colder weather in November brought higher market prices, and the Company's coal units were more in the money than in September and October. Mr. Swez testified that as many of the large coal units tended to be marginal in nature during September through November, those that were on-line tended to stay on-line and those off-line tended to stay off-line due to start-up costs.

Mr. Swez testified that the Company commits its generating units on an economic basis, including considerations made for required unit testing, operational requirements, external customer steam supply, risk of cycling a unit off-line and back on-line, plant heating at Gibson and Cayuga Stations, avoidance of uneconomic cycling, management of Gibson Unit 5 within multiple RTOs and multiple joint owners, consideration of multiple unit startups, MISO charges and credits, congestion and loss impact, coal considerations, and the supply of steam to another generating unit in startup. The daily process to inform its commitment status decision for each unit is designed to minimize the total customer cost by maximizing each unit's economic value. He testified that market participants do not have clear means of informing MISO the cost to shut down a unit. Over time and repeated cycles, component life can be shortened. He testified that the impact on maintenance and capital costs from shortened component life, component failure and increased forced outages can be significant. Mr. Swez testified that although the forecasted energy margin (Daily Profit and Loss Analysis) is an important step in the commit status offer decision, it is not the only input. It informs the decision but does not determine the decision.

Mr. Swez testified that environmental compliance testing occurred at Cayuga Unit 1 and Edwardsport during this FAC reporting period. In addition, there was an unplanned boiler tube leak on Cayuga Unit 1. If the single day's Real-Time impact from the forced outage was eliminated, Cayuga Unit 1 would have had a positive margin for the entire three-month period. Mr. Swez described the commitment status offer for Edwardsport Station. When Edwardsport's gasifiers are available or operating, the station is being offered as Must Run. He testified the reasons for this include: 1) cycling the station on and off would likely increase the station's equivalent forced outage rate, resulting in lower capacity value and less energy value in the MISO energy markets; 2) due to the gasifiers approximate 14-day cycle time, the unit would be unavailable on coal for this period if the gasifiers were brought off-line and forecasting weather and market prices this far int the future is an imperfect science; 3) de-committing Edwardsport gasifiers for long periods of time would cause loss of essential personnel; 4) cycling the station to natural gas for short periods of time is not economic since the gasification system cannot be turned off for short periods of time if the unit is switched over to natural gas, continuing to consume auxiliary energy and not allowing for anticipated savings; 5) natural gas volatility and loss of diversity value of coal; 6) Edwardsport permitting does not contemplate operating on natural gas as a primary fuel over extended durations; and 7) operating solely on natural gas is shortsighted and does not consider a long-term viewpoint. Mr. Swez testified that during the FAC period Edwardsport ran at a high rate, but for a period of planned de-rates in September.

Mr. Swez testified the Company's commitment practices are appropriate and serve to minimize customer costs, while providing operational flexibility. As long as the Company explains its MISO dispatch and commitment process and why such practices are reasonable given the realities of operating generating plants, and the Commission reviews it on a quarterly basis, fuel costs should be approved and not be subject to refund later based on hindsight analysis.

Mr. Gurganus testified that Edwardsport Station provides benefits to Duke Energy Indiana's system and its customers. Since it began operating in 2013, plant performance has continuously improved. ~~The~~According to Mr. Gurganus, the ability to run on both natural gas and coal provides diversity and reliability to Duke Energy Indiana's customers. ~~It~~Edwardsport was built as a long-term asset for customers~~ and will continue as such, with continued improved reliability, output, and reduced operating expenses~~. He testified that today's risks of single-fuel-source energy reliance are increasing, and it is in customers' best interests to diversify. As the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit – particularly one with advanced emission controls (Edwardsport IGCC), so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come. Mr. Gurganus testified that Edwardsport was designed to produce its maximum performance when operating on 100% syngas produced from coal. There is reliability and resiliency value in fuel inventory maintained at coal plants, relative to natural gas. He testified that the Company benefits from the ability to run Edwardsport on natural gas, which can be used as a secondary fuel to operate the combustion turbines when the gasifiers are undergoing planned maintenance or in the event of gasification forced outages or derates. This is important as it allows the Company to maintain service of at least one combustion turbine and the steam turbine so the plant is always maximizing its output as needed by MISO.

Mr. Gurganus testified that offering Edwardsport into MISO with a commit status of "Economic" could result in Edwardsport never being selected to run by MISO due to its long startup and shut down processes, which is not what was intended when the plant was approved. Completely shutting the station's auxiliary systems down and turning them back on is a multi-week-long process. It can take up to fourteen days if all of the gasification systems are allowed to reach ambient conditions, requiring a complete re-start of the plant. He testified regarding the importance to reliability and efficiency of Edwardsport to place the gasifiers in service and leave them in service. Cycling the gasifiers for short periods would decrease the efficiency of the plant through continued use of gasification auxiliary power, as well as impart significant thermal stresses that cause equipment wear and tear and increased maintenance costs. He testified that these practical considerations must be taken into account when deciding how to offer Edwardsport for operation to MISO.

Mr. Gurganus testified that Duke Energy Indiana has been supplying a large industrial customer, International Paper, ~~-~~located adjacent to Cayuga Generating Station, with both electricity and high-pressure steam for forty-five (45) years. The steam customer currently employs 180 employees and produces gypsum paper, brown containerboard and other related products. In addition to being a steam customer, it is also one of the Company's larger energy customers. Mr. Gurganus testified that Cayuga Station goes to great lengths to ensure no interruption to the customer's steam supply by avoiding forced dual unit outages and coordinating planned dual unit outages, as well as avoiding periods of peak energy prices when Cayuga's output is needed the most. Mr. Gurganus explained that Cayuga's delivery of steam to International Paper results in (at most) an approximate 4 MW derate to the unit. It does, however impact the quantity of makeup water required by the station. Because of this, Cayuga maintains a robust water treatment system, for which International Paper pays 80% of the cost. He testified that one of Cayuga's units is offered into MISO with a minimum load of 300 MW (net output) to also ensure consistent steam supply to the customer.

Mr. Gurganus testified that load cycling causes accelerated damage to many unit components, causing increased equipment failures with resulting higher EFOR, higher non-routine maintenance and capital replacement costs. Increased cycling puts the Company's assets at increased risk of increased forced outages and events, which is a main reason why large coal-fired and nuclear power plants are offered into MISO as "Must Run." He testified that most coal-fired units, not just Duke Energy Indiana's units, were not designed for frequent cycling. Frequent cycling is also detrimental to the efficient operation of post-combustion emission controls, as it impacts the ability of such equipment to achieve optimized temperatures and/or chemistry for efficient removal of emissions. This results in higher average emission rates and increased air emissions. He testified that increased cycling is also reasonably expected to result in increased turbine fouling, a leading cause of unit derates which can cost several million dollars during a two to three-month long outage period to correct. In addition, the number of tube leaks by a unit is also expected to increase with frequent cycling. Another expected result of frequent cycling is a shortening of inspection intervals for generator field windings from approximately 10 years to approximately every 5 years. In addition, components which are more vulnerable to damage as a result of more frequent cycling would be expected to fail or otherwise require service at more frequent intervals. Mr. Gurganus testified that frequent cycling results in higher net and operating heat rates on the units, as the units consume more startup fuel and more off-line auxiliary power. Frequently cycled units also generally operate at lower average loads, which are less efficient than operating at higher average loads which results in higher CO_2 emission intensity which could be detrimental to future greenhouse gas emission Affordable Clean Energy ("ACE") rule compliance. Mr. Gurganus testified that the Company's generating units were constructed and have been operated for many years to benefit its customers. The Company's long history of serving customers should not be overlooked or minimized through a focus on short-term losses.

Ms. Diaz described the Company's business relationship and regulatory history with International Paper. ~~For over 45 years, the Company has worked cooperatively with International Paper to produce and deliver steam and abide by the contractual terms of their contract, which the Commission has found to be reasonable, just, practicable and beneficial to the parties.~~ Most recently, in 2012, the Commission approved in its entirety the updated pricing and provisions in the Fourth Amendment as agreed to by Duke Energy Indiana and International Paper (Cause No. 44087). Ms. Diaz described the key terms of the current contract for steam service to International Paper, which is a firm obligation to serve by Duke Energy Indiana with no interruptible service options. There is also no expected termination date specified in the contract, which continues unless either party gives notice.

Ms. Diaz testified that this steam customer is "carved out" in the setting of retail electric rate base rates as part of the Company's jurisdictional separation study. She testified that by carving out International Paper and treating it as an individual customer, the costs and revenues associated with the sale of steam to this single customer 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. Diaz testified that because the steam service to International Paper reduces the MW output of the two coal-fired units at Cayuga Station by up to approximately 20 MW of the approximate 1000 MW available, some of the costs of the generator and step-up at the station are included in the cost allocation to the steam customer along with other rate base and expense items. She testified that the steam supply to International Paper was assigned approximately $2.5 million in revenue requirement to cover variable and fixed costs in the Company's last retail rate case (Cause No. 42359). Ms. Diaz testified that International Paper is charged its pro-rata share each month of operation and maintenance costs associated with the water treatment facilities and explained how their share is calculated, since it benefits both Duke Energy Indiana and International Paper. She testified that demand revenues are also shared with retail electric customers under the current contract through Standard Contract Rider No. 71 based on the level of demand charge revenues received under the new contract as compared to the amount previously assumed when base rates were established. The portion returned to retail electric customers is based on the application of the incremental demand revenues multiplied by the ratio of the environmental rider rates set forth in Rider 62 plus Rider 71 as a portion of the total electric rate for International Paper. She testified that this sharing mechanism provides a benefit to retail electric customers each 6-month rider period of generally more than $100,000 and will continue until the base rates are set in the Company's currently pending retail base rate case (Cause No. 45253), at which time retail electric customers will benefit instead from the allocation of the full current levels of costs assigned to the steam supply. She explained that the sharing construct will end because all costs and revenues will be reset and reflected in base rates using the forecasted 2020 test period. Ms. Diaz testified that International Paper is also charged its share of fuel costs for its electric service via base rates and using the retail electric FAC rates approved in the Company's FAC filings times its electric usage. In addition, it is also charged its share of fuel costs associated with its steam service using rates also developed and approved in the Company's FAC filings, but with calculations specific to steam service. She explained the calculations and testified that the differences between the estimated fuel cost billed and the fuel cost actually incurred are reconciled quarterly and charged or credited directly to International Paper's monthly electric bills and steam invoices. Ms. Diaz testified that having this steam customer in place provides benefits that have existed for decades and that need to be taken into consideration when evaluating unit commitment decisions at Cayuga over a three-month period. Benefits include: fixed cost contribution from International Paper that reduces overall recovery from retail electric customers; sharing of a portion of incremental demand revenues with retail electric customers between rate cases; and the benefit of the Company diversifying its portfolio of customer offerings by providing steam service and allowing the mill to continue to operate and employ Indiana workers~~, which in turns allows the State of Indiana and Vermillion County to retain one of its largest employers.~~.

4. <u>OUCC and Intervenors' Testimony</u>.

A. <u>OUCC Testimony</u>. Mr. Boerger testified that the primary tool Duke Energy Indiana uses to make unit commitment decisions is its Profit and Loss Analysis ("P&L Analysis"), which is performed each weekday. He testified that the P&L Analysis reviews each coal and gas combined cycle unit to identify whether it is expected to earn a profit or lose money each day over a rolling three-week horizon on sales made in the daily energy market operated by MISO. He testified that MISO's commitment process, which is conducted day-ahead and during the operation day, looks at its set of committed units and seeks to decommit units not operating profitably when taking into account both incremental and no-load costs. However, MISO cannot decommit self-committed Must Run units operating unprofitably and will continue to dispatch them based upon their incremental cost. Mr. Boerger testified that no-load costs can lead to a high level of dispatch but unprofitable operation, therefore dispatching a unit above its minimum does not necessarily indicate a self-committed unit was committed in an economic fashion. Mr. Boerger testified that there are costs inherent in using a Must-Run designation that must be recognized and evaluated in determining whether the Company self-committing its units is appropriate in a given situation.

Mr. Boerger testified that the Company's P&L Analysis lacks any support tools used in arriving at unit commitment decisions. The OUCC recommended the Company have a standard approach when using its profit and loss data and technical constraints for unit commitment. Such a tool would allow input from plant personnel regarding the engineering constraints on commitments and be maintained in an information management system. Mr. Boerger testified that in addition to wear and tear costs related to frequent shutdowns and startups, Duke Energy Indiana should also consider wear and tear that could be avoided through commitment decisions that would keep units from running. He testified that the Company should also consider such running-related costs as part of its determinations of the economics of making Must Run unit commitment decisions. Mr. Boerger recommended the Company evaluate such costs and incorporate a reasonable reflection of them in its unit commitment methodology.

Mr. Boerger agreed that the Company must commit its Cayuga units in a manner to accommodate the steam contract, however he testified that it does not appear the Company is being compensated adequately for the provision of steam at Cayuga. He testified that unit commitment-related costs for serving the steam customer are no more hypothetical than the costs Duke Energy Indiana forecasts in its Integrated Resource Plan ("IRP") every three years or the costs it forecasted in the future test year it used in its recent base rate case. He testified that a forecast of such costs should have been incorporated into the Company's contract-related calculations to ensure other customers are not subsidizing this steam customer. Mr. Boerger recommended an annual review by the Company to determine whether all of the costs incurred in serving the steam load under the contract, including unit commitment costs being imposed on other customers, are being properly reflected. Such annual analyses would be reviewed in the Company's next base rate case or other proceedings to evaluate the prudency of the decision to continue or modify the contract.

Mr. Boerger testified that the Company's approach to committing Edwardsport is not the same approach it uses to commit its coal-fired units and its reasons for the difference are not all related to providing electricity to retail customers at the lowest fuel cost reasonably possible. He stated that the Company does not consider offering the Edwardsport unit as economic when the gasifiers are available. Mr. Boerger recommended a determination by the Commission as to whether the Company is committing the Edwardsport Station in a manner consistent with I.C. § 8-1-2-42.3(d)(1). Mr. Boerger also recommended Duke Energy Indiana and its parent company work to encourage MISO to improve its unit commitment system to better handle long-startup-time units.

B. <u>CAC Testimony</u>. Mr. Burgess' key findings were as follows: (1) the Company commits its coal generation units as Must Run even when they are forecasted to yield economic losses, which is most common at Edwardsport Station that operated with a Must Run designation with coal as the primary fuel source; (2) the Company's steam contract has led to Must Run designations at one of the Cayuga generators resulting in higher costs to customers; (3) the Company routinely under-forecasts the economic losses that actually occur from plants that are given a Must Run commitment status, leading to a greater number of Must Run designations and higher costs to customers; and (4) in its modeled forecasts to determine the amount of coal it will burn, the Company presumes Must Run status at several plants, which overestimates the amount of coal it will need. Mr. Burgess recommended the following: (1) a reduction in the amount collected from customers equal to the economic losses due to operating Edwardsport with coal when the Company predicts losses to occur but commits the unit as Must Run. Further reductions should be made for the amount collected by any foregone economic benefits the Company predicts from operating the plant on coal syngas instead; (2) assign economic losses associated with Must Run designations at Cayuga to Duke Energy Indiana or the steam customer; (3) require the Company to provide additional reporting on its unit commitment decisions going forward as part of future FAC applications; and (4) require the removal of Must Run designations from the medium-term generation forecast models used in the FAC as these designations increase the likelihood of coal oversupply.

Mr. Burgess testified regarding his understanding of the Company's decision-making tools and processes influencing its unit commitment status. Mr. Burgess testified that the Company makes a large share of unit commitment decisions outside of the MISO market optimization process and without regard for its own forecast of the value in the MISO market, which constrains the value of its market participation for its customers. He also testified that regular unplanned outages should be anticipated and factored in to the Company's unit commitment process by including an outage risk premium in its P&L Analysis. Mr. Burgess testified that since the Company estimated in its 1998 EPRI study few instances of shutdown costs at Cayuga and none at Edwardsport, it would have made more economic sense to offer these units as Economic rather than Must Run. He testified that committing them as Must Run without properly accounting for the magnitude of any avoidable or non-avoidable costs is not appropriate and sacrifices the added value of full participation in the MISO market optimization process. He testified that Duke Energy Indiana's use of the 1998 EPRI study to estimate its shutdown costs is somewhat outdated. Mr. Burgess testified that if a unit does not fully recover its startup costs through energy market revenue, it will be made whole via MISO Day-Ahead Make Whole Payments. However, units designated as Must Run are not granted any Make Whole Payments if startup costs are not fully recovered, so it is actually in the best interest of the Company's customers to offer the units as Economic as there is less risk that startup costs will go unrecovered.

Mr. Burgess testified that the Company designates Edwardsport as Must Run any time the gasifiers are available, regardless of what may be in the best interest of its customers, and has no economically-based decision-making process for determining the unit commitment status. He testified that the Company is routinely underestimating the economic losses, or overestimating the economic benefits, that occur at units that are designated as Must Run. To the extent the P&L forecasts reveal that the Company has been operating its plants imprudently, the ultimate harm to customers is even greater than these forecasts would suggest. He testified that this means the Company's unit commitment decisions are biased in favor of Must Run designations as its forecasts are overly optimistic. Mr. Burgess testified that when the Company commits a unit as

Must Run despite its own forecast that such commitment would lead to an economic loss, it is reasonable to require Duke Energy Indiana to shoulder the entire economic loss that was actually experienced. Mr. Burgess recommended the Company adjust its P&L analysis to account for the general outage rates of each unit, realizing that forcing units with high outage rates to operate as Must Run could also increase the frequency of unplanned outages and therefore costs for customers. Mr. Burgess testified that the most logical unit commitment status for marginal units is Economic due to MISO Make Whole payments. He testified that the Company's operations at Edwardsport were imprudent as it used coal as the primary fuel source rather than natural gas that would have avoided economic losses and realized economic benefits for customers. He estimated that Duke Energy Indiana's customers could pay an additional $700-800 million more than necessary if it continues to operate in the same way going forward, despite the Company's P&L Forecasts clearly demonstrating that it would be more profitable on natural gas.

Mr. Burgess testified that the Company's steam contract creates ratepayer losses from uneconomic unit commitment. Given that at least one Cayuga unit is committed as Must Run 100% of the time, regardless of its economic competitiveness, it may cost the Company more to generate power for steam than it will earn for that power in the MISO market, putting electric customers at a higher risk. He testified that the steam customer is not responsible or held accountable for the unit's economic losses, which means the Company's retail electric customers are effectively subsidizing the steam supply for International Paper. Mr. Burgess recommended losses caused by the steam contract be removed from the FAC 123 collection from retail electric customers.

Mr. Burgess testified that the Company's coal contracting practices are leading to coal oversupply, distorting commitment practices and leading to higher costs for customers. He testified that coal oversupply has been a persistent problem for many years. Mr. Burgess testified that he does not believe a concern about supplier diversity was a valid basis for purchasing new coal.

Mr. Burgess recommended the Company be required to provide a report for each FAC with the following for each generating unit: (1) hourly unit commitment designation; (2) rationale for each hour with a Must Run designation: (3) Daily P&L Analyses conducted in the week prior to any hour with a Must Run designation; (4) actual Daily P&L results for each hour with a Must Run designation. He testified that if the reporting reveals unreasonable Must Run decisions resulting in economic losses, the Commission should reduce the authorized FAC charge accordingly. In cases where the Must Run designation is related to providing steam to the steam customer, the Commission should require economic losses be assigned to the steam customer or borne by the Company. Mr. Burgess recommended that each coal burn forecast be conducted without the presumption that any units be committed as Must Run and that they follow forecasted MISO market price signals. If fuel burns exceed forecast those amounts can be accounted for in a subsequent FAC via the reconciliation factor.

C. Sierra Club Testimony. Ms. Glick testified ~~that her analysis found~~ that (1) all but one of the Company's coal-fired power plants reported net operational losses during the FAC 123 time period; (2) the Company self-committed at least half of the Company's units ~~were self-committed~~as must run approximately 50 percent or more of the time during the FAC 123 period;

(3) Duke Energy Indiana's commitment and operational practices led to fleet-wide net operational revenues of less than half a million, based on actual revenues and costs reported by the Company; (4) the Company's imprudent, uneconomic commitment and operations practices incurred total actual net losses of $5.2 million during FAC 123 at Edwardsport and Cayuga; (5) ~~the Company's unit commitment decisions did not support committing and operating~~contemporaneous data shows Duke projected energy market losses at Edwardsport ~~on coal-based syngas~~and Cayuga of $3.7 million and $0.4 million during the periods in which the Company committed each plant as must run, meaning that Duke knowingly self-committed these units even though it expected to incur negative energy margins; (6) the Company did not substantiate or quantify its claims that the Edwardsport air permits do not allow the plant to run on natural gas full time, that Edwardsport would lose essential personnel by switching to natural gas operation, or that natural gas prices would increase as a result of converting to natural gas operation at Edwardsport; (7) the Company ignored its own P&L Analysis and relied on no tools to inform Edwardsport's unit commitment practices; (8) the ~~Company has no~~Company's contemporaneous P&L Analysis sheets do not support ~~for committing and operating~~its self-commitment decisions at Cayuga ~~as Must Run and therefore fails~~; and (9) Duke has failed to demonstrate that the uneconomic operation of Cayuga to serve a steam customer is in the best interests of electricity retail ~~customers~~ratepayers.

Ms. Glick testified that Duke relies heavily on self-commitment at its coal units, that is, the use of must run commitment status; all but Cayuga unit 2 and the two Gallagher units were committed as must run well over half the FAC 123 period and Edwardsport and Gibson 1 were committed as must run for 100% of the time both gasifiers were available. While there is nothing inherently unreasonable about self-commitment (*i.e.*, the use of must run commitment to take control of commitment decisions from MISO where a utility validly expects to incur positive net energy margins), uneconomic self-commitment like that practiced by Duke during the FAC 123 period can result in millions of dollars of unnecessary fuel costs for customers. Ms. Glick explained that when an operator commits a unit as must run into the MISO market, the unit may incur losses if the market price of energy falls below the operational cost of the unit. When a unit incurs losses, these unnecessary fuel costs are passed onto Duke customers through the fuel charge.

Ms. Glick testified that the Company's plants are generally uncompetitive with other market resources in the energy market and customers would have been better served had the Company committed its plants economically and purchased energy from the market when prevailing energy prices are expected to be lower than the cost of operating a Duke unit. She testified the Company's market revenue is not covering the fuel and variable costs to operate and are therefore making no contribution towards the fixed and capital costs incurred at its plants. Specifically, Ms. Glick testified that the Company ignores its own P&L Analyses at Edwardsport and Cayuga and regularly makes imprudent unit commitment decisions that foreseeably result in net revenue losses imposed on ratepayers through higher fuel charges. The Company maintained Edwardsport as must run on syngas for all non-outage hours during FAC 123 despite projections showing weekly net operational losses in 50 of the 57 Profit and Loss Analysis sheets produced during the period. As a result of these uneconomic commitment decisions, Duke incurred $3.7 million in losses from operating Edwardsport on coal. Ms. Glick also testified that Duke projected $2.7 million in net revenue from gas operation at Edwardsport, for a total projected difference of $6.5 million between coal-syngas and natural gas operation. Ms. Glick testified that Duke self-committed at least one Cayuga unit as must run for almost the entire FAC 123 period, likely to serve its steam customer, and that these decisions were projected to incur $0.4 million in losses on the MISO energy market and in fact the Cayuga units incurred a total of $1.9 million in losses. Ms. Glick testified that the Company is operating Cayuga when it is not economic in order to provide steam to an industrial customer and these costs are being subsidized by its electric ratepayers. ~~Ms.~~

Ms. Glick testified that the Company should be self-committing its units as must run on a forward-looking basis if it expects to make positive energy market margins and use the economic commitment status when the unit is projected by Duke to operate at a loss. Ms. Glick testified that the Commission should disallow recovery of losses incurred through the imprudent operation of Duke's coal units if Duke does not follow market price signals or the results of its own price-based process and thereby fails to generate or purchase power at the lowest reasonable cost.

As a result of these findings, Ms. Glick recommended the Commission: (1) disallow $3 million of Edwardsport fuel costs for FAC 123, equivalent to the proportion of total variable losses attributable to fuel; (2) disallow $1.7 million in Cayuga fuel costs for FAC 123; (3) require the Company to conduct a cost of service study or alternative analysis to evaluate whether the currently operative steam contract at Cayuga appropriately allocates the costs of uneconomic operation there to serve the steam customer; (4) require the Company to develop a new, price-based profit and loss analysis process for Edwardsport ~~that does not require contemplation of regular cycling when the gasifiers are on. The analysis should include a 3-month look-ahead produced in each FAC that projects revenues from operating on both coal-based syngas and natural gas. If the results indicate the net revenues are highest when operating on natural gas, the daily P&L analysis should continue to be used, but if they are highest when operating on coal/syngas, the Company should produce projections for every 14-day period to assess whether operating on coal continues to be the most-economic option for ratepayers during the FAC period; (4~~to facilitate the choice between coal-syngas and natural gas operation on a quarterly basis by producing a three-month forecast to assess the projected net revenues associated with coal-based syngas and natural gas, then making commitment decisions with the more economically efficient fuel using either the daily Profit and Loss Analysis (natural gas) or 14-day projections to accommodate cycling times (coal-syngas); (5) require the Company to follow price-based signals at Edwardsport and all other plants in making unit commitment and dispatch decisions, and provide a description of any deviation between the results of its forward-looking P&L Analysis and its actual commitment decision; (~~5)~~6) establish a presumption of disallowance of recovery of fuel costs associated with energy market losses incurred at Edwardsport or any plant as a result of not following the results of the Company's own price-based process~~, which should presume imprudence~~; and (~~6~~7) require the Company to publish in every FAC a public accounting for Edwardsport showing total net revenue, monthly gas and coal consumption, hours of gasifier outages, and total net revenue it would have incurred from operating only on natural gas during all hours.

~~Ms. Glick testified that the Company's plants are generally uncompetitive with other market resources in the energy market and customers would have been better served had it committed its plants economically and purchased energy from the market. She testified the Company's market revenue is not covering the fuel and variable costs to operate and are therefore making no contribution towards the fixed and capital costs incurred at its plants. The Company ignores its own P&L Analysis at Edwardsport and Cayuga and regularly makes imprudent unit~~

~~commitment decisions that are responsible for net revenue losses imposed on ratepayers. She testified that the Company should be self-committing its units on a forward-looking basis only if it expects to make positive energy market margins or keep the unit offline if it is projected to operate at a loss. Ms. Glick testified that the Company is operating Cayuga when it is not economic in order to provide steam to an industrial customer and these costs are being subsidized by its electric ratepayers. She testified that the Commission should institute requirements for the Company to provide specific data and analysis in each FAC necessary to assess the prudence of its commitment practices.~~

D. AEE Testimony. Ms. Steinberg testified that the Company's uneconomic self-scheduling of coal generation with guaranteed cost recovery disrupts the market's ability to appropriately price and signal resource characteristics to meet wholesale electric service needs. She testified that seasonal operations of coal plants is becoming standard practice in the industry during periods of the year with lower energy demand and energy prices, and is a more efficient way to operate its coal plants. She testified that the Company should begin planning to implement an accelerated retirement schedule for all of its coal units and develop a substitute portfolio of more cost effective advanced energy technologies. Ms. Steinberg recommended (1) the Commission cease cost recovery for instances where generation is committed to MISO at an economic loss, with the burden of proof on the Company to demonstrate best practices in its commitment decision-making; (2) the Company reduce its coal plant usage in favor of seasonal operations and commit to an accelerated retirement schedule for all units; and (3) plan to build out advanced energy resources to replace retiring generation.

Mr. Stoddard testified that he used a state-of-the-art power systems model, ENELYTIC™, to simulate commitment and dispatch in MISO. He testified that the Company's coal-fired generators operated at a significant financial loss during the FAC 123 and 124 periods, demonstrating that its self-commitment decisions harm the Company's ratepayers and have long-lasting effects. He testified the Commission should not grant recovery of the losses attributable to uneconomic dispatch, which was about 8% of the total energy costs to serve load in FAC 123. He testified that further savings could have been achieved by using selective, seasonal reserve shutdowns that would have lowered costs to serve load by $9.37M. Mr. Stoddard testified that the Company could have retired some or all of its coal units and replaced them with advanced energy resources to further mitigate losses. The Company's failure to accelerate coal unit retirements will continue to be a costly omission in its planning. Mr. Stoddard explained his modeling data and methods. He testified that the results of his model show Duke Energy Indiana's coal units operated at much higher levels than they would have run solely on their economics. This uneconomic dispatch accounts for 93% of the operating losses, principally fuel costs, and is not limited to FAC 123 but is a consistent pattern throughout June 2020. He concluded that the Company has not made every reasonable effort to acquire fuel and generate or purchase power to provide electricity to its retail customers at the lowest fuel cost reasonably possible in the FAC 123 and 124 periods. If the Company's self-commitment decisions are not corrected, his modeling shows this trend continuing and ratepayers charged hundreds of millions of dollars in fuel costs that could have been avoided by greater reliance on economic commitment and dispatch and an accelerated transition to advanced energy resources.

Mr. Cichetti testified that self-commitment bias increases the amount of fuel and purchase power costs recovered in the FAC, and it is not reasonable to approve the pass-through of uneconomic dispatch decisions. He urged the Commission to determine whether the Company has been reasonable and prudent in its efforts to include energy efficiency, renewable energy and demand side management to reduce fuel and purchase power expenses recovered in the FAC. He recommended the Commission deny cost recovery for any amounts that reflect uneconomic dispatch choices and direct the Company to eliminate self-selection commitment bias. He also recommended the Commission determine the extent that increased demand side efficiency could reduce fuel and purchase power expenses recovered using the FAC and take steps to require the Company resume and expand its energy efficiency efforts. Mr. Cichetti recommended the Company include the prospect of future carbon fees in its operations and investment decisions even if they are included on a virtual basis. Finally, he recommended requiring the Company to justify its current unit availability status to determine the net benefits from converting some of its older resources to some form of partial shuttering on a seasonally restricted basis.

Mr. Jonagan recommended the Commission direct the Company to (1) evaluate the potential benefits of seasonal operation of some units; (2) document the cost savings and avoided maintenance that can result by shifting operations to focus more on peak demand periods; (3) conduct an evaluation of the value of the steam contract to its customers relative to reduced operations of the Cayuga plant, or accelerated retirement; and (4) evaluate the economic viability of the operation of the syngas plant at Edwardsport. Mr. Jonagan testified there is an opportunity for the Company to reduce the operations at negative margins and thereby reduce costs to its customers, but there is little or no incentive for the Company to explore these opportunities. He explained how the Company could improve its units' operational flexibility through seasonal operations, a more aggressive cycling strategy during the on-peak season, by reducing the minimum operating load, and by operating Edwardsport as a gas-fired only combined cycle plant.

5. <u>Duke Energy Indiana's Rebuttal</u>. Mr. Swez testified in rebuttal that ~~intervenors'~~<u>intervenors</u> focused mostly on the commitment and operation of Edwardsport Station on coal and the supply of steam to an external customer at Cayuga Station. They failed to focus on long-term benefits to the Company's customers and ignored risks associated with procurement of large volumes of energy from MISO and the realities of the resulting short position. He testified the Company 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. A daily risk adjusted process is performed to inform the commitment status decision for each unit designed to minimize the total customer cost by maximizing each unit's economic value within operational constraints, while not exposing the customer to undue risk of price volatility. Unique operational conditions associated with Edwardsport and Cayuga make these units a target of intervenors' analysis.

Mr. Swez further explained how the Company determines a unit's commitment status and its use of a P&L Analysis to understand the financial impact of operating its units in the energy market and deal with consequences of the different time horizons that typically exist between the next day, 24-hour MISO Day-Ahead market and a unit's minimum up time, which is typically at least 72 hours for larger coal units. He explained that the P&L Analysis projects expected operating margins from operation of each coal and combined cycle unit for the next 21 days based on a unit's operating parameters and expected market prices, which is important to account for factors other than daily operating margin, such as cycling cost, that are not apparent or obvious within a short time horizon of one or two days. Generally, if an on-line unit is expected to have a positive margin or is "in the money," the unit is offered with a commit status of Must Run. If off-line, a unit's margin over the multi-day commitment period is generally at least equal to its startup cost in order to be committed. He testified there are times when a unit is out of the money and the Company commits it as Must Run, such as to avoid an uneconomic cycle, to meet a contract constraint such as supplying steam at Cayuga, for unit testing, or due to additional factors and consideration of a longer time horizon such as Edwardsport Station. Mr. Swez testified that the P&L Analysis is not the primary tool the Company uses to make its commitment decisions, as suggested by Dr. Boerger. It is one of the tools to inform generating unit commitment status offers, other factors including operating constraints, the impact of MISO charges and credits, startup ~~an~~and cycling costs along with risk associate with cycling a unit, and the ability to hedge the customers' supply position (market liquidity) are all considered. The P&L statement is not meant to provide an optimal commitment decision. It is a short-term view of, at the most, the next 21 days. It is meant to inform the commitment decision, but does not determine the commitment decision. Mr. Swez testified that further analysis beyond the P&L analysis is needed to get to the best overall result for customers, namely the realities and risks of operating actual generating units in the real world and the liquidity and ability to hedge the Company's customer energy position.

In response to Dr. Boerger's concern that the Company does not have additional support tools that include technical constraints, Mr. Swez testified the Company has a variety of tools to assist in making dispatch decisions including the short-term GenTrader model that is run each day. Although the purpose of this tool is to assist in forecasting the Company's position, the model does perform an economic commitment of all available generating units. Mr. Swez testified that Dr. Boerger's suggestion to develop a new tool to incorporate a standard approach to technical constraints on unit commitment is almost impossible to create to be useful to analyze each potential situation due to the number of possibilities. Mr. Swez testified that this type of analysis is accomplished by the Company on a situational basis when necessary and a new or different tool is unnecessary.

Mr. Swez responded to Ms. Glick's claim that there were instances that units were imprudently brought back or remained on-line, ~~explaining the basis~~providing a reason for the Company's decision~~ in each instance.~~, namely, that the Company's "strategy for operation" at Edwardsport is to operate the unit as must run whenever the gasifiers are available, and that Cayuga 1 was required to be on-line beginning on October 3 to "supply steam to the external steam customer." In response to Dr. Boerger's recommendation that the Company consider the wear and tear that could be avoided through commitment decisions that would keep units from running, Mr. Swez testified that these types of costs are included within the Company's maintenance costs and the real issue is how to apportion those costs into defined variable O&M rate metrics. In addition, nearly every aspect of operation likely affects cost in some way, but not everything is granular enough, nor sufficiently studied by industry, to be reasonably separately defined, such as load-following cycling costs.

Mr. Swez testified that he is not aware of any Company analysis regarding seasonal operation for the Midwest generating units, but fixed costs, commitments in the MISO capacity market, and contractual obligations to supply steam at Cayuga Station would all need to be considered. The MISO capacity construct is an annual commitment and there is no current provision that would allow a utility to seasonally operate a generator that has been committed into the MISO auction. He testified that~~, in fact,~~ he believed any attempt to purposefully remove a committed generator from service may be seen by the MISO independent market monitor as physically withholding capacity. In addition, MISO has planned outage approval authority and may not approve frequent, extended, and overlapping outages, as suggested by Mr. Jonagan. Mr. Swez testified that the Company commits its generators into the MISO market and is obligated to make them available due to its must offer obligation, 24x7x365, and to the benefit of customers.

Mr. Swez testified that Mr. Stoddard's analysis of the Company's commitment decisions contains errors and is a theoretical backward-looking analysis, employs perfect foresight, and ignores such things as actual unit outages that occurred, physical constraints, joint ownership arrangements, and steam constraint, among other faults. Mr. Stoddard's analysis basically shuts down all generation from Cayuga and Edwardsport stations and ignores implications from the contractual obligation to supply steam to the steam customer at Cayuga. Mr. Swez testified that the many errors in Mr. Stoddard's model render the results untrustworthy. He also testified that at no point has the Company ever engaged in behavior to purposely mandate or distort MISO operators' commitment and dispatch decision, as suggested by Mr. Stoddard.

Mr. Swez testified that offering all coal-fired units with an Economic commitment status at all times~~, as suggested by Intervenors,~~ would not be in the best interest of customers and could cost customers significant benefits in the MISO market due to the fact that the unit may not be committed even when economic to run the unit. The outcome would be dependent on factors such as initial state of the unit, startup cost, startup time, incremental and no-load cost of the unit, and LMP present at the time. He testified that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. It is designed to minimize the cost to reliably and economically serve the demand for the next 24-hour period. He testified that 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 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. Mr. Swez also noted that all available units can be committed by MISO through the RAC process, since this process can look out further than the next day. However, the purpose of the RAC is not to maximize a generator's margin, but to maintain reliability. In response to Ms. Glick's argument that the Company's plants are generally uncompetitive in the MISO market and should instead be committed as Economic with purchased energy from the market, Mr. Swez testified that this is not a discussion of unit commitment practices but rather a longer-term decision related to shutting down Edwardsport gasifiers or refusing to run a unit at Cayuga to supply a steam customer. He testified that Intervenors' criticism of unit commitment are the result of (1) the need to keep at least one Cayuga unit on-line to serve steam to an external customer; and (2) the fact that Edwardsport is being committed when the gasifiers are available and not operated exclusively on natural gas. In response to Mr. Burgess' concern regarding the Company's use of a 1998 EPRI study to estimate shutdown costs, Mr. Swez testified that this study was selected as it was the only study with predictive cycle cost models that utilized actual O&M costs from a significant sample set. He testified that the 1998 cost estimates were escalated to current year costs using Handy Whitman indices, thus the 2001 published date is not significant.

Mr. Swez testified that the current MISO Day-Ahead market is not a multi-day commitment. For units that have commitment costs that wouldn't be recovered for a longer period of time (greater than a day), or for units where the startup time makes the unit physically unable or not practical to be committed by MISO, offering the units as Economic is detrimental to the Company's customers as an off-line unit could go multiple days without ~~a commitment.~~being switched on and that this "is not in the customers' best interest." Mr. Swez noted that other generation owners besides Duke Energy Indiana continue to commit generating units as Must Run in MISO. Mr. Swez ~~testified~~argued that Ms. ~~Glick ignored~~Glick's recommendations fail to account for the unique ~~operation~~operational conditions associated with Edwardsport and Cayuga, ~~failed to consider~~ additional costs that would have resulted from gas hedges had Edwardsport operated exclusively on natural gas, ~~ignored~~ the Gibson 5 joint ownership and multiple RTO configuration impacts, ~~as well as ignored~~ unit testing, operational requirements during winter months, multiple startups, and the impact of additional purchase energy and resulting exposure to additional price risk. ~~He also testified that Ms. Glick's analysis is backward looking, does not consider the impact beyond the next day, and provided no room for consideration of non-economic or qualitative factors and risks.~~ Mr. Swez testified that although the Company entered into financial hedges during FAC 123, it was not enough to mitigate all exposure to purchase power. Decommiting additional units, as suggested by intervenors, would only increase risk to the Company's customer and cause the Company to enter into additional hedges at a higher price or remain unhedged and subject to the volatility of the market.

Mr. Swez ~~explained~~described the multiple ~~reasons~~motivations the Company had for offering Edwardsport with a commitment status of Must Run when its gasifiers are available or operating, and ~~provided quantifiable~~offered quantified values ~~attributed to~~for some of these reasons. He testified that operating Edwardsport on natural gas is a complicated longer-term analysis, ~~outside~~ of which the Daily P&L statements ~~– which does not incorporate additional impacts~~showing market margins is only one component. Mr. Swez testified that in this period of very low market prices, the limited times when multiple Cayuga units were operated shows the Company is economically committing units at Cayuga to the extent possible considering the implications of the steam supply contract. Mr. Swez testified that the results of adding an adjustment to the Daily P&L Analysis for unplanned outages, as suggested by Mr. Burgess, would be minimal since the Company is already including known information related to a forced outage at the time the Daily P&L Analysis is completed, except for derates or forced outages that occurred after the offer deadline and ~~lasting~~lasted until the end of the next day. He testified that the use of a Must Run commitment status prevents unnecessary cycling and extra startups, which results in decreased forced outages.

Mr. Swez testified that imposing additional reporting requirements in each FAC as suggested by Intervenors, would be cumbersome and provide no added value. He testified that Company personnel engage in research, analysis, and discussion each day to determine the optimum generating unit offer for each unit within the constraints given for the benefit of customers. There is no reasonable basis to require a disallowance ~~o~~of fuel costs or require major changes to the Company's dispatch process.

Mr. Gurganus testified in rebuttal that due to recent historic low power prices the Company is running its generation less often and purchasing an increasing amount of its supply from MISO to the benefit of customers, which is what the Company can do when the market so indicates without immediately making the sorts of longer-term decisions Intervenors suggest. He testified that offering its Edwardsport, Cayuga and Gibson units with a commitment status of "economic", largely means they will never run due to their longer start up times and inability to respond to MISO signals with the speed and flexibility of an "advanced energy resource." Mr. Gurganus testified that, contrary to a few intervenors' testimony, the Company does not need to perform an analysis to know that Edwardsport has a 14-day cycling time, would take fewer employees to run a natural gas-fired generating station, and that switching to natural gas all of the time could result in higher market prices for natural gas, especially for the Company's Wheatland and Vermillion Stations. He testified that switching Edwardsport to run on natural gas and "mothballing" the coal-related equipment is a near permanent decision that must be made after extensive modeling and the weighing of risks, costs and benefits, which the Company intends to do as part of its 2021 IRP. Mr. Gurganus testified that the risks of single-fuel-source energy reliance are increasing and believes the best course is one of moderate change over time, as described in the Company's most recent rate case. Mr. Gurganus disagreed with Mr. Jonagan's contention that units with near-term retirement dates should be capable of significant cycling operations because we don't need to worry about end-of-life performance and maintenance. Cycling wear and tear is not a perfectly linear and predictable process, as suggested by Mr. Jonagan and, in fact, cycling~~–~~-induced equipment failure often occurs suddenly and without pre-indication from the generating unit. Mr. Gurganus testified that the Company's large coal-fired generating units were not designed for significant cycling operations and he has no intention of allowing the performance and reliability of the generating fleet to materially degrade as generating unit retirement dates approach.

Ms. Diaz testified in rebuttal that Mr. Burgess' testimony is an attempt to relitigate the steam contract, which is not an issue within the narrow focus of this proceeding. She testified that Dr. Boerger's recommendations to review the steam contract for cost recovery on a frequent basis, such as annually, is also not warranted in this proceeding. There is no requirement in the current steam contract or the Commission's order approving it to perform cost of service studies outside the context of a retail base case or subsequent steam contract amendment proceeding. She testified that the Company will be re-examining the appropriate steam rates in the very near future now that its base electric rates have been updated. Ms. Diaz testified that the Commission has approved the existing steam contract and recently approved allocation of costs to that steam agreement in the retail base rate case. ~~There is no basis for hindsight review of these decisions in this subdocket or any other annual proceeding.~~

Mr. Verderame testified in rebuttal that the Company does not over-forecast its coal consumption as Mr. Burgess suggests. The Company reviews its coal position on a monthly basis by looking at its projected coal burns, coal inventory levels, the amount of coal under contract and the quality characteristics needed for a particular generating station. Upon determining a need for additional coal, the Company determines whether it is prudent to purchase on the spot market or to look to a longer-term solution. The Company uses modeling outputs to assist in evaluating its coal procurement needs, including incorporating a stochastic model that gives the Company expected fuel burns, the range of fuel burns, and probability associated with each range. Mr. Verderame described how the Company ensures it is buying coal at the lowest price reasonably possible, including the use of staggered contract terms, diversified mix of suppliers, and use of indices. He testified that its coal forecasts are made using information available at the time as to fuel supply, load forecast, and commodity pricing, but that there are unforeseen circumstances including weather, unplanned outages, and economic downturns, which may alter the Company's coal needs. Mr. Verderame testified that the Company takes every action available to cost~~-~~-effectively control coal inventories in the least cost-impact manner for customers. Mr. Verderame disagreed with Mr. Burgess' characterization that the Company has a significant oversupply of coal. He explained that it is typical to increase coal supply going into the winter months to ensure reliable coal supply. The Company's 60 days of coal supply during FAC 123 can be attributed to a combination of lower demand during the autumn months and low gas and power prices. He testified the Company had contractual obligations to schedule and ~~deliver~~receive its coal supply and that it utilized offsite storage with no additional cost to the customer. ~~Mr. Verderame explained that the Company's coal inventory has increased through the first half of 2020 as record low natural gas prices and low power prices along with weaker demand related to COVID-19 economic shutdowns have had significant impacts on coal generation, as well as mild weather during the winter of 2019/2020.~~ Mr. Verderame disagreed that the Company is procuring more coal than it needs. He explained that the Company managed to its burn projection as of November 2019 at the time the Company's last purchasing decisions were made. Mr. Verderame disagreed that the Company's projections for coal burn far exceeded actual coal burn during FAC 123. He testified that the Company's over~~-~~-forecast was approximately 10%, which is in line with normal expected fluctuations. Mr. Verderame explained the steps the Company is undertaking to actively manage its coal inventory levels. He also testified that coal supplier diversity is important in providing a reliable supply of reasonably priced coal to customers. There are only approximately five suppliers for the Duke Energy Indiana jurisdiction that provide low-cost reliable supply offers of coal for 2020 and beyond.

6. **Cross-Answering Testimony.** ICC's witness Mr. Robert ~~DeDona~~DiDona testified that the intervening parties are using the FAC process to attack Duke Energy Indiana's coal plants because of their often-stated agenda to see all the coal plants retired. ~~The FAC has a clear statutory purpose and should not be used to evaluate the prudency of long-term resource decisions, as the intervenors are attempting here. Mr. DeDona~~Mr. DiDona testified that looking at only FAC data to conclude which plant is the most economic, a natural gas plant or a coal plant, would be misleading as all fuel-related costs may not be included in an FAC (i.e., natural gas firm transportation and interruptible transportation costs). This means you are not making an apples-to-apples comparison of fuel costs. He further testified that a utility should not purchase all of its coal on a spot basis if it wants to be a reliable power supply and realize steady pricing. Mr. ~~DeDona~~DiDona testified that much of the intervenors' testimony focuses on the relative dispatch costs as identified in the FAC but ignore the justifications for the resource decisions made in the Company's IRP and how it needs to operate its plants consistent with those decisions. He testified that the intervenors are dismissive of the cost of cycling and/or seasonal use of coal plants, including the potential negative impact to machinery. Mr. ~~DeDona~~DiDona testified that AEE witness Stoddard's modeling analysis is problematic at many levels and misstates the impact on ratepayers by ignoring the impact of reduced capacity on energy and capacity prices. In addition, none of the intervenors address the adverse economic costs to the state, locality, and ratepayers from premature shutdowns of existing coal plants as well as the impact on reliability and fuel diversity.

Mr. Lomax testified that OUCC witness Dr. Boerger did not independently analyze and compare wholesale electricity prices from MISO with the costs of generating electricity at Duke Energy Indiana's Edwardsport plant. Further, the OUCC did not specify which reasons for the "must run" commitment of Edwardsport are not consistent with providing electricity to retail customers at the lowest fuel cost reasonably possible.

7. Commission Discussion and Findings.

This subdocket was opened for the ~~limited~~ purpose of investigating Duke Energy Indiana's unit commitment decisions during the FAC 123 reconciliation period of September through November 2019~~.~~, in recognition of this Commission's statutory obligation to assure that Duke's customers receive electric energy service at "lowest fuel cost reasonably possible."[3] As the Commission noted in its Order in Cause No. 38707 FAC 123 (p.7), "[t]he unit commitment decision is clearly not a simple or non-consequential exercise." We also observe that these decisions have significant consequences for customers, as the large negative energy margins Duke incurred during this three-month period at Edwardsport and Cayuga show. Furthermore, the time constraints of the summary FAC process makes the review of ~~such decision~~commitment and other consequential fuel cost decisions very challenging. This subdocket has allowed the Commission, OUCC, and Intervenors to review and analyze in more detail Duke Energy Indiana's unit commitment decisions for the FAC 123 reconciliation period.

~~Both~~In their motion for the instant subdocket, both CAC and Sierra Club ~~challenge~~challenged Duke Energy Indiana's commitment decisions. Specifically, they state that there were "serious issues related to Duke's commitment decisions and fuel purchasing practices underlying Duke's requested fuel costs".[4] CAC and Sierra Club further claim, "Duke knowingly made energy market commitment decisions at the Edwardsport, Cayuga, and Gibson generating facilities that the Company's own projections showed would result in unreasonably incurred fuel costs and (if reimbursed) higher rates for customers during the September to November 2019 period at issue in IURC Cause No. 38707 FAC 123~~".~~."[5] CAC and Sierra Club contend Duke Energy Indiana's "own economic forecasts reveal that it routinely chose to burn fuel to generate power rather than purchase energy even when it projected that such choice would result in significant operational losses".[6] Through its testimony of Dr. Boerger, the OUCC generally agreed with CAC and Sierra Club finding specifically that Duke is not receiving adequate compensation from its steam customer at Cayuga and that the Duke's commitment of Edwardsport as must run "appears to be inconsistent with the requirements of I.C. § 8-1-2-42.3(d)(1)."[7]

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[3] Ind. Code §8-1-2-42(d)(1).

[4] Joint Motion for Subdocket to Investigate Duke's Generation Commitment and Fuel Procurement Decision, IURC Docket No. 38707-FAC123, dated March 6, 2020.

[5] Id.

[6] Id.

[7] Id.

~~Mr. Swez responded to their allegations~~ Based on the additional investigation facilitated by the subdocket proceedings, the Commission agrees with CAC and Sierra Club that Duke failed to "ma[k]e every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible."[8] Duke's own Profit and Loss Analyses showed Duke could have obtained energy for its customers at lower fuel costs had it purchased energy from the MISO market or operated Edwardsport on natural gas rather than burning coal at the Edwardsport and Cayuga units for weeks during the FAC 123 period. Although Duke offered various explanations for its reliance on must run commitment at Cayuga and Edwardsport despite contemporaneous analysis indicating operation of the plants would result in losses in the MISO energy market, none of these explanations withstand scrutiny or justify increased fuel charges for Duke's electricity retail customers.

~~testifying~~Duke does not credibly contest Sierra Club expert Glick's analysis showing a comparison of Duke's *actual* cost and revenue data which shows Duke spent $3.3 million *more* in variable operational costs (fuel and variable O&M costs) at Edwardsport than it would have spent to purchase an equivalent amount of energy on the MISO energy market. These losses were knowingly incurred and therefore imprudently incurred. For the FAC 123 time period, we credit Sierra Club expert Glick's analysis (which, again, Duke does not credibly contest) that Duke's contemporaneous "Profit & Loss" forecasts projected that the use of must run commitment at Edwardsport during the FAC 123 period would cost customers $3.7 million in unnecessary variable operational costs. We observe that the actual losses at Edwardsport during these months were similar to the losses projected by Duke. We agree with OUCC witness Boerger that this pattern of knowingly incurring higher costs for customers at Edwardsport "appears to be inconsistent" and in fact is inconsistent with the requirements of I.C. § 8-1-2-42.3(d)(1).

Although Mr. Swez testified that Duke Energy Indiana commits its generating units on an economic basis, except as required for unit testing, operational requirements, or other infrequent reasons, Mr. Swez's own testimony (both pre-filed and on cross-examination) established that two other motivations, *not* economics, dictate Duke's operational practices at Edwardsport and Cayuga. Mr. ~~. Its commitment process is designed to minimize total~~Swez testified that there can be a broad range of theoretical factors that might impact commitment decisions at Edwardsport and Cayuga, but the record is clear that in FAC 123 Edwardsport was committed as must run whenever the gasifiers are available, rendering the other theoretical constraints irrelevant. Similarly, at Cayuga, the only factor that appeared pertinent to the must run decisions during the FAC 123 time period, was the need to provide steam service to a single customer ~~cost by maximizing each unit's value. Mr. Swez provided a detailed account of the extensive analysis~~. As Mr. Swez admitted, Edwardsport is committed as must run whenever the gasifiers are online due to the 14-day start-up time for the gasifiers and because Duke has committed to the position that long-term coal operation at Edwardsport is beneficial notwithstanding any energy market losses in the foreseeable short-to-medium term. Similarly, at least one Cayuga unit is committed as must run at all times (except when both units are in outage) to ensure Duke meets its contractual commitments to a steam customer.

[8] Ind. Code §8-1-2-42(d)(1).

We find that Duke cannot recoup the imprudent expenditure of fuel costs in service of these operational preferences from retail ratepayers under Indiana law as a knowing decision to incur higher costs—as Duke repeatedly did during this FAC 123 period at Edwardsport— because doing so cannot satisfy the "lowest fuel cost reasonably possible" standard. Duke's defenses for its decisions to incur higher costs with respect to Edwardsport amount to a repudiation of the statements it has made to this Commission that Edwardsport is a "flexible" resource, and we do not credit them on this record as a reason to excuse knowingly incurring millions of dollars in negative energy margins, especially because Duke does not appear to have studied the possibility of switching to gas-only operations for the medium-term, making its arguments against such switch are speculation. For example, while Duke's witnesses worry that switching to gas-only operations might cause a loss of essential personnel, the Company ~~conducts in determining its unit commitment decisions. Specifically, Duke Energy Indiana conducts a Daily P&L Analysis, holds various standup meetings amongst~~admits that it has not studied that issue or identified which personnel might be lost. In sum, we find that Duke acted imprudently by committing the Edwardsport unit as Must Run during extended periods in which its own analysis showed customers would benefit from either the purchase of energy or a switch to natural gas operation (at a positive energy market margin) instead. By persisting in its use of must run commitment for coal/syngas operation at Edwardsport when the Company's internal estimates show gas *or no* operation will incur millions of dollars less in fuel costs for its retail electric customers, Duke has failed to show that it has "provide[d] electricity to its retail customers at the lowest fuel cost reasonably possible" at Edwardsport.[9] We hold that to adhere to the "lowest fuel cost reasonably possible" standard Duke must monitor and reasonably respond to~~Mr. Swez's team, and frequently communicates with station operators to assess local station~~ conditions~~.~~ energy market. The Commission disallows as part of the fuel adjustment charge the fuel-attributable portion of the negative market revenues due to the imprudent operation of Edwardsport on coal/syngas during the FAC 123 period, or $3 million.

~~Mr. Swez testified that there are additional considerations in making unit commitment decisions beyond the daily economic analysis and reviews. These include the Company's joint ownership arrangement of Gibson Unit 5, the unique characteristics of the Company's generating fleet, and the steam supply contract at Cayuga Station, must all be taken into consideration, as discussed by Mr. Swez, Mr. Gurganus, and~~ We acknowledge, as Mr. Gurganus explained in his testimony, that the operational constraints of the Edwardsport gasifiers make it impractical for Duke to respond to market signals on a daily or even weekly basis. However, as Intervenors' testimony showed, FAC 123 included multi-week periods in which Duke forecast losses as a result of coal operation at Edwardsport. Fortunately, as Mr. Gurganus observed, Edwardsport is capable of operating on both natural gas and coal, providing some measure of fuel diversity. Duke customers may now benefit from this feature in light of energy market trends by switching Edwardsport to natural gas operation during month-long periods in which coal operation is predicted to be more expensive than LMPs. It is unreasonable for the Company to continue to limit Edwardsport's operation to a single, more expensive fuel source, when the unit is capable of generating electricity at lower costs for customers on natural gas and when the continued operation of Edwardsport on coal and syngas results in market losses and unnecessary fuel costs to customers as compared to reserve shutdown and energy purchases.

[9] Ind. Code §8-1-2-42(d)(1).

Although Duke offered a number of reasons for its position that the use of natural gas at Edwardsport is impractical, we do not find any of these explanations convincing. First, Duke claims that de-committing the Edwardsport gasifiers will result in the loss of essential personnel, but has failed to identify what positions would be lost or demonstrate that these individuals could not be transferred to other roles within the unit. Second, Duke asserts that a long-term switch to natural gas at Edwardsport would increase gas prices at the Vermillion and Wheatland Station, but this appears to be nothing more than speculation, as the Company provided no evidence for this assertion. Third, Duke suggests that Edwardsport's current Title V permit is incompatible with long-term natural gas operation, but we find this claim unconvincing given that the plant was designed to operate on duel fuels and Duke has not identified what provisions in that permit are inconsistent with natural gas operation or explained why it is able to operate Edwardsport on natural gas *currently* when the gasifiers are offline despite this purported inconsistency. Fourth, Duke points to longer-term concerns with fuel diversity as a reason to maintain coal operation at Edwardsport. Although resource decisions are beyond the scope of this FAC proceeding, we note that Duke primarily relies on its coal-fired units and that the unique benefit of Edwardsport is its flexibility with respect to gas versus coal operation as the relative prices of those two fuels change. Whatever the resource profile of Duke's fleet, it maintains a statutory obligation to generate or purchase electricity at the lowest reasonable fuel cost to customers, and its current operational practices at Edwardsport do not justify the fuel costs the Company is seeking to pass along to customers during the FAC 123 period.

With respect to Cayuga, we find that passing on the increased fuel costs associated with otherwise imprudent operation of the Cayuga units to retail electricity customers would constitute a cross-subsidization of Duke's steam customer that is inconsistent with ratemaking principles and the fuel adjustment charge statute. Duke proffered testimony that it anticipates filing revisions to the steam contract in light of the most recent rate case decision, IURC Cause No. 45253. At this time we offer no opinion as to how Duke and its steam customer should allocate the marginal fuel costs associated with the uneconomic self-commitment of Cayuga to ensure uninterrupted service, however, we hold that these costs cannot be recouped from electricity customers through the FAC mechanism.

~~Ms. Diaz, respectively.~~

~~As Mr. Swez discussed, Duke Energy Indiana is part of a joint ownership arrangement for Gibson Unit 5. Specifically, there are three different owners with three energy offers made to two different RTOs. If any share of the unit is committed in either MISO or PJM, or if any of the three owners desire to run the unit, the unit is committed as Must Run.~~

~~Mr. Gurganus' provided a detailed review of the benefits provided by Edwardsport Station to Duke Energy Indiana customers. Mr. Gurganus also discussed in detail the Edwardsport Station's unique operational characteristics. Specifically, Edwardsport is capable of operating on both natural gas and coal, providing diversity and reliability. This feature is a benefit to Duke Energy Indiana customers. However, Edwardsport Station is unable to be committed with a MISO status of "Economic" due to the long startup and shut down process required by the technology. Mr. Gurganus also discussed that cycling the gasifiers at Edwardsport for short periods would~~

~~decrease the efficiency of the plant through continued use of gasification auxiliary power, as well as impart significant thermal stresses that cause equipment wear and tear and increased maintenance costs. He testified that these practical considerations must be considered when deciding how to offer Edwardsport for operation to MISO. This Commission also found evidence persuasive in IURC Cause No. 45253 that it "would be operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals in an attempt to capture benefits for customers".[10] We continue to find this evidence persuasive and agree with Mr. Gurganus and believe the Company's approach to committing Edwardsport Station is reasonable given its operating characteristics, and derives maximum benefits for Duke Energy Indiana customers.~~

~~Additionally, Mr. Gurganus testified that Duke Energy Indiana has been supplying a large industrial customer adjacent to Cayuga Generating Station with both electricity and high-pressure steam for forty-five (45) years. Ms. Diaz provided a detailed discussion regarding the Company's cooperative relationship with the steam customer to produce and deliver steam and abide by the contractual terms of their contract, which this Commission has found to be reasonable, just, practicable and beneficial to the parties. As the Company's witnesses mention, the Commission has reviewed and approved the steam contract at Cayuga Generating Station on many occasions. We have previously found, most recently in Cause No. 44087, the nearly 200 high-paying jobs provided by the steam customer provides an economic benefit to Vermillion County, the State of Indiana, and Duke Energy Indiana customers. We further note that the Company has indicated it will be working with the steam customer to renegotiate the agreement. Any docket that flows from a new agreement with the steam customer would be the appropriate forum to weigh the merits of the steam contract. As for this subdocket, we believe the Company has been committing the Cayuga units in a manner that complies with the terms of the Commission-approved steam contract. It is reasonable that the units will not always realize a financial gain and the Company may need to commit the units as "Must Run" to ensure that the steam customer can maintain its operations. Complying with the terms of the agreement or committing the Cayuga units as "Must Run", even when it results in a financial loss, is not proof of inappropriate commitment decisions by Duke Energy Indiana. Intervenors have offered no additional evidence other than the fact that the agreement may sometimes require the Company to commit one of the Cayuga units, when the economics might suggest not committing it. We find the Company's approach to committing Cayuga Station is reasonable given the contractual requirements of the steam agreement, and derives maximum benefits for Duke Energy Indiana customers.~~

~~Tellingly, the intervenors find only minor instances where they believe the Gibson Station units were committed inappropriately, all of which were explained in Mr. Swez' rebuttal testimony. We find that this demonstrates Duke Energy Indiana has a robust review and decision making process for its commitment decisions. As such, the Commission agrees with the Company that it is not appropriate for the units at Gibson, Cayuga and Edwardsport to be offered to MISO using a commitment status offer of "Economic" at all times. Despite the assertions of Sierra Club, CAC and other Intervenors, this can lead to inefficient outcomes for Duke Energy Indiana customers. Given the varying characteristics and considerations with each specific Duke Energy Indiana generating unit, we believe the Company's unit commitment decisions during the reconciliation period were reasonable.~~

~~[10] Final Order, IURC Cause No. 45253 at Page 96.~~

~~Although we did not establish this subdocket to review the Company's fuel procurement practices and we hold firm to a previous determination that those procedures can be reviewed in the Company's quarterly FAC filings, we understand that fuel procurement is at least tangentially related to unit commitment decisions. Intervenors presented lengthy testimony suggesting that Duke Energy Indiana's fuel procurement practices has led to the Company making uneconomic unit commitment decisions. We disagree with this assessment. Much like unit commitment decisions, fuel procurement is clearly not a simple or non-consequential exercise. Mr. Verderame testified that the Company reviews its coal position on a monthly basis by looking at its projected coal burns, coal inventory levels, the amount of coal under contract and the quality characteristics needed for a generating station. He explained that upon determining a need for additional coal, the Company determines whether it is prudent to purchase on the spot market or to look to a longer-term solution. The Company uses modeling outputs to assist in evaluating its coal procurement needs, including incorporating a stochastic model which gives the Company expected fuel burns, the range of fuel burns, and probability associated with each range. We note that much like its approach to unit commitment decisions, Duke Energy Indiana's fuel procurement practices are the most robust among the Indiana utilities. However, no matter how robust the analysis and practices, no process can predict the future with exact certainty. This can lead to temporary conditions that in a vacuum would have the appearance of over supply. Nonetheless, we understand the detailed analysis performed by the Company to procure its fuel and find that Duke Energy Indiana's fuel procurement practices, during the reconciliation period, were reasonable and did not negatively impact unit commitment decisions.~~

As we have discussed before, the Commission does not engage in a hindsight analysis. Rather, in determining whether a utility acted prudently we must review the circumstances as they existed considering what was known or should reasonably have been known by the utility at the time of its actions. *See Duke Energy Ind., Inc.,* Cause No. 38707 FAC 76 S1, 2009 WL 3455937 at 17 (IURC Oct. 21 2009). ~~Duke Energy Indiana's testimony supports and explains its calculations, its source of fuel efforts, and its decisions to provide customers with the lowest reasonable fuel costs to the satisfaction of the (d)(l) test. In conclusion, we find Duke Energy Indiana's unit commitment decisions during the reconciliation period of September through November 2019 were reasonable. Accordingly, we find that no refunds are due the Company's retail customers and this subdocket should be closed.~~We observe that Duke already has a reasonable process in place for energy market forecasts, and that when Duke followed its own P&L Analyses in making commitment decisions at the Gibson and Gallagher units, those units did not produce the millions of dollars in losses that Duke acknowledged were accrued at Edwardsport and Cayuga. In fact, Duke's process predicted losses at Edwardsport that were very close to the actual losses that occurred, highlighting that while the P&L analyses process could be improved, the larger problem seems to be Duke's reluctance to follow its own analyses. Indeed, contrary to Duke's witnesses' allegations that Intervenors offered "hindsight" analysis of Duke's losses during the FAC 123 period, we note that expert witnesses for CAC and Sierra Club relied primarily on Duke's *own* contemporaneous market forecasts to demonstrate that the Company's use of Must Run commitment was imprudent. Far from hindsight analysis, Intervenors' testimony emphasized commitment choices for which there was ample evidence that Duke knew at the time would result in losses, and where actual losses closely resembled what the Company itself predicted, as in the case of Ms. Glick's analysis of Edwardsport (showing Duke projected $3.7 million in losses over the FAC period and realized $3.3 million in losses).

In conclusion, we find Duke Energy Indiana's unit commitment decisions, specifically its consistent use of must run commitment status at Edwardsport and Cayuga despite contemporaneous market forecasts showing extended periods of losses during the reconciliation period of September through November 2019, were unreasonable. Accordingly, we will disallow a total of \$4.7 million in fuel costs we find were imprudently expended at those two units during the FAC period. This amount is equal to the proportion attributable to fuel of total negative energy margin accrued during periods in which Duke forecast market losses and nevertheless committed a coal-fired unit as Must Run (which, based on Ms. Glick's testimony, we find was equal to \$3.3 million at Edwardsport and \$1.9 million at Cayuga). These negative energy margins are equal to the difference between the fuel portion of the variable cost of operation of the units during those periods and the relevant Locational Marginal Price, or the cost of energy purchases, on the MISO market during those same periods.

Given these findings with respect to the FAC 123 period, we believe it is appropriate to provide some guidance on recovery of fuel costs in future FAC proceedings. Future cases should be decided, as the one has been, based on the information that Duke had at the time it makes its energy market decisions. To aid the Commission's efficient review of Duke's fuel costs and decisions, Duke should include in its Application for all future FAC proceedings: 1) the Profit & Loss Analyses created by Duke during the applicable FAC period; 2) documentation of the commitment decisions made during the FAC period for each Duke unit whenever those decisions anticipate incurring a loss based on the Profit & Loss Analyses; and 3) net revenue (or losses) from running Edwardsport in the FAC period, defined as energy and ancillary service market revenue less fuel and variable O&M and other related information as described below. In addition, to be filed in the last FAC proceeding of calendar year 2021 or other appropriate proceeding, Duke shall perform a cost of service study, or other robust analysis, for a retrospective period of at least one year, to determine the total fuel costs attributable to uneconomic operation at Cayuga. In future cases, Duke's fuel would be most likely to meet the "lowest fuel cost reasonably possible" standard if Duke documents its commitment decisions at all its coal-fired units more extensively to allow the Commission to evaluate the prudence of those decisions more effectively in future FAC proceedings.

8. **Interim Rates.** ~~As set forth above, we~~We find that ~~no~~ refunds are appropriate as a result of this subdocket. ~~Accordingly, the~~ The potential refund ~~obligations~~obligation imposed by the Commission's Orders in Cause Nos. 38707 FAC 123 ~~through FAC 125 related to this subdocket proceeding are removed.~~is now fixed at \$4.7 million, equivalent to the fuel cost portion of negative energy market margins (variable operational costs minus energy market prices) for generation at Edwardsport and Cayuga during periods in which the Company committed units as those plants as Must Run despite P&L Analyses forecasting losses.

9. **Confidential Information.** On April 29, 2020, May 15, 2020, and October 29, 2020, Duke Energy Indiana filed motions requesting protection of confidential and proprietary information along with supporting affidavits. On May 11, 2017, May 27, 2020, and October 29, 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) sensitive contract terms, revenues and load data information involving certain special contracts approved by the Commission; (ii) generation variable cost data; (iii) Day-Ahead awards; (iv) dispatch information; (v) pricing, commercial terms, and supplier information related to Duke Energy Indiana's coal contracts; and (vi) information identifying generating resource outages, including information regarding the reason and duration of the outage as reported to and held confidential by the North American Electric Reliability Corporation in the Generating Availability data system, as well as generating unit operational characteristics, which is used to calculate a unit's energy or ancillary services supply offer, and confidential indicative capacity and energy prices provided to Duke Energy Indiana by a third party. 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. This subdocket should be, and hereby is, closed.

2. Duke Energy Indiana's unit commitment decisions during the reconciliation period of September through November 2019 were ~~reasonable.~~ unreasonable. Specifically for Edwardsport and Cayuga, the commitment decisions throughout the three-month period did not comply with the "lowest fuel cost reasonably possible" standard of Ind. Code §8-1-2-42(d)(1).

~~3. Duke Energy Indiana's approach to committing Edwardsport Station is reasonable given its operating characteristics, and derives maximum benefits for Duke Energy Indiana customers.~~

3. Duke incurred actual net negative operational margins of $3.3 million at Edwardsport and $1.9 million at Cayuga. These negative margins were predicted by Duke and were due to Duke's imprudent, uneconomic use of the must run commitment decisions during periods in which Duke's market forecasts showed that variable costs at these units would exceed market energy prices.

4. Duke ~~Energy Indiana's approach~~ignored the results of its own price-based P&L Analysis, and in fact relied on no tools or analysis at any point during FAC 123 to ~~committing Cayuga Station is reasonable given the~~ inform or assess Edwardsport's unit commitment practices.

5. Duke uneconomically self-committed its Cayuga units notwithstanding its own P&L projections of negative margins to fulfill a contractual ~~requirements of the steam agreement, and derives maximum benefits for Duke Energy Indiana~~obligation to a single steam customer that requires it to maintain at least one of the Cayuga units as online and at a 300MW net output (70MW above the operational minimum).

~~5.~~6. Duke's proposed fuel adjustment charge would allocate the energy market losses it accrues at Cayuga to meet its operational obligations under the steam contract to its retail electricity customers. Duke has not performed a cost of service study to determine the net system impact to customers~~.~~ of operating Cayuga to serve the steam customer, and has failed to demonstrate that uneconomic operations of the unit to serve the steam customer is in the best interests of retail customers.

~~6. Duke Energy Indiana's approach to committing Gibson Station is reasonable given the Gibson 5 joint ownership and multiple RTO configuration impacts, and derives maximum benefits for Duke Energy Indiana customers.~~

~~8. Duke Energy Indiana's fuel procurement practices, during the reconciliation period, were reasonable and did not negatively impact unit commitment decisions.~~

7. ~~The~~ Duke shall refund retail customers $4.7 million in fuel costs that had previously been imposed "subject to refund" ~~obligations imposed~~ in Cause ~~Nos~~No. 38707 FAC 123 ~~through~~. These refunds shall be allocated in the same manner as the fuel adjustment charge and shall commence with the first billing cycle following approval of this Order by the Commission.

8. To be filed in the last FAC proceeding of calendar year 2021 or other appropriate proceeding, Duke shall perform a cost of service study, or other robust analysis, for a retrospective period of at least one year, to determine the total fuel costs attributable to uneconomic operation at Cayuga for the purpose of serving the steam customer there, and to evaluate whether the economic benefits of the steam contract appropriately cover these additional variable costs.

9. For future FAC cases, and to provide guidance to Duke, we observe that fuel costs are most likely to meet the lowest cost standard if: Duke develops a new, price-based commitment decision analysis process for Edwardsport, commencing with the first complete FAC period following approval of this Order by the Commission, as follows:

    a. At the outset of the FAC period, Duke performs a 3-month look-ahead analysis projecting net energy market revenues for the plant on both syngas and natural gas operation.
    b. If the results of the 3-month forecast indicate that net revenues are highest when the plant is operating on natural gas, the Company should continue to produce and utilize the daily Profit and Loss Analysis.
    c. If the results of the 3-month forecast indicate that net revenues are highest when the plant is operating on coal/syngas, the Company should produce projections for every 14-day period to assess whether operating on coal continues to be the most economic option for ratepayers during that FAC period.

10. Beginning with its next FAC filing, Duke is ordered to produce, under seal, its P&L Analyses for each of its coal-fired units as part of its FAC Application. If Duke's commitment or dispatch decisions at any of its coal-fired units deviate from the results of

its forward-looking price analysis, including the process for Edwardsport set forth above, Duke should document the contemporaneous reason(s) for such a divergence. The Commission will presume imprudence and disallow recovery of that portion of marginal market energy losses attributable to fuel costs for any losses incurred as a result of such deviation from the Company's own price-based process. This presumption is rebuttable.

11. Duke is ordered, beginning with the next full FAC period, to include as part of its FAC Application the following information:

    a. All Profit & Loss Analyses conducted during the FAC period;
    b. The specific commitment decisions made during the FAC period for each Duke unit;
    c. Total net revenue (or losses) from running Edwardsport in the FAC period, defined as energy and ancillary service market revenue less fuel and variable O&M;
    d. Monthly gas and coal consumption at Edwardsport in the FAC period;
    e. Hours when the gasifiers were in outage in the FAC; and
    f. Total net revenue (or losses) that the Company would have incurred/earned from operating Edwardsport on natural gas for all hours in the FAC period (applicable only if Edwardsport operated on coal during the FAC period).

12. As part of its Application for the next complete FAC period, Duke shall perform and file an analysis where each of its coal-fired units are modeled with economic commitment for the entire FAC period. The model shall incorporate startup and shutdown costs. Duke shall also model, with the same constraints, all coal-fired units as must run throughout the same period. Duke shall report the estimated fuel costs associated with the respective economic and must run models.

~~10.~~13. The Commission previously imposed "subject to refund" obligations in Cause Nos. 38707 FAC 124 and FAC 125 ~~related to~~ contingent on the outcome of this proceeding. The evidentiary record in this subdocket proceeding ~~are hereby removed.~~was limited to the FAC 123 period. However, given the Commission's findings with respect to the FAC 123, the Commission finds that similar disallowances are warranted for the FAC 124 and FAC 125 period. The Commission will issue additional Orders in those dockets directing Duke to issue refunds equal to that portion of fuel costs attributable to uneconomic commitment at times when Duke's contemporaneous forecasts anticipated negative energy market margins. The total amount of those refunds will be determined based on evidence already in the record in the FAC 124 and FAC 125 proceedings.

~~11.~~14. The information described in the Confidential Information submitted in this Cause are hereby exempt from the public access requirements of Ind. Code § 5-14-3-4 and shall continue to be held as confidential by the Commission.

~~12.~~15. This Order shall be effective on and after the date of its approval.

<u>HUSTON, FREEMAN, KREVDA, OBER AND ZIEGNER CONCUR</u>:

APPROVED:

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

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Secretary to the Commission