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

IURC CAUSE NO. 38708 FAC 139

DIRECT TESTIMONY

OF

F. SHANE BRADFORD

VICE PRESIDENT POWER GENERATION OPERATIONS

ON

PURCHASED POWER AND COAL INVENTORY

(PUBLIC)

SPONSORING ATTACHMENT FSB-1 AND 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 carried out 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; and in Cause No. 45847 in support of CEI South's request to amend and restate its BTA for the Posey County solar facility. Finally, I provided testimony in CEI South's Clean Energy Cost Adjustment ("CECA") proceeding under Cause No 44909, sub docket CECA 5 and in this Fuel Adjustment Clause ("FAC") proceeding under Cause No. 38708, sub docket FAC 137 S1.

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 December 2022 through February 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 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 139 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 August 2023 through October 2023. 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 December 2022 through February 2023 are as follows:

	Regulation	Spinning	Supplemental	Short-Term
September 2022	$0.0132	$0.0484	$(0.0099)	$(0.0319)
October 2022	$0.0453	$0.0317	$0.0115	$0.0261
November 2022	$0.0384	$0.0202	$0.0045	$0.0057

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: December 2022, $5,795,782.49; January 2023, $74,567.49; and February 2023, $24,608.51. 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 576 hours when the LMP was negative at BCWF, and 1 hour when the LMP was negative at FRII. This resulted in total charges of $35,955.14.

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 $(1,255,283.90).

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. A portfolio of contracts is in place that supports re-pricing opportunities for portions of CEI South's supply in each upcoming year, 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 April 30, 2023, coal inventory at CEI South's coal-fired generating plants stood at approximately 668,087 tons. This is an increase of 187,488 tons from the inventory level reported in FAC 138.

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

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 45–60 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 350,000–550,000 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].

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]
	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 [redacted] to decrease the [redacted] by [redacted] on both contracts and plans to decrease the remaining [redacted] [redacted] [redacted].

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]; however, at this time CEI South is projecting to utilize [redacted] tonnage for Warrick Unit 4 in 2023.

The following tables outline the [redacted] planned to be exercised from these two [redacted] contracts including tonnage needed for Warrick Unit 4 in 2023.

2023 Contracts	Contracted Volume	[redacted]	[redacted]
[redacted] Contract #1	[redacted]	[redacted]	[redacted]
Contract #2	[redacted]	[redacted]	[redacted]
Contract #2 for Warrick Unit 4	[redacted]	[redacted]	[redacted]
Total Contracted Volume	[redacted]		[redacted]

2023 Contracts	[redacted]	[redacted]	[redacted]
[redacted] Contract #1	[redacted]	[redacted]	[redacted]
[redacted] Contract #2	[redacted]	[redacted]	[redacted]
[redacted] Contract #2 for Warrick Unit 4	[redacted]	[redacted]	[redacted]
Total Contracted Volume	[redacted]		[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 [redacted] tons [redacted] of the contracted delivery volume.

Q. Given the 2022 spot purchase shortfall from [redacted] and the 2022 [redacted] from [redacted] discussed in previous FAC testimony, please show the total 2022 coal projected to be taken in 2023 or 2024.

A. The following table shows the planned 2023 coal from [redacted] after the [redacted] as well as the [redacted] from 2022 that will be taken in 2023, totaling [redacted] tons. The [redacted] 2022 [redacted] is planned to be taken in [redacted] is also shown. Currently the plan is to accept the 2022 [redacted].

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

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

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

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.

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

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

A. The 2023 projected yearend inventory of [redacted] tons is high especially with plans to retire Brown Units 1 & 2 and exit the Joint Operating Agreement ("JOA") with Alcoa for Warrick Unit 4 in 2023, leaving only Culley Units 2 and 3 as the only coal burning units in CEI Souths fleet; however, it is necessary to manage contractual obligations.

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

A. CEI South currently plans to manage the [redacted] on the remaining [redacted] contract downward and accept the [redacted]. The following table shows the projected starting inventory, planned contractual deliveries, projected coal burn, total available inventory, and projected ending inventory in 2024.

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

Q. How does CEI South plan to manage such a high coal inventory 2024 with only Culley Units 2 and 3 operating?

A. Although CEI South plans to exit the JOA with Alcoa on Warrick Unit 4 at the end of

2023, there is still a possibility that the Warrick 4 JOA [redacted]. If this were to occur, the inventory would be adequate to share between Culley and Warrick. [redacted] CEI South plans to lower the [redacted] of the remaining [redacted]-ton contract and accept the [redacted] If inventory levels turn out to be more than can be stored at Culley and possibly Warrick, there are a few options that can be explored. They include (a) expanding the coal pile area at Culley, (b) working with [redacted] to defer some of the 2024 coal into 2025, (c) [redacted] (d) place the coal in temporary storage, possibly at the Brown site or (e) work with [redacted] to reduce committed volumes giving them the opportunity to sell a portion of the coal committed to CEI South at a higher price. Note that CEI South has additional flexibility in 2025 when the [redacted]-ton [redacted] This provides a range of [redacted] tons to [redacted] tons. Carrying extra coal inventory at the end of 2024 [redacted] while reducing the 2025 coal take to the minimum [redacted] tons [redacted] should benefit customers.

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 is currently planned in 2024 to re-price years 2025-2027. Please note, due to the planned retirement of the Brown plant, Contract #1 will expire at the end of 2023 and not be renewed.

Contract	Tons	2022	2023	2024	2025	2026	2027
Contract #1	[redacted]	Year 2	Year 3	N/A	N/A	N/A	N/A
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 retire the Brown units in October of 2023. The goal will be to reduce coal inventory at Alcoa Warrick Unit 4 as close to zero as possible; however, due to the expected lower coal burn and [redacted], coal may possibly have to be stored on the AB Brown coal pile in 2024. CEI South has already increased the [redacted] on each of the two [redacted]-ton contracts, [redacted] the [redacted] on Contracts #1 and #2 respectively, and [redacted] on both contracts. CEI South currently maintains the ability to [redacted] by [redacted]. As a result, the flexibility of the two [redacted]-ton contracts range from [redacted] tons to [redacted] tons in 2023 to meet the needs of all CEI South coal units. In addition, CEI South has an agreement with [redacted] to supply any supplemental coal required for Warrick Unit 4 in 2023 [redacted].

TROY SOLAR PROJECT

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

A. Production from January–March 2023 from the Troy Solar field was 15,329 MWh. Production estimates for this FAC period are included on Petitioner's Exh. 2, Attachment RMW-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 for the 2022-2023 winter.

A. CEI South's winter gas hedging strategy included two products: baseload gas (used primarily for igniters at the coal generators) and a call option. CEI South purchased 2,000 dth/day of baseload gas for the period of November 1, 2022 through March 31, 2023, with each month contracted with separate Requests for Proposals (RFPs) prior to the beginning of each respective month. Additionally, CEI South secured a 15,000 dth/day transportation contract with [redacted] for the period of December 22, 2022 through March 31, 2023, CEI South conducted an RFP for supply for a 16,000 dth/day call option for the period of January 1, 2023 through March 31, 2023. [redacted] was the winning bidder for the call option. Please see Attachment FSB-2 for detailed winter purchase information.

Baseload fixed purchases for winter 2022-23 totaled 302,000 dth at a weighted average price of [redacted]/dth. Spot market purchases for the winter totaled 235,000 dth at a weighted average price of [redacted]/dth. Total purchases were 537,000 dth at a weighted average price of [redacted]/dth. Total gas consumption by the combustion turbines for winter was approximately 626,000 dth, with the difference between total usage and purchases made up with storage withdrawals. The dollar cost averaging of the baseload purchases with spot purchases was beneficial to CEI South during winter 2022-23.

Q. What impact did Winter Storm Elliott have on CEI South's generating units' consumption of natural gas?

A. As discussed in FAC 138, consumption of natural gas by the natural gas combustion turbines at A.B. Brown was near historical daily peak demand during the period of December 23 – December 25.

Q. Did CEI South's Gas Supply group experience any gas procurement issues due to Winter Storm Elliott?

A. Yes. As explained in FAC 138, when soliciting for additional supply in the market, suppliers were reluctant to transact since there were constraints on Texas Gas Supply, which led to CEI South Gas procurement issues.

Q. Did CEI South's Gas Transportation group issue penalties to CEI South due to under nomination?

A. Yes. As a result of the temperature forecast for December 23 – December 27, CEI South Gas Transportation group issued an Operational Flow Order ("OFO") for the entire period. CEI South Electric was issued penalties as a result of under nomination during the December 23–December 27 OFO period.

Q. Please explain why CEI South Gas would collect penalties from CEI South Electric?

A. CEI South Electric is a transportation customer on the CEI South Gas distribution system and therefore subject to the tariff rules and regulations just the same as all other gas transportation customers delivering gas to the CEI South gas distribution system.

Q. How are these penalties being treated by CEI South Gas?

A. CEI South Gas will treat the assessed penalties as a passthrough in the normal process of their GCA. No net income impact will be realized, but rather a credit, or reduction of gas costs for the CEI South Gas customers.

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, 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

5-15-2023

Date

CENTERPOINT ENERGY INDIANA SOUTH
Determination of MISO Components of Fuel Cost
December 2022 and January and February 2023

Line No.	Energy Market & ASM FAC Adjustment Components	Actual December 2022	Actual January 2023	Actual February 2023
1	Delta LMP	$ 5,335,664.20	$ (132,608.56)	$ 241,744.99
2	DA Virtuals Bids and Offers for Load	-	-	-
3	DA RSG 1st Pass Distribution Amount	11,894.21	10,081.25	8,052.62
4	DA RSG Make Whole Payment	-	-	-
5	DA Regulation Amount	(1,965.66)	(16,860.14)	(42,905.82)
6	DA Spinning Reserve Amount	(3,886.88)	(8,580.15)	(18,921.78)
7	DA Supplemental Reserve Amount	(17.10)	(53.91)	(16.75)
8	DA Ramp Capability Amount	(1,615.78)	(109.81)	(226.33)
9	DA Short-Term Reserve Amount	(1,475.63)	(2,683.06)	(1,719.41)
10	RT Marg. Loss Surplus Credit	(57,653.70)	(91,966.56)	(31,631.31)
11	RT Virtuals Bids and Offers for Load	-	-	-
12	RT RSG 1st Pass Distribution Amount	183,622.18	87,070.46	7,072.81
13	RT RSG Make Whole Payment Amount	(82,523.95)	(49,330.47)	(117.07)
14	RT Price Volatility Make Whole Payment Amount	(6,353.49)	(4,535.44)	(8,044.59)
15	RT Net Inadvertent Energy	63,894.27	(25,904.35)	(16,329.74)
16	RT Revenue from Uninstructed Deviation	-	-	-
17	RT Uninstructed Deviation	-	-	-
18	RT Demand Response Allocation Uplift Charge	(6.37)	2,378.64	760.45
19	RT Regulation Amount	4,196.39	5,926.83	20,742.94
20	RT Spinning Reserve Amount	(4,122.56)	(3,629.23)	490.14
21	RT Supplemental Reserve Amount	(1,256.85)	(266.90)	1.63
22	RT Regulation Cost Distribution Amount	5,134.99	17,131.22	12,645.27
23	RT Spinning Reserve Cost Distribution Amount	18,867.37	11,994.66	6,661.60
24	RT Supplemental Reserve Cost Distribution Amount	(3,862.88)	4,369.32	1,470.86
25	RT Excessive Deficient Energy Deployment Charge Amount	6,876.94	5,720.11	16,355.85
26	RT Contingency Reserve Deployment Failure Charge Amount	-	-	-
27	RT Net Regulation Adjustment Amount	1,619.98	(70.91)	108.84
28	RT Ramp Capability Amount	(344.72)	(696.13)	(1,292.13)
29	RT Short-Tem Reserve Amount	1,768.07	(743.99)	36.88
30	Short-Term Reserve Cost Distribution Amount	(12,409.41)	9,873.38	1,884.71
31	Short-Term Reserve Deployment Failure Charge Amount			
32	FTR (Revenue) / Expenses	-	(1,173.20)	-
33	ARR (Revenue) / Expenses	(146,706.95)	(146,708.52)	(146,709.54)
34	Subtotal	5,309,336.66	(331,375.46)	50,115.11
35	Plus: Residual Load Adjustment Volume Changes			
36	Plus: MISO Charges (above) on sales billed to IMPA	-	-	-
37	Total (To RMW-2, Sch 5, line 23)	$ 5,309,336.66	$ (331,375.46)	$ 50,115.11

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

Cause No. 38708 FAC 139

Petitioner's Exhibit No. 1
Attachment FSB-1
CEI South
Schedule 2

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

December 2022

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
12/01/22	6.800	0.60	7.40	12,500	92.50
12/02/22	6.215	0.60	6.82	12,500	85.19
12/03/22	4.815	0.60	5.42	12,500	67.69
12/04/22	4.815	0.60	5.42	12,500	67.69
12/05/22	4.815	0.60	5.42	12,500	67.69
12/06/22	4.210	0.60	4.81	12,500	60.13
12/07/22	4.460	0.60	5.06	12,500	63.25
12/08/22	4.525	0.60	5.13	12,500	64.06
12/09/22	4.765	0.60	5.37	12,500	67.06
12/10/22	4.995	0.60	5.60	12,500	69.94
12/11/22	4.995	0.60	5.60	12,500	69.94
12/12/22	4.995	0.60	5.60	12,500	69.94
12/13/22	6.715	0.60	7.32	12,500	91.44
12/14/22	7.160	0.60	7.76	12,500	97.00
12/15/22	6.600	0.60	7.20	12,500	90.00
12/16/22	6.740	0.60	7.34	12,500	91.75
12/17/22	6.585	0.60	7.19	12,500	89.81
12/18/22	6.585	0.60	7.19	12,500	89.81
12/19/22	6.585	0.60	7.19	12,500	89.81
12/20/22	5.980	0.60	6.58	12,500	82.25
12/21/22	5.250	0.60	5.85	12,500	73.13
12/22/22	6.140	0.60	6.74	12,500	84.25
12/23/22	7.295	0.60	7.90	12,500	98.69
12/24/22	6.555	0.60	7.16	12,500	89.44
12/25/22	6.555	0.60	7.16	12,500	89.44
12/26/22	6.555	0.60	7.16	12,500	89.44
12/27/22	6.555	0.60	7.16	12,500	89.44
12/28/22	4.895	0.60	5.50	12,500	68.69
12/29/22	4.115	0.60	4.72	12,500	58.94
12/30/22	3.695	0.60	4.30	12,500	53.69
12/31/22	3.695	0.60	4.30	12,500	53.69

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

January 2023

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu		Heat Rate Btu/kWh	Daily Benchmark $/MWh
01/01/23	3.550	0.60	4.15	4	12,500	51.88
01/02/23	3.550	0.60	4.15		12,500	51.88
01/03/23	3.550	0.60	4.15		12,500	51.88
01/04/23	3.650	0.60	4.25		12,500	53.13
01/05/23	3.810	0.60	4.41		12,500	55.13
01/06/23	3.755	0.60	4.36		12,500	54.44
01/07/23	3.415	0.60	4.02		12,500	50.19
01/08/23	3.415	0.60	4.02		12,500	50.19
01/09/23	3.415	0.60	4.02		12,500	50.19
01/10/23	3.665	0.60	4.27		12,500	53.31
01/11/23	3.310	0.60	3.91		12,500	48.88
01/12/23	3.350	0.60	3.95		12,500	49.38
01/13/23	3.550	0.60	4.15		12,500	51.88
01/14/23	3.435	0.60	4.04		12,500	50.44
01/15/23	3.435	0.60	4.04		12,500	50.44
01/16/23	3.435	0.60	4.04		12,500	50.44
01/17/23	3.435	0.60	4.04		12,500	50.44
01/18/23	3.415	0.60	4.02		12,500	50.19
01/19/23	3.105	0.60	3.71		12,500	46.31
01/20/23	2.930	0.60	3.53		12,500	44.13
01/21/23	3.130	0.60	3.73		12,500	46.63
01/22/23	3.130	0.60	3.73		12,500	46.63
01/23/23	3.130	0.60	3.73		12,500	46.63
01/24/23	3.385	0.60	3.99		12,500	49.81
01/25/23	3.335	0.60	3.94		12,500	49.19
01/26/23	3.080	0.60	3.68		12,500	46.00
01/27/23	2.705	0.60	3.31		12,500	41.31
01/28/23	2.745	0.60	3.35		12,500	41.81
01/29/23	2.745	0.60	3.35		12,500	41.81
01/30/23	2.745	0.60	3.35		12,500	41.81
01/31/23	2.805	0.60	3.41		12,500	42.56

February 2023

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu		Heat Rate Btu/kWh	Daily Benchmark $/MWh
02/01/23	2.675	0.60	3.28	3	12,500	40.94
02/02/23	2.660	0.60	3.26		12,500	40.75
02/03/23	2.645	0.60	3.25		12,500	40.56
02/04/23	2.395	0.60	3.00		12,500	37.44
02/05/23	2.395	0.60	3.00		12,500	37.44
02/06/23	2.395	0.60	3.00		12,500	37.44
02/07/23	2.185	0.60	2.79		12,500	34.81
02/08/23	2.350	0.60	2.95		12,500	36.88
02/09/23	2.415	0.60	3.02		12,500	37.69
02/10/23	2.400	0.60	3.00		12,500	37.50
02/11/23	2.370	0.60	2.97		12,500	37.13
02/12/23	2.370	0.60	2.97		12,500	37.13
02/13/23	2.370	0.60	2.97		12,500	37.13
02/14/23	2.400	0.60	3.00		12,500	37.50
02/15/23	2.425	0.60	3.03		12,500	37.81
02/16/23	2.440	0.60	3.04		12,500	38.00
02/17/23	2.485	0.60	3.09		12,500	38.56
02/18/23	2.260	0.60	2.86		12,500	35.75
02/19/23	2.260	0.60	2.86		12,500	35.75
02/20/23	2.260	0.60	2.86		12,500	35.75
02/21/23	2.260	0.60	2.86		12,500	35.75
02/22/23	2.095	0.60	2.70		12,500	33.69
02/23/23	2.075	0.60	2.68		12,500	33.44
02/24/23	2.185	0.60	2.79		12,500	34.81
02/25/23	2.345	0.60	2.95		12,500	36.81
02/26/23	2.345	0.60	2.95		12,500	36.81
02/27/23	2.345	0.60	2.95		12,500	36.81
02/28/23	2.560	0.60	3.16		12,500	39.50

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - December - Cause No. 38708 FAC 139

S55's through 12/31

												Test for Outages and Derates						
Dec 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	MWs Out of Service	11% of Winter Rated Capacity	Are Unit MWs Out of Service > 11% Winter Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
90.00	Dec 15	9	$ 2,855.53	30.810	$ 92.68	$ 2,772.90	$ 82.63	*Brown 1 and Culley 3 were on outage*	689	-	$ -	689	138.71	YES	100	-	$ 2.68	$ -
89.81	Dec 18	19	$ 4,124.30	43.400	$ 95.03	$ 3,897.88	$ 226.42	*Brown 1 and Culley 3 were on outage*	739	-	$ -	739	138.71	YES	100	-	$ 5.22	$ -
89.81		8	$ 10,870.61	116.700	$ 93.15	$ 10,481.18	$ 389.43		739	-	$ -	739	138.71	YES	100	-	$ 3.34	$ -
89.81		10	$ 2,236.01	17.000	$ 131.53	$ 1,526.82	$ 709.19		689	-	$ -	689	138.71	YES	100	-	$ 41.72	$ -
89.81	Dec 19	12	$ 2,346.52	22.000	$ 106.66	$ 1,975.89	$ 370.63	*Brown 1 and Culley 3 were on outage*	689	-	$ -	689	138.71	YES	100	-	$ 16.85	$ -
89.81		13	$ 7,490.15	80.100	$ 93.51	$ 7,194.02	$ 296.13		779	-	$ -	779	138.71	YES	100	-	$ 3.70	$ -
89.81		14	$ 7,453.15	57.500	$ 129.62	$ 5,164.25	$ 2,288.90		534	-	$ -	534	138.71	YES	100	-	$ 39.81	$ -
98.69		6	$ 39,575.09	291.200	$ 135.90	$ 28,737.95	$ 10,837.14		810	-	$ -	810	138.71	YES	100	-	$ 37.22	$ -
98.69		7	$ 67,235.54	309.300	$ 217.38	$ 30,524.20	$ 36,711.34		897	-	$ -	897	138.71	YES	100	-	$ 118.69	$ -
98.69		8	$ 97,650.16	319.400	$ 305.73	$ 31,520.95	$ 66,129.21		897	-	$ -	897	138.71	YES	100	-	$ 207.04	$ -
98.69		9	$ 370,719.05	344.400	$ 1,076.42	$ 33,988.15	$ 336,730.90		847	-	$ -	847	138.71	YES	100	-	$ 977.73	$ -
98.69		10	$ 146,206.81	318.700	$ 458.76	$ 31,451.87	$ 114,754.94		847	-	$ -	847	138.71	YES	100	-	$ 360.07	$ -
98.69		11	$ 194,150.90	325.200	$ 597.02	$ 32,093.34	$ 162,057.56		847	-	$ -	847	138.71	YES	100	-	$ 498.33	$ -
98.69		12	$ 187,133.70	315.300	$ 593.51	$ 31,116.33	$ 156,017.37		760	-	$ -	760	138.71	YES	100	-	$ 494.82	$ -
98.69		13	$ 160,652.00	240.500	$ 667.99	$ 23,734.46	$ 136,917.54		760	-	$ -	760	138.71	YES	100	-	$ 569.30	$ -
98.69		14	$ 93,730.08	233.200	$ 401.93	$ 23,014.04	$ 70,716.04		760	-	$ -	760	138.71	YES	100	-	$ 303.24	$ -
98.69	Dec 23	15	$ 62,952.61	245.500	$ 256.43	$ 24,227.90	$ 38,724.71	*Brown 1, Brown 2, and Culley 3 were on outage*	760	-	$ -	760	138.71	YES	100	-	$ 157.74	$ -
98.69		16	$ 127,524.67	237.600	$ 536.72	$ 23,448.27	$ 104,076.40		760	-	$ -	760	138.71	YES	100	-	$ 438.03	$ -
98.69		17	$ 551,365.94	235.700	$ 2,339.27	$ 23,260.76	$ 528,105.18		760	-	$ -	760	138.71	YES	100	-	$ 2,240.58	$ -
98.69		18	$ 727,095.25	297.600	$ 2,443.20	$ 29,369.55	$ 697,725.70		810	-	$ -	810	138.71	YES	100	-	$ 2,344.51	$ -
98.69		19	$ 633,793.57	317.600	$ 1,995.57	$ 31,343.31	$ 602,450.26		810	-	$ -	810	138.71	YES	100	-	$ 1,896.88	$ -
98.69		20	$ 318,856.55	304.300	$ 1,047.84	$ 30,030.76	$ 288,825.79		810	-	$ -	810	138.71	YES	100	-	$ 949.15	$ -
98.69		21	$ 281,897.98	263.900	$ 1,068.20	$ 26,043.76	$ 255,854.22		810	-	$ -	810	138.71	YES	100	-	$ 969.51	$ -
98.69		22	$ 258,925.72	245.800	$ 1,053.40	$ 24,257.51	$ 234,668.21		810	-	$ -	810	138.71	YES	100	-	$ 954.71	$ -
98.69		23	$ 220,786.55	229.260	$ 963.04	$ 22,625.21	$ 198,161.34		810	-	$ -	810	138.71	YES	100	-	$ 864.35	$ -
98.69		24	$ 146,495.38	218.350	$ 670.92	$ 21,548.52	$ 124,946.86		810	-	$ -	810	138.71	YES	100	-	$ 572.23	$ -
89.44		1	$ 123,617.81	236.250	$ 523.25	$ 21,129.73	$ 102,488.08		810	-	$ -	810	138.71	YES	100	-	$ 433.81	$ -
89.44		2	$ 138,828.33	176.550	$ 786.34	$ 15,790.28	$ 123,038.05		810	-	$ -	810	138.71	YES	100	-	$ 696.90	$ -
89.44		3	$ 109,991.66	164.250	$ 669.66	$ 14,690.19	$ 95,301.47		810	-	$ -	810	138.71	YES	100	-	$ 580.22	$ -
89.44		4	$ 101,333.39	157.850	$ 641.96	$ 14,117.79	$ 87,215.60		810	-	$ -	810	138.71	YES	100	-	$ 552.52	$ -
89.44		5	$ 127,652.08	151.550	$ 842.31	$ 13,554.33	$ 114,097.75		810	-	$ -	810	138.71	YES	100	-	$ 752.87	$ -
89.44		6	$ 107,055.52	150.600	$ 710.86	$ 13,469.36	$ 93,586.16		810	-	$ -	810	138.71	YES	100	-	$ 621.42	$ -
89.44		7	$ 126,258.84	176.630	$ 714.82	$ 15,797.43	$ 110,461.41		810	-	$ -	810	138.71	YES	100	-	$ 625.38	$ -
89.44		8	$ 149,846.89	182.700	$ 820.18	$ 16,340.32	$ 133,506.57		810	-	$ -	810	138.71	YES	100	-	$ 730.74	$ -
89.44		9	$ 213,649.28	180.910	$ 1,180.97	$ 16,180.23	$ 197,469.05		760	-	$ -	760	138.71	YES	100	-	$ 1,091.53	$ -
89.44		10	$ 113,987.50	157.450	$ 723.96	$ 14,082.01	$ 99,905.49		760	-	$ -	760	138.71	YES	100	-	$ 634.52	$ -
89.44		11	$ 107,500.71	137.970	$ 779.16	$ 12,339.76	$ 95,160.95		760	-	$ -	760	138.71	YES	100	-	$ 689.72	$ -
89.44	Dec 24	12	$ 77,089.52	106.200	$ 725.89	$ 9,498.32	$ 67,591.20	*Brown 1, Brown 2, and Culley 3 were on outage*	760	-	$ -	760	138.71	YES	100	-	$ 636.45	$ -
89.44		13	$ 48,298.00	77.330	$ 624.57	$ 6,916.24	$ 41,381.76		760	-	$ -	760	138.71	YES	100	-	$ 535.13	$ -
89.44		14	$ 14,590.44	79.690	$ 183.09	$ 7,127.31	$ 7,463.13		760	-	$ -	760	138.71	YES	100	-	$ 93.65	$ -
89.44		15	$ 6,351.01	46.630	$ 136.20	$ 4,170.49	$ 2,180.52		515	-	$ -	515	138.71	YES	100	-	$ 46.76	$ -
89.44		17	$ 7,754.17	25.880	$ 299.62	$ 2,314.66	$ 5,439.51		515	-	$ -	515	138.71	YES	100	-	$ 210.18	$ -
89.44		18	$ 9,780.68	33.210	$ 294.51	$ 2,970.24	$ 6,810.44		515	-	$ -	515	138.71	YES	100	-	$ 205.07	$ -
89.44		19	$ 3,702.27	29.630	$ 124.95	$ 2,650.05	$ 1,052.22		565	-	$ -	565	138.71	YES	100	-	$ 35.51	$ -
89.44		20	$ 5,013.75	38.110	$ 131.56	$ 3,408.48	$ 1,605.27		565	-	$ -	565	138.71	YES	100	-	$ 42.12	$ -
89.44		21	$ 9,698.32	42.360	$ 228.95	$ 3,788.59	$ 5,909.73		565	-	$ -	565	138.71	YES	100	-	$ 139.51	$ -
89.44		22	$ 6,340.26	50.200	$ 126.30	$ 4,489.79	$ 1,850.47		565	-	$ -	565	138.71	YES	100	-	$ 36.86	$ -
89.44		23	$ 6,792.62	17.360	$ 391.28	$ 1,552.64	$ 5,239.98		565	-	$ -	565	138.71	YES	100	-	$ 301.84	$ -
89.44		24	$ 3,258.76	32.390	$ 100.61	$ 2,896.90	$ 361.86		565	-	$ -	565	138.71	YES	100	-	$ 11.17	$ -
					$ -	$ -	$ -		-	-	$ -	-	138.71	N/A	N/A	-	$ -	$ -
89.44		1	$ 4,938.56	43.650	$ 113.14	$ 3,903.97	$ 1,034.59		565	-	$ -	565	138.71	YES	100	-	$ 23.70	$ -
89.44		2	$ 2,659.93	25.070	$ 106.10	$ 2,242.21	$ 417.72		565	-	$ -	565	138.71	YES	100	-	$ 16.66	$ -
89.44		4	$ 524.23	3.880	$ 135.11	$ 347.02	$ 177.21		565	-	$ -	565	138.71	YES	100	-	$ 45.67	$ -
89.44		6	$ 1,088.77	12.080	$ 90.13	$ 1,080.41	$ 8.36		565	-	$ -	565	138.71	YES	100	-	$ 0.69	$ -
89.44	Dec 25	7	$ 2,847.99	25.570	$ 111.38	$ 2,286.93	$ 561.06	*Brown 1 and Culley 3 were on outage*	565	-	$ -	565	138.71	YES	100	-	$ 21.94	$ -
89.44		8	$ 3,939.34	17.240	$ 228.50	$ 1,541.91	$ 2,397.43		565	-	$ -	565	138.71	YES	100	-	$ 139.06	$ -
89.44		9	$ 1,497.98	7.520	$ 199.20	$ 672.57	$ 825.41		515	-	$ -	515	138.71	YES	100	-	$ 109.76	$ -
89.44		10	$ 1,155.69	11.550	$ 100.06	$ 1,033.01	$ 122.68		515	-	$ -	515	138.71	YES	100	-	$ 10.62	$ -
89.44		18	$ 4,494.43	48.620	$ 92.44	$ 4,348.48	$ 145.95		515	-	$ -	515	138.71	YES	100	-	$ 3.00	$ -
89.44		23	$ 5,325.36	48.430	$ 109.96	$ 4,331.48	$ 993.88		565	-	$ -	565	138.71	YES	100	-	$ 20.52	$ -
89.44		1	$ 836.62	5.180	$ 161.51	$ 463.29	$ 373.33		565	-	$ -	565	138.71	YES	100	-	$ 72.07	$ -
89.44		2	$ 2,788.52	24.100	$ 115.71	$ 2,155.46	$ 633.06		565	-	$ -	565	138.71	YES	100	-	$ 26.27	$ -
89.44		5	$ 1,947.54	18.980	$ 102.61	$ 1,697.53	$ 250.01		565	-	$ -	565	138.71	YES	100	-	$ 13.17	$ -
89.44		6	$ 2,963.59	28.430	$ 104.24	$ 2,542.72	$ 420.87		565	-	$ -	565	138.71	YES	100	-	$ 14.80	$ -
89.44		7	$ 4,387.36	36.850	$ 119.06	$ 3,295.79	$ 1,091.57		565	-	$ -	565	138.71	YES	100	-	$ 29.62	$ -
89.44		8	$ 7,197.71	56.140	$ 128.21	$ 5,021.05	$ 2,176.66		565	-	$ -	565	138.71	YES	100	-	$ 38.77	$ -
89.44		9	$ 6,224.07	59.100	$ 105.31	$ 5,285.79	$ 938.28		565	-	$ -	565	138.71	YES	100	-	$ 15.88	$ -

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - December - Cause No. 38708 FAC 139

S55's through 12/31

												Test for Outages and Derates						
Dec 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	MWs Out of Service	11% of Winter Rated Capacity	Are Unit MWs Out of Service > 11% Winter Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
89.44		10	$ 6,891.50	62.480	$ 110.30	$ 5,588.09	$ 1,303.41		515	-	$ -	515	138.71	YES	100	-	$ 20.86	$ -
89.44		11	$ 7,331.80	70.100	$ 104.59	$ 6,269.60	$ 1,062.20		515	-	$ -	515	138.71	YES	100	-	$ 15.15	$ -
89.44		12	$ 8,189.23	66.890	$ 122.43	$ 5,982.51	$ 2,206.72		515	-	$ -	515	138.71	YES	100	-	$ 32.99	$ -
89.44		13	$ 5,479.32	59.300	$ 92.40	$ 5,303.67	$ 175.65		515	-	$ -	515	138.71	YES	100	-	$ 2.96	$ -
89.44	Dec 26	14	$ 4,808.40	19.300	$ 249.14	$ 1,726.15	$ 3,082.25	*Brown 1 and Culley 3 were on outage*	515	-	$ -	515	138.71	YES	100	-	$ 159.70	$ -
89.44		15	$ 4,397.66	31.000	$ 141.86	$ 2,772.58	$ 1,625.08		515	-	$ -	515	138.71	YES	100	-	$ 52.42	$ -
89.44		16	$ 5,758.72	42.300	$ 136.14	$ 3,783.23	$ 1,975.49		515	-	$ -	515	138.71	YES	100	-	$ 46.70	$ -
89.44		17	$ 7,721.47	55.900	$ 138.13	$ 4,999.58	$ 2,721.89		565	-	$ -	565	138.71	YES	100	-	$ 48.69	$ -
89.44		18	$ 7,672.41	49.500	$ 155.00	$ 4,427.18	$ 3,245.23		565	-	$ -	565	138.71	YES	100	-	$ 65.56	$ -
89.44		19	$ 8,646.23	49.300	$ 175.38	$ 4,409.29	$ 4,236.94		565	-	$ -	565	138.71	YES	100	-	$ 85.94	$ -
89.44		20	$ 14,472.05	88.300	$ 163.90	$ 7,897.38	$ 6,574.67		565	-	$ -	565	138.71	YES	100	-	$ 74.46	$ -
89.44		21	$ 8,549.63	61.500	$ 139.02	$ 5,500.44	$ 3,049.19		565	-	$ -	565	138.71	YES	100	-	$ 49.58	$ -
89.44		22	$ 8,267.87	60.200	$ 137.34	$ 5,384.17	$ 2,883.70		565	-	$ -	565	138.71	YES	100	-	$ 47.90	$ -
89.44		23	$ 4,071.00	41.500	$ 98.10	$ 3,711.68	$ 359.32		565	-	$ -	565	138.71	YES	100	-	$ 8.66	$ -
89.44		24	$ 606.96	4.000	$ 151.74	$ 357.75	$ 249.21		565	-	$ -	565	138.71	YES	100	-	$ 62.30	$ -
89.44		1	$ 21,704.47	171.090	$ 126.86	$ 15,301.95	$ 6,402.52		652	-	$ -	652	138.71	YES	100	-	$ 37.42	$ -
89.44		2	$ 46,092.51	288.140	$ 159.97	$ 25,770.67	$ 20,321.84		889	-	$ -	889	138.71	YES	100	-	$ 70.53	$ -
89.44		3	$ 35,099.03	280.470	$ 125.14	$ 25,084.68	$ 10,014.35		889	-	$ -	889	138.71	YES	100	-	$ 35.71	$ -
89.44		4	$ 31,241.98	285.660	$ 109.37	$ 25,548.86	$ 5,693.12		889	-	$ -	889	138.71	YES	100	-	$ 19.93	$ -
89.44		5	$ 20,226.38	177.300	$ 114.08	$ 15,857.36	$ 4,369.02		889	-	$ -	889	138.71	YES	100	-	$ 24.64	$ -
89.44		6	$ 23,923.90	200.200	$ 119.50	$ 17,905.49	$ 6,018.41		889	-	$ -	889	138.71	YES	100	-	$ 30.06	$ -
89.44		7	$ 26,576.44	231.200	$ 114.95	$ 20,678.07	$ 5,898.37		889	-	$ -	889	138.71	YES	100	-	$ 25.51	$ -
89.44		8	$ 49,131.17	344.650	$ 142.55	$ 30,824.81	$ 18,306.36		889	-	$ -	889	138.71	YES	100	-	$ 53.12	$ -
89.44		9	$ 40,969.22	290.500	$ 141.03	$ 25,981.74	$ 14,987.48		889	-	$ -	889	138.71	YES	100	-	$ 51.59	$ -
89.44	Dec 27	10	$ 34,940.03	277.500	$ 125.91	$ 24,819.05	$ 10,120.99	*Brown 1, Culley 3, and Warrick 4 were on outage*	839	-	$ -	839	138.71	YES	100	-	$ 36.47	$ -
89.44		11	$ 28,860.28	261.700	$ 110.28	$ 23,405.92	$ 5,454.36		839	-	$ -	839	138.71	YES	100	-	$ 20.84	$ -
89.44		12	$ 26,334.13	245.700	$ 107.18	$ 21,974.92	$ 4,359.21		839	-	$ -	839	138.71	YES	100	-	$ 17.74	$ -
89.44		13	$ 22,902.62	224.800	$ 101.88	$ 20,105.66	$ 2,796.96		839	-	$ -	839	138.71	YES	100	-	$ 12.44	$ -
89.44		14	$ 20,151.02	218.700	$ 92.14	$ 19,560.09	$ 590.93		839	-	$ -	839	138.71	YES	100	-	$ 2.70	$ -
89.44		17	$ 22,204.60	194.300	$ 114.28	$ 17,377.80	$ 4,826.80		1,084	-	$ -	1,084	138.71	YES	100	-	$ 24.84	$ -
89.44		18	$ 57,437.60	396.440	$ 144.88	$ 35,456.80	$ 21,980.80		1,047	-	$ -	1,047	138.71	YES	100	-	$ 55.45	$ -
89.44		19	$ 40,869.09	377.130	$ 108.37	$ 33,729.75	$ 7,139.34		1,047	-	$ -	1,047	138.71	YES	100	-	$ 18.93	$ -
89.44		20	$ 28,113.44	241.400	$ 116.46	$ 21,590.33	$ 6,523.11		1,047	-	$ -	1,047	138.71	YES	100	-	$ 27.02	$ -
89.44		21	$ 22,233.10	223.000	$ 99.70	$ 19,944.67	$ 2,288.43		1,047	-	$ -	1,047	138.71	YES	100	-	$ 10.26	$ -
68.69		1	$ 21,646.28	293.310	$ 73.80	$ 20,146.88	$ 1,499.40		889	-	$ -	889	138.71	YES	100	-	$ 5.11	$ -
68.69		7	$ 23,687.77	300.950	$ 78.71	$ 20,671.65	$ 3,016.12		889	-	$ -	889	138.71	YES	100	-	$ 10.02	$ -
68.69		8	$ 29,667.76	323.990	$ 91.57	$ 22,254.23	$ 7,413.53		889	-	$ -	889	138.71	YES	100	-	$ 22.88	$ -
68.69	Dec 28	9	$ 26,605.04	322.720	$ 82.44	$ 22,166.99	$ 4,438.05	*Brown 1, Culley 3, and Warrick 4 were on outage*	839	-	$ -	839	138.71	YES	100	-	$ 13.75	$ -
68.69		10	$ 21,976.57	296.300	$ 74.17	$ 20,352.25	$ 1,624.32		839	-	$ -	839	138.71	YES	100	-	$ 5.48	$ -
68.69		18	$ 17,768.00	257.470	$ 69.01	$ 17,685.10	$ 82.90		889	-	$ -	889	138.71	YES	100	-	$ 0.32	$ -
68.69		19	$ 20,177.26	282.160	$ 71.51	$ 19,381.01	$ 796.25		889	-	$ -	889	138.71	YES	100	-	$ 2.82	$ -
53.69		8	$ 12,528.32	223.840	$ 55.97	$ 12,017.52	$ 510.80		889	-	$ -	889	138.71	YES	100	-	$ 2.28	$ -
53.69	Dec 30	9	$ 14,942.20	260.000	$ 57.47	$ 13,958.88	$ 983.32	*Brown 1, Culley 3, and Warrick 4 were on outage*	889	-	$ -	889	138.71	YES	100	-	$ 3.78	$ -
53.69		11	$ 17,390.56	285.700	$ 60.87	$ 15,338.66	$ 2,051.90		839	-	$ -	839	138.71	YES	100	-	$ 7.18	$ -
53.69		12	$ 15,482.95	287.200	$ 53.91	$ 15,419.19	$ 63.76		839	-	$ -	839	138.71	YES	100	-	$ 0.22	$ -
Total			**$ 7,321,081.29**	**17,409.500**		**$ 1,525,298.82**	**$ 5,795,782.49**		**80,598.000**	**-**	**$ -**	**80,598.000**				**-**		**$ -**

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - January - Cause No. 38708 FAC 139

S55's through 1/31

												Test for Outages and Derates						
Jan 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	MWs Out of Service	11% of Winter Rated Capacity	Are Unit MWs Out of Service > 11% Winter Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
51.88	Jan 2	7	$ 5,448.76	92.110	$ 59.15	$ 4,778.21	$ 670.55	*Brown 2, Culley 3, and Warrick 4 were on outage*	889	-	$ -	889	138.71	YES	100	-	$ 7.28	$ -
51.88		11	$ 7,626.27	140.250	$ 54.38	$ 7,275.47	$ 350.80		839	-	$ -	839	138.71	YES	100	-	$ 2.50	$ -
51.88	Jan 3	18	$ 2,770.01	43.950	$ 63.03	$ 2,279.91	$ 490.10	*Culley 2, Culley 3, and Warrick 4 were on outage*	734	-	$ -	734	138.71	YES	100	-	$ 11.15	$ -
53.13	Jan 4	8	$ 8,559.33	156.440	$ 54.71	$ 8,310.88	$ 248.46	*Culley 2, Culley 3, and Warrick 4 were on outage*	734	-	$ -	734	138.71	YES	100	-	$ 1.59	$ -
53.13		18	$ 10,105.97	126.480	$ 79.90	$ 6,719.25	$ 3,386.72		734	-	$ -	734	138.71	YES	100	-	$ 26.78	$ -
55.13	Jan 5	18	$ 170.50	2.880	$ 59.20	$ 158.76	$ 11.74	*Culley 2, Culley 3, and Warrick 4 were on outage*	734	-	$ -	734	138.71	YES	100	-	$ 4.08	$ -
55.13		21	$ 2,420.77	40.850	$ 59.26	$ 2,251.86	$ 168.91		734	-	$ -	734	138.71	YES	100	-	$ 4.13	$ -
54.44	Jan 6	8	$ 8,408.32	136.850	$ 61.44	$ 7,449.84	$ 958.48	*Culley 2, Culley 3, and Warrick 4 were on outage*	647	-	$ -	647	138.71	YES	100	-	$ 7.00	$ -
54.44		9	$ 5,251.49	87.950	$ 59.71	$ 4,787.82	$ 463.67		597	-	$ -	597	138.71	YES	100	-	$ 5.27	$ -
54.44		10	$ 3,811.06	67.620	$ 56.36	$ 3,681.10	$ 129.96		597	-	$ -	597	138.71	YES	100	-	$ 1.92	$ -
54.44		21	$ 18,602.55	105.780	$ 175.86	$ 5,758.45	$ 12,844.10		647	-	$ -	647	138.71	YES	100	-	$ 121.42	$ -
50.19	Jan 7	2	$ 16,705.30	134.690	$ 124.03	$ 6,759.82	$ 9,945.48	*Culley 2, Culley 3, and Warrick 4 were on outage*	734	-	$ -	734	138.71	YES	100	-	$ 73.84	$ -
50.19	Jan 8	18	$ 10,579.64	83.620	$ 126.52	$ 4,196.72	$ 6,382.92	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 76.33	$ -
50.19		20	$ 5,226.16	96.940	$ 53.91	$ 4,865.22	$ 360.94		584	-	$ -	584	138.71	YES	100	-	$ 3.72	$ -
50.19	Jan 9	7	$ 7,884.66	154.500	$ 51.03	$ 7,754.05	$ 130.61	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 0.85	$ -
50.19		9	$ 16,647.43	164.390	$ 101.27	$ 8,250.41	$ 8,397.02		534	-	$ -	534	138.71	YES	100	-	$ 51.08	$ -
53.31	Jan 10	8	$ 24,088.62	139.300	$ 172.93	$ 7,426.50	$ 16,662.12	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 119.61	$ -
53.31		11	$ 4,956.82	84.790	$ 58.46	$ 4,520.41	$ 436.41		534	-	$ -	534	138.71	YES	100	-	$ 5.15	$ -
53.31		17	$ 4,485.24	58.900	$ 76.15	$ 3,140.14	$ 1,345.10		534	-	$ -	534	138.71	YES	100	-	$ 22.84	$ -
53.31		19	$ 12,561.41	87.750	$ 143.15	$ 4,678.22	$ 7,883.19		584	-	$ -	584	138.71	YES	100	-	$ 89.84	$ -
53.31		20	$ 6,568.70	71.190	$ 92.27	$ 3,795.35	$ 2,773.35		584	-	$ -	584	138.71	YES	100	-	$ 38.96	$ -
48.88	Jan 11	8	$ 1,610.10	32.080	$ 50.19	$ 1,567.91	$ 42.19	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 1.32	$ -
48.88		9	$ 2,573.09	52.480	$ 49.03	$ 2,564.96	$ 8.13		584	-	$ -	584	138.71	YES	100	-	$ 0.15	$ -
51.88	Jan 13	21	$ 28.01	0.360	$ 77.81	$ 18.68	$ 9.33	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 25.93	$ -
51.88		22	$ 3,131.44	54.540	$ 57.42	$ 2,829.26	$ 302.18		584	-	$ -	584	138.71	YES	100	-	$ 5.54	$ -
50.44	Jan 14	1	$ 2,010.82	39.050	$ 51.49	$ 1,969.60	$ 41.22	*Culley 2 and Culley 3 were on outage*	584	-	$ -	584	138.71	YES	100	-	$ 1.06	$ -
50.44		6	$ 87.41	1.450	$ 60.28	$ 73.14	$ 14.27		584	-	$ -	584	138.71	YES	100	-	$ 9.84	$ -
50.44		8	$ 867.10	15.020	$ 57.73	$ 757.58	$ 109.52		584	-	$ -	584	138.71	YES	100	-	$ 7.29	$ -
Total			**$ 193,186.98**	**2,272.210**		**$ 118,619.52**	**$ 74,567.49**		**17,814.000**	**-**	**$ -**	**17,814.000**				**-**		**$ -**

CenterPoint Energy Indiana - South
Market Settlements Group
Purchased Power Over Benchmark Explanations - February - Cause No. 38708 FAC 139

S55's through 2/28

												Test for Outages and Derates						
Feb 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	MWs Out of Service	11% of Winter Rated Capacity	Are Unit MWs Out of Service > 11% Winter Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85%-15%	Over Benchmark Price	Total Unrecoverable Dollars
40.94	Feb 1	9	$ 327.80	7.340	$ 44.66	$ 300.48	$ 27.32	*Culley 3 was on outage*	444	-	$ -	444	138.71	YES	100	-	$ 3.72	$ -
34.81	Feb 7	24	$ 149.20	3.030	$ 49.24	$ 105.48	$ 43.72	*Culley 3 was on outage*	494	-	$ -	494	138.71	YES	100	-	$ 14.43	$ -
38.56	Feb 17	11	$ 3,605.83	12.200	$ 295.56	$ 470.47	$ 3,135.36	*Culley 2 was on Reserve Shutdown, and Culley 3 was on outage*	534	-	$ -	534	138.71	YES	100	-	$ 257.00	$ -
38.56		21	$ 34.89	0.880	$ 39.65	$ 33.94	$ 0.95		584	-	$ -	584	138.71	YES	100	-	$ 1.08	$ -
35.75	Feb 20	9	$ 3,835.41	106.480	$ 36.02	$ 3,806.66	$ 28.75	*Culley 2, Culley 3, and Brown 2 were out outage*	779	-	$ -	779	138.71	YES	100	-	$ 0.27	$ -
35.75	Feb 21	7	$ 3,345.91	49.010	$ 68.27	$ 1,752.11	$ 1,593.80	*Culley 2, Culley 3, and Brown 2 were out outage*	829	-	$ -	829	138.71	YES	100	-	$ 32.52	$ -
35.75		8	$ 3,366.56	85.100	$ 39.56	$ 3,042.33	$ 324.24		829	-	$ -	829	138.71	YES	100	-	$ 3.81	$ -
33.69	Feb 22	8	$ 3,732.75	110.600	$ 33.75	$ 3,725.89	$ 6.86	*Culley 2, Culley 3, and Brown 2 were out outage*	829	-	$ -	829	138.71	YES	100	-	$ 0.06	$ -
33.44	Feb 23	8	$ 3,425.84	73.500	$ 46.61	$ 2,457.69	$ 968.15	*Culley 2, Culley 3, and Brown 2 were out outage*	829	-	$ -	829	138.71	YES	100	-	$ 13.17	$ -
34.81	Feb 24	7	$ 6,397.30	112.030	$ 57.10	$ 3,900.10	$ 2,497.20	*Culley 2, Culley 3, and Brown 2 were out outage*	829	-	$ -	829	138.71	YES	100	-	$ 22.29	$ -
34.81		8	$ 8,685.98	135.080	$ 64.30	$ 4,702.54	$ 3,983.44		779	-	$ -	779	138.71	YES	100	-	$ 29.49	$ -
34.81		9	$ 7,926.13	148.540	$ 53.36	$ 5,171.12	$ 2,755.01		779	-	$ -	779	138.71	YES	100	-	$ 18.55	$ -
34.81		10	$ 6,838.88	173.120	$ 39.50	$ 6,026.83	$ 812.05		779	-	$ -	779	138.71	YES	100	-	$ 4.69	$ -
34.81		11	$ 4,693.65	113.260	$ 41.44	$ 3,942.92	$ 750.73		779	-	$ -	779	138.71	YES	100	-	$ 6.63	$ -
34.81		12	$ 4,237.87	97.400	$ 43.51	$ 3,390.79	$ 847.08		779	-	$ -	779	138.71	YES	100	-	$ 8.70	$ -
34.81		13	$ 4,747.13	120.700	$ 39.33	$ 4,201.93	$ 545.20		779	-	$ -	779	138.71	YES	100	-	$ 4.52	$ -
34.81		14	$ 4,646.84	129.800	$ 35.80	$ 4,518.73	$ 128.11		779	-	$ -	779	138.71	YES	100	-	$ 0.99	$ -
34.81		15	$ 4,314.16	121.800	$ 35.42	$ 4,240.22	$ 73.94		779	-	$ -	779	138.71	YES	100	-	$ 0.61	$ -
34.81		17	$ 3,450.05	90.600	$ 38.08	$ 3,154.06	$ 295.99		779	-	$ -	779	138.71	YES	100	-	$ 3.27	$ -
34.81		18	$ 4,518.44	115.760	$ 39.03	$ 4,029.95	$ 488.49		779	-	$ -	779	138.71	YES	100	-	$ 4.22	$ -
34.81		19	$ 3,738.48	82.600	$ 45.26	$ 2,875.55	$ 862.93		829	-	$ -	829	138.71	YES	100	-	$ 10.45	$ -
34.81		20	$ 6,199.93	150.690	$ 41.14	$ 5,245.97	$ 953.96		829	-	$ -	829	138.71	YES	100	-	$ 6.33	$ -
34.81		21	$ 3,788.38	88.700	$ 42.71	$ 3,087.91	$ 700.47		829	-	$ -	829	138.71	YES	100	-	$ 7.90	$ -
34.81		22	$ 3,415.73	79.900	$ 42.75	$ 2,781.56	$ 634.17		829	-	$ -	829	138.71	YES	100	-	$ 7.94	$ -
36.81	Feb 25	7	$ 1,440.17	28.200	$ 51.07	$ 1,038.13	$ 402.04	*Culley 2, Culley 3, and Brown 2 were out outage*	829	-	$ -	829	138.71	YES	100	-	$ 14.26	$ -
36.81		8	$ 1,512.90	36.900	$ 41.00	$ 1,358.40	$ 154.50		829	-	$ -	829	138.71	YES	100	-	$ 4.19	$ -
36.81		9	$ 1,918.69	46.200	$ 41.53	$ 1,700.76	$ 217.93		779	-	$ -	779	138.71	YES	100	-	$ 4.72	$ -
36.81		10	$ 1,918.92	42.900	$ 44.73	$ 1,579.28	$ 339.64		779	-	$ -	779	138.71	YES	100	-	$ 7.92	$ -
36.81		11	$ 1,570.80	38.500	$ 40.80	$ 1,417.30	$ 153.50		779	-	$ -	779	138.71	YES	100	-	$ 3.99	$ -
36.81		19	$ 2,909.80	70.660	$ 41.18	$ 2,601.21	$ 308.59		829	-	$ -	829	138.71	YES	100	-	$ 4.37	$ -
36.81		20	$ 3,439.34	90.700	$ 37.92	$ 3,338.94	$ 100.40		829	-	$ -	829	138.71	YES	100	-	$ 1.11	$ -
39.50	Feb 28	8	$ 1,880.59	40.600	$ 46.32	$ 1,603.70	$ 276.89	*Culley 2 was on Reserve Shutdown, Culley 3 was on outage*	829	-	$ -	829	138.71	YES	100	-	$ 6.82	$ -
39.50		9	$ 2,148.41	49.400	$ 43.49	$ 1,951.30	$ 197.11		779	-	$ -	779	138.71	YES	100	-	$ 3.99	$ -
Total			**$ 118,162.76**	**2,652.180**		**$ 93,554.25**	**$ 24,608.51**		**25,347.000**	**-**	**$ -**	**25,347.000**				**-**		**$ -**

Attachment FSB-2 (CONFIDENTIAL)

CEI South Winter 2022-23 Natural Gas Purchases

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