SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

IURC CAUSE NO. 38708 FAC 141

DIRECT TESTIMONY

OF

F. SHANE BRADFORD

VICE PRESIDENT POWER GENERATION OPERATIONS

ON

PURCHASED POWER AND COAL INVENTORY

SPONSORING ATTACHMENT FSB-1 THROUGH FSB-2

DIRECT TESTIMONY OF F. SHANE BRADFORD

INTRODUCTION

Q. Please state your name and business address.

A. My name is F. Shane Bradford. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. By whom are you employed?

A. I am employed by Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South")[1].

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of CEI South, which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner CEI South?

A. I am Vice President, Power Generation Operations.

Q. Please describe your educational background.

A. I received a Bachelor of Science in Civil Engineering (1992) from the University of Dayton and a Master's in Business Administration (2002) from Indiana State University.

Q. Please describe your professional experience.

A. I began my career in the utility industry at Dayton Power and Light Co. performing various maintenance and production roles within the electric generation division from 1992 to 1999. In 1999, I joined Cinergy's electric generation division and fulfilled various maintenance and production responsibilities until 2003 when I became a plant manager for one of Cinergy's subsidiaries Trigen Cinergy Solutions LLC. In 2004, I

[1] For the sake of clarity, my testimony refers to CEI South, even though in certain situations, I may be referring to one of CEI South's predecessor companies.

took a position with CEI South as a Power Plant Director responsible for providing leadership and management focused on safe, environmentally responsible, reliable, and efficient electric generation. In 2021, I was named Director, Power Supply Service where I was responsible for Wholesale Power Marketing, Market Settlements, and Market Development. I was named to my current position in January 2023.

Q. What are your present duties and responsibilities as Vice-President of Power Generation Operations?

A. I am responsible for the overall budgeting, operation, maintenance, and personnel decisions for CEI South's electric generation fleet. In addition, I have responsibility for ensuring the demand of our customers is met at a reasonable cost through the production and purchase of electric energy, including fuel purchases, necessary to meet the needs of our jurisdictional customers. I am responsible for completing these functions while ensuring compliance with the environmental requirements of all applicable regulatory or governmental agencies. As part of overseeing CEI South's generation assets, I supervise personnel providing cost inputs to the modeling associated with the Integrated Resource Plan process. In addition, I have responsibility for the commercial negotiations and dealings with generation resources.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A. Yes. I provided testimony before the Commission in Cause No. 45501 in support of CEI South's request for (1) a certificate of public convenience and necessity ("CPCN") to purchase and acquire, indirectly through a Build Transfer Agreement ("BTA"), a 300 MWac solar facility in Posey County, Indiana and (2) authorization to enter into a Power Purchase Agreement ("PPA") to purchase energy and capacity from a 100 MWac solar project in Warrick County. I also provided testimony before the Commission in Cause No. 45564 in support of CEI South's request for a CPCN to construct two natural gas combustion turbines providing approximately 460 MW of capacity. In addition, I provided testimony before the Commission in Cause No. 45754 in support of CEI South's request for a CPCN to purchase and acquire, indirectly through a BTA, a 130 MWac solar facility in Pike County, Indiana; in Cause No. 45836 in support of CEI South's request for a CPCN to purchase and acquire, indirectly through a BTA, a wind facility; in Cause No. 45847 in support of CEI South's request to amend and restate its BTA for the Posey County solar facility; and in Cause No 45903 in support of CEI South's request for a CPCN to recover costs associated with closing the Culley East ash pond as required by the CCR Rule. Finally, I provided testimony in CEI South's Clean Energy Cost Adjustment ("CECA") proceeding under Cause No 44909, its Environmental Cost Adjustment ("ECA") under Cause No. 45052, its Reliability Cost and Revenue Adjustment ("RCRA") under Cause No. 43406, and in this Fuel Adjustment Clause ("FAC") proceeding under Cause No. 38708.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information regarding CEI South's power purchases and related costs as a participant in the Midcontinent Independent System Operator ("MISO") Energy Market, CEI South's fuel supply, and to sponsor Attachment FSB-1, which consists of schedules that present the calculations of the MISO components included in fuel costs, the calculations of the daily benchmark prices applicable to purchased power for June 2023 through August 2023 (the "Reconciliation Period"), and information about over-benchmark purchased power costs that are reasonable and recoverable under the applicable settlement. I will also present an update to the 2023 and 2024 coal plan.

MISO

Q. Are you generally familiar with the operations of MISO, including MISO Day 2 Market Initiative and Day 3 Ancillary Services Market ("ASM")?

A. Yes, I am.

Q. Have you reviewed the Commission's June 1, 2005, Order in Cause No. 42685 ("42685 Order") and June 30, 2009, Phase II Order in Cause No. 43426 ("ASM Phase II Order")?

A. Yes.

Q. Is CEI South's proposed recovery of costs for the Reconciliation Period consistent with your understanding of the Commission's 42685 Order and ASM Phase II Order?

A. Yes, CEI South's FAC 141 filing is consistent with my understanding of those Commission Orders.

Q. Please summarize your understanding of the impact of MISO Day 2 on CEI South's operations.

A. MISO's implementation of the Day 2 Market Initiative resulted in operational changes for CEI South. MISO Day 2 features a wide-area security constrained centralized dispatch across a significant geographic footprint spanning 36 Local Balancing Authorities across fifteen states and Manitoba. Through centralized dispatch, this market brings about an integration of system operations and market operations unlike what existed in this region prior to the start of Day 2. This caused both changes to existing operating procedures and the creation of new operational infrastructure. These operational changes result in costs and cost structures that differ in form from those that previously existed.

As a result of the existence of the Day 2 market, the cost for CEI South to serve its native load customers now includes both its own generation and MISO dispatched economic energy purchases.

Q. Briefly describe the MISO costs and revenues that CEI South is seeking to include in this FAC proceeding.

A. Consistent with the 42685 Order, CEI South is requesting that fuel-related MISO costs and revenues track through its current FAC. Attachment FSB-1, Schedule 1, contains a summary of the determination of MISO Components of Fuel Costs, exclusive of purchased power costs, for the Reconciliation Period. In addition, CEI South is requesting recovery of projected MISO costs for the period of February 2024 through April 2024. These projected costs include the estimated level of the net effect of delta Locational Marginal Pricing ("LMPs"), Day Ahead and Reliability Assessment

Commitment ("RAC") recovery of unit commitment costs, Financial Transmission Right ("FTR") revenue and expenses, and Real Time Marginal Loss Surplus credits.

Q. Are costs associated with MISO's ASM included in the amounts for which you are seeking recovery in this FAC?

A. Yes. Consistent with the Commission's Phase I Order in Cause No. 43426, dated August 13, 2008, CEI South has included for recovery in the FAC those costs for charge types identified as "modified" under the ASM and which were previously recovered in the FAC. Additionally, the Commission issued its ASM Phase II Order on June 30, 2009, that authorized CEI South to include certain new MISO charges and credits as a cost of fuel for recovery in its FAC proceedings.

Q. Did the ASM Phase II Order contain any reporting requirements?

A. Yes. In compliance with the Phase II Order, CEI South must report the monthly average ASM Cost Distribution average dollar per megawatt hours ("MWh") paid for Regulation, Spinning, Supplemental, and Short-Term Reserves. The amounts for June 2023 through August 2023 are as follows:

	Regulation	Spinning	Supplemental	Short-Term
June 2023	$0.0307	$0.0287	$0.0080	$0.0339
July 2023	$0.0333	$0.0330	$0.0039	$0.0414
August 2023	$0.0203	$0.0266	$0.0105	$0.2218

Q. Given the centralized MISO economic dispatch structure of the Day 2 market, how does CEI South explicitly identify the quantity of purchased power and wholesale sales in each hour?

A. If in a given hour CEI South withdraws more MWh from the grid at its load zone than CEI South generating units inject to the grid, those excess MWh withdrawn are purchased power amounts. Conversely, if in a given hour CEI South generating units inject more MWh to the grid than CEI South withdraws from the grid at its load zone, those excess MWh injected are allocated to wholesale sale amounts.

Q. Is the proposed pass through of Revenue Sufficiency Guarantee ("RSG") amounts in this Cause consistent with your understanding of the Commission's July 16, 2008, Order in Cause No. 43475?

A. Yes.

Q. Are MISO fuel components also included in this FAC?

A. Yes. All the requested MISO components qualify for recovery in this FAC pursuant to the Commission's Orders in Cause Nos. 42685, 43475, 43426, and 38708 FAC 73. In addition, as a result of FERC Order 719 (issued on October 17, 2008) and FERC Order 745 (issued on March 15, 2011) additional charge types have been included for recovery. These charge types were effective June 12, 2012, and discussed in FAC 96 and FAC 97.

PURCHASED POWER RECOVERY

Q. Please describe the mechanism in place for recovery of the cost of energy purchased in MISO Energy Markets.

A. Pursuant to an approved settlement, the cost associated with each purchase is calculated for a given hour as the product of the number of MW purchased for that hour and the purchase price for that hour. To assist in the FAC review of the reasonableness of power purchases, the settlement provides that a benchmark price is applied to purchases and any purchases made in the course of MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and are fully recoverable in the FAC up to the benchmark.

Above-benchmark purchases are also recoverable, so long as the purchases can be shown to be reasonable based on an evaluation conducted with factors set forth in the settlement. As explained by the Commission in Cause No. 41363:

> Our March 10, 1999, Docket Entry was clear that we contemplated that a benchmark would merely be a triggering mechanism-that is, if a benchmark is exceeded the utility would have the opportunity to submit additional evidence demonstrating the reasonableness of its power purchases for cost recovery purposes. Every electric generating utility

> should have the opportunity to request recovery of and justify the reasonableness of purchased power costs above the benchmark. In the event a utility exceeds the benchmark, the standard to be used to review such purchases will be of the reasonableness of the decisions under the circumstances which were known (or which reasonably should have been known) at the time the purchases were made, not an after the fact focus using hindsight judgment.

(IURC Order, Aug. 18, 1999, p. 11).

Q. What is CEI South's benchmark for purchased power costs?

A. In Cause No. 43414, the Commission approved the establishment of daily benchmarks. The daily benchmarks are established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 Btu/kWh, and using the NYMEX Henry Hub Gas Day Ahead price plus $0.60/MMBtu gas transport charge for a generic gas-fired GT. Changes were approved in Cause No. 43414 to the parameters used to determine amounts over the daily benchmarks.

Q. Is a Schedule showing the Daily Benchmarks for purchased power for the Reconciliation Period included in this Cause?

A. Yes. Attachment FSB-1, Schedule 2, presents the Daily Benchmark amounts for each day in the Reconciliation Period.

Q. What are the amounts of purchased power in excess of the Daily Benchmarks incurred by CEI South during the Reconciliation Period?

A. As shown on Attachment FSB-1, Schedule 3, CEI South determined that purchased power costs exceeded the Daily Benchmarks during the Reconciliation Period as follows: June 2023, $21,232.84; July 2023, $8,927.57; and August 2023, $66,427.35. These costs were incurred pursuant to MISO's security constrained economic dispatch across its footprint because MISO elected to utilize other generation when CEI South needed additional power.

Q. Are all over-benchmark purchases during the Reconciliation Period determined to be recoverable?

A. Yes. Applying the criteria established by the Benchmark Settlement CEI South has determined that all the over benchmark purchases are recoverable. Attachment FSB-1, Schedule 3 provides the reason each purchase was made. As contemplated by the Commission in its Order in Cause No. 42770, all these purchases were within "the utility's reasonably expected cost of purchased power under an economic dispatch regime." CEI South acted appropriately in the operation of its generation and its participation in MISO to maintain safe, adequate, and reliable service to its retail customers. The beneficiaries of these purchases were CEI South's retail customers. Without these purchases, CEI South could not have met the demands of its retail customers while complying with MISO dispatch instructions. Recovery of these purchased power costs only makes CEI South whole for costs incurred to meet the demand of retail customers.

Q. Why does MISO at times choose to instruct CEI South to purchase from the market rather than operate generation internal to its control area?

A. Since the 42685 Order, MISO has dispatched generation. MISO first considers its security constrained economic dispatch model to determine what generation is necessary to meet the next day's system demand with the lowest total cost. If this evaluation shows that the total daily cost is predicted to be less using market purchases rather than calling for CEI South's internal generation, then that is the MISO directive CEI South will be given for the Day Ahead market. Additional consideration will be given to the potential impact to system congestion, which is impacted by market purchases versus CEI South peaking generation operation. The summation of these variables is that every day's evaluation has a different set of conditions and inputs which can only be evaluated by MISO on a regional basis. Thus, like any generator, CEI South is sometimes required by MISO to make economic purchases at the lowest cost reasonably possible. With the influx of new generation sources such as wind, and the dramatic reduction in gas prices, other generation sources now are available in the market at competitive prices. Some of these sources, like wind, are so inexpensive in off peak hours that they are selected in the Day Ahead market. The reasonable purchase costs reflected in the FAC are the product of MISO's economic dispatch.

Q. Does CEI South ever deviate from MISO dispatch in order to operate its gas peaking generation?

A. Generally, CEI South follows instructions from MISO on when to operate gas peaking generation. CEI South's on-duty system generation operators are provided plans from MISO, and they follow those dispatch plans. Most often, MISO will call on peaking units in the Real Time (intra-day) market but will on occasion also call for a Peaker through the Day Ahead market. The system generation operators will generally vary from these MISO plans only when notified by local transmission system operators that there is a local distribution or transmission constraint that would be eliminated by the use of peaking generation.

In terms of determining whether to operate the peaking units for purely economic reasons, CEI South's system generation operator evaluates the Real Time Market price of power and compares it to the alternative of starting a natural gas peaking unit for a brief period. The operator monitors the five-minute price signals to determine if they believe the hourly market price will integrate high enough to justify starting a gas turbine. This determination is made knowing that the next five-minute price signal will likely change. A higher price often exists due to an event on the system that sends a price signal for generators to increase production. Once generation is increased, the price will drop; therefore, given these conditions the operator will almost always choose to follow the MISO dispatch signal rather than betting on a sustained higher price.

In addition, when evaluating the operation of a specific gas turbine, the operator must consider, among other things, (1) the time it takes to bring the unit on line, (2) the actual cost of fuel consumed during the period of time from initial firing until the unit is synchronized to the system, as well as the cost of gas used during controlled unit shut down, and (3) the likelihood that the unit will run at a reduced capacity factor, which increases the heat rate, adding to run costs. These must be spread over the total cost of the MWh produced by the machine. These are reasons why the cost of production during short periods often exceeds the price of power purchased from the economic marketplace.

Moreover, failure to comply with MISO's dispatch directive would result in assessment of uninstructed deviation charges of unknown amounts to CEI South. Given these cost and price risks, absent unusual market conditions, it is unlikely CEI South will ignore MISO dispatch and operate its peaking units for economic reasons.

Q. Are any purchases from the Benton County Wind Farm ("BCWF") and Fowler Ridge II ("FRII") included in this FAC?

A. Yes. Pursuant to the approval received in Cause No. 43259, CEI South began receiving power from BCWF on May 7, 2008, when the facility began commercial operation. CEI South's Renewable Energy Purchase Agreement ("REPA") with FRII was approved in Cause No. 43635 on June 17, 2009, and FRII began commercial operation on December 16, 2009. Consistent with the order in Cause No. 43635, CEI South has included in this FAC those charges or credits related to the REPA that are treated by the Commission as components of fuel.

Q. Are there any amounts shown as purchased power from BCWF and FRII included in the monthly work papers?

A. Yes. The details of power purchased from BCWF and FRII are included in the confidential work papers provided to the OUCC.

Q. How has CEI South estimated the generation received from BCWF in this FAC?

A. In response to the fluctuations in CEI South's share of generation of BCWF, CEI South's projections reflect recent historical output from BCWF. CEI South has created an output profile for BCWF that is based on CEI South's monthly average actual share of generation received from BCWF since March 2013 when BCWF was designated a Dispatchable Intermittent Resource ("DIR"). CEI South will update this output profile and its estimates for BCWF in each future FAC based on recent historical data.

Q. Have negative LMPs from BCWF or FRII been experienced?

A. Yes. LMPs can be negative whenever there is congestion on a node. MISO uses negative pricing to rein in a bottleneck, which can occur with wind energy. For the FAC period there were 27 hours when the LMP was negative at BCWF, and 11 hours when the LMP was negative at FRII. This resulted in total charges of $1,472.77.

Q. Please describe how CEI South uses the DIR designation.

A. MISO has attempted to address the operational challenges associated with the variable nature of wind power by allowing these resources to participate fully in MISO's economic dispatch under a DIR resource designation. After consulting with MISO regarding requirements and stipulations around registering wind farms, CEI South was notified that it was required to register BCWF as a DIR. The registration was completed in December 2012, and BCWF became a DIR on March 1, 2013. CEI South is not required to register FRII as a DIR because it meets an exception through its firm transmission into MISO.

Q. How has DIR impacted CEI South and its customers?

A. Generally, since BCWF was registered as a DIR in March of 2013, generation output for CEI South customers has been reduced.

SALES OF RENEWABLE ENERGY CERTIFICATES

Q. Did CEI South include sales of Renewable Energy Certificates ("RECs") in this FAC?

A. Yes. Sales of RECs were recorded in the Reconciliation Period. The net amounts of those sales are included, as reductions to the cost of purchased power, in the calculation of purchased power costs for the respective months. For the Reconciliation Period, purchased power costs have been reduced by the net REC sales proceeds of $(1,266,841.03).

FUEL FOR GENERATION

Q. What sources of fuel does CEI South use for generating purposes, and what costs are incurred?

A. CEI South utilizes coal and natural gas for electric generation and incurs the costs of purchasing those fuels, including fuel-related transportation and storage costs. In addition, CEI South has solar, wind, battery storage, and landfill gas as part of the electric generation portfolio.

Q. Please describe CEI South's coal purchasing practices.

A. CEI South utilizes Indiana coal as its primary fuel source for electric generation. Coal is purchased primarily under multi-year contracts to maintain a reliable source of coal.

Q. Does CEI South have a portfolio of supply contracts with staggered pricing terms in place to mitigate potential coal market volatility?

A. Yes. Two contracts are currently in place that has supported re-pricing opportunities for portions of CEI South's supply, and given volume flexibility provided for under these contracts, also leaves opportunities for spot purchases as needed. The contracts also provide coal with specifications that support CEI South's emissions compliance strategy.

Q. Has CEI South made every reasonable effort to provide power as economically as possible?

A. Yes. CEI South's generating units are offered into the MISO Day Ahead and Real Time markets and are dispatched by the MISO on an economic basis. CEI South has contracted through competitive processes to purchase its coal requirements from nearby mines at reasonable market prices. Purchasing from mines in close proximity to CEI South's generating stations helps minimize transportation costs while providing a reliable, reasonably priced fuel supply.

COAL INVENTORY

Q. What is the status of CEI South's coal inventory?

A. As of October 31, 2023, coal inventory at CEI South's coal-fired generating plants stood at approximately 403,397 tons. This is a decrease of 163,608 tons from the inventory level reported in FAC 140.

Q. Please provide the month-ending coal inventory levels by plant and total in 2023.

A.

Month	Brown	Culley	Warrick	Total
January	153,785	219,205	107,609	480,599
February	209,489	286,997	78,892	575,378
March	261,386	335,288	86,528	683,202
April	243,210	348,711	76,166	668,087
May	187,304	352,801	87,367	627,472
June	184,705	366,275	71,768	622,748
July	171,896	336,957	58,152	567,005
August	154,018	320,032	44,371	518,421
September	83,887	301,553	44,531	429,971
October	77,206	298,253	27,938	403,397

Q. Does CEI South have an inventory target to assure reliability?

A. Yes. CEI South's target inventory is driven in part by the risk CEI South is willing to take regarding deliveries being suspended due to a mine issue (safety, Mine Safety and Health Administration, productivity issues, employee retention or strike, etc.), or rail or truck transportation issues (equipment issues or employee retention or strikes), and how long these supply interruptions might reasonably be expected to last. The target inventory also attempts to account for the carrying costs for holding the inventory. Considering these various factors of mine risks, transportation risks, and carrying costs, CEI South generally targets a reserve inventory of about 30–60 days. The level of burn can vary, and therefore, target inventory should fall within a range. For CEI South's operating purposes, inventory of approximately [redacted] tons is a good target.

COAL SUPPLY PLAN

Q. Please provide an update to CEI South's 2023 coal supply plan to include delivery options with [redacted] [redacted].

A. CEI South entered 2023 with 420,750 tons of coal in inventory. For 2023, CEI South currently has in place coal deliveries priced under two contracts previously reviewed by the Commission. Because CEI South negotiated the ability to adjust the contract amount in any given year, CEI South can reduce the total 2023 specified contract volumes of [redacted] tons to a 2023 firm commitment of [redacted] tons or increase the 2023 firm commitment to [redacted] tons. The table below shows the individual contracts and the [redacted] associated with each.

2023 Contracts	Contracted Volume	[redacted]	[redacted]
[redacted] Contract #1	[redacted]	[redacted]	[redacted]
[redacted] Contract #2	[redacted]	[redacted]	[redacted]
Total Contracted	[redacted]		

The following table shows the individual contracts and the [redacted] that can be exercised in tons associated with each contract.

2023 Contracts	Contracted Volume	[redacted]	[redacted]
[redacted] Contract #1	[redacted]	[redacted]	[redacted]
[redacted] Contract #2	[redacted]	[redacted]	[redacted]
Total Contracted	[redacted]	[redacted]	[redacted]

The [redacted] must be decided by [redacted] of the year prior to the actual year the coal is taken or, in this case, by [redacted], for coal to be taken in 2023. [redacted]; therefore, CEI South decided to exercise the [redacted] to increase both contract volumes by [redacted].

[redacted] must be decided [redacted] before the beginning of each calendar quarter. CEI South chose to exercise the first [redacted] 2023 [redacted] to increase the [redacted] by [redacted] on both contracts. For the second 2023 [redacted], CEI South chose to decrease Contract #1 by [redacted] and increase Contract #2 by [redacted]. CEI South chose to exercise the third and fourth 2023 [redacted] to decrease the [redacted] by [redacted] on both contracts.

In addition, with the expired third [redacted] contract that occurred at the end of 2022 and the intent to remain in the Joint Operating Agreement with Alcoa on Warrick Unit 4 through 2023, CEI South negotiated the ability for [redacted] to provide the coal needed for Warrick Unit 4 in 2023 [redacted].

To manage the 2023 inventory levels, CEI South and [redacted] have agreed that [redacted] will deliver [redacted] tons in 2023 and [redacted] 2023 [redacted].

Q. Was all 2022 contracted coal delivered in 2022?

A. No. The 2022 spot purchase from [redacted] tons [redacted] of the contracted [redacted] tons. The 2022 [redacted] contracted tons [redacted] tons [redacted] of the contracted delivery volume.

Q. Given the 2022 spot purchase shortfall from [redacted], please show how the [redacted] was taken.

A. The following table shows the planned 2023 coal from [redacted] as well as the [redacted] from 2022 that will be taken in 2023, totaling [redacted] tons.

2023 Total Volume	[redacted]
[redacted] Contract #1	[redacted]
[redacted] Contract #2	[redacted]
[redacted] Contract #2 for Warrick Unit 4	[redacted]
[redacted] 2022 [redacted][2]	[redacted]
Total 2023 Projected Delivery Volume	[redacted]

Q. Please explain how the [redacted] 2022 [redacted] tons [redacted] will be addressed.

A. CEI South and [redacted] have agreed to forego [redacted] tons of the 2022 [redacted] tonnage. The remaining 2022 [redacted] is planned to be taken in 2024 (please see table below).

2022 [redacted]	
2022 [redacted]	[redacted]
2022 [redacted]	[redacted]
Total 2022 [redacted]	[redacted]

[2] Both CEI South and [redacted] agreed to forego the remaining [redacted] tons of the [redacted]-ton contract.

Q. What is the projected coal burn and the projected year-end inventory in 2023?

A. The following table shows the 2023 beginning inventory, planned deliveries, total inventory, projected coal burn, and projected year-end inventory. As mentioned in my testimony above, to manage the 2023 inventory levels, CEI South reduced coal deliveries to [redacted] tons.

Beginning Inventory	[redacted]
Planned Deliveries	[redacted]
Total Inventory	[redacted]
Projected Burn	[redacted]
Inventory Adjustment	[redacted]
Projected Year-end Inventory	[redacted]

Q. Is this an adequate inventory level at the end of 2023?

A. Yes. The 2023 projected yearend inventory of [redacted] tons is somewhat high with leaving only F.B. Culley Units 2 and 3 as the only coal burning units in 2024 in CEI South's fleet.

Q. Please provide an update to the 2024 coal plan.

A. The following table shows the 2024 projected starting inventory, planned contractual deliveries, projected coal burn, total available inventory, and projected ending inventory in 2024 – making the 2024 year-end inventory manageable.

2023 Projected Ending Inventory	[redacted]
[redacted]	[redacted]
2024 Contractual Deliveries[3]	[redacted]
2024 Total Available Inventory	[redacted]
2024 Projected Coal Burn	[redacted]
2024 Projected Year-end Inventory	[redacted]

Q. Does CEI South have opportunities to re-negotiate its contract prices over the next several years?

A. Yes, CEI South's remaining coal contract contains contractual re-opener language signified by "Price Re-opener" set forth below. The next price reopener for Contract #2

3 CEI South exercised the [redacted] Contract #2 volume [redacted], still leaving the [redacted].

is currently planned for 2024 to re-price years 2025-2027.

Contract	Tons	2022	2023	2024	2025	2026	2027
Contract #2	[redacted]	Year 1 Price Reopener	Year 2	Year 3	Year 1 Price Reopener	Year 2	Year 3

Q. Please expand on the 2023 coal plan for the Brown and Warrick facilities.

A. As mentioned earlier, CEI South plans to exit the JOA with Alcoa on Warrick Unit 4 at the end of 2023 and the Brown units retired in October of 2023. The goal will be to reduce coal inventory at Alcoa Warrick Unit 4 as close to zero as possible. Also, the remaining A.B. Brown coal inventory is approximately [redacted] tons and will, over time, be taken to F.B. Culley.

TROY SOLAR PROJECT

Q. Please provide an update on the 50MW Troy Solar project.

A. Production for the Reconciliation Period from the Troy Solar field was 33,078 MWh. Production estimates for this FAC period are included on Petitioner's Exh. 2, Attachment BKA-2, Schedule 1, Line 4, under "Solar Generation."

NATURAL GAS PROCUREMENT FOR OPERATIONS OF PEAKING UNITS

Q. Please describe the hedging products that CEI South procured during the Reconciliation period.

A. CEI South's reconciliation period gas hedging strategy included two products: baseload gas (used primarily for igniters at the coal generators) and daily delivered gas. Please see Confidential Attachment FSB-2 for detailed reconciliation period purchase information.

Baseload fixed purchases for the reconciliation period totaled [redacted] dth at a weighted average price of [redacted]/dth. Spot market purchases for the period totaled [redacted] dth at a weighted average price of [redacted]/dth. Total purchases were [redacted] dth at a weighted average price of [redacted]/dth. Total gas consumption by the combustion turbines for the reconciliation period was approximately [redacted] dth, with the difference between total usage and purchases covered with storage withdrawals. The dollar cost averaging of the baseload purchases with spot purchases was beneficial to CEI South during the reconciliation period.

Q. Please describe the hedging products that CEI South proposes to use during the Projection period.

A. CEI South conducted four separate Request for Proposals (RFP's) to procure a total fixed volume of [redacted] dth/day for the period of November 1, 2023, through March 31, 2024. Additionally, CEI South secured a [redacted] dth/day transportation contract with [redacted] for the period of November 2023 through March 2024. CEI South conducted an RFP in October 2023 for supply for a [redacted] dth/day call option for the period of November 1, 2023, through March 31, 2024. [redacted] and [redacted] were the winning bidders for the call option. Please see Confidential Attachment FSB-3 for detailed winter supply information.

CONFIDENTIALITY

Q. What portions of this testimony is CEI South requesting to be treated as confidential information?

A. CEI South's confidentiality request relates to the pricing for winter gas procurement, [redacted] with some coal supply contracts as well as other contractual terms, re-pricing of coal contracts and other concessions, tonnage figures calculated using such optionality, and other details related to costs ("Confidential Provisions"). Confidentiality also relates to rail transportation rates, fuel surcharges, competitive bids, and minimum requirements.

Q. Why has CEI South requested that such information be treated as confidential?

A. These Confidential Provisions of the testimony contain pricing for winter gas procurement and [redacted] and other confidential terms that were negotiated between CEI South and its natural gas and coal suppliers. If the pricing and optionality became generally known or readily ascertainable to the other parties with whom CEI South is negotiating or to other utilities with whom CEI South would compete, this knowledge would provide considerable economic value to such parties. In effect, knowledge of pricing and optionality provisions by other suppliers would establish a floor in future negotiations, thereby limiting the potential terms and benefits that could accrue to ratepayers, shareholders, and CEI South. Knowledge of the pricing and optionality provisions by potential coal suppliers could enable them to gain an unfair advantage in future competitive situations and negotiate a lower price and optionality provision than would otherwise be possible. The lower optionality provisions would diminish the flexibility available to CEI South's operations to the disadvantage of CEI South and its customers. Further, disclosure of the coal suppliers' optionality provisions would be of significant value to the coal suppliers' competitors, which could prove harmful to the coal suppliers. In addition, CEI South requests that coal transportation rates, competitive bids, and contract terms remain confidential to protect supplier's confidential information as well as the economic value competitive parties could gain from this information in an open energy market. CEI South is requesting that, pursuant to Indiana Code § 5-14-3-4(a)(4), the Commission find that the Confidential Provisions of the Contract contain "trade secrets" as that term is defined in Indiana Code § 24-2-3-2 and are thereby exempt from public access.

Q. Has CEI South taken any steps to maintain the confidentiality of this information?

A. Yes. In accordance with Indiana Code § 24-2-3-2, the information contained in the Confidential Provisions of the testimony has been the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Within CEI South, this information will be disclosed only to those people directly involved with negotiating coal supply contracts. Outside of CEI South, this information will be disclosed only to individuals who have signed a confidentiality agreement.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

VERIFICATION

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH

F. Shane Bradford

F. Shane Bradford
Vice President, Power Generation Operations

11-15-23
Date

CENTERPOINT ENERGY INDIANA SOUTH
Determination of MISO Components of Fuel Cost
June, July and August 2023

Line No.	Energy Market & ASM FAC Adjustment Components	Actual June 2023	Actual July 2023	Actual August 2023
1	Delta LMP	$ 186,747.82	$ 335,381.58	$ 320,230.07
2	DA Virtuals Bids and Offers for Load	-	-	-
3	DA RSG 1st Pass Distribution Amount	5,073.95	12,837.15	11,053.85
4	DA RSG Make Whole Payment	68.62	134.77	(1,024.57)
5	DA Regulation Amount	(7,780.93)	(13,612.93)	(7,504.53)
6	DA Spinning Reserve Amount	(49,791.37)	(25,489.27)	(28,571.59)
7	DA Supplemental Reserve Amount	(179.96)	(9.42)	(1,081.10)
8	DA Ramp Capability Amount	(2,863.37)	(1,334.42)	(2,840.23)
9	DA Short-Term Reserve Amount	(15,665.26)	(20,725.11)	(72,222.03)
10	RT Marg. Loss Surplus Credit	(71,649.37)	(70,532.91)	(127,086.92)
11	RT Virtuals Bids and Offers for Load	-	-	-
12	RT RSG 1st Pass Distribution Amount	1,445.36	17,528.35	27,879.78
13	RT RSG Make Whole Payment Amount	(11,846.99)	(59,171.55)	(40,209.66)
14	RT Price Volatility Make Whole Payment Amount	(12,792.66)	(6,986.19)	(5,908.17)
15	RT Net Inadvertent Energy	(4,818.52)	11,027.63	(10,604.21)
16	RT Revenue from Uninstructed Deviation	-	-	-
17	RT Uninstructed Deviation	-	-	-
18	RT Demand Response Allocation Uplift Charge	11.14	220.94	2,571.33
19	RT Regulation Amount	(3,027.69)	8,836.63	3,164.86
20	RT Spinning Reserve Amount	5,584.47	3,197.06	8,605.99
21	RT Supplemental Reserve Amount	(56.76)	(77.12)	(3,535.72)
22	RT Regulation Cost Distribution Amount	12,988.81	15,904.27	9,776.41
23	RT Spinning Reserve Cost Distribution Amount	12,124.93	15,738.13	12,793.41
24	RT Supplemental Reserve Cost Distribution Amount	3,387.38	1,846.81	5,036.90
25	RT Excessive Deficient Energy Deployment Charge Amount	7,702.08	8,323.27	7,579.63
26	RT Contingency Reserve Deployment Failure Charge Amount	3,005.70	-	-
27	RT Net Regulation Adjustment Amount	362.67	46.88	53.87
28	RT Ramp Capability Amount	(874.17)	(2,152.19)	(849.37)
29	RT Short-Tem Reserve Amount	111.41	(590.27)	(22,726.86)
30	Short-Term Reserve Cost Distribution Amount	14,351.64	19,743.09	106,814.49
31	Short-Term Reserve Deployment Failure Charge Amount			
32	FTR (Revenue) / Expenses	80,800.58	81,802.57	84,243.83
33	ARR (Revenue) / Expenses	(79,139.76)	(79,139.67)	(79,139.67)
34	Subtotal	73,279.75	252,748.07	196,499.77
35	Plus: Residual Load Adjustment Volume Changes			
36	Plus: MISO Charges (above) on sales billed to IMPA	-	-	-
37	Total (To BKA-2, Sch 5, line 23)	$ 73,279.75	$ 252,748.07	$ 196,499.77

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

CENTERPOINT ENERGY INDIANA SOUTH
Calculation of Daily Benchmark
Based on NYMEX Henry Hub Day Ahead Natural Gas Price

June 2023						July 2023						August 2023					
Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh	Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh	Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
06/01/23	2.100	0.60	2.70	12,500	33.75	07/01/23	2.515	0.60	3.12	12,500	38.94	08/01/23	2.570	0.60	3.17	12,500	39.63
06/02/23	1.770	0.60	2.37	12,500	29.63	07/02/23	2.515	0.60	3.12	12,500	38.94	08/02/23	2.490	0.60	3.09	12,500	38.63
06/03/23	1.720	0.60	2.32	12,500	29.00	07/03/23	2.515	0.60	3.12	12,500	38.94	08/03/23	2.430	0.60	3.03	12,500	37.88
06/04/23	1.720	0.60	2.32	12,500	29.00	07/04/23	2.515	0.60	3.12	12,500	38.94	08/04/23	2.470	0.60	3.07	12,500	38.38
06/05/23	1.720	0.60	2.32	12,500	29.00	07/05/23	2.515	0.60	3.12	12,500	38.94	08/05/23	2.525	0.60	3.13	12,500	39.06
06/06/23	1.955	0.60	2.56	12,500	31.94	07/06/23	2.640	0.60	3.24	12,500	40.50	08/06/23	2.525	0.60	3.13	12,500	39.06
06/07/23	1.970	0.60	2.57	12,500	32.13	07/07/23	2.515	0.60	3.12	12,500	38.94	08/07/23	2.525	0.60	3.13	12,500	39.06
06/08/23	2.110	0.60	2.71	12,500	33.88	07/08/23	2.485	0.60	3.09	12,500	38.56	08/08/23	2.650	0.60	3.25	12,500	40.63
06/09/23	2.075	0.60	2.68	12,500	33.44	07/09/23	2.485	0.60	3.09	12,500	38.56	08/09/23	2.770	0.60	3.37	12,500	42.13
06/10/23	1.860	0.60	2.46	12,500	30.75	07/10/23	2.485	0.60	3.09	12,500	38.56	08/10/23	2.910	0.60	3.51	12,500	43.88
06/11/23	1.860	0.60	2.46	12,500	30.75	07/11/23	2.570	0.60	3.17	12,500	39.63	08/11/23	2.810	0.60	3.41	12,500	42.63
06/12/23	1.860	0.60	2.46	12,500	30.75	07/12/23	2.590	0.60	3.19	12,500	39.88	08/12/23	2.625	0.60	3.23	12,500	40.31
06/13/23	1.950	0.60	2.55	12,500	31.88	07/13/23	2.550	0.60	3.15	12,500	39.38	08/13/23	2.625	0.60	3.23	12,500	40.31
06/14/23	2.025	0.60	2.63	12,500	32.81	07/14/23	2.500	0.60	3.10	12,500	38.75	08/14/23	2.625	0.60	3.23	12,500	40.31
06/15/23	2.080	0.60	2.68	12,500	33.50	07/15/23	2.490	0.60	3.09	12,500	38.63	08/15/23	2.735	0.60	3.34	12,500	41.69
06/16/23	2.170	0.60	2.77	12,500	34.63	07/16/23	2.490	0.60	3.09	12,500	38.63	08/16/23	2.655	0.60	3.26	12,500	40.69
06/17/23	2.135	0.60	2.74	12,500	34.19	07/17/23	2.490	0.60	3.09	12,500	38.63	08/17/23	2.545	0.60	3.15	12,500	39.31
06/18/23	2.135	0.60	2.74	12,500	34.19	07/18/23	2.430	0.60	3.03	12,500	37.88	08/18/23	2.555	0.60	3.16	12,500	39.44
06/19/23	2.135	0.60	2.74	12,500	34.19	07/19/23	2.520	0.60	3.12	12,500	39.00	08/19/23	2.450	0.60	3.05	12,500	38.13
06/20/23	2.135	0.60	2.74	12,500	34.19	07/20/23	2.510	0.60	3.11	12,500	38.88	08/20/23	2.450	0.60	3.05	12,500	38.13
06/21/23	2.390	0.60	2.99	12,500	37.38	07/21/23	2.615	0.60	3.22	12,500	40.19	08/21/23	2.450	0.60	3.05	12,500	38.13
06/22/23	2.230	0.60	2.83	12,500	35.38	07/22/23	2.605	0.60	3.21	12,500	40.06	08/22/23	2.575	0.60	3.18	12,500	39.69
06/23/23	2.295	0.60	2.90	12,500	36.19	07/23/23	2.605	0.60	3.21	12,500	40.06	08/23/23	2.605	0.60	3.21	12,500	40.06
06/24/23	2.235	0.60	2.84	12,500	35.44	07/24/23	2.605	0.60	3.21	12,500	40.06	08/24/23	2.590	0.60	3.19	12,500	39.88
06/25/23	2.235	0.60	2.84	12,500	35.44	07/25/23	2.670	0.60	3.27	12,500	40.88	08/25/23	2.425	0.60	3.03	12,500	37.81
06/26/23	2.235	0.60	2.84	12,500	35.44	07/26/23	2.650	0.60	3.25	12,500	40.63	08/26/23	2.465	0.60	3.07	12,500	38.31
06/27/23	2.615	0.60	3.22	12,500	40.19	07/27/23	2.605	0.60	3.21	12,500	40.06	08/27/23	2.465	0.60	3.07	12,500	38.31
06/28/23	2.690	0.60	3.29	12,500	41.13	07/28/23	2.480	0.60	3.08	12,500	38.50	08/28/23	2.465	0.60	3.07	12,500	38.31
06/29/23	2.700	0.60	3.30	12,500	41.25	07/29/23	2.515	0.60	3.12	12,500	38.94	08/29/23	2.585	0.60	3.19	12,500	39.81
06/30/23	2.500	0.60	3.10	12,500	38.75	07/30/23	2.515	0.60	3.12	12,500	38.94	08/30/23	2.500	0.60	3.10	12,500	38.75
						07/31/23	2.515	0.60	3.12	12,500	38.94	08/31/23	2.490	0.60	3.09	12,500	38.63

Total (To BKA-2, Sch 5, line 21)

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - June - Cause No. 38708 FAC 141

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
32.13	Jun 7	10	$ 171.02	5.280	$ 32.39	$ 169.62	$ 1.40	*Brown 1 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 0.27	$ -
32.13		14	$ 240.11	7.230	$ 33.21	$ 232.26	$ 7.85		160	-	$ -	335	130.90	YES	100	-	$ 1.09	$ -
33.88	Jun 8	16	$ 160.91	4.300	$ 37.42	$ 145.66	$ 15.25	*Brown 1 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 3.55	$ -
30.75	Jun 10	18	$ 2.66	0.070	$ 38.00	$ 2.15	$ 0.51	*Brown 2 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 7.25	$ -
30.75		19	$ 907.34	25.850	$ 35.10	$ 794.89	$ 112.45		160	-	$ -	335	130.90	YES	100	-	$ 4.35	$ -
30.75		20	$ 2,017.50	59.260	$ 34.04	$ 1,822.25	$ 195.26		160	-	$ -	335	130.90	YES	100	-	$ 3.29	$ -
30.75		21	$ 1,098.05	33.880	$ 32.41	$ 1,041.81	$ 56.24		160	-	$ -	335	130.90	YES	100	-	$ 1.66	$ -
30.75	Jun 11	17	$ 2,403.27	68.120	$ 35.28	$ 2,094.69	$ 308.58	*Brown 2 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 4.53	$ -
31.88	Jun 13	18	$ 241.29	7.080	$ 34.08	$ 225.68	$ 15.62		160	-	$ -	335	130.90	YES	100	-	$ 2.21	$ -
32.81	Jun 14	14	$ 3,286.13	96.000	$ 34.23	$ 3,150.05	$ 136.08	*Brown 2 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 1.42	$ -
32.81		15	$ 4,440.30	122.500	$ 36.25	$ 4,019.59	$ 420.71		160	-	$ -	335	130.90	YES	100	-	$ 3.43	$ -
32.81		16	$ 2,615.36	68.650	$ 38.10	$ 2,252.61	$ 362.75		160	-	$ -	335	130.90	YES	100	-	$ 5.28	$ -
32.81		17	$ 1,235.28	32.860	$ 37.59	$ 1,078.24	$ 157.04		160	-	$ -	335	130.90	YES	100	-	$ 4.78	$ -
32.81		18	$ 818.05	21.630	$ 37.82	$ 709.75	$ 108.30		160	-	$ -	335	130.90	YES	100	-	$ 5.01	$ -
33.50	Jun 15	13	$ 413.54	11.500	$ 35.96	$ 385.25	$ 28.29	*Brown 2 and Culley 2 were on outage*	160	-	$ -	335	130.90	YES	100	-	$ 2.46	$ -
33.50		14	$ 1,151.46	29.570	$ 38.94	$ 990.60	$ 160.87		160	-	$ -	335	130.90	YES	100	-	$ 5.44	$ -
33.50		15	$ 2,372.78	55.400	$ 42.83	$ 1,855.90	$ 516.88		160	-	$ -	335	130.90	YES	100	-	$ 9.33	$ -
33.50		16	$ 3,136.38	68.480	$ 45.80	$ 2,294.08	$ 842.30		160	-	$ -	335	130.90	YES	100	-	$ 12.30	$ -
33.50		17	$ 3,873.11	78.850	$ 49.12	$ 2,641.48	$ 1,231.64		160	-	$ -	335	130.90	YES	100	-	$ 15.62	$ -
33.50		18	$ 3,234.05	68.460	$ 47.24	$ 2,293.41	$ 940.64		160	-	$ -	335	130.90	YES	100	-	$ 13.74	$ -
33.50		19	$ 2,885.77	73.390	$ 39.32	$ 2,458.57	$ 427.21		160	-	$ -	335	130.90	YES	100	-	$ 5.82	$ -
33.50		20	$ 1,728.82	47.300	$ 36.55	$ 1,584.55	$ 144.27		160	-	$ -	335	130.90	YES	100	-	$ 3.05	$ -
33.50		21	$ 595.06	16.800	$ 35.42	$ 562.80	$ 32.26		160	-	$ -	335	130.90	YES	100	-	$ 1.92	$ -
34.63	Jun 16	16	$ 1,461.35	39.400	$ 37.09	$ 1,364.23	$ 97.12	*Brown 2 was on outage and Culley 2 was on Reserve Shutdown*	250	-	$ -	245	130.90	YES	100	-	$ 2.47	$ -
34.63		17	$ 1,422.65	37.000	$ 38.45	$ 1,281.13	$ 141.53		250	-	$ -	245	130.90	YES	100	-	$ 3.83	$ -
34.63		18	$ 1,118.19	30.510	$ 36.65	$ 1,056.41	$ 61.78		250	-	$ -	245	130.90	YES	100	-	$ 2.02	$ -
34.19	Jun 17	16	$ 1,193.28	33.900	$ 35.20	$ 1,158.97	$ 34.31	*Brown 2 was on outage and Culley 2 was on Reserve Shutdown*	250	-	$ -	245	130.90	YES	100	-	$ 1.01	$ -
34.19		17	$ 1,674.84	43.300	$ 38.68	$ 1,480.34	$ 194.50		250	-	$ -	245	130.90	YES	100	-	$ 4.49	$ -
34.19		18	$ 597.96	15.100	$ 39.60	$ 516.24	$ 81.72		250	-	$ -	245	130.90	YES	100	-	$ 5.41	$ -
34.19		19	$ 1,141.08	33.200	$ 34.37	$ 1,135.04	$ 6.04		250	-	$ -	245	130.90	YES	100	-	$ 0.18	$ -
34.19	Jun 18	19	$ 396.73	9.250	$ 42.89	$ 316.24	$ 80.49	*Brown 2 was on outage and Culley 2 was on Reserve Shutdown*	250	-	$ -	245	130.90	YES	100	-	$ 8.70	$ -
34.19		20	$ 654.79	11.360	$ 57.64	$ 388.38	$ 266.41		250	-	$ -	245	130.90	YES	100	-	$ 23.45	$ -
					$ -	$ -	$ -		-	-	$ -	-	130.90	N/A	N/A	-	$ -	$ -
37.38	Jun 21	10	$ 8,667.09	54.030	$ 160.41	$ 2,019.37	$ 6,647.72	*Culley 2 was on Reserve Shutdown and Warrick 4 was on outage*	250	-	$ -	150	130.90	YES	100	-	$ 123.04	$ -
37.38		23	$ 281.98	7.110	$ 39.66	$ 265.74	$ 16.24		250	-	$ -	150	130.90	YES	100	-	$ 2.28	$ -
35.44	Jun 24	8	$ 644.59	6.100	$ 105.67	$ 216.17	$ 428.42	*Culley 2 was on Reserve Shutdown and Warrick 4 was on outage*	250	-	$ -	150	130.90	YES	100	-	$ 70.23	$ -
35.44		16	$ 766.48	5.650	$ 135.66	$ 200.22	$ 566.26		170	-	$ -	150	130.90	YES	100	-	$ 100.22	$ -
35.44	Jun 25	17	$ 1,495.22	16.120	$ 92.76	$ 571.26	$ 923.96	*Culley 2 was on Reserve Shutdown and Warrick 4 was on outage*	250	-	$ -	-	130.90	N/A	N/A	-	$ 57.32	$ -
35.44	Jun 26	6	$ 5,965.67	70.700	$ 84.38	$ 2,505.47	$ 3,460.20	*Culley 2 was on Reserve Shutdown and Warrick 4 was on outage*	250	-	$ -	150	130.90	YES	100	-	$ 48.94	$ -
41.13	Jun 28	15	$ 899.26	18.300	$ 49.14	$ 752.59	$ 146.67	*Culley 2 was on Reserve Shutdown and Warrick 4 was on outage*	250	-	$ -	150	130.90	YES	100	-	$ 8.01	$ -
41.13		16	$ 1,892.29	34.200	$ 55.33	$ 1,406.48	$ 485.82		250	-	$ -	150	130.90	YES	100	-	$ 14.21	$ -
41.13		17	$ 570.85	8.750	$ 65.24	$ 359.84	$ 211.01		250	-	$ -	150	130.90	YES	100	-	$ 24.12	$ -
41.13		18	$ 683.55	11.140	$ 61.36	$ 458.13	$ 225.42		250	-	$ -	150	130.90	YES	100	-	$ 20.23	$ -
41.13		19	$ 368.87	7.080	$ 52.10	$ 291.17	$ 77.71		250	-	$ -	150	130.90	YES	100	-	$ 10.98	$ -
38.75	Jun 30	12	$ 480.40	11.900	$ 40.37	$ 461.13	$ 19.28	*Warrick 4 was on outage*	160	-	$ -	150	130.90	YES	100	-	$ 1.62	$ -
38.75		13	$ 1,078.83	26.870	$ 40.15	$ 1,041.21	$ 37.62		160	-	$ -	150	130.90	YES	100	-	$ 1.40	$ -
38.75		14	$ 998.58	20.150	$ 49.56	$ 780.81	$ 217.77		-	20.15	$ 217.77	150	130.90	YES	100	-	$ 10.81	$ -
38.75		19	$ 1,645.84	32.340	$ 50.89	$ 1,253.18	$ 392.67		-	32.34	$ 392.67	150	130.90	YES	100	-	$ 12.14	$ -
38.75		20	$ 641.65	11.900	$ 53.92	$ 461.13	$ 180.53		160	-	$ -	150	130.90	YES	100	-	$ 15.17	$ -
38.75		21	$ 1,904.17	48.900	$ 38.94	$ 1,894.88	$ 9.30		160	-	$ -	150	130.90	YES	100	-	$ 0.19	$ -
					$ -	$ -	$ -		-	-	$ -	-	130.90	N/A	N/A	-	$ -	$ -
Total			$ 77,674.43	1,646.720		$ 56,441.65	$ 21,232.84		9,240.000	52.490	$ 610.43	12,310				-		$ -

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - Jul - Cause No. 38708 FAC 141

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity 1190	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
40.50		15	$ 1,162.82	22.950	$ 50.67	$ 929.48	$ 233.35		250	-	$ -	150	130.90	YES	100	-	$ 10.17	$ -
40.50		16	$ 1,912.73	39.560	$ 48.35	$ 1,602.18	$ 310.55		250	-	$ -	150	130.90	YES	100	-	$ 7.85	$ -
40.50	Jul 6	17	$ 2,199.61	37.250	$ 59.05	$ 1,508.63	$ 690.99	*Warrick 4 was on outage*	250	-	$ -	150	130.90	YES	100	-	$ 18.55	$ -
40.50		18	$ 2,068.28	39.790	$ 51.98	$ 1,611.50	$ 456.79		250	-	$ -	150	130.90	YES	100	-	$ 11.48	$ -
40.50		19	$ 1,550.26	32.230	$ 48.10	$ 1,305.32	$ 244.95		250	-	$ -	150	130.90	YES	100	-	$ 7.60	$ -
38.56	Jul 8	15	$ 3,170.99	75.040	$ 42.26	$ 2,893.77	$ 277.22	*Culley 2 was on Reserve Shutdown, Brown 1 and Warrick 4 were on outage*	250	-	$ -	395	130.90	YES	100	-	$ 3.69	$ -
38.56		17	$ 1,650.63	40.220	$ 41.04	$ 1,551.00	$ 99.63		250	-	$ -	245	130.90	YES	100	-	$ 2.48	$ -
38.56	Jul 9	18	$ 2,234.08	51.170	$ 43.66	$ 1,973.27	$ 260.81	*Culley 2 was on Reserve Shutdown, Brown 1 was on outage*	250	-	$ -	245	130.90	YES	100	-	$ 5.10	$ -
38.56		19	$ 1,821.33	45.970	$ 39.62	$ 1,772.74	$ 48.59		250	-	$ -	245	130.90	YES	100	-	$ 1.06	$ -
39.38	Jul 13	15	$ 347.19	7.700	$ 45.09	$ 303.19	$ 44.00	*Culley 2 was on Reserve Shutdown*	250	-	$ -	-	130.90	N/A	N/A	-	$ 5.71	$ -
38.75	Jul 14	13	$ 1,131.53	14.260	$ 79.35	$ 552.58	$ 578.96	*Culley 2 was on Reserve Shutdown*	250	-	$ -	-	130.90	N/A	N/A	-	$ 40.60	$ -
38.75		14	$ 3,731.55	19.420	$ 192.15	$ 752.53	$ 2,979.03		90	-	$ -	-	130.90	N/A	N/A	-	$ 153.40	$ -
38.94	Jul 29	18	$ 260.35	4.400	$ 59.17	$ 171.33	$ 89.02	*Culley 2 was on Reserve Shutdown*	250	-	$ -	-	130.90	N/A	N/A	-	$ 20.23	$ -
38.94		16	$ 2,645.61	52.120	$ 50.76	$ 2,029.45	$ 616.16		250	-	$ -	245	130.90	YES	100	-	$ 11.82	$ -
38.94	Jul 30	17	$ 4,027.19	78.610	$ 51.23	$ 3,060.92	$ 966.27	*Culley 2 was on Reserve Shutdown, and Brown 1 was on outage*	250	-	$ -	245	130.90	YES	100	-	$ 12.29	$ -
38.94		18	$ 3,912.44	97.860	$ 39.98	$ 3,810.47	$ 101.97		250	-	$ -	245	130.90	YES	100	-	$ 1.04	$ -
38.94		19	$ 4,296.48	99.180	$ 43.32	$ 3,861.87	$ 434.61		250	-	$ -	245	130.90	YES	100	-	$ 4.38	$ -
38.94		14	$ 2,702.32	68.000	$ 39.74	$ 2,647.78	$ 54.54		250	-	$ -	245	130.90	YES	100	-	$ 0.80	$ -
38.94	Jul 31	15	$ 3,008.51	75.100	$ 40.06	$ 2,924.24	$ 84.27	*Culley 2 was on Reserve Shutdown, and Brown 1 was on outage*	250	-	$ -	245	130.90	YES	100	-	$ 1.12	$ -
38.94		16	$ 4,358.72	102.800	$ 42.40	$ 4,002.83	$ 355.89		250	-	$ -	245	130.90	YES	100	-	$ 3.46	$ -
Total			$ 48,192.62	1,003.630		$ 39,265.08	$ 8,927.57		4,840.000	-	$ -	3,595				-		$ -

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - August - Cause No. 38708 FAC 141

S55's through 8/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity 1190	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
39.63	Aug 1	16	$ 9,070.94	217.060	$ 41.79	$ 8,601.00	$ 469.94	*Culley 2 was of Reserve Shutdown, Culley 3 was offline due to a unit trip*	250	-	$ -	270	130.90	YES	100	-	$ 2.17	$ -
39.63		17	$ 10,417.19	220.190	$ 47.31	$ 8,725.03	$ 1,692.16		250	-	$ -	270	130.90	YES	100	-	$ 7.69	$ -
38.63	Aug 2	14	$ 11,518.48	234.640	$ 49.09	$ 9,062.97	$ 2,455.51	*Culley 2 was on Reserve Shutdown, Culley 3 was offline due to a unit trip, and Brown 2 was offline for repair*	170	64.64	$ 676.46	515	130.90	YES	100	-	$ 10.47	$ -
38.63		15	$ 10,403.74	250.150	$ 41.59	$ 9,662.04	$ 741.70		170	80.15	$ 237.65	515	130.90	YES	100	-	$ 2.97	$ -
38.63		16	$ 9,956.25	215.690	$ 46.16	$ 8,331.03	$ 1,625.22		90	125.69	$ 947.07	515	130.90	YES	100	-	$ 7.53	$ -
38.63		21	$ 13,369.15	301.840	$ 44.29	$ 11,658.57	$ 1,710.58		250	51.84	$ 293.79	515	130.90	YES	100	-	$ 5.67	$ -
37.88	Aug 3	11	$ 8,078.34	196.500	$ 41.11	$ 7,442.44	$ 635.90	*Culley 2 was on Reserve Shutdown, Culley 3 and Brown 2 were on outage*	170	26.50	$ 85.76	515	130.90	YES	100	-	$ 3.24	$ -
37.88		12	$ 7,273.83	165.400	$ 43.98	$ 6,264.53	$ 1,009.31		170	-	$ -	515	130.90	YES	100	-	$ 6.10	$ -
37.88		13	$ 8,695.10	179.800	$ 48.36	$ 6,809.93	$ 1,885.18		170	9.80	$ 102.75	515	130.90	YES	100	-	$ 10.48	$ -
37.88		14	$ 7,691.73	178.300	$ 43.14	$ 6,753.11	$ 938.62		90	88.30	$ 464.83	515	130.90	YES	100	-	$ 5.26	$ -
37.88		15	$ 9,134.06	204.200	$ 44.73	$ 7,734.08	$ 1,399.99		90	114.20	$ 782.95	515	130.90	YES	100	-	$ 6.86	$ -
37.88		16	$ 11,673.13	219.200	$ 53.25	$ 8,302.20	$ 3,370.93		90	129.20	$ 1,986.88	515	130.90	YES	100	-	$ 15.38	$ -
37.88		17	$ 17,651.97	223.700	$ 78.91	$ 8,472.64	$ 9,179.33		90	133.70	$ 5,486.26	515	130.90	YES	100	-	$ 41.03	$ -
37.88		18	$ 12,918.74	229.800	$ 56.22	$ 8,703.68	$ 4,215.07		90	139.80	$ 2,564.26	515	130.90	YES	100	-	$ 18.34	$ -
37.88		19	$ 13,617.38	281.400	$ 48.39	$ 10,658.03	$ 2,959.36		90	191.40	$ 2,012.87	515	130.90	YES	100	-	$ 10.52	$ -
37.88		20	$ 26,203.26	347.900	$ 75.32	$ 13,176.71	$ 13,026.55		250	97.90	$ 3,665.71	515	130.90	YES	100	-	$ 37.44	$ -
37.88		21	$ 4,999.09	125.700	$ 39.77	$ 4,760.89	$ 238.20		250	-	$ -	515	130.90	YES	100	-	$ 1.90	$ -
37.88		24	$ 7,261.32	188.900	$ 38.44	$ 7,154.59	$ 106.73		250	-	$ -	515	130.90	YES	100	-	$ 0.57	$ -
38.38	Aug 4	11	$ 9,880.61	255.700	$ 38.64	$ 9,812.49	$ 68.12	*Culley 2 was on Reserve Shutdown, Brown 2 was on outage*	250	5.70	$ 1.52	245	130.90	YES	100	-	$ 0.27	$ -
38.38		12	$ 7,957.49	204.300	$ 38.95	$ 7,840.01	$ 117.48		250	-	$ -	245	130.90	YES	100	-	$ 0.58	$ -
38.38		13	$ 10,271.53	225.500	$ 45.55	$ 8,653.56	$ 1,617.97		250	-	$ -	245	130.90	YES	100	-	$ 7.18	$ -
38.38		14	$ 11,979.36	253.800	$ 47.20	$ 9,739.58	$ 2,239.79		90	163.80	$ 1,445.54	245	130.90	YES	100	-	$ 8.83	$ -
38.38		15	$ 8,186.88	166.400	$ 49.20	$ 6,385.60	$ 1,801.28		90	76.40	$ 827.03	245	130.90	YES	100	-	$ 10.83	$ -
38.38		16	$ 5,921.98	108.800	$ 54.43	$ 4,175.20	$ 1,746.78		90	18.80	$ 301.83	245	130.90	YES	100	-	$ 16.05	$ -
38.38		17	$ 6,017.89	109.000	$ 55.21	$ 4,182.88	$ 1,835.02		90	19.00	$ 319.87	245	130.90	YES	100	-	$ 16.84	$ -
38.38		18	$ 5,060.59	101.700	$ 49.76	$ 3,902.74	$ 1,157.85		90	11.70	$ 133.20	245	130.90	YES	100	-	$ 11.38	$ -
38.38		19	$ 6,105.77	143.530	$ 42.54	$ 5,507.96	$ 597.81		90	53.53	$ 222.95	245	130.90	YES	100	-	$ 4.17	$ -
39.06	Aug 6	16	$ 7,412.33	172.500	$ 42.97	$ 6,738.37	$ 673.96	*Culley 2 was on Reserve Shutdown, Brown 1 was on outage*	250	-	$ -	395	130.90	YES	100	-	$ 3.91	$ -
39.06		17	$ 11,298.42	245.700	$ 45.98	$ 9,597.78	$ 1,700.64		250	-	$ -	245	130.90	YES	100	-	$ 6.92	$ -
39.06		18	$ 8,616.83	188.800	$ 45.64	$ 7,375.09	$ 1,241.74		250	-	$ -	245	130.90	YES	100	-	$ 6.58	$ -
39.06		19	$ 7,867.87	183.700	$ 42.83	$ 7,175.87	$ 692.00		250	-	$ -	245	130.90	YES	100	-	$ 3.77	$ -
39.06	Aug 7	17	$ 168.46	4.010	$ 42.01	$ 156.64	$ 11.82	*Culley 2 was on Reserve Shutdown*	170	-	$ -	245	130.90	YES	100	-	$ 2.95	$ -
39.06		18	$ 275.34	3.660	$ 75.23	$ 142.97	$ 132.37		250	-	$ -	245	130.90	YES	100	-	$ 36.17	$ -
39.06		20	$ 34.34	0.630	$ 54.51	$ 24.61	$ 9.73		250	-	$ -	245	130.90	YES	100	-	$ 15.44	$ -
40.31	Aug 14	10	$ 3,676.15	69.440	$ 52.94	$ 2,799.33	$ 876.82	*Culley 2 was on Reserve Shutdown*	250	-	$ -	-	130.90	N/A	N/A	-	$ 12.63	$ -
40.69	Aug 16	16	$ 1,384.63	30.900	$ 44.81	$ 1,257.26	$ 127.37	*Culley 2 was on Reserve Shutdown, Brown 1 was on outage*	170	-	$ -	325	130.90	YES	100	-	$ 4.12	$ -
40.69		17	$ 1,313.27	27.100	$ 48.46	$ 1,102.64	$ 210.63		170	-	$ -	325	130.90	YES	100	-	$ 7.77	$ -
40.69		18	$ 1,272.42	27.200	$ 46.78	$ 1,106.71	$ 165.71		170	-	$ -	325	130.90	YES	100	-	$ 6.09	$ -
40.69		19	$ 1,037.09	24.500	$ 42.33	$ 996.86	$ 40.23		170	-	$ -	325	130.90	YES	100	-	$ 1.64	$ -
39.31	Aug 17	19	$ 1,136.70	28.690	$ 39.62	$ 1,127.89	$ 8.81	*Culley 2 was on Reserve Shutdown, Brown 1 was on outage*	170	-	$ -	325	130.90	YES	100	-	$ 0.31	$ -
38.31	Aug 26	15	$ 18.20	0.320	$ 56.88	$ 12.26	$ 5.94	*Culley 2 and Warrick 4 were on outage*	160	-	$ -	240	130.90	YES	100	-	$ 18.56	$ -
38.31		17	$ 87.91	1.360	$ 64.64	$ 52.11	$ 35.80		160	-	$ -	240	130.90	YES	100	-	$ 26.33	$ -
38.31		18	$ 157.38	2.820	$ 55.81	$ 108.04	$ 49.34		160	-	$ -	240	130.90	YES	100	-	$ 17.50	$ -
38.31	Aug 28	15	$ 307.15	7.980	$ 38.49	$ 305.74	$ 1.41	*Brown 1 was on outage*	160	-	$ -	245	130.90	YES	100	-	$ 0.18	$ -
38.31		16	$ 562.02	7.600	$ 73.95	$ 291.18	$ 270.84		160	-	$ -	245	130.90	YES	100	-	$ 35.64	$ -
38.31		17	$ 1,546.16	11.600	$ 133.29	$ 444.43	$ 1,101.73		160	-	$ -	245	130.90	YES	100	-	$ 94.98	$ -
38.31		18	$ 412.03	4.800	$ 85.84	$ 183.90	$ 228.13		160	-	$ -	245	130.90	YES	100	-	$ 47.53	$ -
Total			$ 319,900.50	6,592.410		$ 253,473.17	$ 66,427.35		8,160.000	1,602.050	$ 22,559.17	16,175				-		$ -

CONFIDENTIAL Attachment FSB-2

Natural Gas Purchases for the Period of June, July, and August 2023

The foregoing Attachment is confidential and trade secret and will be provided under seal to the Commission.

CONFIDENTIAL Attachment FSB-2

Gas Supply with Projected Reservation Costs for the Period of
November 2023 through March 2024

The foregoing Attachment is confidential and trade secret and will be provided under seal to the Commission.