BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 16
Saffran Q3 2025 Outage Testimony

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the third quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



David Saffran

Dated: November 19, 2025

Major Forced Outage Report (Q3, 2025)

Michigan City 12 August 15 *84 hours*	1B aeration blower motor failed and tripped the 480-volt breaker. The 1B blower motor shorted to ground, and blower 3B was not developing adequate pressure. A minimum of two blowers is required for proper operation. The 1B blower motor and 3B blower were replaced.
R. M. Schahfer 16A July 18 *240 hours*	Turbine flame scanner #14 out of service and spark rods not igniting. A secondary problem concerning damaged fuel nozzles and combustion can baskets was discovered during startup and forced the unit offline. The fuel nozzles and baskets were replaced and the unit placed in service.
R. M. Schahfer 16A August 21 *976 hours*	Unit 16A transitioned to a forced outage after high vibration was experienced during operation. A borescope inspection showed significant blade damage to the forward compressor. Repairs are currently ongoing and expect to be completed at the end of April 2026.
R. M. Schahfer 16B August 6 *1,331 hours*	The unit stalled twice at 2,375 rpm while in startup. This prompted a borescope inspection. The inspection revealed damage to the compressor section of the turbine beginning in Row 9, with heavy damage throughout the mid and aft compressor sections. The turbine assembly was removed and sent out for inspection and repair. The unit is expected to be available mid-February 2026.
R. M. Schahfer 17 July 1 *182 hours*	The unit was taken offline due to a boiler wall tube leak on the southwest corner. The root cause was wall thinning, likely due to falling slag. Three dutchmen were used to replace the failed tubes.
R. M. Schahfer 17 August 7 *264 hours*	The unit was removed from service for an unsafe boiler flue gas leak. The root cause was due to normal wear in a harsh flue gas environment.

	Contractors completed all required ductwork repairs and the unit placed in service.
R. M. Schahfer 17 August 18 *125 hours*	Boiler wall tube leaks. The root cause was washout likely due to boiler cleaning or a malfunctioning soot blower. Three dutchmen were used to replace the bad tubes.
R. M. Schahfer 17 September 6 *201 hours*	Boiler wall tube leaks on the lower slope. The likely cause was due to wall thinning caused by falling slag. A dutchmen and two pad welds were required to replace bad tubes and repair previously installed dutchmen.
R. M. Schahfer 18 July 9 *1,996 hours*	The unit tripped due to high turbine bearing vibration indications on all rotor bearings. Initial inspections inside the upper condenser hot well revealed significant damage to the upper portion of the condenser tubes on the governor end. One of the L-0 blades on the governor end liberated approximately 1/3 of the way down from the tip. Management is weighing options. The unit is currently scheduled to retire December 31, 2025
Norway Hydro June 6 *559 hours*	All turbine units were shut down three times due to low river water and low dissolved oxygen readings. This is an Out of Management Control event. No additional action is needed.

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Exhibit 17
DOE Order No. 202-20-2

Department of Energy
Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker

Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

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Exhibit 18
Wagner November Testimony

VERIFIED DIRECT TESTIMONY OF JOHN A. WAGNER

Q1. Please state your name, business address and title.

A1. My name is John A. Wagner. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410. I am Manager, Fuel Supply for Northern Indiana Public Service Company LLC ("NIPSCO").

Q2. Please describe your educational and employment background.

A2. I graduated from Macomb College with an A.A.S. degree in automotive design, from Wayne State University with a B.S. in mechanical engineering, and I earned a M.B.A. from the University of Michigan. From 1998 to 2015, I held engineering and fuel procurement roles with increasing levels of responsibility at DTE Energy. My last role there was Director of Fuel Supply where I was responsible for the procurement of coal, natural gas, and oil for 10,000 MW of electric generating capacity as well as the oversight of DTE's coal transshipment terminal in Superior, Wisconsin. I started my employment as Manager, Fuel Supply at NIPSCO in 2016.

Q3. What are your responsibilities as Manager, Fuel Supply?

A3. As Manager, Fuel Supply, I am responsible for supervising the purchase and transport of coal used for generating electric energy, that includes negotiation and administration of coal supply agreements, coal transportation agreements, railcar leases, and railcar maintenance service agreements. In addition, Fuel Supply is responsible for the collection of fuel cost data, fuel accounting support and the disposal and sale of coal combustion residuals.

Q4. Are you familiar with the Company's Verified Petition, including the schedules attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony is to (1) summarize the fuel mix used by NIPSCO's fossil-fueled generation during July, August, and September 2025 ("Reconciliation Period"); (2) describe NIPSCO's coal procurement process and the coal supply agreements that governed coal shipments NIPSCO received during the Reconciliation Period; (3) provide the delivered cost of the coal consumed by NIPSCO's generating stations

during the Reconciliation Period and summarize any known factors that affected the delivered cost; (4) provide an overview of the coal market, coal pricing, transportation markets, and factors that likely affected those markets during the Reconciliation Period; (5) provide NIPSCO's estimated cost of coal consumption for February, March, and April 2026 (the "Forecast Period") and the assumptions used to develop NIPSCO's fuel forecast and factors that could impact the forecast; (6) provide a status update for NIPSCO's railcar fleet, utilization, and cost management; (7) provide an overview of NIPSCO's coal inventory; (8) provide an update on the status of NIPSCO's Railroad Litigation;[1] and (9) provide an update on the status of coal and transportation decrements.

Q6. What was the generation mix, by fuel type, of the energy produced by NIPSCO's fossil-fueled generation during the Reconciliation Period?

A6. NIPSCO's coal-fired generation provided 44.5% of the energy generated

[1] On September 30, 2019, NIPSCO filed a complaint in the United States District Court for the District of Columbia against the Union Pacific Railroad Company, BNSF Railway Company, CSX Transportation, Inc., and Norfolk Southern Railway Company (currently pending in Civil Action No. 1:19-cv-02927-PLF, consolidated for pre-trial purposes in Misc. No. 1:20-mc-00008-BAH, MDL No. 2925) for illegally conspiring to use rail fuel surcharges as a mechanism to fix, raise, maintain, and stabilize the prices of rail freight transportation services sold in the United States (the "Railroad Litigation").

during the Reconciliation Period, and 55.5% of the energy generated was gas-fired. NIPSCO's coal-fired generation consumes coal from various supply regions. A mix of Powder River Basin ("PRB") coal and Northern Appalachian ("NAPP") coal is consumed at the Michigan City Generating Station ("Michigan City"). Illinois Basin ("ILB") coal is consumed in Units 17 and 18 at the R. M. Schahfer Generating Station ("Schahfer").

Q7. How does NIPSCO procure its coal supply?

A7. NIPSCO solicits as many prospective suppliers as reasonably possible to provide offers for specific coal types and tonnage based on a portion of NIPSCO's estimated future delivery requirements. NIPSCO confirms that a prospective supplier can meet specific quality and quantity requirements and sends a supplier a request for proposal. If a supplier decides to participate, they send offers by email to Fuel Supply.

NIPSCO then performs an evaluation that ranks the offers on a total cost basis, compares offers to published price indices, and considers reliability of the producer/supplier and transportation provider(s). The total cost analysis includes the coal free-on-board (or "F.O.B.") mine price, quality, transportation costs, reliability, railcar costs, dust treatment, emission

control costs, costs associated with coal combustion byproducts and other operational costs. NIPSCO then negotiates commercial terms and conditions with the supplier with the most competitive offer and enters into an agreement after the contract receives legal and executive approval. Agreements are considered a term supply agreement if the contract term is one (1) year or longer.

Q8. What factors need to be considered in purchasing fuel for NIPSCO's coal-fired generating units?

A8. Factors that are considered in purchase evaluations for a specific generating unit include the delivered cost, operational costs, cost of emissions controls, and management of coal combustion byproducts. In addition, combustion and emission characteristics are critical and may eliminate a coal source from consideration if these characteristics adversely affect a generating unit's reliability, increase the total cost (fuel and operational costs) of generation, or inhibit NIPSCO's ability to comply with emission limits. Reliability of the coal source and coal transportation from that source are also critical factors.

Q9. What coal supply agreements were in effect during the Reconciliation

Period?

A9. NIPSCO had three supply contracts that were effective during the Reconciliation Period as follows: one agreement with Peabody COALSALES, LLC ("Peabody") for PRB coal, one agreement with Core Natural Resources ("Core", formerly Arch Coal and CONSOL) for PRB coal, one agreement with American Consolidated Natural Resources ("ACNR") for NAPP coal, and one agreement with Peabody for ILB coal.

Q10. Does NIPSCO have a financial interest in any of the coal producers currently under contract?

A10. No.

Q11. Did NIPSCO sell any coal purchased by NIPSCO to any other party during the Reconciliation Period?

A11. No.

Q12. Did NIPSCO make any new commitments for either spot or term coal purchases or coal transportation during the Reconciliation Period?

A12. Yes. NIPSCO purchased ILB coal from Peabody with a minimum obligation of 45,000 tons and NIPSCO can ship up to 150,000 tons.

Q13. Did NIPSCO renegotiate and/or amend any of its coal or transportation agreements during the Reconciliation Period?

A13. No.

Q14. Did any of NIPSCO's term coal contracts effective during the Reconciliation Period have price adjustments?

A14. Yes. One (1) of the contracts has mostly fixed prices specified in the contract, and a portion of the volume under this agreement was priced using a coal market index. In addition, all NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications.

Q15. What is the purpose of price adjustments in term coal contracts?

A15. In general, producers and customers are reluctant to execute longer term contracts with fixed prices without some type of market price adjustment mechanism. Maintaining a price close to market is beneficial to both parties. For example, long-term coal supply agreements with fixed prices could end up well above future market prices making electricity generated with that supply uneconomic. Therefore, the producer and customer may work together to establish an equitable price adjustment methodology. For

example, the price may be calculated based on a mix of prompt and year-ahead published market prices. The adjustment methodology is incorporated into the terms and conditions of the agreement and price adjustments may be made monthly, quarterly, or annually. Historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("BTU") basis when the shipment quality varies from guaranteed quality specifications. Other price adjustments can occur due to governmental imposition (e.g., federal or state agencies levy taxes or change rules that increase the cost of mining or production) or the payment of damages.

Q16. What was the delivered cost of coal consumed[2] by NIPSCO's generating stations for the twelve (12) months ending September 30, 2025 and for the Reconciliation Period?

[2] Starting with FAC 129, NIPSCO now reports the delivered cost of coal consumed during the Reconciliation Period. This methodology is comparable to the cost of coal consumed for power generation projected for the forecast period.

A16. The delivered cost of coal consumed for the twelve (12) months ending September 30, 2025 was $76.41 per ton or $3.707 per million BTU. The cost of coal consumed during the Reconciliation Period was $65.74 per ton or $3.285 per million BTU.

Q17. What factors affected NIPSCO's delivered cost of coal consumed during the Reconciliation Period when compared to the prior quarter?

A17. As stated above, NIPSCO's delivered cost of coal consumed during the Reconciliation Period was $65.74 per ton or $3.285 per million BTU. The system delivered cost of coal consumed during the prior Reconciliation Period was $82.61 per ton, and $3.985 per million BTU. When compared to the prior Reconciliation Period, the delivered cost of coal consumed decreased by $16.87 per ton and $0.700 on a per million BTU basis.

The majority of the decrease is due to the change in the mix of coal consumed during the Reconciliation Period when compared to the prior quarter. Specifically, Schahfer consumed 35.3% of tonnage and Michigan City consumed 64.7% of total system tonnage during the Reconciliation Period. The mix contribution in the prior Reconciliation Period was 60.0% and 40.0% for Schahfer and Michigan City, respectively. The cost of ILB

coal used at Schahfer is higher than the mix of coal used at Michigan City. PRB coal delivered prices declined, which contributed to the decrease in the delivered cost of coal consumed. NAPP and ILB delivered costs and railroad fuel surcharges were modestly lower as well when compared to the prior Reconciliation Period and contributed to a portion of the decrease.

Q18. What was the average spot market price of coal during the Reconciliation Period?

A18. The average spot market price during the Reconciliation Period was $14.07 per ton for PRB coal (down $0.06) per ton when compared to the prior Reconciliation Period), $44.83 per ton for ILB coal (up $1.75 per ton when compared to the prior Reconciliation Period), and $56.58 per ton for NAPP coal (up $0.75 per ton when compared to the prior Reconciliation Period). NIPSCO tracks spot market prices through discussions with brokers and by reviewing various daily and weekly coal publications. These are average F.O.B. mine spot market prices only and do not include the cost of transportation and are only an indication of prices NIPSCO may pay if purchases were made during the Reconciliation Period. Requesting specific quality parameters and the relative illiquidity of coal markets can impact

actual purchase pricing.

Q19. What are the current market prices for spot coal?

A19. As of November 10, 2025, the estimated F.O.B. mine spot market prices for December 2025 delivery were approximately $15.00 per ton for PRB coal, $46.50 per ton for ILB coal, and $57.50 per ton for NAPP coal.

Q20. What are the market prices for coal during the Forecast Period?

A20. As of November 10, 2025, the estimated F.O.B. mine spot market prices for delivery during the Forecast Period were $15.00 per ton for PRB coal, $46.50 per ton for ILB, coal and $57.50 per ton for NAPP coal. Again, these prices do not include the cost of transportation.

Q21. What energy market trends and factors affected the market for coal and transportation and may continue to impact the market going forward?

A21. Wholesale, day-ahead electricity prices were roughly 22.9% higher during the Reconciliation Period when compared with the same period in 2024. Higher energy demand and higher natural gas pricing helped drive an increase in coal demand compared to the same quarter in 2024. The federal Energy Information Agency ("EIA") projects the U.S. electric energy supply

mix for 2025 and 2026 in its latest outlook[3] as follows:

- Renewable generation (including hydro) provided 23% of the nation's energy mix in 2024 and is expected to provide 24% and 26% in 2025 and 2026, respectively.

- Nuclear comprised 19% of electric generation in 2024 and is expected to provide 18% of the mix in 2025 and 2026.

- Natural gas-fired generation provided 42% of the mix and is expected to provide 40% in 2025 and 2026.

- Coal-fired generation provided 16% of the energy in 2024 and is expected to provide 17% of the mix in 2025 and 16% of the mix 2026.

- U.S. coal production[4] decreased by 11.4% in 2024 when compared with 2023 levels and is expected to increase 2.8% in 2025 and decline 3.3% in 2026.

[3] *EIA Short-Term Energy Outlook November 2025:* https://www.eia.gov/outlooks/steo/

[4] *Ibid (Table 6. U.S. Coal Supply, Consumption, and Inventories)*

Henery Hub spot pricing averaged $2.28 per MCF during 2024 and is expected to rebound to $3.60 in 2025 and increase to $4.17 in 2026.[5] Illinois Basin spot coal prices are up roughly 18%, PRB spot coal prices are up 7%, and NAPP spot coal prices are up 16% when compared to year-ago levels.[6] Despite increases in coal prices, relatively low natural gas prices and increasing renewable generation has kept coal-fired generation as the marginal energy source. However, stronger energy and natural gas prices resulted in increased coal demand that led to higher coal prices. The EIA also expects utilities will increase inventories by the end of 2026 that could lead to additional coal demand. In addition, several planned U.S. coal generation retirements have been delayed due to the President's executive orders issued in April 2025. Notwithstanding, near-term uncertainty and higher energy prices may allow coal pricing to increase, but long-term trends should limit price volatility. Coal demand will likely decline in the long run, driven by the age of the coal units, coal unit retirements, and/or

[5] *Ibid (Table 5b. Regional Natural Gas Prices)*

[6] *NIPSCO Proprietary Over-The-Counter price assessment*

decreased utilization, low natural gas prices, and increased renewable production.

The dynamics described above continued to keep prices soft in all energy markets during the Reconciliation Period. API 2 (coal delivered to Amsterdam, Rotterdam, and Antwerp) prices were roughly 18.3% lower year over year during the Reconciliation Period.[7] Coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand and export markets have provided relatively steady sales opportunities during the year. The EIA reported coal exports reached 108.4 million tons in 2024 (five-year high). However, global coal demand has softened during 2025 and exports are expected to fall to 96.0 million tons this year and 99.2 million tons in 2026.[8] Overall, the outlook for global coal use is somewhat stable and export opportunities are expected to remain steady. The U.S. economy outlook assumed by EIA in their outlook assumes GDP will grow by 2.0% in 2025 and 2.2% in 2026.[9]

[7] *NIPSCO Proprietary Over-The-Counter price assessment (API2)*
[8] *EIA Short-Term Energy Outlook November 2025 (reference Table 6.)*
[9] *EIA Short-Term Energy Outlook November 2025*

For transportation, railroad performance continues to trend better than historical norms and has been consistent. Notwithstanding, reduced investment in coal production and coal transportation capacity, supplier bankruptcies, and mine closures over the last several years have caused coal supply chain constraints and these supply and capacity reductions may lead to market volatility if energy prices and demand rebound. In addition, variable coal demand impacts supply chain efficiency and can lead to unpredictable coal supplier and railroad performance.

Q22. What is NIPSCO's estimate for the cost of coal to be used for power generation during the Forecast Period?

A22. NIPSCO's cost of coal consumed for generation in the Forecast Period is estimated to be $49.91 per ton and $2.620 per million BTU.

Q23. What data and assumptions do the Fuel Supply group use to develop pricing estimates for the Forecast Period?

A23. In developing the estimate for the Forecast Period, NIPSCO's Fuel Supply group incorporates coal contract prices inclusive of any adjustments specified in the agreement, dust treatment costs, freeze conditioning costs (seasonal), railcar lease cost, railcar maintenance costs, estimates of contract

prices (fixed prices and indexed contract rates using forward LMP forecasts), transportation fuel surcharges using the monthly average price of U.S. On-Highway Diesel Fuel ("HDF"), Association of American Railroad's All-Inclusive Index Less Fuel ("AIILF") adjustments and estimates of future coal purchase prices. In addition, Fuel Supply also provides a forecast of beginning inventory values in dollars and quantities in tons for each of the generating stations. These assumptions are provided to NIPSCO's Energy Supply & Optimization group, which uses these assumptions to develop the forecast for the period.

Q24. Please describe the factors NIPSCO believes will impact coal supply, demand, and cost of the coal commodity to be purchased and shipped to its stations during the Forecast Period.

A24. The market dynamics described above appear to have kept coal demand somewhat stable globally and coal supply for utility generators in 2025 and into 2026 should be adequate. Given the uncertainty in the energy markets due to delayed coal generation retirements, projected increases in electricity demand due to the emergence of data centers, crypto mining, and other load growth drivers, there could be volatility in all energy commodity

prices that could impact supply. That said, there are multiple factors that typically impact coal supply and demand including, but not limited to, power prices, natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions which impact supply. Notwithstanding, NIPSCO's 2025 purchases are expected to meet forecasted coal delivery requirements and coal producers are obligated to perform under these agreements. NIPSCO has discussions with all its coal suppliers on a regular basis, and suppliers indicated they will meet NIPSCO's contracted coal supply requirements. Regarding the cost of coal, the price of coal used for the Forecast Period consists of fixed prices. If demand exceeds current coal supply obligations, NIPSCO may need to purchase additional tonnage, which may impact fuel costs during the Forecast Period.

Q25. What factors will impact coal transportation costs during the Forecast Period?

A25. There are two key factors that could impact coal transportation costs during the Forecast Period. One factor, power prices, may impact coal transportation costs under two transportation contracts that are indexed to

station LMPs. Contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. A second factor is the price of HDF. Two coal transportation agreements have mileage-based fuel surcharges (governed by each carrier's fuel surcharge tariff) that are calculated monthly using the average weekly spot price of HDF. Fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the Forecast Period. For reference, the spot price of HDF as of November 10, 2025 was $3.837 per gallon[10] (a 9.0% year-over-year increase). The EIA expects downward pressure on oil prices due to higher production and lower demand. Given these assumptions, the EIA expects HDF prices to decline modestly over the next two years and forecasts diesel prices will average $3.66 per gallon during 2025 and decrease to $3.50 in 2026.[11] Based on this outlook, fuel surcharges under NIPSCO's transportation agreements are expected to remain flat or trend modestly lower through the end of 2026.

Q26. What was the status of NIPSCO's railcar fleet during the Reconciliation Period?

[10] *EIA Gasoline and Diesel Fuel Update, November 12, 2025*: https://www.eia.gov/petroleum/gasdiesel/
[11] *Short-Term Energy Outlook November 2025 (Energy Prices Table 2.):*

A26. NIPSCO's fleet size was 641 railcars (five 125-car sets with 2.6% spares) at the end of the Reconciliation Period. The typical spare railcar pool ranges between 2% and 8%. During the Reconciliation Period, NIPSCO utilized 80% of the fleet in July and utilization averaged 67% during the Reconciliation Period. As mentioned in FAC-148, NIPSCO negotiated the early return of 125 railcars, and these cars were collected and released to the lessor in June. NIPSCO stored one to two sets at Schahfer the during the Reconciliation Period as operations required. One Michigan City set was stored at a third-party location August. Storage requirements varied during the Reconciliation Period as coal consumption fluctuated due to planned and forced unit outages and to control inventory ahead of Schahfer's retirement at the end of 2025. Consumption continues to trend below historical rates driven by periods of economic reserve (idle coal units) due to volatile and softening energy market conditions during the period, renewable production, much better-than-expected railroad performance, and planned and unplanned station maintenance outages. Coal unit consumption was only 46% of the system's maximum coal demand rate during the Reconciliation Period and railcar utilization exceeded station generation utilization rates. NIPSCO frequently evaluates

its railcar needs and considers demand/delivery requirements (forecasted, historical, and actual), railroad performance, station unloading performance, and the timing of lease expirations. NIPSCO will continue to use commercially reasonable efforts to manage its railcar fleet to ensure economic, and reliable coal deliveries.

Q27. Please describe NIPSCO's efforts to mitigate railcar costs incurred during periods of lower than anticipated train set utilization.

A27. To mitigate cost while balancing reliability, NIPSCO was able to reduce the fleet early with the return of 125 railcars in June as mentioned above. In addition, NIPSCO has plans to reduce the fleet by 229 railcars when Schahfer Units 17 and 18 retire at the end of 2025. NIPSCO also minimized storage costs during the Reconciliation Period by (1) storing one to two unit trains at Schahfer at no cost and (2) storing only one set of Michigan City's railcars at a third party storage in August as Michigan City's inventory increased during the latter half of the Reconciliation Period.

Notwithstanding, the availability of coal gondolas is extremely limited and relying on that market to obtain railcars for short-term needs can adversely impact coal supply reliability and is not prudent. In addition, the timing of

lease terms can preclude fleet size changes as leasing decisions are made on a forward-looking basis. The determination of fleet size is a multivariate analysis (NIPSCO's system set requirements can vary by two to three sets depending on consumption, railroad performance, and station unloading performance assumptions) and it can take several months to bring cars into the fleet, and it is an even longer process when returning cars. In addition, moving rail cars in and out of service is a costly process[12]. Therefore, the forward-looking nature of lease agreements and the time and costs required to place cars in and out of service make it difficult to make short-term changes to the size of the fleet and it is not prudent, practical, nor economic to dynamically change the fleet size when coal demand deviates from the forecast. In addition, railcars provide delivery reliability and can be invaluable if demand increases and/or railroad performance degrades.

NIPSCO also consults with industry experts and as discussed in my prior testimony, and as mentioned in prior filings, some large utilities continue to hold "excess" railcars out of concern that it may be difficult and/or more

[12] There are significant costs to *place* cars into service, including out of route transportation charges, locomotive charges, car mark stenciling costs, inspection costs and other costs. There are costs to *return* cars to lessors including out of route movements charges, locomotive release charges, shop costs, return maintenance costs, car mark stenciling costs, and other costs.

expensive to lease cars if demand improves. Through discussions with industry experts, I am aware that the market for coal cars is very tight, and lease rates have increased dramatically. Overall, the total number of railcars available in the market has decreased substantially over the last few years because scrap rates of coal railcars have been aggressive, and this dynamic has reduced railcar availability and caused lease rates to increase. One industry expert expects that utilities may need to build railcars as the age of the fleet approaches end of life and as coal railcars continue to attrite. Therefore, NIPSCO's fleet must have sufficient capacity to react to increases in demand or decreases in railroad performance without depending on the market for railcars. For reference, NIPSCO's fleet size at the end of the Reconciliation Period can provide 76% of NIPSCO's maximum coal unit demand and at average railroad cycle times.

Given the tight supply of railcars in the market and the uncertainty in demand and railroad performance, NIPSCO has taken a conservative approach to fleet management to ensure supply reliability.

Q28. Does NIPSCO have fuel supply concerns during the Forecast Period?

A28. No. NIPSCO is proactively administering coal and rail transportation

agreements to address any potential coal supply and/or coal transportation shipment issues. In addition, all anticipated coal supply requirements for 2025 should be met under current coal supply and transportation agreements. Coal market demand has softened significantly over the past two years and the stress on the coal supply chain has decreased. However, if coal demand increases, utilities may struggle to schedule deliveries as railroads and coal producers have rationalized assets, labor, and production, and it may take time for production and shipments to rise to meet any rapid increase in demand. Notwithstanding, NIPSCO continues to work closely with its rail carriers to ensure coal deliveries meet demand during the Forecast Period.

Q29. Please provide a summary of NIPSCO's coal inventory during the Reconciliation Period.

A29. The days of coal inventory supply[13] at Schahfer was approximately 16 days[14] (down seven days from the prior quarter) at the end of the Reconciliation Period. Michigan City's PRB coal inventory was 26 days[15]

[13] *Days of supply is calculated using the highest recorded daily consumption over the last 10 years.*
[14] *Schahfer's ILB coal inventory target is 40 days (+ or – 10)*
[15] *Michigan City's PRB coal inventory target is 25 days (+7,-5) and 30 days (+ or - 10) for NAPP coal*

and the NAPP inventory was at 40 days at the end of the Reconciliation Period.

Q30. In accordance with the Commission's Order in Cause No. 38706-FAC-125, please provide an update on the status of the Railroad Litigation and provide any substantive developments and/or determinations.

A30. On June 24, 2025, the judge granted the defendant railroads' motion for summary judgment and directed the court clerk to close the case. NIPSCO's Notice of Appeal was filed on July 24, 2025 in the U.S. Circuit Court of Appeals for the District of Columbia Circuit. NIPSCO's appeal was consolidated with similar appeals filed by other plaintiffs from the Railroad Litigation. Currently, NIPSCO's counsel is coordinating with the other plaintiff law firms in developing the arguments to be raised in the briefing before the appellate judges, which will occur in a consolidated manner. No briefing schedule has yet been established by the appellate court. NIPSCO Witness Krupa provides an update on the deferred costs associated with the Railroad Litigation.

Q31. Does NIPSCO currently anticipate utilizing decrement pricing?

A31. No, not at this time. NIPSCO will continue to update the Commission

about decrement pricing in future FAC filings.

Q32. Has NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible?

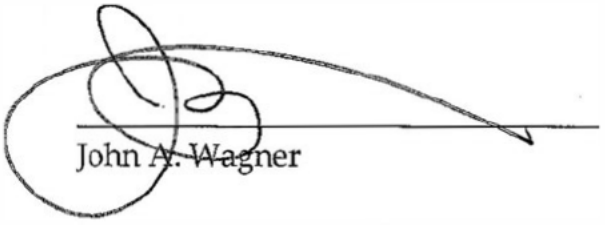
A32. Yes.

Q33. Does this complete your prepared direct testimony?

A33. Yes.

VERIFICATION

I, John A. Wagner, Manager, Fuel Supply for Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



John A. Wagner

Dated: November 19, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 19
NIPSCO CPCN Discovery Responses

OFFICIAL
EXHIBITS

IURC
JOINT - NIPSCO / CAC
EXHIBIT No. 6
7-11-24 AR
DATE REPORTER

Joint NIPSCO-CAC Exhibit 6

Witness Augustine

NIPSCO's Public Responses to CAC Data Requests 1-11, 1-12, 1-13, 1-14, 3-14, 3-15, 3-19, 5-2, 5-4, 6-5, 7-1, 10-1, 10-2, 10-3, 17-1, 23-1, 24-1, 25-2, 28-1, and 32-1

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-011:
Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine), page 28. With regards to the "latest information associated with MISO's seasonal resource adequacy construct": (a) Please identify the referenced "time of the analysis" (b) Please identify the seasonal capacity accreditation for intermittent resources used in the 2023 Portfolio Analysis. (c) Please identify the seasonal planning reserve margin targets used in the 2023 Portfolio Analysis. (d) Please state whether capacity accreditation under MISO's seasonal resource adequacy construct has changed since the values used in the 2023 Portfolio Analysis. If so, please identify how the values have changed. (e) Please state whether seasonal planning reserve margin targets have changed since the targets used in the 2023 Portfolio Analysis. If so, please identify how the targets have changed.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: (a) The assumptions for the 2023 portfolio analysis were developed at the end of 2022 and finalized in January 2023. (b) As in the 2021 IRP, NIPSCO's 2023 portfolio analysis evaluated seasonal capacity accreditation and seasonal reserve margin targets for MISO's summer and winter seasons. The summer and winter seasonal capacity accreditation assumptions used in the 2023 portfolio analysis for wind and solar resources are documented in the "Generic Capacity Credit" tab in Confidential Attachment 7-C to Mr. Augustine's direct testimony and are summarized as follows: NIPSCO assumed that wind resources would receive a winter capacity accreditation of 25% throughout the study period and a summer capacity accreditation of 16.3% throughout the study period. NIPSCO assumed that solar resources would

receive a winter capacity accreditation of 6.6% throughout the study period, with solar capacity accreditation changing over time in accordance with the table below:

Solar Capacity Credit Assumptions

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
50.0%	47.9%	45.8%	43.8%	41.7%	39.6%	37.5%	35.4%	33.3%	31.3%

2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
29.2%	27.1%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%

(c) As in the 2021 IRP, NIPSCO's 2023 portfolio analysis evaluated seasonal capacity accreditation and seasonal reserve margin targets for MISO's summer and winter seasons. The assumed summer planning reserve margin target used in the 2023 portfolio analysis was 7.4%, and the assumed winter planning reserve margin target used in the 2023 portfolio analysis was 25.5%.

(d) Estimates of seasonal capacity accreditation remain dynamic at MISO, particularly regarding forward-looking views of the effective load carrying capability ("ELCC") for intermittent resources. MISO produced a Wind and Solar Capacity Report for Planning Year 2023-2024 in March 2023 (https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf) and identified the following seasonal capacity accreditations for 2023-24:

	Summer	Winter
Solar	50%	5%
MISO-Wide Wind	18.1%	40.3%
Zone 6 Wind	13.8%	29.6%

In April 2023, MISO published assumptions documentation for its long-range transmission planning ("LRTP") analysis that included summer accreditation expectations for solar and wind over time. In this documentation, solar ELCC was projected to start at 50% in 2023, falling to 20% by 2037, while wind ELCC was projected to be constant at 16.6% over the whole study period. These assumptions are documented on page 4 in the following report:

https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf.

While these two reports published at nearly the same time illustrate the dynamic nature of capacity accreditation assumptions at MISO right now, they also demonstrate that no significant accreditation changes have been made since NIPSCO developed the values used in the 2023 portfolio analysis.

(e) The latest summer and winter seasonal planning reserve margin targets remain at 7.4% and 25.5%, respectively, consistent with the assumptions used in the 2023 portfolio analysis. These targets were set in MISO's Loss of Load Expectation ("LOLE") Study Report for Planning Year 2023-2024, which can be found at the following location: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf. As part of this study, MISO performed some "outyear" analysis that provided perspectives on the potential change in seasonal reserve margins over time (See Section 10, Appendix E of the LOLE report referenced above). In these outyear projections, MISO suggested the potential for summer reserve margins to increase slightly, while winter reserve margins were projected to remain around 25%. NIPSCO will continue to track MISO analysis on this topic, including the next LOLE report, which will set the targets for next year's Planning Resource Auction.

Supplemental Response:

(e) See the supplemental direct testimony of Pat Augustine at Question / Answer 10.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-012:
Please identify and produce for each of the following the most recent forecasts obtained, created, or reviewed by NIPSCO: (a) Natural gas prices (b) Coal prices (c) MISO energy prices (d) MISO capacity prices (e) NOx emission allowance prices
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: CRA's Fall 2023 commodity price update is provided as CAC Request Confidential 1-012 Attachment A. This includes the most recent market forecasts obtained and reviewed by NIPSCO for the requested fuel, MISO market, and emission allowance prices.

CAC Request 1-013:

Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine) at page 32 line 11 to page 33 line 5. With regards to the evaluation of the potential conversion of one or two units at the Schahfer plant:

(a) Please identify and produce all NIPSCO analyses of the potential conversion, including all workpapers, modeling input and output files, and other supporting documents.

(b) Please state whether NIPSCO has analyzed the net present value revenue requirement ("NPVRR") of converting the Schahfer coal units to gas compared to the NPVRR of the Schahfer gas peaker plant proposed in this proceeding. If so, please produce such analysis and any supporting workpapers, modeling input and output files, or other documents. If not, please explain why not.

(c) Please identify how the fast-start, quick-ramping, and reliability characteristics of converted Schahfer coal units to gas would compare to those same characteristics for the proposed Schahfer gas peaker.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's analysis of the potential conversion of one or two units at the Schahfer plant was conducted as part of its 2018 IRP, and all workpapers and summaries of modeling inputs and outputs can be found in CAC Request 1-013 Confidential Attachment A, which is Confidential Appendix D to the 2018 IRP. The following information was provided in the appendices:

- Coal-to-gas conversion portfolio details in the "Portfolio Legend" tab;
- Operational parameter assumptions for the Schahfer Unit conversion candidates on the "Existing Fleet Parameters" tab;

- Expectations for ongoing fixed operations and maintenance ("FOM") costs, coal-to-gas conversion capital costs, and ongoing capital expenditures for the conversion candidates on the "Unit FOM Capital – Retirements" tab within Portfolios 6b and 6c;
- Detailed annual revenue requirement projections and a summary of the projected net present value of revenue requirements ("NPVRR") for the two coal-to-gas conversion portfolios (Portfolios 6b and 6c) across all four IRP scenarios in the "Rev Req Components – Retirements" tab;
- Additional portfolio cost and financial output reports in the "Ret6b Summary," "Ret6c Summary," "Ret6b Contracts," "Ret6c Contracts," "Ret6b Resources," "Ret6c Resources," "DetailedFinOutputRetirements 6b," and "DetailedFinOutputRetirements 6c" tabs.

(b) NIPSCO has not additionally analyzed the net present value of revenue requirements ("NPVRR") of converting the Schahfer coal units to gas compared to the CT Project proposed in this proceeding because the gas peaker provides the load following generation and supporting reliability attributes needed and identified in the 2021 IRP and in NIPSCO's subsequent diligence associated with this application, including the Flexible Resource Analysis. The 2021 IRP analyzed a set of replacement portfolios across dispatchability and emissions criteria. Based on that analysis, the portfolio with a new gas peaker scored the highest and provides required flexibility to the NIPSCO fleet.

(c) The proposed CT Project is anticipated to have a start time as low as 11 minutes and a ramp rate of approximately 140 MWs per minute. Final performance data is dependent on the results of the competitive RFP for the CT equipment. Converting the existing units to natural gas would have start and ramp times similar to their current status as coal-fired generation with ramp rates of 3 MWs per minute, and a start up target of 22 hours after a 1 hour notice. The attributes associated with either the coal-fired or natural gas-fired thermal steam units are attuned to base load units operating over long periods of time with little variability in the energy produced. The attributes of the combustion turbines, specifically the very fast start up times and very quick ramp rates, are supportive of energy sources working in conjunction with renewable energy sources to "fill in the gap" related to the intermediate nature of renewable energy resources. As such, converting the existing Schahfer units to natural gas will not follow the load and provide the flexibility attributes that NIPSCO requires.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-014:

Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine) at page 35. With regards to the effective load carrying capability ("ELCC") discussed therein:

(a) Please identify for each of the years 2023 through 2052 the ELCC for four-hour duration storage resources assumed in the 2023 Portfolio Analysis.

(b) Please identify and produce any analysis, study, or other document supporting the assumption that the ELCC for four-hour duration storage resources would decline to 70% by 2040.

(c) Please explain the basis for the contention that a gas peaker "is likely to have a stable ELCC around 95%," and identify and produce any analysis, study, or other document supporting that contention.

(d) Please state whether the ELCC values for four-hour duration storage and a new gas peaker plant assumed in the 2023 Portfolio Analysis are consistent with MISO's most recent Seasonal Accredited Capacity values for those resources. If not, please explain how use of MISO's most recent values would impact the results of the 2023 Portfolio Analysis.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's 2023 portfolio analysis included a fundamental dispatch analysis that was conducted for the years 2023-2042, followed by an additional ten years of extrapolation and revenue requirement calculations. The ELCC assumption for four-hour duration storage resources for the 2023-2042 time period is provided below and also summarized in the "Generic Capacity Credit" tab of Confidential Attachment 7-C to Mr. Augustine's direct testimony. Given the extrapolation methodology used beyond 2042, the analysis implicitly assumes the ELCC values remain constant beyond 2042.

2023	88%
2024	87%
2025	86%
2026	85%
2027	84%
2028	83%
2029	82%
2030	81%
2031	79%
2032	78%
2033	77%
2034	76%
2035	75%
2036	74%
2037	73%
2038	72%
2039	71%
2040	70%
2041	70%
2042	70%

(b) MISO has produced recent analysis supportive of the assumption that the ELCC for four-hour duration storage could decline to 70% by 2040. For example, MISO's April 2023 assumptions documentation for its long-range transmission planning ("LRTP") analysis includes an expectation for storage ELCC to decline to 75% by 2037, quite close to the assumption of 73% by 2037 in NIPSCO's 2023 portfolio analysis. This is documented on page 4 of the assumptions found here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf. In addition, MISO's Renewable Integration Impact Assessment report projected a decline in storage ELCC to 64% with 30 GW (ICAP) of storage capacity in the system, declining to as low as 19% with 100 GW (ICAP) of storage capacity. This is documented in Figure RA-32 here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf. In addition, research across the industry and in other ISOs suggests that the capacity credit for storage would be expected to drop over time as a result of increasing renewable and storage penetration and when the width of the peak

net load period exceeds the hours of storage duration. See, for example, an NREL study on dynamic storage capacity valuation here: https://www.nrel.gov/docs/fy18osti/71462.pdf.

(c) As a dispatchable thermal resource without duration limitations, a gas peaker unit's ELCC is likely to be influenced most directly by its forced outage rate and not the changing net load profiles in the MISO market over time. In MISO's 2023-2024 Loss of Load Expectation ("LOLE") Study, used to set planning reserve margin targets, forced outage rates and planned maintenance factors were calculated over a five-year (2017-2021) period for thermal units. For combustion turbines greater than 50 MW, the unit type representing the new gas peaker NIPSCO requests approval for in this Cause, MISO identified a 4.07% forced outage rate, which would imply an approximate 96% ELCC. Over the last six MISO LOLE studies, the forced outage rate for this unit type averaged 4.87%, implying an ELCC value just above 95%. See Section 3.2.1 in the 2023-2024 LOLE study here: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

(d) Estimates for seasonal capacity accreditation remain dynamic at MISO, particularly regarding forward-looking views of the effective load carrying capability ("ELCC") for resources like storage. Last year, in June, 2022, The "Managing Reliability Risk in the MISO Footprint" report (https://cdn.misoenergy.org/20220616%20Board%20of%20Directors%20Item%2008a%20Reliability%20Imperative625168.pdf) produced an estimate of an 87.5% capacity credit for battery storage, consistent with the starting point assumed in NIPSCO's 2023 portfolio analysis. And as noted in subpart (b) to this request, MISO's assumptions document for the LRTP analysis documented one potential outlook for storage ELCC, although a lack of operating resources in the market has limited MISO's ability to publish any more recent class-average data. Thus, NIPSCO believes that the ELCC values assumed in the 2023 portfolio analysis remain consistent with the most recent information published by MISO.

CAC Request 3-014:

Please refer to Mr. Augustine's testimony at page 29, lines 5-9.

a. Please explain how the energy communities bonus adder was incorporated for renewable and battery storage projects.
b. Please explain if there was an assumed number of MWs eligible for the energy communities bonus adder or if the bonus adder was evaluated on a project by project basis.
c. If any projects modeled within Aurora qualify for the energy communities bonus adder, please provide the names of those projects as they were modeled in Aurora.

Objections:

Response:

(a) As part of the assumptions development process for the 2023 portfolio analysis, CRA reviewed bids from the 2022 RFP to identify the potential for energy community bonus qualification for new renewable and battery storage projects in the near-term. The near-term tax credit-eligible additions in the portfolios that NIPSCO evaluated included solar and wind PPAs (where the developer is assumed to incorporate any federal tax credit benefits within the PPA price) and new owned battery storage. No battery storage bids in the 2022 RFP were located in energy communities, although NIPSCO has identified the potential for utilizing remaining interconnection rights from Schahfer units 17 and 18 as potential sites for storage that would qualify for the bonus energy communities credit. (See NIPSCO's response to CAC Request 1-005.) Thus NIPSCO focused its modeling of bonus credits on the opportunity for a subset of near-term storage projects to be eligible for the 10% ITC adders.

(b) Although no bidders to NIPSCO's 2022 RFP offered storage projects located within energy communities, NIPSCO and CRA made the assumption that up to 150 MW of new battery storage could be located in an energy community, such as at the Schahfer site, and receive the 10% ITC bonus and a 40% ITC for the total project cost. All near-term solar and wind additions in the portfolios that were evaluated (up to 200 MW of new solar and up to 400 MW

of new wind) were modeled as PPAs with no separate analysis of tax credit eligibility. All long-term generic solar additions were common across the three portfolios NIPSCO evaluated in the 2023 portfolio analysis, with tax credit eligibility assuming prevailing wage and apprenticeship requirements are met and no bonus credit.

(c) The 150 MW of four-hour battery storage in 2026 incorporated in Portfolios 1 and 2 were assumed to qualify for the energy communities 10% ITC bonus adder. In addition, the 125 MW of 4-hour battery storage in 2028 incorporated in Portfolio 3 was assumed to qualify for the same bonus credit. These projects are named "Storage A1_2026" and "Generic 4-Hour Storage_Ref_2028" in the Aurora input database workpapers provided in NIPSCO's supplemental response to CAC Request 1-010.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Response to
Citizens Action Coalition of Indiana, Inc.'s Third Set of Data Requests

CAC Request 3-015:
Please refer to the workbook "Gas Peaker_NIPSCO_Confidential Attachment 7-C_09122023", worksheets "Rev Req Components", "Portfolio 1", "Portfolio 2", and "Portfolio 3". Please provide versions of these worksheets that are not hardcoded values and show the supporting calculations, with all formulas and links intact.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret. The requested worksheets are proprietary information to Charles River Associates and are unavailable
Response:
Please see objections.
Supplemental Response:
CAC Request 3-015 Confidential Attachment A, which contains the requested workbooks with all formulas and links intact, has been provided to the CAC pursuant to terms of a nondisclosure agreement CAC executed with Charles River Associates. CAC Request 3-015 Confidential Attachment A can be provided to any party to this proceeding that executes a separate nondisclosure agreement with Charles River Associates.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Third Set of Data Requests

CAC Request 3-019:

Please refer to the Flexible Resource Analysis presented in "Gas Peaker_NIPSCO Confidential Attachment 7-D_09122023".

a. Please explain how the charge and discharge of battery storage resources was modeled in the flexible resource analysis.
b. Please explain if battery resources were assumed to only be charged from NIPSCO resources.
c. Please explain if the discharge of battery storage resources was assumed to be a four hour consecutive period limited.
d. Please explain how any cycle limitations were implemented for battery storage resources.

Objections:

Response:

(a) The Flexible Resource Analysis was designed to evaluate and quantify the frequency and duration of NIPSCO's potential future net load exposure based on uncertainty in sub-hourly load, wind output, and solar output. The Flexible Resource Analysis was not designed to evaluate dispatch of individual units. As such, the key outputs were summaries of net load and net load ramps, including evaluations of the frequency and duration of net load exposure events. Thus, the methodology used in the Flexible Resource Analysis did not require NIPSCO to model the charge and discharge of battery resources.

(b) See part (a).

(c) See part (a).

(d) See part (a).

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Fifth Set of Data Requests
[Denotes Confidential Information]

CAC Request 5-002:

Re: NIPSCO response to data request CAC 3-001(a) ("The Flexible Resource Analysis (Confidential Attachment 7-D to Mr. Augustine's direct testimony) specifically pointed to the need for a gas-peaking asset in conjunction with the diverse portfolio of assets NIPSCO is constructing to include existing natural gas, wind, solar, battery storage, and flexible natural gas resources"): Please give a pinpoint citation to the part of NIPSCO's Conf. Attachment 7-D that establishes the need for a gas-peaking asset.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

The Flexible Resource Analysis was not intended to identify a single resource or set of resources, but rather assess how much flexible capacity NIPSCO would require to maintain reliability and mitigate against market risk as dispatchable generation retires and is replaced largely by non-dispatchable generation.

As stated on page 19 of Mr. Augustine's direct testimony, the Flexible Resource Analysis was intended to: "more fully assess the energy adequacy and flexibility characteristics of the IRP's preferred portfolio and to analyze the potential market exposure that could result from increasing reliance on renewable generation. The flexibility study was designed to (i) assess the portfolio's flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources; and (ii) perform sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The flexibility study was conducted to evaluate the risks associated with times of resource unavailability and market purchase exposure."

NIPSCO's Preferred Portfolio F from the 2021 IRP included a new natural gas peaking plant based on NIPSCO's integrated scorecard summary of a range of key planning objectives, as documented in Section 9.3 of the IRP. In that section of the 2021 IRP on p. 257, NIPSCO also noted that "the quantities and characteristics of storage and gas peaking resource additions require further study to confirm reliability can be

maintained and to understand the value of each resource type given ongoing and potential market and policy changes." The Flexible Resource Analysis was one means of performing further study of each resource type, with one major conclusion affirming that long-duration dispatchable resources provide value that shorter-duration resources cannot. Please see slide 8 of Confidential Attachment 7-D, with further detail provided on slide 12.

CAC Request 5-004:

Re: NIPSCO response to data request CAC 1.011(b).

(a) Please explain NIPSCO's or Mr. Augustine's basis for assuming wind will have a 25% winter capacity accreditation throughout the study period.

(b) Please explain NIPSCO's or Mr. Augustine's basis for assuming wind will have a 16.3% summer capacity accreditation throughout the study period

(c) Please explain NIPSCO's or Mr. Augustine's basis for assuming solar will have a winter capacity accreditation of 6.6% throughout the study period.

(d) Regarding the chart at the end of your response to CAC 1.011(b):

(i) Please confirm if the phrase "solar capacity accreditation changing over time" was intended to say "**summer** capacity accreditation changing over time."

(ii) Please explain NIPSCO's or Mr. Augustine's basis for assuming the year-by-year summer capacity accreditations for solar shown in the chart.

Objections:

Response:

(a) NIPSCO initially developed the wind winter capacity accreditation assumption of 25% during the 2021 IRP process, as documented in the "Generic Capacity Credit" tab of Appendix D to NIPSCO's 2021 IRP. As of the time of the 2021 IRP analysis, MISO had been indicating that winter capacity accreditation for wind would likely be higher than prevailing summer accreditation, and NIPSCO relied on multiple MISO data sources for guidance. For example, the MISO Resource Adequacy Subcommittee meeting in February, 2021 indicated a 20% winter capacity accreditation (see slide 22 here: https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf), while MISO reviews of intermediate seasonal accredited capacity based on historical wind resource performance for planning years 2019-20 and 2020-21, (as well as 2021-22 and 2022-23) generally averaged around 25% (see slide 41 here: https://cdn.misoenergy.org/20220824%20RASC%20Item%2007c%20Non-

Thermal%20Accreditation%20Presentation%20(RASC-2019-2%202020-4)626036.pdf). Although MISO's Renewable Integration Impact Assessment report contemplates modestly declining capacity accreditation for wind over time, the 25% assumption was used as representative of the likely long-term expectation for wind resources.

(b) NIPSCO initially developed the wind summer capacity accreditation assumption of 16.3% during the 2021 IRP process, as documented in the "Generic Capacity Credit" tab of Appendix D to NIPSCO's 2021 IRP. The assumption was developed based on MISO's most recent Wind and Solar Capacity Credit report as of the time of the analysis. That report included a MISO-wide assumption of 16.3% for wind resources, as documented here: https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf. Although MISO's Renewable Integration Impact Assessment report contemplates modestly declining capacity accreditation for wind over time (see for example, Figure RA-20 here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf) and although Zone 6 has historically had lower capacity accreditation than MISO as a whole, the 16.3% assumption was used as representative of the likely long-term expectation for wind resources in NIPSCO's portfolio. This remains broadly consistent with MISO expectations. For example, the latest long-range transmission planning ("LRTP") assumptions include an assumed flat 16.6% wind accreditation over the forecast horizon. See page 4 here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

(c) NIPSCO initially developed the solar winter capacity accreditation assumption of 6.6% during the 2021 IRP process. This was discussed in detail with stakeholders during the May 20, 2021 public advisory meeting and documented in the meeting minutes in Appendix A to NIPSCO's 2021 IRP. See p. 260 of Appendix A, which includes the following comments from the public advisory meeting: *"Based on NIPSCO's preliminary analysis of the coincidence of solar output with its coincident winter peak loads, the IRP analysis is planning to use 6.6% for the winter solar capacity credit. This number will be further reviewed based on hourly solar shapes that NIPSCO has from its planned solar projects and any future data received in the 2021 RFP. To arrive at the preliminary 6.6% number, CRA looked at the top 10-20 winter peak hours and noted that those tend to occur during the early morning and evening hours. On average, the solar*

output during those hours was approximately 6.6% of nameplate capacity. While geographic diversity could help improve that number in aggregate, and while different projects are likely to have different ratings, this is the general range for what will be used for the winter credit in this IRP." The 6.6% assumption was also consistent with MISO's assumptions for solar accreditation at the time of the analysis of approximately 5% during the winter months (See for example, slide 22 from the MISO Resource Adequacy Subcommittee meeting in February, 2021: https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf)

(d)

(i) Confirmed. The table of numbers at the end of the response to CAC 1-011(b) shows the assumed solar capacity accreditation for the summer season, and the phrase was intended to say "**summer** capacity accreditation changing over time in accordance with the table below."

(ii) NIPSCO initially developed the solar summer capacity accreditation assumptions during the 2021 IRP process, relying largely on information produced by MISO in its Renewable Integration Impact Assessment. The assumptions and associated rationale were documented with stakeholders during NIPSCO's May 20, 2021 public advisory meeting. See in particular slide 21 from the May meeting, which can also be found on page 140 of Appendix A to NIPSCO's 2021 IRP. Recent MISO documentation has remained supportive of this general summer capacity accreditation trajectory. For example, MISO's April 2023 assumptions documentation for its long-range transmission planning ("LRTP") analysis includes an expectation for solar ELCC to decline to 26% by 2035 and 20% by 2037, quite close to the assumption of 25% by 2035 in NIPSCO's 2021 IRP and subsequent 2023 portfolio analysis. This is documented on page 4 of the assumptions found here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Sixth Set of Data Requests
[denotes confidential]

CAC Request 6-005:

Re: Direct Testimony of Walter at page 29, lines 5-9 ("NIPSCO currently projects capacity factors below 20%, except in the initial months of operation. During these initial months, based on the proposed GHG Rules, either the capacity factors must be limited to 20% or the CTs must achieve the Intermediate Load emission limitations"); NIPSCO response to data request CAC 1.19 (including Conf. Att. A).

(a) Why did NIPSCO's 2021 IRP and 2023 portfolio analysis project [redacted] for the new gas CTs compared to [redacted]?
(b) If the proposed new CTs were limited to no more than 20% capacity factor in the initial months of operation due to federal greenhouse gas emissions rules, how would NIPSCO obtain alternate energy and capacity to meet its retail load requirements? Please provide all analyses, proposals, and documents in NIPSCO's possession used to answer the question.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's 2023 portfolio analysis projects higher capacity factors in 2026 and 2027 as a result of declining reserve margins in the wider MISO market as coal capacity retires and before significant replacement wind, solar, and other capacity is added to the broader system. The Reference Case in NIPSCO's 2021 IRP did not project higher capacity factors for the new peaker in 2026 and 2027 relative to other years, although the Status Quo Extended scenario did project higher capacity factors in 2026 relative to other years (See the "F Resources" tab in Appendix D to NIPSCO's 2021 IRP, which documents capacity factor projections for all resources across the four IRP scenarios). The different projections affirm the fact that multiple factors, including the gas peaker's heat rate, future natural gas prices, regional load growth trends, regional retirement

and expansion activity, and others will determine future capacity factors for the gas peaker plant. Note that even though NIPSCO's 2023 portfolio analysis projected a capacity factor higher than 20% for the partial year of 2026 (which is heavily influenced by the higher capacity factor summer months), annual capacity factors in 2027 and beyond were all projected to be lower than 20%.

(b) NIPSCO would not expect a limit on capacity factors to materially impact accredited capacity for the plant, especially if a change in operations were able to limit run hours during times of energy surplus within the wider MISO market. Even if capacity were derated, NIPSCO expects to have sufficient capacity to meet peak load requirements once the peaker is operational and while the Michigan City coal plant and existing older vintage Schahfer peaking units are operational. This was demonstrated on pages 37 and 38 of Mr. Augustine's direct testimony. As a member of MISO, NIPSCO is able to buy energy from the market as needed and sell energy when generation exceeds retail demand. In 2026 and 2027, NIPSCO expects to maintain a significant energy long position relative to retail load requirements, so minor adjustments in the gas peaker's output would not materially impact NIPSCO's energy position and only marginally lower the net sales position. This was shown on page 38 of Mr. Augustine's direct testimony, with aggregate portfolio generation projections also provided in the "Gen Mix by Portf – Cancellation" tab in Confidential Attachment 7-C to Mr. Augustine's direct testimony.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Responses to
Citizens Action Coalition of Indiana, Inc.'s Seventh Set of Data Requests

CAC Request 7-001:

Please refer to the figure labeled "Summer Supply-Demand Balance" at page 37 and the figure labeled "Winter Supply-Demand Balance" at page 38 in Witness Augustine's testimony.

a. Please provide the supporting workbooks, with all formulas and links intact, used to develop each figure.
b. For the reported planning reserve margin, please explain if a coincidence factor was applied to determine the planning reserve margin.
    i. If a coincidence factor was applied, please identify the summer and winter coincidence factors and explain the basis for those factors.
    ii. If a coincidence factor was not applied, please explain why not.
c. If not already included in the supporting workbook used to develop the figures on pages 37-38, please provide the summer and winter resource accreditation for each individual resource within the portfolio.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a. Please find the supporting workbook as CAC Request 7-001 Confidential Attachment A. The "S-D Balance" tab contains referenced figures from Mr. Augustine's testimony. Cells B1 and B2 on this tab allow the user to toggle by portfolio and by summer and winter season.
b. Yes, a coincidence factor was applied to NIPSCO's native peak load forecast to arrive at a peak load estimate coincident with the MISO peak for planning reserve margin calculation purposes. These factors are based on NIPSCO's internal analysis of internal peak relative to the system peak based on historical data. Thus, the peak load in the "Load" tab of CAC Request 7-001 Confidential Attachment A contains load that has already been adjusted by the

coincidence factor and will be lower than the NIPSCO system peak load reported in Chapter 3 of NIPSCO's 2021 IRP. NIPSCO's coincidence factor for summer and winter are included in the "Load" tab of CAC Request 7-001 Confidential Attachment A.

c. The summer and winter resource accreditations are included in CAC Request 7-001 Confidential Attachment A in the "New Resource ELCC" tab.

Supplemental Response:

For sub-parts (a) through (c), refer to the confidential workpaper to Mr. Augustine's supplemental direct testimony which contains NIPSCO's latest summer and winter supply-demand balances, inclusive of the updated MISO PRMR and capacity accreditation information along with the capacity purchases already made by NIPSCO.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-001:
Please provide the forecast of total peak load by each of the four seasons and by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Please refer to the "Demand Monthly Peak" tab in CAC Request 1-010 Confidential Attachment B for NIPSCO's peak load forecast by month. A summary of the forecast of total peak load by each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-001 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-002:
Please confirm the portion of 2022 peak load by sector (residential, commercial, and industrial) for each of the four seasons, and if available, by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO is not currently able to track historical peak loads by class, so this data is not available for historical years like 2022. The forecast, however, did develop peaks by class using sample customer load factor information, which is the same forecast used for the 2021 IRP. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's forecast of peak load for the residential, commercial, and industrial sectors for each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-002 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November. Note that the industrial sector includes firm load served by NIPSCO, including Tier 1 load on the 831/531 rate. Tier 2 and 3 load on the 831/531 rate is not served by NIPSCO and is excluded. Note that the individual monthly peaks by sector may not align, so the seasonal peaks summarized in CAC Request 10-002 Confidential Attachment A are not necessarily coincident. Note that this summary excludes railroad, street lighting, public authority, and company use load. Note that this summary also excludes the gross-up factor for losses that is incorporated when evaluating NIPSCO's system-wide peak for reserve margin planning purposes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-003:
Please confirm the portion of 2022 peak load by rate class for each of the four seasons, and if available, by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO is not currently able to track historical peak loads by class, so this data is not available for historical years like 2022. The forecast, however, did develop peaks by class using sample customer load factor information, which is the same forecast used for the 2021 IRP. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's forecast of peak load at the most granular level available for each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-003 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November. Note that the industrial sector includes firm load served by NIPSCO, including Tier 1 load on the 831/531 rate. Tier 2 and 3 load on the 831/531 rate is not served by NIPSCO and is excluded. Note that the individual monthly peaks by rate class may not align, so the seasonal peaks summarized in CAC Request 10-003 Confidential Attachment A are not necessarily coincident. For example, different rate classes may peak in different months within each season, so the sum of the individual industrial rate class components provided in CAC Request 10-003 Confidential Attachment A may not equal the aggregate industrial sector seasonal peak provided in CAC Request 10-002 Confidential Attachment A for certain seasons. Note that this summary also excludes the gross-up factor for losses that is incorporated when evaluating NIPSCO's system-wide peak for reserve margin planning purposes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Seventeenth Set of Data Requests
[Denotes Confidential Information]

CAC Request 17-001:

Refer to page 17 of Confidential Attachment A to your response to CAC 1-010. With regards to the statement "[redacted]":

a. Please state whether that statement is referring only to the decision of when between 2026 and 2028 to retire Michigan City 12, or whether it suggests a potential that NIPSCO would retire Michigan City 12 sometime after 2028.
b. Please state whether NIPSCO is currently considering a retirement date for Michigan City 12 after 2028.
    i. If so, please identify any such post-2028 retirement date(s) that is being considered, and explain what factors could lead to selection of such a later retirement date rather than 2028.
    ii. If not, please explain why not.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a. The statement "[redacted]" refers only to the decision to retire Michigan City 12 between 2026 and 2028.
b. NIPSCO is not currently considering a retirement date for Michigan City 12 after 2028. NIPSCO is currently operating within the action plan parameters of its 2021 IRP.

Note: NIPSCO made all language in the *request* PUBLIC.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Third Set of Data Requests
[Denotes confidential information]

CAC Request 23-001:

Re: NIPSCO Confidential Attachment 7-D (Flexible Resource Analysis):

(a) Please confirm that the system analysis described on slides 54-69 includes the Commonwealth Edison transmission region of Illinois. For anything other than an unequivocal confirmation, please explain in detail.
(b) For the Flexible Resource Analysis, what generation expansion assumptions were used for the Commonwealth Edison transmission region?
(c) For the Flexible Resource Analysis, what load forecast assumptions or methodologies were used for the Commonwealth Edison transmission region?
(d) For the Flexible Resource Analysis, how did Charles River Associates or NIPSCO integrate the wind and solar power buildout requirements contained in the Illinois Power Agency Act as modified by the Climate and Equitable Jobs Act of 2021 (Illinois Public Act 102-0662), codified at 20 ILCS 3855/1-75(c)(1)(C)(i)?
(e) For the Flexible Resource Analysis, how did Charles River Associates or NIPSCO integrate energy efficiency requirements contained in the Illinois Public Utilities Act as modified by the Climate and Equitable Jobs Act of 2021 (Illinois Public Act 102-0662), codified at 220 ILCS 5/8-103B?

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) Slides 54-69 include a number of key metrics associated with the Flexible Resource Analysis that were done for both the NIPSCO zone and the broader region. The key findings summarized in slides 7-12 and in slides and graphics labeled "NIPSCO" throughout slides 54-69 of Confidential Attachment 7-D were based *only on analysis performed for NIPSCO's zone.* The separate system analysis, which is summarized in certain graphics and slides labeled "system", included the Commonwealth Edison ("ComEd") zone of PJM in Illinois.

(b) CRA used its regional Eastern Interconnect Aurora model database for the four scenarios NIPSCO developed in its 2021 IRP to develop estimates for future installed capacity in the ComEd zone for the single study year (2030) that was evaluated in the Flexible Resource Analysis. The table below shows the installed capacity assumptions for the ComEd zone in MW for each resource type across the four scenarios.



(c) CRA used PJM's load forecast at the time of the analysis for the ComEd zone for the single study year (2030) that was evaluated in the Flexible Resource Analysis. The table below provides a summary of the monthly energy and peak load assumptions that were used for the ComEd zone.

Month	Energy (MWh)	Peak (MW)
1	8,450,352	14,621
2	7,346,976	13,930
3	7,515,144	12,768
4	6,832,800	12,009
5	7,300,872	15,220
6	8,465,760	20,049
7	9,727,056	20,876
8	9,425,736	20,500
9	7,737,840	17,629
10	7,155,792	12,797
11	7,164,720	12,614
12	8,035,944	14,177

(d) CRA's scenario analysis evaluated a range of renewable buildouts for the ComEd region, ranging to over 3,000 MW of solar and over 13,000 MW of wind by 2030, as documented in subsection (b) to this response. CRA's analysis did not assume any specific targets from Illinois' Climate and Equitable Jobs Act of 2021 for the ComEd zone, given uncertainty in locational siting of projects in ComEd versus the rest of the state (which was not modeled in the Flexible Resource Analysis) and uncertainty associated with specific procurement plans as of the time of the analysis. Given that procurement activities currently lag well behind targets, the approach and assumptions remain reasonable. The Illinois Power Agency's ("IPA") 2024 Long-Term Renewable Resources Procurement Plan report filed with the Illinois Commerce Commission in October 2023 acknowledges that current procurements are currently falling well short of target, and even with successful procurements over the next few years, the IPA acknowledges that the 2030 goal is unlikely to be met (The full report, including the procurement summary in Figure 3-2, can be found here: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2024-long-term-plan-20-oct-2023-.pdf)

(e) CRA's analysis incorporated PJM's load forecast for the ComEd zone, which is inclusive of energy efficiency assumptions. CRA did not separately adjust the forecast for energy efficiency targets or requirements from Illinois' Climate and Equitable Jobs Act of 2021.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Fourth Set of Data Requests
[Denotes confidential information]

CAC Request 24-001:

Re: NIPSCO Confidential Attachment 7-D (Flexible Resource Analysis).

(a) On slides 19-22 ("[redacted]"), what type of [redacted] NIPSCO's system in this modeling?

(b) If the answer to part (a) is gas combustion turbine generating capacity, does the analysis on slides 19-22 consider [redacted] shown on page 5-6 of the Simple Cycle Gas Turbine Engineering Study (NIPSCO Conf. Att. 4-A)?

(c) If the answer to part (a) is not gas combustion turbine generating capacity, how does the analysis incorporate [redacted]?

(d) On slides 23-24 ("Analysis of Duration of Short Events"), does the analysis consider [redacted] shown on page 5-6 of the Engineering Study?

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) Slides 19-22 of Confidential Attachment 7-D evaluated the change in market exposure risk associated with the addition of *any* flexible, dispatchable capacity. As explained in NIPSCO Witness Augustine's direct and rebuttal testimonies, the Flexible Resource Analysis was designed to assess the energy adequacy and flexibility characteristics of NIPSCO's portfolio from the 2021 IRP and characterize risks associated with potential market exposure. The analysis did not assess specific resource additions beyond the 2021 IRP's preferred portfolio, but instead identified the characteristics of new resource additions that could

help mitigate market exposure risk. See Witness Augustine's direct testimony at Q&A 24 and Witness Augustine's rebuttal testimony at Q&A 16 for additional explanation.

(b) See response to part (a). No resource-specific analysis was performed. Slides 19-22 identified the impacts associated with adding additional MW of any flexible, dispatchable capacity to the portfolio without evaluation of seasonal performance variations.

(c) See response to part (a). No resource-specific analysis was performed. Slides 19-22 identified the impacts associated with adding additional MW of any flexible, dispatchable capacity to the portfolio without evaluation of seasonal performance variations.

(d) The Flexible Resource Analysis considered seasonal capacity ratings and operational assumptions for NIPSCO's existing fleet of resources, including Sugar Creek, and generic assumptions for the 300 MW new peaking facility identified in the 2021 IRP. Since the analysis was designed to assess the 2021 IRP's preferred portfolio and characterize market exposure risks (including the duration of such exposure risks as outlined on slides 23-24 of Confidential Attachment 7-D), it did not consider seasonal performance variation of gas combustion turbines from the referenced Engineering Study, which was conducted after the Flexible Resource Analysis was performed.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Fifth Set of Data Requests
[Denotes confidential information]

CAC Request 25-002:

(a) Regarding "PJM's load forecast at the time of the analysis for the ComEd zone" as referenced in response to data request CAC 23.01(c): Admit that the relevant PJM load forecast at the time of the Flexible Resource Analysis was the 2023 PJM Load Forecast Report dated January 2023, available at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx. For anything other than admission, please explain.

(b) Regarding the 2023 PJM Load Forecast Report referenced in part (a), admit that the Distributed Solar Adjustment to Summer Peak Load for 2030 assumed in the report for the ComEd zone is 701 megawatts, as shown on page 54 of the report. For anything other than admission, please explain.

(c) Regarding the Illinois Power Agency's 2024 Long-Term Renewable Resources Procurement Plan ("LTRRPP") filed with the Illinois Commerce Commission in October 2023, as referenced by NIPSCO in response to data request CAC 23.01(d): admit that at page 149, the Illinois Power Agency states that the Adjustable Block Program encoded in Illinois law at Section 1-75(c)(1)(C) of the Illinois Power Agency Act "targets approximately 12,375,000 RECs delivered annually [...] by 2030 [...] necessitating perhaps up to 7,000 megawatts of new distributed generation and community solar capacity."

(d) Admit that the Adjustable Block Program referenced in Sections 1-75(c)(1)(C)(i) and 1-75(c)(1)(K) of the Illinois Power Agency Act covers RECs from distributed solar and community solar projects and is separate from utility-scale renewable generation REC procurements referenced in Sections 1-75(c)(1)(C)(i), (c)(1)(G)(i), (c)(1)(G)(ii), (c)(1)(G)(iii), and 1-75(c)(1)(G)(v) of the Illinois Power Agency Act.

(e) Admit that, according to page 150 of the Illinois Power Agency's 2024 LTRRPP, "Illinois Shines" is an alternate name for the Adjustable Block Program.

(f) Admit that at page 148 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program initially opened in January 2019.

(g) Admit that at page 150 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program has led "to the energized or planned development of over 1,600 MW of new solar generation in Illinois thus far."

(h) Admit that at page 157 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program has procured, to date since 2019, new solar projects' RECs totaling approximately 4.1 million annual RECs.

(i) Admit that according to pages 153 (including footnote 293) and 154 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency has, in program years prior to the 2024-2025 program year, reserved 70% of Adjustable Block Program capacity for distributed and community solar projects in what it calls "Group B," covering Commonwealth Edison transmission territory.

(j) Admit that according to pages 168 and 177 of the Illinois Power Agency's 2024 LTRRPP, the "Public Schools" and "Equity Eligible Contractor" project categories of the Adjustable Block Program both include distributed solar and community solar projects.

(k) Admit that that according to page 158 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency is reserving, in the Adjustable Block Program, 286 MW combined of community solar and distributed solar project capacity in the Commonwealth Edison transmission region for each of program years 2024-2025 and 2025-2026, plus a separate 391 MW combined of statewide distributed generation and community solar project capacity in each of those two program years.

(l) Admit that according to page 154 of the Illinois Power Agency's 2024 LTRRPP, the annual Adjustable Block Program total statewide capacity was set at 667 MW for program years prior to 2024-2025, and is increasing to 800 MW for program year 2024-2025, because, according to the Illinois Power Agency, "The solar market in Illinois is currently exhibiting immense growth, but the Program's categories [were] not appropriately sized to provide for stable growth within the Program."

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence.

NIPSCO further objects to subparts (c), (d), (e) – (l) of this Request on the separate and independent grounds and to the extent that this Request seeks publicly available information.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

As noted in NIPSCO's response to CAC Request 23-001, the key findings summarized in slides 7-12 of Confidential Attachment 7-D and those used to support the major conclusions from the Flexible Resource Analysis offered in NIPSCO Witness Augustine's testimony were based on the NIPSCO zonal analysis, which evaluated the frequency, magnitude, and duration of NIPSCO's exposure to the market. The additional system level analysis referred to in CAC Request 23-001 included a broader market-level review, including assumptions for the PJM-ComEd zone in the year 2030.

(a) The market models used for the analysis were consistent with those used to develop market scenarios for NIPSCO's 2021 IRP. As such, PJM's load forecast from 2020 was used for the ComEd Zone. The report can be downloaded here: https://www.pjm.com/-/media/planning/res-adeq/load-forecast/previous-load-forecast-reports.ashx.

(b) As noted in NIPSCO's response to subpart (a) of this request, PJM's load forecast from 2020 was used for the Distributed Solar Adjustment. The relevant Distributed Solar Adjustment can be found on p. 56 of the 2020 load forecast report referenced in NIPSCO's response to subpart (a).

(c) See objections. The document speaks for itself.

(d) The scope and meaning of Illinois law is not relevant. Please see objections.

(e) through (l) See objections. The document speaks for itself.

CAC Request 28-001:

(a) At page 11, lines 9-11 of his rebuttal testimony (NIPSCO Ex. 7-R), Mr. Augustine states that "For modeling purposes, in order to ensure an 'apples-to-apples' comparison with other potential resource options, only the direct costs of the project were included in my analysis."

i. Please confirm that this means that Mr. Augustine's cost modeling as described on page 39 of this direct testimony (NIPSCO Ex. 7) did not include the $83,638,000 of indirect costs contained in NIPSCO Attachment 5-A. If "only the direct costs" (and, by implication, indirect) costs refer to some other amount, identify that amount and the document in which it is located.

ii. In Mr. Augustine's experience, what indirect costs are typically needed for other technology types including wind, solar, and battery storage? Please provide any documents that support your response.

(b) At page 27, lines 3-4 of his rebuttal testimony, Mr. Augustine states that aeroderivative turbines have "faster ramping" than battery storage. Please provide all the documents, with pinpoint citations, that support your position.

Objections:

Response:

(a)

i. Mr. Augustine's direct testimony on page 39 noted that "Based on bids received in the 2022 RFP, the thermal peaker resource incorporated in the preferred portfolio from the 2023 portfolio analysis had an assumed all-in direct capital cost of $1,440/kW." This value of $1,440/kW was used in the 2023 portfolio analysis presented in Mr. Augustine's direct testimony. In addition, on pages 39-40, Mr. Augustine's direct testimony compared this modeling assumption to the direct cost estimate of the CT Project and confirmed consistency, while noting that, "The direct cost estimate, inclusive of AFUDC, for the CT Project is currently estimated to be $560,053,449, which is $1,400/kW for approximately 400 MW." The capital costs used for the new gas peaker capacity in the 2023 portfolio analysis were detailed in CAC Request 3-015 Confidential Attachment A. The capital cost assumptions for new technology additions were

documented in the "Portfolio Inputs -->" tabs. Note that these were presented in 2021$/kW, with the "Inflation" tab providing inflation factors for nominal costs.

ii. As noted in Mr. Augustine's rebuttal testimony at p. 11, "indirect costs are generally ancillary to the core project components and incorporate overheads and other internal allocations." Overheads associated with labor and administrative costs not occurring at the specific project site may be necessary for any resource type, including wind, solar, and battery storage.

(b) This is an inaccurate representation of Mr. Augustine's statement. In referencing CAC Witness Sommer's evaluation of the CT Project relative to battery storage additions, Mr. Augustine's statement at page 27 argues that Witness Sommer should not have relied solely on an ancillary services analysis of frame combustion turbines relative to battery storage when NIPSCO's CT Project includes both frame combustion turbines and aeroderivative turbines. The full context of Mr. Augustine's statement at page 27 from lines 1-4 stated that Witness Sommer's "comparisons with gas peaking technology are based only on the frame combustion turbine technology evaluated in NIPSCO's 2021 IRP without consideration for potential additional value associated with faster ramping and more flexible aeroderivative turbines." Thus, Mr. Augustine's statement noted that aeroderivative turbines are faster ramping *than frame combustion turbines* and did not indicate that aeroderivative turbines are faster ramping than battery storage. In fact, Mr. Augustine acknowledged that "Witness Sommer reasonably points to the potential for greater ancillary services value for battery storage resources" on p. 26 of his direct testimony and would acknowledge that battery storage resources have such potential value as a result of flexibility and fast ramping attributes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Thirty-Second Set of Data Requests

CAC Request 32-001:
Re: NIPSCO response to data request CAC 28.01 NIPSCO's response to CAC 28.01(a)(ii) states: "As noted in Mr. Augustine's rebuttal testimony at p. 11, 'indirect costs are generally ancillary to the core project components and incorporate overheads and other internal allocations.' Overheads associated with labor and administrative costs not occurring at the specific project site may be necessary for any resource type, including wind, solar, and battery storage." Please provide specific examples, including all supporting documents, of any indirect costs that Mr. Augustine has not previously included in any prior modeling on NIPSCO's behalf.
Objections:
Response:
In other prior modeling done on NIPSCO's behalf, including the 2018 and 2021 IRPs and the various CPCN applications referenced on p. 3 of Mr. Augustine's direct testimony, capital cost assumptions for new resources were developed from bids received by third-party developers of assets for sale to NIPSCO via Build Transfer Agreements. These capital cost assumptions included only direct costs, and Mr. Augustine's modeling analyses did not include additional indirect cost adders associated with NIPSCO overhead costs and other internal allocations, such as those documented by NIPSCO Witness Baacke in his rebuttal testimony on pages 22 and 23.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 20
IURC Schahfer Gas Plant Order

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") PURSUANT TO IND. CODE CH. 8-1-8.5 TO CONSTRUCT AN APPROXIMATELY 400 MEGAWATT NATURAL GAS COMBUSTION TURBINE ("CT") PEAKING PLANT ("CT PROJECT"); (2) APPROVAL OF THE CT PROJECT AS A CLEAN ENERGY PROJECT AND AUTHORIZATION FOR FINANCIAL INCENTIVES INCLUDING TIMELY COST RECOVERY THROUGH CONSTRUCTION WORK IN PROGRESS RATEMAKING UNDER IND. CODE CH. 8-1-8.8; (3) AUTHORITY TO RECOVER COSTS INCURRED IN CONNECTION WITH THE CT PROJECT; (4) APPROVAL OF THE BEST ESTIMATE OF COSTS OF CONSTRUCTION ASSOCIATED WITH THE CT PROJECT; (5) AUTHORITY TO IMPLEMENT A GENERATION COST TRACKER MECHANISM ("GCT MECHANISM"); (6) APPROVAL OF CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF RELATING TO THE PROPOSED GCT MECHANISM; (7) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; AND (8) ONGOING REVIEW OF THE CT PROJECT, ALL PURSUANT TO IND. CODE CH. 8-1-8.5 AND 8-1-8.8, AND IND. CODE §§ 8-1-2-0.6 AND 8-1-2-23.	**CAUSE NO. 45947** **APPROVED:**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Kristin E. Kresge, Administrative Law Judge

On September 12, 2023, Northern Indiana Public Service Company LLC ("Petitioner" or "NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking, among other relief, a certificate of public convenience and necessity ("CPCN") to construct an approximately 400 megawatt ("MW") natural gas combustion turbine ("CT") peaking plant ("CT Project") pursuant to Ind. Code ch. 8-1-8.5, and associated ratemaking and accounting treatment for the CT Project pursuant to Ind. Code ch. 8-1-8.8.[1]

[1] On August 11, 2023, NIPSCO provided its notice of intent to file an application for a CPCN in accordance with the Commission's General Administrative Order 2023-03.

Also on September 12, 2023, Petitioner filed the testimony and attachments of the following (all of whom are employees of Petitioner except as otherwise noted): Alison M. Becker, Manager of Regulatory Policy (Petitioner's Exhibit 1); David T. Walter, Vice President of Power Delivery (Petitioner's Exhibit 2); David Austin, Director of Transmission (Petitioner's Exhibit 3); Steven Warren, Senior Manager, Sargent & Lundy ("S&L") (Petitioner's Exhibit 4); Greg Baacke, Senior Director of Major Projects (Petitioner's Exhibit 5); Karl E. Stanley, Vice President of Supply & Optimization for NiSource Inc. (Petitioner's Exhibit 6);[2] Patrick N. Augustine, Vice President of Charles River Associates' Energy Practice, Charles River Associates ("CRA") (Petitioner's Exhibit 7); and Kevin J. Blissmer, Manager of Regulatory, NiSource Corporate Services Company ("NCSC") (Petitioner's Exhibit 8).

Petitions to intervene were filed by the Citizens Action Coalition of Indiana, Inc. ("CAC"); NIPSCO Industrial Group ("IG"); United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 ("USW"); and Primary Energy Recycling Holdings LLC ("Primary Energy"), all of which were granted.

On December 18, 2023, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated January 25, 2024.

On January 16, 2024, Petitioner filed the supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S). The supplemental testimony reflected a one-year delay of the in-service date of the proposed CT Project.

On February 9, 2024, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated February 20, 2024.

A public field hearing was held in LaPorte, Indiana on March 14, 2024, during which members of the public presented testimony related to the relief sought in this Cause.

On April 16, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and attachments of its witnesses, all of whom are employees of the OUCC's Electric Division: Cynthia M. Armstrong, Assistant Director (Public's Exhibit 1); John W. Hanks, Utility Analyst (Public's Exhibit 2); Roopali Sanka, Utility Analyst (Public's Exhibit 3); Gregory L. Krieger, Utility Analyst (Public's Exhibit 4); and Brittany L. Baker, Utility Analyst (Public's Exhibit 5). Also on that date, intervenors filed the testimony and attachments of their witnesses, including the following: Michael P. Gorman, Managing Principal, Brubaker and Associates, Inc. (IG Exhibit 1); Anna Sommer, Principal, Energy Futures Group (CAC's Exhibit 1); Robert G. James, Managing Director, Lumen Project Management Consultants (CAC's Exhibit 2); and Benjamin Inskeep, Program Director of CAC (CAC's Exhibit 3). USW did not file testimony. Primary Energy intervened after the deadline for intervenor testimony; therefore, Primary Energy

[2] Petitioner originally prefiled the Verified Direct Testimony of Andrew S. Campbell. NIPSCO filed a Notice of Substitution of Witness on January 16, 2024.

was precluded from filing testimony.

The OUCC also filed written consumer comments on April 19, 2024 (Public's Exhibit 6).

On May 21, 2024, NIPSCO filed the rebuttal testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-R),[3] Mr. Warren (Petitioner's Exhibit 4-R), Mr. Baacke (Petitioner's Exhibit 5-R), Mr. Stanley (Petitioner's Exhibit 6-R), Mr. Augustine (Petitioner's Exhibit 7-R), Mr. Blissmer (Petitioner's Exhibit 8-R), and Stephen Holcomb, Director of Environmental Policy & Sustainability, NCSC, (Petitioner's Exhibit 9-R).

On June 17, 2024, NIPSCO filed revisions to reflect the marking of various confidential information in its case-in-chief, supplemental direct testimony, and rebuttal testimony from confidential to highly confidential.

On July 8, 2024, the Presiding Officers issued a docket entry question, to which NIPSCO responded on July 8, 2024.

The evidentiary hearing in this matter commenced on July 11, 2024, at 9:30 a.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana, at which time evidence was offered by NIPSCO, the OUCC, CAC, and IG without objection. Among the evidence offered at the hearing were certain stipulations between Petitioner and various intervenors with respect to certain facts and admissibility of specific exhibits, all of which were prefiled before the evidentiary hearing.

Based upon the applicable law and the evidence of record, the Commission finds:

1. Notice and Commission Jurisdiction. Due, legal, and timely notice of the public field hearing and evidentiary hearing in this Cause was given and published as required by law. NIPSCO is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Pursuant to Ind. Code chs. 8-1-8.4 and 8-1-8.5, Petitioner may seek Commission approval of the CPCN requested in this Cause. Under applicable law, the Commission has jurisdiction over Petitioner and the relief sought by Petitioner in this Cause.

2. Petitioner's Characteristics. NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO provides electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.

NIPSCO owns, operates, manages, and controls electric generating, transmission and distribution plant and equipment and related facilities, which are used and useful in the production, transmission, distribution and furnishing of electric energy, heat, light and power to the public.

[3] Petitioner originally prefiled the Verified Rebuttal Testimony of Robert C. Sears. NIPSCO filed a Notice of Substitution of Witness on May 29, 2024.

3. Relief Requested. In this Cause, NIPSCO requests the Commission (1) issue a CPCN pursuant to Ind. Code ch. 8-1-8.5 to construct the CT Project; (2) approve the CT Project as a clean energy project and authorize financial incentives, including timely cost recovery through construction work in progress ("CWIP") ratemaking under Ind. Code Ch. 8-1-8.8; (3) authorize recovery of costs incurred in connection with the CT Project; (4) approve the best estimate of costs of construction associated with the CT Project; (5) authorize implementation of a Generation Cost Tracker ("GCT") Mechanism; (6) approve changes to NIPSCO's Electric Service Tariff relating to the proposed GCT Mechanism; (7) approve specific ratemaking and accounting treatment for the CT Project; and (8) approve ongoing review of the CT Project, all pursuant to Ind. Code ch. 8-1-8.5 and 8-1-8.8, and Ind. Code §§ 8-1-2-0.6 and 8-1-2-23.

4. The Parties' Evidence.[4]

A. Petitioner's 2021 IRP and 2023 Portfolio Analysis. Mr. Augustine provided an overview of NIPSCO's resource planning process and reviewed the conclusions from the last several years, particularly its most recent the Integrated Resource Plan ("IRP") submitted November 15, 2021 (the "2021 IRP"). He also reviewed major market developments since the 2021 IRP and summarized the portfolio analysis that CRA and NIPSCO performed in 2023 based on these major market developments (the "2023 portfolio analysis"). Mr. Augustine stated the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by additional analyses NIPSCO has performed.

Mr. Augustine testified the operational and cost characteristics of the CT Project are fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis, which developed a preferred portfolio with between 400 MW and 442 MW of new nameplate thermal peaking capacity additions in the near-term. He stated NIPSCO's Flexible Resource Analysis concluded that increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized, cost-effective thermal resource as compared to expensive storage additions.

Mr. Augustine testified that overall, the addition of the CT Project to NIPSCO's portfolio is fully supported by and consistent with the conclusions of the Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

In his supplemental testimony, Mr. Augustine presented updated information from Midcontinent Independent System Operator ("MISO") related to planning reserve margin requirements ("PRMR"), capacity accreditation, and NIPSCO's supply and demand balance. He explained that while the 2021 IRP and the 2023 portfolio analysis both incorporated the assumption that new gas peaking capacity would be in service in 2026, NIPSCO's 2021 IRP explicitly called for the procurement of short-term capacity as needed from the MISO market, and

[4] Unless otherwise noted, the summary below reflects updated information included in NIPSCO's supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S) filed January 16, 2024.

the 2023 portfolio analysis included an expectation that short-term capacity purchase opportunities would be pursued through 2027. Therefore, a 2027 in-service date for the CT Project, accommodated by capacity market purchases to meet reserve margin requirements, remains consistent with NIPSCO's most recent resource planning conclusions. Mr. Augustine testified the change in in-service date does not impact the operational and cost characteristics of the CT Project, which were shown to be fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis. He explained that based on the latest information from MISO regarding PRMR and capacity accreditation, the capacity purchase requirements through 2027 should be manageable and in line with historical levels, although NIPSCO will need to continue to actively monitor market conditions and evolving MISO rules as part of its ongoing capacity procurement plans. Mr. Augustine concluded the addition of the CT Project to NIPSCO's portfolio continues to be fully supported by and consistent with the conclusions of NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

OUCC witness Mr. Hanks had concerns that NIPSCO's incorporation of misaligned results of an all-source request for proposal ("RFP") – together with an RFP that solicited bids for a particular technology configuration – inflates the cost of the thermal peaking resource incorporated into the 2023 portfolio analysis, which could potentially to distort the results of the resource selection process used within the IRP. Mr. Hanks argued the costs used for new generic peaking capacity in the 2023 portfolio analysis were artificially inflated, making NIPSCO's estimate for the CT Project appear more reasonable, and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Hanks also suggested that the $1,400/kW metric for capital costs for the CT Project used in NIPSCO's analysis understated the costs of the project by excluding $83.68 million in indirect costs. Mr. Hanks testified that the $/kW metric is more accurately reflected as $1,609/kW.

CAC witness Ms. Sommer noted the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Ms. Sommer argued there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis, such as a portfolio with battery storage and more demand response. Ms. Sommer suggested that under the proposed direct loss of load ("DLOL") structure, battery resources will have stronger capacity accreditation than natural gas peaker resources. Ms. Sommer stated NIPSCO's capacity calculations overstate both summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. Ms. Sommer performed a levelized cost analysis to compare the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site to suggest that new battery additions would be lower cost than NIPSCO's proposed CT Project.

IG witness Mr. Gorman stated that, instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study. Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Gorman testified that NIPSCO failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project.

In rebuttal, Mr. Augustine testified that while the OUCC and intervenors directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, no one testified NIPSCO does not need this type of new capacity, which was identified in its 2021 IRP and in the subsequent analyses. Mr. Augustine addressed the OUCC and intervenors' testimonies in relation to the 2023 portfolio analysis, the Flexible Resource Analysis, NIPSCO's future supply-demand balance, and additional analysis and considerations that were introduced.

Mr. Gorman testified that instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study, Mr. Augustine responded that Mr. Gorman provided an incomplete characterization of the analysis NIPSCO performed in support of its requested CPCN. He stated that the Flexible Resource Analysis was only one component of the further diligence NIPSCO performed on the preferred portfolio from its 2021 IRP. He said that although the conclusions from the Flexible Resource Analysis supported and contributed to NIPSCO's sizing decision for the CT Project, NIPSCO also performed a 2023 portfolio analysis to assess the performance of alternative portfolio options against updated market conditions and the latest available information.

Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Augustine responded that although MISO's seasonal construct was implemented after the submission of NIPSCO's 2021 IRP, NIPSCO anticipated this change and evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options in its 2021 IRP to develop portfolios based on capacity requirements for both the summer and winter seasons. He also stated NIPSCO's 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after the Federal Energy Regulatory Commission ("FERC") approved MISO's seasonal construct. He testified higher winter reserve margin targets contributed to higher requirements for dispatchable thermal or storage capacity additions in the 2023 portfolio analysis relative to the levels evaluated in NIPSCO's 2021 IRP, which was directly accounted for in the portfolio construction.

Ms. Sommer's testified she did not perform independent modeling in part due to concerns the portfolios that were examined included projects that NIPSCO has canceled. Mr. Augustine responded that while some of the portfolios did include projects that had been canceled, preferred Portfolio 3 was explicitly developed to incorporate the risk of project cancellations, specifically the potential loss of four out of ten or 700 MW of solar and 30 MW of storage of NIPSCO's current solar and solar plus storage projects. He stated that consistent with these assumptions, NIPSCO has since filed termination notices for these four projects and has used the 2023 portfolio analysis to support replacement of these projects with incremental wind and solar capacity,[5] as explicitly modeled in preferred Portfolio 3 and approved by the Commission.

Mr. Hanks argues the costs used for new peaking capacity in the 2023 portfolio analysis were artificially inflated and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Augustine responded that Mr. Hanks

[5] NIPSCO filed a CPCN for the 200 MW Appleseed solar project and the 200 MW Templeton wind project in Cause No. 45887 (approved September 13, 2023) and a CPCN for the 200 MW Carpenter wind project in Cause No. 45908 (approved October 18, 2023).

appeared to misunderstand what NIPSCO requested in the two RFPs that were issued in 2022, as well as the types of bids that were received. As a result, he argued the comparisons Mr. Hanks attempted to make are inappropriate. He stated that contrary to Mr. Hanks' claims, NIPSCO's Schahfer Development or Engineering, Procurement, and Construction ("EPC") RFP was not technology and configuration restricted. He explained while NIPSCO did require a dispatchable, blackstart-capable resource at the Schahfer site with several other performance criteria, no restrictions were placed on the technology and configurations that could be proposed by bidders, and bids into this RFP were used by NIPSCO and CRA to arrive at the $1,440/kW direct capital cost number presented in his direct testimony and in the 2023 portfolio analysis.

Mr. Augustine testified Mr. Hanks' criticism that the capital costs for the CT Project used in his analysis understate the costs of the project by excluding indirect costs is misplaced. He stated that for modeling purposes, to ensure an "apples-to-apples" comparison with other potential resource options, only the direct costs of the project were included in his analysis, which is both commonplace and appropriate. He explained that while NIPSCO includes indirect costs in the overall project cost estimate, these costs are generally ancillary to the core project components and incorporate overheads and other internal allocations. He testified that including these company-specific indirect costs in weighing resource options would serve only to skew the results and the purpose of the portfolio and revenue requirement modeling analysis he performed is primarily to compare costs of resource options; therefore, excluding indirect costs provides a direct cost comparison, which is a more meaningful and reasonable approach.

Ms. Sommer testified the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Mr. Augustine responded that the Flexible Resource Analysis was designed to assess the energy adequacy and flexibility characteristics of NIPSCO's preferred portfolio from the 2021 IRP and to analyze and characterize the potential for market exposure risk. He stated that as Ms. Sommer correctly points out, the Flexible Resource Analysis was not an economic assessment, but a means of assessing the magnitude, frequency, and duration of market exposure risk and the overall ability for NIPSCO's portfolio to be positioned to respond to evolving market conditions and bring its fair share of reliability attributes to the system in the face of uncertain MISO rules. Mr. Augustine testified although NIPSCO did not quantify the costs of market exposure risk in the Flexible Resource Analysis, the key outcomes are supportive of the fact that additions of long-duration dispatchable capacity like the CT Project will improve reliability and reduce market exposure cost risk for customers, which Ms. Sommer did not challenge.

Mr. Augustine testified Ms. Sommer's argument that there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis is inaccurate. He stated that in addition to the resource attribute needs identified in the Flexible Resource Analysis, NIPSCO's 2023 portfolio analysis specifically evaluated a portfolio with additional battery storage resources and no new thermal peaking capacity to assess the economic tradeoffs relative to the portfolio that contained the new peaker, and that it concluded the portfolio with new peaking capacity was lower cost for customers. He noted NIPSCO's 2021 IRP did the same and concluded that the portfolio with new peaker capacity performed similarly or better on cost-based metrics than a portfolio relying only on storage and best on the reliability metrics. Mr. Augustine testified NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project.

Mr. Gorman testified NIPSCO has failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project. Mr. Augustine explained NIPSCO's 2021 IRP did evaluate a scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman. Mr. Augustine noted NIPSCO incorporated the potential for additional industrial load migration to the new industrial rate service structure. The scenario incorporated a reduction of firm industrial load in Rate 831 down to 70 MW. He further explained that NIPSCO's 2021 IRP shows its preferred portfolio performed well under these assumptions.

Ms. Sommer proposes battery storage and demand response resources be deployed because these resources can be added quicker than the CT project can be built. Mr. Augustine testified while development and deployment timelines will vary by resource, NIPSCO's preferred portfolio from its 2021 IRP and 2023 portfolio analysis contemplated new battery storage and demand side management resource additions by 2028, and he expects additional capacity additions will be identified as NIPSCO continues its ongoing resource planning activities in 2024 and beyond. He explained the resource is expected to be in service by the end of 2027, in advance of the 2028/29 planning year when the MISO rules are due to change, and the resource offers a firm, dispatchable addition to NIPSCO's portfolio that will help fill the existing and emerging capacity gap.

Mr. Augustine disagreed with Ms. Sommer's suggestion that battery resources will have stronger capacity accreditation than natural gas peaker resources and her statement that NIPSCO's capacity calculations overstate summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. He testified future capacity accreditations under D-LOL remain too uncertain to definitively make such a claim, and the forward-looking information published by MISO is supportive of the assumptions used in NIPSCO's 2023 portfolio analysis, which included stable accreditation for gas resources and declining accreditations for four-hour battery storage resources over time.

In response to Ms. Sommer's levelized cost analysis, which compared the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site and suggested that new battery additions would be lower cost than NIPSCO's proposed CT Project, Mr. Augustine opined that while levelized cost analysis can be a useful way of comparing resource options, Ms. Sommer's calculations were not performed correctly, nor do they replace the 2023 portfolio analysis performed by NIPSCO and CRA, which aimed to provide a more holistic comparison of NIPSCO's preferred portfolio concept versus one that relies primarily on new storage additions. Mr. Augustine described a significant calculation error and several limitations relative to the 2023 portfolio analysis in Ms. Sommer's analysis.

Mr. Hanks' and Ms. Sommer's oppose NIPSCO's application in part because of the cost of the aeroderivative turbine component, and Mr. Hanks' argues NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units. Mr. Augustine testified NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis identified growing 3-hour and 10-minute ramping requirements by 2030.

B. <u>CT Project</u>. In her direct testimony, Ms. Becker explained how NIPSCO supported, through sufficient evidence, the statutory requirements for the issuance of a CPCN, including financial incentives, under Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and 8-1-8.8-11. She sponsored Attachment 1-A showing each element of Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and ch. 8-1-8.8 and identified the NIPSCO witness with supporting testimony.

Ms. Becker explained how NIPSCO supported the requirements set out in Ind. Code § 8-1-2-0.6. She sponsored Attachment 1-C showing each of the Five Pillars, which includes reliability, affordability, resiliency, stability, and environmental sustainability. and identified the NIPSCO witness with supporting testimony. She also explained how NIPSCO has addressed the guidelines for additional evidence to be provided pursuant to IURC GAO 2022-01. She sponsored Attachment 1-D providing the required information as it pertains to NIPSCO's request for approval under Ind. Code chs. 8-1-8.5 and 8-1-8.8 in this Cause. She also sponsored Attachment 1-G, which is the Affidavit of Andy Witmeier, Director of Resource Utilization for MISO, providing a qualitative assessment regarding the new generation, including NIPSCO's request to MISO. In her supplemental testimony, Ms. Becker described NIPSCO's follow-up contact with MISO considering the shift in the in-service date.

Ms. Becker testified NIPSCO followed the guidelines applicable to applications for a CPCN established in the Commission's General Administrative Order 2023-03 ("GAO 2023-03"). She sponsored NIPSCO's notice of its intent to file an application for a CPCN as Attachment 1-E. She also testified NIPSCO met to discuss its filing with the Commission on May 8, 2023, the OUCC on May 24, 2023, and CAC on July 12, 2023. She sponsored an index of issues and identification of the witness(es) addressing each of the issues as Attachment 1-F.

As it relates to the statutory requirements set out in Ind. Code § 8-1-8.5-4, Ms. Becker addressed the requirement to consider conservation and load management. She testified that based on her experience with NIPSCO's energy efficiency ("EE") initiatives, NIPSCO could not derive sufficient energy savings from EE to replace Schahfer. She said NIPSCO is committed to the development of demand response programs for all customer groups but concluded that demand response would not eliminate the need for the CT Project, and, based on how such plants are constructed, would likely not reduce the size of the project.

Mr. Walter described NIPSCO's current generation fleet and explained the ultimate portfolio NIPSCO currently expects to have in place to serve its customers after its coal-fired generating units are retired over the next five years. He opined the CT Project is a clean energy project as that term is defined in Ind. Code § 8-1-8.8-2. He addressed how the proposed construction of the CT Project relates to the Five Pillars outlined in Ind. Code § 8-1-2-0.6.

Mr. Austin explained NIPSCO's gas distribution system as it relates to the CT Project, the quick-start, fast-ramping, and other important capabilities of the CT Project at the Schahfer site, and the CT Project's contribution to NIPSCO's system reliability.

Mr. Warren sponsored the Engineering Study prepared by S&L, which set forth the Class 3 cost estimate for NIPSCO's proposed simple cycle gas turbine project that was used by NIPSCO to develop its best estimate of the costs of the proposed CT Project. He presented information regarding the engineering work completed by S&L in support of NIPSCO's request for approval

of a new peaker power plant to be located at the Schahfer site.

Mr. Baacke explained the CT Project, including key specifications and characteristics, the approach to configuration selection and the contracting strategy for the CT Project. He also provided the project schedule and the best estimate of costs of construction. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units (dependent on the results of the CT original equipment manufacturer ("OEM") bid event). Finally, he discussed how the CT Project satisfies Ind. Code § 8-1-8.5-5(e).

Mr. Stanley discussed: (1) how the CT Project will interconnect into the MISO market through the replacement generation interconnection process, (2) NIPSCO's need for capacity from a peaking unit, and (3) how NIPSCO will procure gas supply for the Project at the lowest reasonable cost. Finally, he discussed how the CT Project is consistent with the resource alternatives that must be evaluated under Ind. Code § 8-1-8.4-4.

i. Best Estimate. In his direct testimony, Mr. Baacke stated NIPSCO employed S&L to help develop a scope of work to obtain preliminary quotes for major equipment during the engineering study phase to support the cost estimate shown in Appendix 20 of the Engineering Study (Highly Confidential Attachment 4-A). He stated S&L then supported NIPSCO by drafting technical specifications for the EPC RFP. He said the cost estimated by S&L was compared to the costs for gas-fired projects bid into the EPC RFP. He explained that after NIPSCO elected to move forward with the self-build option to capture cost savings and other advantages, S&L developed technical specifications to support a competitive bid event for the procurement of turbines for the CT Project that occurred in June 2023 (the "turbine equipment RFP") with bids received August 7, 2023. He indicated that similar competitive bid events are planned to be completed for other major equipment as well as major construction contracts.

Mr. Baacke testified the EPC RFP was issued in Fall 2022, seeking bids for projects between 370 MW to 450 MW. He stated technical specifications for the EPC RFP were drafted because of the work previously performed in collaboration with S&L during the engineering study phase. He testified bidders were requested to provide proposals with a combination of industrial frame and aeroderivative combustion turbines meeting specific performance criteria. He explained the performance criteria included desired machine sizing, cold start timing, ramp rates, minimum emission compliant loads, emission limits, remote start and operational capabilities, and other reliability capabilities.

Mr. Baacke described the results of the proposals were received from three bidders. One bid did not meet the performance criteria of the technical specifications and provided less than five pages of information and was not evaluated for further consideration. A second bid provided a proposal that consisted of ten refurbished aeroderivative turbines which did not align with the RFP criteria or the performance criteria of the technical specifications. A third bid aligned with the technical specifications however, the proposal price was $100 million more than the self-build option costs of construction. He testified NIPSCO ultimately chose the self-build option, which is in the best interest of NIPSCO and its customers.

Mr. Baacke described the procurement and bid process NIPSCO is using to purchase equipment for the CT Project. He stated NIPSCO plans to utilize a multi-prime contracting strategy for the CT Project, which is different from an engineering, procurement, and construction contracting strategy in which a single entity would be utilized to perform all engineering, procurement, construction, and start up and commissioning activities to complete the project. He stated NIPSCO plans to hold competitive bid events whenever practical for major equipment such as generator step-up transformers, unit auxiliary transformers, generator circuit breakers, switchgear, and other associated auxiliary equipment and to procure smaller equipment and materials through preferred suppliers that were identified through prior strategic sourcing events.

Mr. Baacke testified NIPSCO's multi-prime contracting strategy applies to construction on the CT Project as well. He stated NIPSCO plans to develop bid packages to competitively bid the three major scopes of construction in 2024: (1) site preparation/civil construction contract, (2) general works construction contract, and (3) an electrical installation contract. Mr. Baacke testified that under this planned construction and bid process, NIPSCO will have allowed third parties to submit firm and binding bids for the construction of the CT Project on NIPSCO's behalf that meet all the technical, commercial and other specifications so as to enable ownership of the CT Project to vest with NIPSCO not later than the date the facility becomes commercially available.

Mr. Baacke testified the best estimate of the total cost of construction for the CT Project is $641,223,000, which includes indirect costs but excludes allowance for funds used during construction ("AFUDC"). He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. He stated that based upon estimates of AFUDC at the time of this filing, the total estimated cost, including AFUDC of $2,468,449, is $643,691,449.[6] Mr. Baacke stated the cost estimate was developed with the support of S&L. Mr. Baacke sponsored the best estimate of cost summary in Attachment 5-A as well as a more detailed estimate of cost summary in Confidential Attachment 5-B.

In his supplemental direct testimony, Mr. Baacke discussed supply chain challenges that affected the project schedule and how NIPSCO's election to self-build utilizing a multi-prime contracting strategy has allowed NIPSCO to pivot in the face of these challenges without a presently anticipated impact to the best estimate. He sponsored an updated CT Project schedule and best estimate of costs of construction.

Mr. Baacke stated NIPSCO's originally estimated in-service date for end of year 2026 was with the understanding the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained this timeline included some flexibility as is typical for significant construction projects, especially given supply chain challenges are more commonplace since COVID-19. He stated that based on the expectation that the combustion turbines and generation step-up transformers would be the longest lead time equipment, NIPSCO went out for bid on these components before filing its request for a CPCN and noted NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Mr. Baacke testified NIPSCO's election to self-build with a multi-prime contracting

[6] NIPSCO Witness Mr. Blissmer testified that if NIPSCO's proposed CWIP ratemaking is approved, AFUDC is projected to be very limited, and would include only actual AFUDC accrued to date and through the effective date of the GCT Mechanism, expected to be in October 2024.

strategy was beneficial in the face of these supply chain challenges because it allowed NIPSCO to pivot without a presently anticipated impact to the best estimate. He noted other contracting structures, such as with an EPC contractor, would likely have required the execution of a change order to shift the in-service date to end of year 2027 and increased costs as a result. Additionally, he stated NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its vendor relationship.

In his supplemental testimony, Mr. Baacke testified the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. Based upon estimates of AFUDC at the time of this supplemental filing, Mr. Baacke testified the total estimated cost, including AFUDC of $1,531,039, is $642,754,039.

OUCC witness Ms. Armstrong recommended costs associated with certain pollution control technology be removed from the CT Project best estimate. Ms. Armstrong stated NIPSCO can seek approval of any future pollution control costs as federally mandated costs under the Federal Mandate Statute at Ind. Code ch. 8-1-8.4. Ms. Armstrong stated the OUCC does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable.

OUCC witness Mr. Hanks stated NIPSCO's best estimate potentially double counts indirect costs. Mr. Hanks stated NIPSCO did not justify a 5% escalation factor and recommended its proposed escalation be reduced to 3% to match its electric Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan. Mr. Hanks compared the cost of NIPSCO's proposed CT Project to average technology costs from the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook of 2023 and to the cost of CEI South's CTs.

OUCC witness Mr. Krieger stated the OUCC is concerned with NIPSCO's estimated owner's costs. He believed NIPSCO's application of a simple nine percent is not supported or justified for a complex project. Mr. Krieger believed the owner's costs would be significantly less when an EPC contractor is hired.

IG witness Mr. Gorman stated NIPSCO's cost estimate should be rejected because it is not based on firm pricing because of competitive bids received from contractors, but rather on preliminary market analysis of the expected costs.

CAC witness Ms. Sommer argued for prejudgment of the prudency of certain actions and prospective disallowance of costs. Ms. Sommer argues for a cost cap on project costs. Ms. Sommer recommended denial of NIPSCO's request based on the cost of the aeroderivative turbines. Ms. Sommer recommended that costs to serve customers in order to accommodate a delay in the online date of the CT Project be disallowed including but not limited to capacity and energy costs.

Mr. Baacke disagreed with CAC witness Mr. James' assertion that a self-build approach is not in customers' best interests and adds significant risk to the Project cost. He testified NIPSCO has experience with both EPC and multi-prime contracts and provided some of NIPSCO's history of successfully executing on large and complex projects below.

In response to several witnesses claims that entering an EPC contract can mitigate cost risk and multi-prime contracting may translate into additional ratepayer costs, Mr. Baacke testified that while EPC contracts can provide some benefits, the parties fail to appreciate that, to create certainty, an EPC contractor is paid for risks that could potentially be avoided, mitigated, or not occur at all. Mr. Baacke testified that both contracting strategies have benefits and the potential for increased costs; however, for the CT Project, and after careful consideration, NIPSCO determined the multi-prime contracting strategy offers a greater potential for savings on the overall cost of the project, especially when managed effectively and scoped accurately.

OUCC witness Mr. Krieger and CAC witness Mr. James claim NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. Mr. Baacke explained NIPSCO is leveraging engineering firms including S&L, construction contractors, and suppliers, including the original equipment manufacturer ("OEM"), who have completed comparable projects. He testified NIPSCO's Major Projects team has completed a number of projects of varying complexity, including several projects that are first of their kind or one-of-a-kind projects and at the time of completion, within the industry.

Mr. Baacke testified Mr. Krieger's review of the accuracy as a percentage of budget for each project that he has served a major role is not a fair and complete picture of his project management experience. This review only shows the project variances in absolute dollars, which ignores the variances on these projects have been both higher and lower than the original budgets. He stated that in relative dollars, NIPSCO's original budgets versus actual costs for the referenced projects shows that, on an overall original budget of $1.41 billion, projects that have been completed under Mr. Baacke's direction and supervision reflect a negative variance of approximately -2.4%. This data reflects NIPSCO's commitment to manage the construction of the CT Project such that the Project is executed on time and on budget.

Mr. Baacke clarified S&L's scope of work in the CT Project. He stated S&L has also been contracted by NIPSCO to complete the detailed design for the CT Project. He testified NIPSCO plans to contract with S&L to provide onsite support during construction, start up and testing to provide quality assurance and quality control during installation. Mr. Baacke testified the costs associated with these additional services is included in NIPSCO's best estimate.

Mr. Baacke sponsored Attachment 5-R-A and Confidential Attachment 5-R-B showing the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred and that based upon estimates of AFUDC at the time of this rebuttal filing, the total estimated cost, including AFUDC of $2,680,234, is $643,903,234.

Mr. Baacke emphasized NIPSCO's best estimate although reasonable, is still an estimate; customers will pay the actual costs of the CT Project. He testified that prices for practically all products and materials in the U.S. are increasing, including the key equipment needed to construct the CT Project; this is an undeniable macroeconomic fact, which is beyond NIPSCO's control. He testified NIPSCO ran a competitive RFP, engaged S&L to assist with engineering and cost estimation, chose a multi-prime contracting approach which was $100 million lower in cost than

any viable EPC option, and brought a reasonable, best estimate to the Commission to support a finding of best estimate of costs in this proceeding.

ii. Configuration and Competitive Procurement. Mr. Baacke testified the CT Project is expected to consist of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. He explained NIPSCO is targeting an F Class combustion turbine for the larger industrial frame turbine, which has been on the market for over 30 years and has a proven history of solid, reliable performance. General Electric's F Class combustion turbine has been upgraded to its 7FA.05 model with power output and heat rate values at ISO conditions of approximately 239 MWs and 8,871 btu/kWh (LHV) and shorter start times to as little as 11 minutes and ramp rates as high as 50 MWs per minute. Similar performance exists for Siemens Energy's SGT6-5000F combustion turbine. Larger industrial frame units typically have a lower capital cost per kilowatt to install, require fewer machines, and generally have longer intervals between maintenance when compared to aeroderivative turbines.

He explained NIPSCO is including three smaller aeroderivative or similarly sized industrial frame turbines in the CT Project. Aeroderivative turbines are typically more efficient, start faster and frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. These features, along with market import capabilities, allow a utility to install large volumes of renewable energy and still maintain the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when the intermittent renewable resources are not available for short or prolonged periods of time.

Mr. Baacke testified NIPSCO chose the preferred configuration to maximize benefits to NIPSCO and its customers. This preferred configuration was needed to conduct an RFP to seek proposals for the EPC RFP. NIPSCO and S&L developed a decision matrix to select the equipment configuration that would be used for purposes of the EPC RFP. This evaluation included performance criteria to align with the Flexible Resource Analysis, operational factors, costs, environmental factors, and schedule.

Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated NIPSCO already owns the property. He said constructing the CT Project on this site provides cost savings and advantages for NIPSCO, its customers, and the local economy.

As discussed by NIPSCO witness Mr. Stanley, NIPSCO holds interconnection rights at the Schahfer site related to Units 17 and 18 that will be retiring by the end of 2025. The MISO grid interconnection rights can be transferred from existing coal units to the CT for up to three years after retirement.

OUCC witness Mr. Hanks claims the EPC RFP prevented bidders from proposing less expensive all industrial frame configurations, Mr. Baacke testified EPC RFP bidders were not prevented from proposing all industrial frame configurations. He testified the technical specifications for the EPC RFP, which are over two hundred pages, were provided to the parties in discovery and shows that the EPC RFP asked bidders to select a combination of industrial frame and aeroderivative CTs and optionally, reciprocating internal combustion engines that could meet certain defined constraints, including (1) total net output between 370 MW and 450 MW; (2) maximum machine size of 275 MW; (3) at least one machine 150 MW or larger; (4) 10-minute

cold start capability for 150 MW or more; (5) 50 MW/minute minimum ramp rate for at least 150 MW of the Facility's machines; and (6) at least one machine with a minimum emission compliant load less than or equal to approximately 25 MW. He testified the defined constraints were assembled to provide potential bidders with enough information to know the type of project that would fit the needs identified by NIPSCO and CRA through the Flexible Resource Analysis, but freely allowed potential bidders to provide bids that would include one larger industrial frame machine and multiple smaller aeroderivative or industrial frame units.

Mr. Baacke noted that while Mr. Hanks claims NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness Mr. James claims the quality of NIPSCO's EPC RFP was wanting insofar as it relies upon a project that needs more definition and planning. Mr. Baacke testified that while the OUCC and CAC appear to disagree on the appropriate level of detail needed in the RFP, NIPSCO's balanced approach falls reasonably between the two.

Mr. Baacke testified NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show NIPSCO properly vetted the EPC RFP bids. He stated given the EPC RFP bid results and NIPSCO's history with successful project execution, NIPSCO made the prudent decision to pursue a multi-prime contracting strategy.

OUCC witness Ms. Sanka's claims NIPSCO failed to evaluate the configuration with one large industrial frame and smaller industrial frame, similarly sized to the aeroderivative turbines, in the decision matrix of S&L's Engineering Study. Mr. Baacke testified this criticism is misplaced. He explained smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines; therefore, it was not necessary to perform a separate analysis for a large industrial frame with smaller industrial frame machines.

NIPSCO witnesses Mr. Augustine and Mr. Holcomb explain in their rebuttal testimony that the U.S. Environmental Protection Agency released greenhouse gas emission rules for the power sector on April 24, 2024, which lay out the best system of emission reduction standards for new natural gas-fired facilities based on their capacity factor. Mr. Holcomb explained that based on the expected operational characteristics of NIPSCO's proposed units, the overall CT Project will be able to operate within the standards of the rule. Furthermore, given their higher efficiencies, the aeroderivative turbines will be able to more easily achieve the 1,170 lb. CO2/MWh standard than the frame turbine, offering more flexibility and optionality for NIPSCO to operate the units at higher capacity factors should conditions within the MISO market make such operations beneficial for its customers.

OUCC witness Ms. Sanka claims that, base load plants come at a lower initial cost and have lower operations and maintenance costs compared to a peaker plant containing aeroderivative units, making them more financially viable. Therefore, in a 30-year lifespan, the cost-effectiveness of using a configurated base load plant outweighs the benefits of using a configuration containing aeroderivative technology for peaker plants. Mr. Augustine explained Ms. Sanka's framing of the cost-effectiveness evaluation is incomplete, particularly as resource planning questions become more complex.

5. Commission Discussion and Findings. Since the issuance of its 2021 IRP, NIPSCO has continued to evaluate and analyze its generation needs considering ongoing changes in market rules, supply chain, and other broader market changes. NIPSCO's most current analysis identifies a need for a gas-fired resource between 400 MW and 442 MW. Based on the needs associated with the retirement of most of NIPSCO's coal-fired generation by the end of 2025 and the addition of renewable resources, NIPSCO seeks to construct and operate the CT Project as a part of its overall, diverse portfolio of generation assets. Once operational, the facility will be a central part of NIPSCO's electric generating fleet, because it will provide key reliability attributes and additional capacity, particularly in the winter season.

NIPSCO's Flexible Resource Analysis concluded increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized thermal resource as compared to more expensive storage additions. The Flexible Resource Analysis identified potential reliability issues resulting from the relatively large share of planned renewable generation in NIPSCO's preferred portfolio and assessed flexibility needs on an inter-hour and intra-hour basis. The analysis also evaluated how NIPSCO's mix of resources is likely to perform in 2030 compared to 2021 and identified that the 10-minute ramp requirements are increasing by 150 MW. NIPSCO's EPC RFP specifications for the proposed CT Project included requirements of a 10-minute ramp cold start capability for 150 MW or more and a 50 MW/minute ramp rate for at least 150 MW. The OUCC agrees NIPSCO needs load-following generation. We conclude that the CT Project is an economical decision that will aid in reliability; therefore, the Commission grants the requested CPCN for the CT Project.

A. CPCN for CT Project Under Ind. Code § 8-1-8.5-5. Ind. Code § 8-1-8.5-2 states that a public utility must obtain a CPCN from the Commission prior to constructing, purchasing, or leasing a facility for the generation of electricity. Ind. Code § 8-1-8.5-5 sets forth the criteria for approving a utility-specific generation proposal. In granting a CPCN, the Commission must make findings on the best estimate of the project's cost based on the record, whether the proposal is consistent with our statewide analysis or a utility-specific proposal, and whether public convenience and necessity require the project. The Commission must also consider the items set forth in Ind. Code § 8-1-8.5-4. We address the required findings and review each factor in Ind. Code § 8-1-8.5-4 below.

i. Best Estimate of Costs. Under Ind. Code § 8-1-8.5-5(b)(1), a CPCN may be granted only if the Commission makes a finding "as to the best estimate of construction, purchase, or lease costs based on the evidence of record[.]"

Mr. Baacke explained the CT Project, including key specifications and characteristics, as well as NIPSCO's approach to configuration selection and contracting strategy. He provided the project schedule, the best estimate of costs of construction, and NIPSCO's request for ongoing review pursuant to Ind. Code § 8-1-8.5-6. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. Mr. Walter explained NIPSCO's cost estimate is the best estimate currently available and will be updated as the project proceeds, consistent with the Commission's requirements and NIPSCO's request for ongoing review.

Mr. Walter testified NIPSCO began with a competitive EPC RFP and engaged the assistance of Sargent and Lundy. Based on available information in the market and the bids received, NIPSCO determined the best path is to self-build the CT Project, leveraging the available interconnection rights from retiring generation at Schahfer. NIPSCO issued its turbine equipment RFP in June 2023 and executed an agreement with its turbine manufacturer on March 29, 2024 to reserve the selected equipment. Mr. Baacke's supplemental direct testimony described unexpected supply chain challenges impacting NIPSCO's ability to timely procure breakers and generator step-up transformers, and explained that this caused NIPSCO to shift the expected in-service date for the CT Project to year-end 2027. Despite this change, the best estimate of the total cost of construction did not change.

Mr. Blissmer testified NIPSCO is currently carrying significant preliminary, survey, and investigation costs on its books that it will record to the cost of owned generating resources, a portion of which will be applied to the new CT Project. These preliminary, survey, and investigation costs were not challenged by any party and are included in NIPSCO's best estimate of the cost of construction for the CT Project.

NIPSCO's best estimate of the total cost of construction (excluding AFUDC) for the CT Project is $641,223,000. NIPSCO confirmed its cost estimate in its supplemental testimony based on updated supply chain information. Mr. Blissmer explained NIPSCO removed escalation and reduced the amount of contingency associated with owner's costs and certain equipment. The total estimated cost of the CT Project, including estimated AFUDC of $2,680,234, is $643,903,234. This AFUDC estimate assumes NIPSCO's proposed forward looking GCT Mechanism is approved.

The following discussion details the challenges to NIPSCO's best estimate.

a. <u>Configuration of CT Project</u>. CAC witness Mr. James opined NIPSCO and S&L progressed through project initiation with less than adequate attention to current best practices for early project definition, namely a Front-End Engineering and Design ("FEED") study, and that NIPSCO's process to reach a final investment decision remains questionable. Based on the evidence presented, we find that NIPSCO and S&L's design and engineering process was thorough, consistent with industry standards, including the Association for the Advancement of Cost Engineering cost classification, and rigorous in evaluating three different configurations for the design of the CT Project. Mr. Warren explained FEED studies evaluate whether a project should move forward at each step or stage and is unnecessary because of the IRP process and S&L's Engineering Study. The process NIPSCO used to develop its CT Project is like processes we have seen used by other utilities for which we have approved CPCNs. While FEED studies have been used for other projects in Indiana, we have only seen them in connection with novel technologies, such as coal gasification or carbon capture. In designing and engineering the CT Project, NIPSCO leveraged S&L's extensive power industry expertise. S&L's Engineering Study provided NIPSCO with the level of information needed to determine the technology and configuration that best meet the simple cycle gas turbine requirements.

Based on the evidence of record, we find NIPSCO's CT Project was properly scoped, designed, and engineered and that NIPSCO and S&L's up-front design activities reasonably align with the intended purpose of CAC witness Mr. James' recommended design process. As such,

NIPSCO is not required to complete any further front-end engineering and design diligence.

The OUCC and CAC took issue with NIPSCO's EPC RFP. The OUCC asserts that NIPSCO's EPC RFP was too narrow. CAC witness Mr. James alleges that a lack of detail contributed to the poor response rate to the RFP. The OUCC and CAC both challenge the aeroderivative turbines due to their cost. OUCC witnesses Ms. Sanka and Mr. Hanks assert that operational characteristics of the aeroderivative units do not justify the higher overall expenditure when compared to a configuration comprised of only industrial frame turbines. CAC witness Ms. Sommer recommended denial of the CT Project due to the three aeroderivative turbines and suggested reducing the cost of the CT Project by replacing the aeroderivative turbines with a second industrial frame machine.

Three of the Five Pillars we are charged with evaluating in the context of a CPCN for new generation are reliability, resiliency, and stability. We observe that before us is a request for new generation that is specifically designed with load-following characteristics to support NIPSCO's evolving generation fleet. NIPSCO's 2021 IRP Short-Term Action Plan identified a need for a thermal peaking option to mitigate the energy adequacy and flexibility characteristics of the IRP's largely renewable, and therefore intermittent, preferred portfolio. NIPSCO conducted further diligence through its Flexible Resource Analysis, which evaluated the risks associated with times of resource unavailability and market purchase exposure. Informed by these analyses, in its EPC RFP, NIPSCO sought bids for projects between 370 MW and 450 MW with certain performance criteria. This analysis further refined the need by noting that there is a significant growth in the need for faster ramping resources. The analysis shows that 150 MW with a ramp rate of 10 minutes is needed by 2030. As such, the EPC RFP specification included, among other things, 10-minute cold start capability for 150 MW or more and 50 MW/minute minimum ramp rate for at least 150 MW of the facility's machines. NIPSCO witness Mr. Baacke pointed out the Engineering Study recognized that smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, rendering a separate evaluation of an all-industrial frame configuration unnecessary. The technical specifications for NIPSCO's turbine equipment were appropriately driven by the key performance criteria identified in the Flexible Resource Analysis. The cost of the CT Project here is below the $1,440/kW in direct capital cost that was assumed in the 2023 portfolio analysis, which was based on the responses to NIPSCO's 2022 RFP.

The OUCC seeks to reduce the best estimate to remove the aeroderivative configuration. Mr. Krieger provides the reduction in cost as a range of $30-40 million; he does not provide the methodology to arrive at this amount. Ms. Sanka compared the cost of three aeroderivative units to the cost of a single larger frame unit using data pulled from Public Exhibit No. 3 Confidential Attachment RS-3, and her comparison produces a difference of $37.6 million. The single larger frame unit, which Ms. Sanka used for comparison, does not possess the same 10-minute cold start and ramp rates that the smaller industrial units or aeroderivative units. Ms. Sanka stated her objection is that NIPSCO did not evaluate a configuration with three smaller industrial frame units sized to match the aeroderivative units. However, the OUCC's proposed reduction is based upon a peaker unit that would not possess the start time and ramping rates that NIPSCO requires.

The OUCC's and CAC's evidence fails to counter the fact that aeroderivative turbines provide several attributes that complement NIPSCO's largely renewable portfolio, including fast start capability, the ability to start and stop multiple times per day without impacting maintenance

cycles, and high efficiency. The fast-ramping capability of the aeroderivative turbines provides functionality that will satisfy reliability needs within NIPSCO's service territory and the MISO footprint.

CAC witness Ms. Sommer testifies that, if certain MISO market reforms are implemented, NIPSCO will likely need more capacity starting in 2028, even if the proposed CT Project enters into service. It is this capacity potential that unlocks the unique customer benefit of the aeroderivative turbines. NIPSCO's rebuttal evidence establishes that the aeroderivative units provide NIPSCO with flexibility to qualify as an intermediate load unit and potentially operate at greater capacity factors than an industrial frame unit, while remaining compliant with the Rule's emissions limits. Absent adequate capacity, to manage resource adequacy, NIPSCO will have to purchase capacity on the market. It is this rationale that drives us to decline CAC's invitation to prejudge NIPSCO's proactive capacity purchases as described by NIPSCO witness Mr. Stanley.

OUCC witness Hanks' testimony raises general arguments about the cost of the CT Project, intimating that its cost per kilowatt should not exceed the cost of CEI South's CTs approved in Cause No. 45564 or the average cost per kilowatt located in the EIA 2023 Energy Outlook. We reject comparison between the CT Project and the average cost per kW figures in the EIA's 2023 Outlook, as EIA's own Administrator plainly stated that the Outlook is not intended to provide estimates or predictions. Mr. Hanks did not attempt to reconcile the many factors that could impact – positively or negatively – the installed cost per kW of various technologies. As to Cause No. 45564, we note that NIPSCO and CEI South operate under different generation constraints and customer composition. CEI South's project was designed three years ago within a different market. There is substantial record evidence describing the current high demand for critical equipment and contractors within the power industry. CEI South's CTs were designed before the escalation in demand for CTs occurred, which has created a more competitive construction market. The OUCC did not include the estimated $27.3 million in annual expense CEI South will incur to receive gas supply from a new 24-mile pipeline. The estimated cost of NIPSCO's gas interconnection (which is under $1.5 million) was discussed by NIPSCO witness Mr. Austin in his direct testimony and was included within the best estimate for the CT Project.

The technical specifications for the combustion turbine equipment were sufficiently defined, appropriately developed to address the needs of NIPSCO's renewable portfolio without limiting bidders to a specific kind of technology, and consistent with industry standards. We find NIPSCO's preferred configuration of one industrial frame turbine and three aeroderivative turbines is appropriately informed by the results of the bid event and will provide critical, stable, load-following generation. Finally, given the substantial evidence on the important, load-following attributes the aeroderivative turbines provide, we find the aeroderivative turbines are cost-justified and appropriately included in NIPSCO's preferred configuration for the CT Project.

b. <u>Contracting Strategy for CT Project</u>. The OUCC and the CAC challenged NIPSCO's decision to self-build the CT Project, as opposed to utilizing an EPC contractor. OUCC witness Mr. Krieger testified the OUCC is concerned with NIPSCO's self-build project management approach including its ability to properly manage construction, as well as its ability to manage and mitigate financial challenges. CAC witness Mr. James testified NIPSCO lacks experience constructing power plants and NIPSCO's contracting strategy is similar to one of the strategies Duke Energy Indiana attempted to employ during the construction of the

Edwardsport Integrated Gasification Combined Cycle project.

The record contains evidence regarding the results of NIPSCO's EPC RFP bid. Mr. Baacke's direct testimony stated NIPSCO received three EPC bids – one that was $100 million more than the self-build option, and two bids that were inconsistent with technical specifications. NIPSCO conducted extensive due diligence to evaluate each bid received to determine whether its technical specifications could be met at a reasonable cost, and ultimately chose to self-build the CT Project.

The OUCC and CAC express general concerns that, without an EPC contractor, the risk of ratepayer-borne cost overruns from the construction of the CT Project has increased. This criticism ignores the fact that NIPSCO solicited bids from the EPC market and received only one bid that would have met its technical requirements, which we found were appropriately defined and reasonably driven by system needs, at a price that is $100 million more than NIPSCO's best estimate of construction in this Cause. While an EPC contract is a valid way to execute a generation project, it is not a requirement to receive a CPCN in Indiana nor is it a guarantee against project cost overruns.

OUCC witness Mr. Krieger and CAC witnesses Ms. Sommer and Mr. James claimed NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. The evidence in this Cause establishes that NIPSCO conducted diligence in both resource planning decisions and project design, engineering, and contracting. The evidence in this proceeding demonstrates that NIPSCO's team has sufficient experience to handle this project.

This is NIPSCO's first time overseeing construction of a new gas-fired generation project. The CT Project has undergone extensive upfront design and engineering. It will be built on an existing NIPSCO-owned site. No land acquisition will be needed and there is only the need for a 1,500-foot lateral pipeline to access NIPSCO's natural gas system. NIPSCO has prudently extended its runway to complete the CT Project through year-end 2027 and given the substantial reservation payment to the turbine equipment manufacturer, the evidence supports NIPSCO has a project plan in place enabling the CT Project to be constructed on time and on budget within reasonable constraints. The multi-prime strategy selected by NIPSCO produces a best estimate of costs that is $100 million less than the cost that would be produced under the only responsive EPC bid NIPSCO received.

CAC and NIPSCO agree demand for EPC contractors in the power industry is high. NIPSCO witness Mr. Warren testified this high level of demand has shifted EPC contractors' interest to larger projects that maximize their potential profits. We do not believe it would be prudent to require NIPSCO to pursue an EPC contract that could exceed the cost of NIPSCO's multi-prime contracting strategy by $100 million.

S&L has experience executing gas-fired generation projects. Based upon the evidence of record, we conclude NIPSCO selected a competent partner in S&L, and that this collaboration will continue throughout construction and start-up/commissioning of the CTs.

NIPSCO has availed itself of ongoing review of the CT Project pursuant to Ind. Code § 8-1-8.5-6. In issuing a CPCN, we approve the best estimate of costs. To the extent the utility incurs costs more than the best estimate that we approve, the utility will have the burden of demonstrating that the additional cost is reasonable. If other parties believe that the increase should be rejected, they retain the right to take such a position. The CAC and OUCC's fears over risk and escalation are all appropriately mitigated through ongoing review, which can serve to protect ratepayers from unnecessary costs and project mismanagement.

NIPSCO contends choosing the self-build option will decrease costs by $100 million. Due to the expected cost savings, the Commission approves NIPSCO choosing this option. The Commission emphasizes the importance of the estimated $100 million savings being realized. These savings shall be reflected in the updated cost estimates in the semi-annual filings discussed later in this order.

c. Best Estimate Cost Components. OUCC witnesses Mr. Hanks and Mr. Krieger challenged NIPSCO's indirect costs, alleging they lacked support and were potentially double counted in S&L's cost estimate. However, Mr. Baacke's rebuttal testimony explained that the confidential version of the best estimate shows one line item for "Indirects," which represents NIPSCO's indirect costs while S&L's indirect costs are reflected as "Misc Inside the Fence," "Misc Electric Interconnect," "Misc Gas Interconnect," and "Misc Water Interconnect" in NIPSCO's best estimate. He stated NIPSCO explained each cost category and how they were estimated in response to CAC discovery and that the itemization of S&L's indirect costs in Section 10.2.3 of the Engineering Study confirms these costs do not duplicate NIPSCO's indirect costs. We agree. NIPSCO's internal indirect costs are capital overhead and stores, freight, and handling while S&L's indirect costs are associated with construction management and start-up and commissioning support. These line items are separate and distinct, and we find that NIPSCO's evidence supports concluding no indirect costs were double counted.

Mr. Hanks challenged NIPSCO's proposed 5% escalation factor and recommended it be reduced to 3%, as was approved in NIPSCO's electric TDSIC Plan. We are convinced by NIPSCO's evidence that a 5% escalation factor is appropriate. NIPSCO's supplemental testimony describes the global supply chain uncertainty, which prompted the shift in the CT Project's in-service date to end of year 2027. Mr. Baacke's rebuttal testimony provides specific detail on the 70% cost increase for 345kV breakers, which NIPSCO has witnessed in a few months in late 2023. Given that NIPSCO's electric TDSIC Plan was approved before the COVID-19 pandemic and its resulting supply chain issues, we conclude reducing NIPSCO's escalation factor to what was approved in that proceeding is not appropriate. Accordingly, we find NIPSCO's 5% escalation factor is reasonable and approved.

Mr. Krieger opposed NIPSCO's 9% estimate for owner's costs, arguing it is too simple for a high-cost capital project and that owner's costs would be lower under an EPC contract. Based on updated cost information from executed contracts with certain suppliers, NIPSCO updated the 9% owner's cost estimate to $41,210,000 in Mr. Baacke's rebuttal testimony. We addressed the parties' concern with NIPSCO's contracting strategy above and found NIPSCO's self-build, multi-prime approach will reduce the cost of the CT Project for the benefit of customers. Based on the evidence provided, we conclude NIPSCO's estimated owner's costs are informed by executed contracts and are approved.

d. Pollution Control Technology. OUCC Witness Armstrong testified the Selective Catalytic Reduction units are not needed for the CT Project to meet current environmental requirements and that if they are required in the future, NIPSCO could seek recovery of any future pollution control costs through the Federally Mandated Cost Management ("FMCA") statute. Mr. Holcomb's rebuttal testimony confirmed the CT Project will comply with the final Greenhouse Gas ("GHG") Rule; therefore, NIPSCO updated the best estimate to reflect removal of the Selective Catalytic Reduction units. We approve this revision to the scope of the CT Project and recognize that as federal environmental regulations may change, Indiana law offers options utilities may consider for recovering compliance costs, including the FMCA statute.

e. Conclusion on Best Estimate. We find NIPSCO has submitted sufficient evidence supporting its best estimate on the cost to construct the CT Project, which is driven by its preferred configuration and contracting strategy along with its projected $100 million savings due to utilizing the self-build option. NIPSCO's best estimate is based on a detailed engineering analysis, information from turbine manufacturers and contractor bid events from which capital costs, operating costs, performance characteristics, and construction schedules were determined. The best estimate reasonably reflects the current market, industry trends, and the potential cost impact of project risk and factors beyond NIPSCO's control. The CT Project is reasonably designed to manage industry and economic challenges while facilitating the capacity and energy resources required by NIPSCO to meet its customers' ongoing need for electricity. Based on the evidence, we find that $641,223,000 (excluding AFUDC) is the best estimate of the cost of construction of the CT Project.

ii. Consistency with Petitioner's 2021 and 2023 Portfolio Analysis. Ind. Code § 8-1-8.5-5(b)(2) provides that a CPCN shall be granted only if the Commission has made a finding that either:

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under [Ind. Code § 8-1-8.5-3(e)(1)] and approved under subsection (d).

Ind. Code § 8-1-8.5-3(e)(1) provides that a public utility may submit "a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility[.]" Mr. Augustine sponsored Petitioner's 2021 IRP as Petitioner's Highly Confidential Attachment 7-B and a summary of the key inputs and outputs associated with the 2023 portfolio analysis as Petitioner's Highly Confidential Attachment 7-C. Thus, we find NIPSCO has submitted a utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

The record demonstrates that the CT Project is consistent with the Short-Term Action Plan identified in Petitioner's 2021 IRP.

We note at the outset that we have recently expressed support of NIPSCO's 2021 IRP process, stating that "NIPSCO's 2021 IRP process, which occurred in concert with the 2022 RFP, was robust and well developed, ultimately resulting in the Short-Term Action Plan on which the

proposed Appleseed and Templeton PPAs are based." *N. Ind. Pub. Serv. Co.*, Cause No. 45926 (IURC Nov. 22, 2023) at 20 citing *N. Ind. Pub. Serv. Co.*, Cause No. 45587 (IURC Sept. 13, 2023). IRPs are created at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. NIPSCO performed the 2021 IRP analysis and has appropriately responded to changes in the electric industry and the broader market and now seeks approval of generation additions based on the same foundation we have repeatedly found was sufficient. NIPSCO's 2021 IRP did not rely on a single set of assumptions that could later be invalidated by evolving market conditions. Since the 2021 IRP was issued, the timeline for implementation of the Short-Term Action Plan identified in the 2021 IRP has been three years (2022–2024), and NIPSCO's proposed CT Project is consistent with this timeline.

NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. The 2021 IRP continued to affirm earlier retirement of coal capacity resulted in lower costs for customers. The 2021 IRP concluded new additions should be predominantly renewable resources, supplemented by a diverse mix of other technologies, including an uprate to NIPSCO's existing Sugar Creek combined cycle, new thermal peaking capacity, new energy storage capacity, new distributed energy resources, and additional demand side management programs. These conclusions were informed by review of all metrics on NIPSCO's integrated scorecard, including cost to customer, scenario and stochastic-based cost risk, carbon emissions, resource optionality, impacts on the local economy, and a comprehensive quantitative reliability assessment, which included analysis of ancillary services, blackstart requirements, dispatchability, and other technical reliability parameters. Given evolving MISO market rules related to intermittent resource accreditation, seasonal reserve margin planning, and other reliability planning considerations, relative to NIPSCO's 2018 IRP, the 2021 IRP concluded that additional dispatchable resources like thermal peaking capacity and storage were necessary additions to the portfolio.

NIPSCO conducted an additional technical reliability assessment to ensure the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and North American Electric Reliability Corporation ("NERC") standards, were accounted for. As part of the assessment, eight reliability criteria were identified, and different portfolio options were evaluated against each of them. The reliability criteria included blackstart capability, energy adequacy, dispatchability and automatic generation control, operational flexibility and frequency support, volt-ampere reactive ("VAR") support or reactive power, geographic location relative to load, predictability and firmness of supply, and short-circuit strength sufficiency. NIPSCO's analysis concluded portfolios that included new thermal resources (natural gas-fired peakers and combined cycles, including those with hydrogen enablement) scored better on the reliability criteria than portfolios reliant only on new renewables and storage and no new incremental thermal capacity.

The record demonstrates the 2023 portfolio analysis accounted for NIPSCO's ongoing resource planning and other market conditions and developments that have occurred since the 2021 IRP was completed, including, among other things, updated pricing from NIPSCO's 2022 RFP, changes to the MISO resource adequacy construct, commodity pricing updates, and changes to federal law.

We have previously concluded that, "[i]nherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions." *Northern Indiana Public Service Co., LLC*, Cause No. 45462, at 62 (May 5, 2021). The Commission has previously found that utilities should utilize "an array of best practices, including basing model inputs on its 2022 RFP, which allow[s] for an informed forecast at that time." *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021). The evidence demonstrates that NIPSCO has utilized best practices for an informed forecast.

IG witness Mr. Gorman recommended denial of NIPSCO's requested CPCN based on his belief that NIPSCO had not updated its 2021 IRP and had not analyzed several material developments since the completion of the 2021 IRP including: (1) the introduction of MISO's seasonal resource adequacy construct; (2) the enactment of the Inflation Reduction Act; (3) the presence of supply chain constraints, tariff uncertainty and inflationary cost pressure; and (4) additional RFPs with Charles River Associates to assess the latest market data for new resources. His claims are contradicted by evidence in the record. Mr. Augustine explained Mr. Gorman's testimony does not acknowledge or reference NIPSCO's 2023 portfolio analysis. As discussed, this analysis used the preferred portfolio themes from NIPSCO's 2021 IRP and updated their composition according to the latest market information, which resulted in additional wind capacity, less solar capacity, and more thermal peaking or storage capacity. Mr. Augustine's direct testimony discussed how NIPSCO anticipated MISO's seasonal construct in its 2021 IRP, which evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options to develop portfolios based on capacity requirements for both the summer and winter seasons, and that its 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after FERC approved MISO's seasonal construct. NIPSCO's 2023 portfolio analysis has been relied upon to support approval of other generation projects.[7] As such, we find NIPSCO's resource planning and selection process to select its Short Term Action Plan, including the CT Project, is consistent with its 2021 IRP, and is therefore consistent with NIPSCO's utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

Mr. Gorman testified NIPSCO's evaluation of the proposed CT Project was deficient because it failed to consider planned changes to its future Rate 531 Tier 1 load and instead relied on its future supply demand positions based on its 2021 IRP without modifying any assumptions associated with expected reductions in Rate 531 Tier 1 load. Mr. Augustine's rebuttal testimony outlined three reasons why this criticism is invalid: (1) the Rate 831/531 Modification Agreement approved in Cause No. 45772 recognizes Tier 1 commitments may decline over time, but that no firm declarations of commitment reductions have been made by any Rate 531 customer, and it is not certain that all seven current Rate 531 customers would elect to reduce their demand to the tariff minimum as outlined by Mr. Gorman; (2) even if the proposed CT Project is approved and all seven Rate 531 customers reduce their commitments over a multi-year period through 2033 as outlined in the Rate 831/531 Modification Agreement, NIPSCO will likely still require additional capacity purchases or other capacity additions to meet current seasonal MISO planning requirements as well as potential future changes associated with resource accreditation rules at MISO to meet potential future demand growth; and (3) NIPSCO's 2021 IRP did evaluate a

[7] Cause No. 45926 (Gibson Solar), Cause No. 45887 (Appleseed Solar and Templeton Wind), Cause No. 45908 (Carpenter Wind), and in NIPSCO requests for changes in cost and ownership structure for various solar and solar plus storage projects in Cause Nos. 45936, 46028, and 46032, the latter two of which are still pending.

scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman, and NIPSCO's preferred portfolio was found to perform well under such assumptions. Mr. Augustine explained NIPSCO was not required to "hard code" into its demand forecast a reduction that may not come to fruition; instead, as it did, NIPSCO's 2021 IRP and 2023 portfolio analysis are based on probabilistic modeling which included numerous load scenarios, including the scenario Mr. Gorman advocated for.

The evidence of record demonstrates the CT Project is consistent with and supported by the 2021 IRP and 2023 portfolio analysis. The 2021 IRP concluded flexible thermal generation resources, additional solar capacity and a diverse mix of other resources including storage, emerging technologies, and market purchases/capacity were necessary additions to the portfolio for it to meet current and future load and reserve margin requirements. Moreover, as further discussed below, the CT Project is consistent with the Flexible Resource Analysis which found that flexible, dispatchable capacity resources are needed to complement NIPSCO's largely renewable portfolio – particularly resources that can meet specific ramp requirements.

We conclude NIPSCO's resource planning process is appropriate given the amount of uncertainty around timing and actual amounts of load reduction. Ms. Becker testified the Rate 531 customers may reduce their load, but they have not done so yet and NIPSCO cannot assume that they will. Furthermore, and as noted by CAC witness Ms. Sommer, NIPSCO likely will need an additional 400+ MW of capacity beginning in 2028, which could be partially addressed by further reductions of Rate 531 Tier 1 load. Based on the evidence, we find NIPSCO's 2021 IRP, as supplemented and supported by the 2023 portfolio analysis, is a valid basis for approval of the CT Project, and the CT Project is consistent with the 2021 IRP.

iii. Consistency with Commission's Energy Analysis. Ind. Code § 8-1-8.5-3(a) provides that "the commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion facilities for generation of electricity." The Commission issued its 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis") in October 2018.

The data and analysis underlying NIPSCO's proposal and the state of the overall electric industry have continued to develop since the 2018 Statewide Analysis. Mr. Walter's direct testimony noted that multiple IRPs have been completed since the most recent report. The record in this Cause demonstrates that MISO, MISO's Independent Market Monitor ("IMM"), and the NERC support the need for flexible, dispatchable resources to pair with increasing levels of renewable generation to ensure reliability.

Based on the evidence of record, we find NIPSCO's proposal to build the CT Project, which offers a flexible, dispatchable resource that will support NIPSCO's predominantly renewable generating portfolio and that of other Indiana electric utilities, is consistent with the Commission's energy analysis, including the 2018 Statewide Analysis and developments since that report was issued.

iv. Public Convenience and Necessity. Under Ind. Code § 8-1-8.5-5(b)(3), before granting a CPCN, the Commission must make "a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the

facility[.]" "The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need." Indiana Michigan Power Co., Cause No. 44871, at 30 (March 26, 2018). NIPSCO contends that its preferred configuration of one industrial frame unit and three aeroderivative units is reasonable and appropriate given NIPSCO's fast-ramping, load-following needs. Based on the evidence of record, we agree, as explained further below.

Our determination of public convenience and necessity under Ind. Code § 8-1-8.5-5(b)(3) is also guided by Ind. Code § 8-1-8.5-4(b), which provides the factors that the Commission must consider in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity.[8]

a. Ind. Code § 8-1-8.5-4(b)(1). Mr. Stanley described NIPSCO's involvement in MISO, an independent system operator, and testified this portion of the statutory language predates the formation of MISO. He stated the statutory concepts of "interchange of power" and "pooling of facilities" would seem to be addressed through use of an independent system operator. Mr. Stanley explained that while the current MISO market effectively utilizes the existing capacity resources to meet the overall energy requirements of the region, including NIPSCO, NIPSCO's membership in MISO does not eliminate its need to meet the capacity requirements of its customers, including adding new capacity resources to address potential load growth and reliable load-following generation. As to the remaining elements of Subsection (b)(1), Mr. Stanley testified NIPSCO has conducted several all-source RFPs, and joint ownership and power purchases were not excluded by those RFPs to the extent other electric utilities were interested. Mr. Augustine testified NIPSCO's all-source RFPs, its IRP, and the 2023 portfolio analysis allowed for and considered numerous resource options, including solar, solar plus storage, storage, thermal, wind, hydrogen, and a range of structures that may include both energy and capacity.

The evidence of record shows NIPSCO's participation in MISO was specifically considered in the development of its Short Term Action Plan, including the proposed CT Project, which supports the conclusion that Petitioner's current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated, and Ind. Code § 8-1-8.5-4(b)(1) has been satisfied.

b. Ind Code § 8-1-8.5-4(b)(2). While some of the parties challenged the size and technology composition of NIPSCO's proposed CT Project, which we addressed above, no party proposed an alternative to the CT Project or stated NIPSCO does not have a need for the type of new capacity that was identified in its 2021 IRP and in the subsequent analyses undertaken after the submission of the IRP. The OUCC "agrees that load-following replacement generation capacity is necessary to reliably serve NIPSCO's customers" and "recognizes that NIPSCO's IRP and updated analysis shows additional replacement capacity for retiring generation is needed to preserve reliability, resiliency, and stability." Pub. Ex. 1 at 3. The

[8] No party identified an applicable federal phaseout mandate for purposes of Ind. Code § 8-1-8.5-4(b)(3). Ind. Code § 8-1-8.5-4(b)(4) is discussed later in the order.

CAC points out if recent proposed MISO market reforms are implemented, "NIPSCO likely needs more capacity starting in 2028" even when assuming the proposed CT Project enters into service. CAC Ex. 1 at 21, 24. These statements affirm NIPSCO's requirement for incremental capacity, and the evidence of record supports NIPSCO's CT Project as a required addition that will help fill this need.

Regarding maintaining essential reliability services, NERC, in its 2022 Long-Term Reliability Assessment, states: "[r]etiring conventional generation is being replaced with large amounts of wind and solar; … As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability." *Id*. at 18-19.

Regarding "refurbishment of existing facilities," NIPSCO witness Mr. Augustine testified NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP and found conversion cost more than the alternatives. Section 4.10.5 of NIPSCO's 2018 IRP noted the analysis "showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the 2022 RFP results and replacing both units would cost customers at least $540 million more." Mr. Augustine explained a refueled Unit 17 or 18 would not be a viable alternative to the CT Project as it would not possess the fast-start/quick-ramping and reliability characteristics of a peaking facility that the 2021 IRP and the 2023 portfolio analysis called for. No party challenged this evidence.

As to cogeneration, NIPSCO witness Mr. Stanley testified renewable generation has been a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, and the CT Project is intended to complement the substantial renewable fleet NIPSCO has added and continues to add. He explained cogeneration, if available, would have been responsive to the 2022 RFPs. NIPSCO witness Ms. Becker testified on conservation and load management by describing NIPSCO's three demand response programs and its robust portfolio of demand side management/energy efficiency programs targeted towards residential, commercial and industrial customers. She explained NIPSCO carried out a lengthy analysis of demand side management/energy efficiency resources included in its IRP process, including completing a market potential study to determine the achievable amount of savings. Ms. Becker explained NIPSCO's 2021 IRP modeling demonstrates energy efficiency will be an important part of NIPSCO's resource options in the future and will be particularly important to help mitigate against the need to build new generation to serve incremental load; however, NIPSCO's modeling indicates the most economical option for customers over the long term is to execute on its preferred portfolio, including, but not limited to, adding the proposed CT Project, adding solar and wind resources, and retiring coal generation. She concluded, based on her experience with NIPSCO's energy efficiency initiatives, NIPSCO could not derive sufficient energy savings to replace this generation.

NIPSCO engaged in the 2022 RFP process to inform its planning activities. Multiple RFPs were issued in 2022 to identify costs and availability of resource options to fulfill the 2021 IRP's short-term action plan.

c. Conclusion. NIPSCO conducted the 2022 RFP to meet its capacity needs, and the RFP responses enabled NIPSCO to consider a variety of alternatives. Given the foregoing evidence, the Commission finds Petitioner has satisfied the requirement under

Ind. Code § 8-1-8.5-4(b)(2); it considers alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. NIPSCO's 2021 IRP and subsequent 2023 portfolio analysis show that the proposed construction of the CT Project at the Schahfer site is a reasonable, least-cost resource to support NIPSCO's Short Term Action Plan and meet its customers' needs for electricity. The CT Project is designed to reliably cycle in response to the MISO market and will displace the retiring Schahfer coal units with more efficient and controllable load-following capacity.

Based on the evidence of record, the Commission finds Petitioner has shown a need for the proposed CT Project and that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. Competitive Procurement. Ind. Code § 8-1-8.5-5(b)(5) requires us to make certain findings under Ind. Code § 8-1-8.5-5(e) if the proposed facility has a generating capacity of more than 80 MW, as is the case here:

> Before granting a certificate to the applicant, the commission:
>
> (1) must, in addition to the findings required under subsection (b), find that:
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
> (2) shall also consider the following factors:
> (A) Reliability.
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.
>
> The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

There are two different requirements for a CPCN. The first, Ind. Code § 8-1-8.5-5(e)(1)(A), is to confirm the reasonableness and reliability of the cost estimate. The second, Ind. Code § 8-1-8.5-5(e)(1)(B), is to assure actual costs incurred are, to the extent commercially practicable, based on competitive procurement.

NIPSCO conducted multiple RFPs in 2022 to identify the costs and availability of resource options to fulfill the 2021 IRP's short-term action plan and to respond to changing market conditions, including an RFP for a gas-fired generation resource. The RFPs provided actionable

resource cost data that incorporated the latest policy, technology, and macroeconomic information. The RFPs provided information related to the latest costs of storage resources and the viability of alternative natural gas peaker options at the time they were solicited.

The statute requires the estimate to be the result, to the extent commercially practicable, of a competitively bid engineering, procurement or construction contract. Petitioner conducted the EPC RFP bid event and leveraged the information through that process to develop its best estimate for the cost to construct the CT Project through a multi-prime contracting strategy. NIPSCO's best estimate of construction reflects information received from equipment bid events for the CT original equipment manufacturer, generator step-up transformers, unit auxiliary transformers, and diesel generator. Accordingly, we find Ind. Code § 8-1-8.5-5(e)(1)(A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. Mr. Baacke described the construction and bid process NIPSCO will use through the multi-prime contracting strategy, whereby NIPSCO plans to develop competitive bids for all major scopes of construction. He testified that under the planned construction and bid process, NIPSCO will allow third parties to submit firm and binding bids for construction of the CT Project on NIPSCO's behalf that meet all of the technical, commercial, and other specifications so as to enable ownership of the CT Project to vest with NIPSCO no later than the date the facility becomes commercially available. This satisfies Ind. Code § 8-1-8.5-5(e)(1)(B).

Regarding Ind. Code § 8-1-8.5-5(e)(2), based on the evidence of record, we find the proposed CT Project is reliable. The record establishes Petitioner engaged in an All-Source RFP process to inform its overall generation transition plan. Thus, we find that the requirements of Ind. Code § 8-1-8.5-5(e) are satisfied.

vi. Conclusion on CPCN for CT Project. Based on the evidence of record, the Commission finds NIPSCO has met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity will be served construction of the CT Project. Therefore, we grant NIPSCO's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

B. Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a). Ind. Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

NIPSCO requested ongoing review of the CT Project, including review of progress reports and any revisions to the best estimate, as the construction proceeds, and associated ratemaking treatment consistent with such review. OUCC witness Mr. Krieger recommends the Commission require NIPSCO to submit quarterly progress reports providing construction status, and accounting updates including project to date spending and remaining balances of contingency, escalation, owner's costs and indirects. Ms. Becker testified Mr. Krieger's recommended quarterly reporting

requirements go beyond the yearly reporting required by the statute. She stated NIPSCO plans to file its GCT Mechanism semi-annually, which will provide the Commission and the parties an opportunity to review costs incurred to date and relevant project updates. She stated this cadence already exceeds the annual update requirement in the statute and that requiring quarterly reports from NIPSCO on top of this review is unnecessary and excessive. We find Ms. Becker's proposal reasonable given that it is more than contemplated by the statute.

We find NIPSCO shall report to the Commission a summary of the information related to the CT Project as contemplated under Ind. Code § 8-1-8.5-6(a), including any changes to scope, schedule, and the best estimate. In its initial report, NIPSCO is directed to include: (1) manufacturer, model number, and operational characteristics of the turbine generator and (2) anticipated total annual MW-hour ("MWh") output for the CT Project in each of its semi-annual GCT filing stylized as 45947 GCT XX. The initial report shall be filed on or before December 30, 2024 as a compliance filing in this Cause.

NIPSCO shall report semi-annually in this Cause to the Commission a summary of the information related to the CT Project, including safety, scope, schedule, and owner's cost contingency, as well as revisions to the cost estimate and update on the natural gas transportation and lateral pipeline. In addition, due to recent global supply chain issues that could potentially limit the availability of components necessary to build the CTs, Petitioner shall include in its semi-annual filings, an update on any supply-chain-related challenges and/or delays beginning on December 30, 2024.

The final project report shall contain the following information: (1) the actual total cost of construction; (2) the total MW output for the facility; and (3) the actual in-service (commercial operation) date for the facility. The final project report shall be filed in this Cause.

C. Clean Energy Project and Financial Incentives Under Ind. Code § 8-1-8.8-11. NIPSCO seeks approval of its CT Project as a clean energy project pursuant to Ind. Code § 8-1-8.8-11. Ind. Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating financial incentives for clean energy projects, if the projects are found to be reasonable and necessary." An "eligible business" is an energy utility that "proposes to construct or repower a facility described in IC 8-1-37-4(a)(21)." Ind. Code § 8-1-8.8-6(5). A "clean energy project" similarly includes "[p]rojects to construct or repower a facility as described in IC 8-1-37-4(a)(21)" Ind. Code § 8-1-8.8-2(5). We have already found that NIPSCO is an "energy utility." The only disputed issue of applicability is whether the CT Project qualifies as a project under Ind. Code § 8-1-37-4(a)(21). That subsection includes in the definition of "clean energy resource . . . [e]lectricity that is generated from natural gas at a facility constructed or repowered in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." NIPSCO witness Mr. Walter testified the CT Project will displace electricity generated from the coal-fired generating plants at Schahfer Units 17 and 18 and Michigan City Unit 12.

CAC witness Mr. Inskeep asserted Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project." Mr. Inskeep stated NIPSCO did not demonstrate the CT Project is displacing electricity generated from the coal-fired Schahfer Units 17 and 18 and

Michigan City Unit 12. NIPSCO witness Mr. Stanley's stated NIPSCO will be using the injection rights from the retiring Schahfer units for purposes of MISO interconnection. NIPSCO's 2021 IRP's Short Term Action Plan plainly shows NIPSCO's overall plan to retire Schahfer Units 17 and 18 and Michigan City Unit 12 are related to and dependent on the addition of several resources, including a gas peaking resource. NIPSCO witness Mr. Holcomb explained that along with increasing levels of zero-emission renewable energy in the electric system, the CT Project will keep NIPSCO and NiSource on track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels.

Partial displacement of retiring coal-fired energy generation with a gas peaking resource has been a component of NIPSCO's IRP modeling and related CPCN regulatory filings since 2021. As such, we find the CT Project is being constructed to displace energy from an existing coal-fired generation facility and is therefore eligible for the relief provided in Ind. Code § 8-1-8.8-11.

i. <u>The Clean Energy Project is Just and Reasonable</u>. According to Ind. Code § 8-1-8.8-11, the Commission shall encourage clean energy projects by creating financial incentives for such projects, if found to be just and reasonable. While Chapter 8.8 does not set forth specific factors the Commission should consider in approving a clean energy project, the Commission has considered some of the factors outlined in Chapters 8.5 and 8.7 in other cases. Similarly, in determining the reasonableness and necessity for the CT Project, we find it appropriate to consider the principles reflected in the following Chapter 8.5 factors in our consideration: (1) the cost of the CT Project; (2) the consistency of the CT Project to NIPSCO's 2021 IRP; (3) the need for the CT Project; (4) and the competitive solicitation of the CT Project.

a. <u>The Cost of the CT Project</u>. The evidence in this Cause supports a finding that the energy to be generated by the CT Project is reasonably priced compared to other alternatives and provides material benefits. The best estimate of the costs is $100 million below the price for an EPC contract for a comparable facility and the cost is consistent with the costs assumed in the 2023 portfolio analysis.

b. <u>Consistency of the CT Project to NIPSCO's IRP</u>. The CT Project is consistent with NIPSCO's 2021 IRP (as updated in the 2023 portfolio analysis).

c. <u>The Need for the CT Project</u>. The CT Project fills the need for fast-start, quick-ramping generation that will complement NIPSCO's overall generation transition and follow the load. This evidence reflects that MISO, NIPSCO's grid operator, has indicated a system-wide need for controllable resources to ensure system reliability, particularly as more intermittent resources are added to the system. NIPSCO has demonstrated that the CT Project is necessary to assure reliability, resiliency, and stability of NIPSCO's supply of electricity.

d. <u>The Competitive Solicitation of the CT Project</u>. We have previously found and reiterate that NIPSCO's procurement of the CT Project has been and will continue to be through competitive solicitation.

Based on the evidence of record, we find the CT Project is a clean energy project under Ind. Code § 8-1-8.8-11 and is just reasonable. The record shows the addition of the CT Project to NIPSCO's resource mix will provide needed energy and capacity. We find the energy and capacity

provided through the CT Project are reasonable and necessary additions to NIPSCO's portfolio of generating resources to meet the need for electricity within NIPSCO's service area, while also mitigating the risk through the diversification and use of an economic mix of resources that provides flexibility.

ii. Cost Recovery. Having found the CT Project is a clean energy project and is eligible for the financial incentives pursuant to Ind. Code § 8-1-8.8-11 ("Section 11"), we turn now to NIPSCO's proposal to recover its costs during construction through the GCT Mechanism until such time as the project is included in base rates after being placed in service. Petitioner's witness Mr. Blissmer described the proposed GCT Mechanism and how it would work. NIPSCO anticipates these filings will be made by October 15 (reflecting the forward-looking period of March through August) and April 15 (reflecting the forward-looking period of September through February). NIPSCO anticipates a 120-day procedural schedule from filing to Commission order and rate implementation (on a bills rendered basis). Any variance between the forecasted tracker revenue requirement and the amounts collected will be compared to the actual revenue requirement based on the final books and records. The resulting variance would be captured in a reconciliation report within each tracker filing.

The revenue requirement for capital costs included in the GCT will be calculated by first computing the monthly average CWIP, or net plant in service when appropriate, over the forecasted six-month period. NIPSCO's direct testimony reflected NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective Weighted Average Cost of Capital ("WACC"). Up and until the CT Project is placed in service, there would be no depreciation expense. When and to the extent the CT Project is projected to be placed in service in a six-month forecast period, the GCT will commence the recovery of depreciation expense at NIPSCO's most recently approved depreciation rates (currently Cause No. 45772), which would be reconciled when actual depreciation expense is recognized in a future tracker. This avoids any deferral of depreciation expense. Similarly, forecasted property taxes will be included in the GCT and reconciled when actual property tax expense is recognized in a future tracker.

Mr. Blissmer testified NIPSCO proposes to allocate the costs associated with the CT Project based on NIPSCO's Commission approved demand allocators for the GCT Mechanism, whereby the demand allocators are based upon revenue attributable to each of NIPSCO's rate schedules used to establish NIPSCO's Commission approved electric base rates in Cause No. 45772. NIPSCO will adjust its allocation percentages to reflect the significant migration of customers amongst the various rates for each semi-annual tracker filing, as it does with other tracking mechanisms. This adjustment is appropriate to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement. He described other changes to NIPSCO's electric service tariff relating to the proposed GCT Mechanism: (1) addition of Rider 595 – Generation Cost Tracker; (2) addition of Appendix L – Generation Cost Tracker Factors; (3) update to Appendix A to include Rider 595; and (4) update to the Table of Contents to add Rider 595 and Appendix L. NIPSCO anticipates its first GCT Mechanism filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. As an additional financial incentive under Section 11, NIPSCO requests the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test.

Mr. Blissmer explained how this proposed GCT Mechanism is authorized by new legislation. He testified House Enrolled Act 1421 ("HEA 1421"), among other things, amended the definition of "clean energy projects" in Ind. Code § 8-1-8.8-2 to include "[p]rojects to construct or repower a facility described in IC 8-1-37-4(a)(21)" and amended Section 11(a)(1) limiting when CWIP ratemaking can be authorized for a clean energy project as a financial incentive.

Mr. Blissmer testified NIPSCO's proposal satisfies the additional requirements relating to the authorization of CWIP ratemaking for a clean energy project as a financial incentive stating HEA 1421, among other things, amends Section 11(a) concerning financial incentives to provide:

> The commission may not approve a financial incentive under this subdivision unless the commission finds that the eligible business has demonstrated the timely recovery of costs and expenses incurred during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing savings over the life of the project.

Mr. Blissmer testified the construction financing costs will result in a gross financing savings over the life of the project. He explained the Summary tab includes the results from the data contained in the remaining tabs and presents two scenarios: (1) the top half presents the revenue requirement and financing costs portion of the revenue requirement under NIPSCO's proposed CWIP ratemaking treatment, and (2) the bottom half presents the same information under an alternative scenario where the asset is reflected in rates after being placed in service as part of a general rate case. He stated that under both scenarios, the CT is assumed to be placed in service in December 2027, the general rate case test year is assumed to be calendar year 2027, and the Step 2 rates in that general rate case are assumed to become effective on a bills rendered basis in March 2028. He explained that from that point forward, the sequence and timing of rate implementation under both scenarios is the same, as the CT Project under the GCT will have rolled into base rates and that the only difference from March 2028 over the remaining life of the project is the result of the higher accrued rate base (including regulatory asset) produced by the accrual of AFUDC and post-in service carrying costs ("PISCC") under the traditional model. He explained he has not included property taxes in the calculation because property taxes are not financing costs. He did include depreciation expense because the regulatory asset resulting from the deferral of depreciation expense would be reflected in rate base and thus depreciation does produce different financing costs under the two scenarios.

Mr. Blissmer concluded under NIPSCO's forward-looking GCT proposal, the total revenue from financing costs is $1,609,808,326, and under the traditional general rate case scenario, the total revenue from financing costs is $1,691,794,736, with the difference between these two amounts of $81,986,410 being the gross financing savings over the life of the CT Project. With a backward looking GCT Mechanism, the total gross financing savings over the life of the CT Project would be $48,019,573.

Mr. Blissmer testified NIPSCO's proposed financial incentive of CWIP ratemaking is just and reasonable. He stated the gross financing savings produces lower rates for customers. NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained the primary benefit for a utility from CWIP ratemaking, from a financial health standpoint, is that it will provide NIPSCO cash flow during a potentially lengthy construction period. He testified CWIP ratemaking improves near term cash flow and mitigates the negative effects of the

significant additional debt taken on to construct the project.

In addition to CWIP ratemaking resulting in savings and producing lower rates for customers, Mr. Blissmer testified that it has long been recognized that CWIP ratemaking is a benefit to customers because it prevents so-called "rate shock." He explained that for large capital projects, waiting until the project enters service to include costs in rate base can lead to a significant one-time increase in the rate base and, in return, rates and that CWIP protects against that type of rate shock by phasing in the costs of the new facilities over the construction period.

Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on several factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates costs in the first GCT filing after approval would result in an incremental 2025 charge of approximately $0.56 to a 668 kWh per month residential bill, which is significantly lower than the $1.25/month impact based on a 2026 in-service date.

OUCC witness Ms. Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. She contended NIPSCO should instead use project-specific financing costs or the cost of short-term debt.

IG witness Mr. Gorman testified the CWIP tracker is not just and reasonable simply because there are financial savings. Both IG witness Mr. Gorman and CAC witness Mr. Inskeep claimed the analysis of gross financing savings is inconsistent with Ind. Code § 8-1-8.8-11(a)(1)(B) in that it does not include net present value analysis. Mr. Inskeep also objected to the forward-looking version of the GCT Mechanism, alleging it was inconsistent with the verb tense of Ind. Code § 8-1-8.8-11(a)(1)and did not provide for "timely" recovery of costs.

In his rebuttal testimony, Mr. Blissmer testified NIPSCO is modifying its GCT proposal to remove WACC, and to apply its then current AFUDC rate. He stated he recalculated the gross financial savings from the use of CWIP ratemaking using both the forward-looking (NIPSCO's proposal) and backward-looking (NIPSCO's alternative proposal) using the estimated AFUDC rate instead of the WACC. He testified that (1) as shown in Petitioner's Exhibit 8-R Attachment 8-R-A, with the forward-looking GCT, the gross financial savings are now estimated to be over $9 million greater utilizing the estimated AFUDC rate than the savings calculated in his supplemental direct testimony using the WACC, and (2) as shown in Attachment 8-R-B, with the backward looking GCT, the gross financial savings are now estimated to be over $6 million greater utilizing the estimated AFUDC rate. He testified both alternatives continue to produce gross financial savings when compared to traditional ratemaking consistent with Ind. Code § 8-1-8.8-11(a)(1)(B), with the forward-looking version producing greater gross financial savings. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Mechanism. Mr. Inskeep claimed the delay of in-service date of the CT Project has caused an increase in total financing costs, which Mr. Blissmer explained fails to acknowledge his supplemental direct testimony that the one-year delay produces $65 million in customer savings through 2028.

Having found the CT Project is "clean energy project" under Ind. Code § 8-1-8.8-2(5) and having found the CT Project is just and reasonable, we are now required by Ind. Code § 8-1-8.8-11(a) to create financial incentives for the CT Project. Specifically, NIPSCO has requested we approve its proposed GCT Mechanism, which would provide for construction work in progress ratemaking as allowed by Ind. Code § 8-1-8.8-11(a)(1). Subsection 11(a)(1) provides that we may authorize "[t]he timely recovery of costs and expenses incurred during construction and operation of the project," but we may not do so "unless the commission finds the eligible business has demonstrated that the timely recovery of costs and expenses during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing cost savings over the life of the project."

Mr. Blissmer presented the calculation of his gross financial savings in his direct and supplemental direct testimony. Using the forward-looking GCT, Mr. Blissmer calculated the gross financial savings in direct testimony at $81,986,410 over the life of the CT Project. Using the more traditional backward looking GCT Mechanism, there would be reduced savings of $48,019,573. In rebuttal, Mr. Blissmer changed the financing cost rate to the AFUDC rate rather than the WACC in response to OUCC witness Mr. Baker. This change increased the gross financing cost savings by $9 million (total savings of approximately $91 million) for the forward-looking version and by $6 million (total savings of approximately $54 million) for the backward-looking version.

IG witness Mr. Gorman and CAC witness Mr. Inskeep objected to Mr. Blissmer's calculations on the grounds that they were not done on a present value basis. The statute, by its terms, does not require the calculation to be done based upon net present value. Instead, the statute requires the demonstration of gross financing cost savings over the life of the project. The Commission is a creature of statute with delegated authority from the Indiana General Assembly. When a statute does not require interpretation, and is unambiguous as Section 11 is, the Commission shall follow the law as written. Had the General Assembly intended the calculation to be done on a net present value basis as argued by Messrs. Gorman and Inskeep, it would not have used the word "gross" and would have instead used "net present value." We find that, as calculated by NIPSCO witness Mr. Blissmer, both the forward-looking and backward-looking versions of the proposed GCT Mechanism will generate "gross financing cost savings" over the life of the CT Project.

We are unpersuaded by Messrs. Gorman and Inskeep's assertion NIPSCO did not demonstrate the proposed GCT Mechanism as just and reasonable, particularly because neither witness responded substantively to Mr. Blissmer's direct testimony describing how the GCT benefits customers through the avoidance of so-called "rate shock" when a large construction project is reflected in rates in a single step. By recovering costs through the GCT Mechanism during the construction period, the rate impact from the CT Project will be reflected in steps over six-month increments. The ultimate cost to customers once the CT Project is fully reflected in rates will be lower because of the greatly reduced AFUDC.

The General Assembly has specifically directed affordability as one of the attributes to be considered in the context of generation transition. One of the tools provided by the General Assembly in the case of transition to clean energy projects is a CWIP tracker, which, as explained by Mr. Blissmer, produces the benefits of lower rates and smaller rate increases. We cannot simply ignore the benefits a CWIP tracker will contribute to affordability by lowering rates and smoothing

and mitigating rate increases during generation transition. NIPSCO's testimony on the overall benefits of CWIP ratemaking on credit quality, which ultimately informs the carrying charge applied to NIPSCO's investment and, therefore, customer rates, was effectively unrebutted. Mr. Inskeep asserted various other arguments against CWIP ratemaking generally, including that it creates generational inequities and erodes a utility's incentive to efficiently manage a project. These are not objections to whether this proposal meets the requirements of the statute, and they ignore the fact that the legislative decision has already been made to allow CWIP ratemaking. We find that, under Section 11, both the forward- and backward-looking versions of NIPSCO's proposed GCT Mechanism are just and reasonable.

We now move to the question of which method we should approve: the forward-looking or backward-looking GCT. As explained by Mr. Blissmer, NIPSCO has proposed the backward-looking GCT Mechanism in the alternative in the event we were not to approve the forward-looking version. With the forward-looking GCT, NIPSCO would reflect CWIP financing costs projected to occur over the next six-month billing period in each tracker filing. The projected CWIP financing costs would then be adjusted to the actual incurred costs and expenses by way of the reconciliation process. In this fashion, there would be no AFUDC reflected in the total cost of the CT Project except for the limited AFUDC that has already been accrued and expected to be accrued until rates take effect in March 2025 under the GCT Mechanism. In addition, there would be no depreciation to defer. The backward-looking GCT, in contrast, would reflect CWIP financing costs that had been incurred over the previous six-months. With the backward-looking GCT, there would be AFUDC accrued during each six-month period until the costs are reflected in the GCT. In addition, there would be depreciation deferred between the in-service date and reflection in rates. This AFUDC and deferred depreciation would increase the overall cost of the CT Project, which is why the backward-looking version of the GCT produces less gross financing cost savings.

Mr. Inskeep had two objections to the forward-looking version of the GCT. First, he claimed the statute uses past tense and that this precludes recovery of projected costs. Second, he claimed that because NIPSCO would be recovering financing costs before they have been incurred, the recovery would not be "timely" as the statute requires. We are unpersuaded by either argument. First, it is important to note that whether the tracker looks forward or backward will not change that NIPSCO will recover only its actual costs. With the reconciliation process inherent in the proposed tracker, NIPSCO's recovery will always be based upon its actual costs incurred. The statute requires that the mechanism provide for timely recovery of costs and expenses incurred during construction. With the forward-looking mechanism coupled with its reconciliation process, NIPSCO's proposal provides for recovery of the costs and expense that are actually "incurred," and this recovery begins during the same six-month period during which those costs are being incurred. The forward-looking GCT Mechanism would result in timely recovery consistent with the statute. In addition, given that the forward-looking GCT Mechanism produces approximately $37 million in gross financing cost savings ($91 million less $54 million) when compared to the backward-looking mechanism, it is the method that creates a more affordable result for customers. Further, Ind. Code § 8-1-8.8-11(a)(4) authorizes us to approve other financial measures we consider appropriate, and we consider the forward-looking GCT to be appropriate. The General Assembly has established an infrastructure policy "to use all practicable means and measures, including financial and technical assistance, in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and

maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens." Ind. Code § 8-1-2-0.5. Denying a utility the use of a forward-looking tracker that would produce an additional $37 million in gross financial savings for customers based upon verb tense would be inconsistent with this overall infrastructure policy and the pillar of affordability. Accordingly, we find NIPSCO's proposed forward-looking GCT Mechanism using the AFUDC rate as reflected on rebuttal should be approved.

We further approve Petitioner's request that the operating income associated with the CT Project recovered through the GCT Mechanism be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test. This is an appropriate additional financial incentive under Section 11, and it is therefore approved.

D. <u>The Five Pillars</u>. In HEA 1007, the Indiana General Assembly declared it is the continuing policy of the State that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the five pillars of electric utility service. See also Ind. Code § 8-1-8.5-4(b)(4). Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service: as reliability, affordability, resiliency, stability, and environmental sustainability. NIPSCO witness Ms. Becker's Petitioner's Exhibit No. 1 Attachment 1-C identifies the seven different NIPSCO witnesses who sponsored testimony supporting each of the Pillars.

We address the Five Pillars in the order in which they are listed in Ind. Code § 8-1-2-0.6, acknowledging that no one pillar takes precedence over the others and that each must be balanced against the others.

Based on the evidence of record and having considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6, the Commission finds NIPSCO's proposed CT Project and related proposals are consistent with and appropriately balance the legislative directive in this state policy statement.

i. <u>Reliability</u>. Reliability is ensuring customers have the power they need when they need it. We have recognized that in a dramatically shifting generation landscape the need for fast start/quick ramping resources is magnified. Southern Ind. Gas & Elec. Co., Cause No. 45564 (IURC 6/28/2022). NIPSCO witness Mr. Austin's testimony informs us this need is increasing. Evidence of record supports findings that the proposed CT Project addresses needs identified by key stakeholders, including MISO, NERC, the MISO IMM, and others, and addresses needed attributes to directly support NIPSCO's overall generation portfolio.

Both the NERC and MISO have warned stakeholders that, as the penetration of solar generation increases, the challenge of steeper ramping needs for the non-solar fleet magnifies. Mr. Austin cited numerous publications from NERC, MISO, and MISO's IMM discussing the need to install fast-starting, quick ramping generation to support the growing portfolio of renewable resources and maintain reliable service. NERC specifically recognizes the important role regulatory policy plays in ensuring a reliable grid. Mr. Austin explained that 2023 marked the first year, "energy policy" has been added as a risk profile to Electric Reliability Organization ("ERO") Priorities Report. Mr. Austin, quoted the ERO Priorities report stating: "[t]raditional resource adequacy approaches that assume the system is adequately planned if there is enough generation capacity during peak load hours have become insufficient given the accelerated changes in

resource mix, extreme weather events, and fuel dependencies." Petitioner's Exhibit No. 3. The 2022 Long-Term Reliability Assessment issued December 2022 states as follows:

> As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.

Further, NIPSCO witness Mr. Austin explained the proposed CT Project will help meet MISO's Resource Adequacy Requirements. The 2023 Organization of MISO States- MISO Survey Results (published July 14, 2023) reflect delayed retirements and capacity additions have resulted in a capacity surplus of 1,500 MW for the 2024/25 planning year. Id. Demand growth is projected to continue for five years across all four seasons at 0.8 GW or 0.68% per year on average across the MISO footprint and the results show a deterioration of MISO's current capacity surplus above the required capacity level, to a sizeable projected shortfall of 2,100 MW in summer 2025/26. This demonstrates a growing need for dispatchable resources to support system reliability within the MISO region, including Indiana.

NIPSCO witness Mr. Austin explained why batteries, inverter-based resources ("IBRs"), and energy storage resources ("ESR") do not meet system reliability needs. NERC and MISO's IMM reach similar conclusions, as the NERC highlights in its 2022 Long-Term Reliability Assessment and notes:

> … IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation.

The IMM, in its 2022 State of the Market Report for the MISO Electricity Markets, concurs, stating that:

> Although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not fully substitutable for conventional generation. This is particularly true as the quantities of ESRs rise, which causes the marginal value of ESRs to fall.

NIPSCO witness Mr. Stanley explained MISO's interest in the significant transition of electric generation in the MISO region:

> MISO is focused on reliability, and that means it is focused on ensuring the resource portfolio has the necessary capability and attributes. Yet, due to decarbonization goals, economics and customer preferences, key existing resources will retire. Some plans to build new resources with the needed attributes are delayed or abandoned, and other technologies are not ready for broad deployment. Proposed replacement capacity has shown to be lacking key traits given current technologies. The gap between retirement capabilities and attributes is a growing reliability

concern.

Petitioner's Exhibit No. 6. The Executive Summary in the 2022 State of the Market Report goes on to outline different attributes or characteristics provided by different generation resource types and reflects that gas resources have a significant relative advantage over renewable resources in providing: (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. It is these attributes that the CT Project will offer to NIPSCO's generation portfolio, for the benefit of all of its customers and the broader MISO region. In addition, while still in development and under review, NIPSCO witness Mr. Augustine cited from MISO's Resource Adequacy Subcommittee October 2022 presentation that noted the importance of key technical attributes like blackstart and detection of short circuit strength and prioritized a set of attributes associated with capacity, energy adequacy, flexibility, and essential reliability services. These priority attributes are consistent with the reliability criteria NIPSCO evaluated within the economic and non-economic assessments that were conducted during the 2021 IRP.

NIPSCO conducted extensive diligence on the reliability of the potential resource portfolios in its 2021 IRP. The Non-Economic Reliability Assessment evaluated each potential portfolio based on the following reliability criteria and metrics: (1) blackstart capability, (2) energy adequacy, (3) dispatchability, (4) operational flexibility and frequency support, (5) VAR support, (6) location, (7) predictability and firmness, and (8) short circuit strength. In 2023, NIPSCO conducted the Flexible Resource Analysis to assess the preferred portfolio's flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources and performed a sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The Flexible Resource Analysis showed the preferred portfolio of approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and three-hour ramp requirements in extreme conditions without reliance on the market and revealed a 150 MW growth in NIPSCO's need for capacity with a 10-minute ramp rate by 2030. NIPSCO's CT Project in its preferred configuration is designed to fill this capacity gap ensuring service on NIPSCO's entire system is reliable.

Our review of the evidence of record regarding the attributes of the aeroderivative turbines leads us to conclude that their operational characteristics are a vital part of the CT Project's expected reliability. NIPSCO witness Mr. Baacke explained aeroderivative turbines are typically more efficient, start faster and more frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. We conclude it is these features that will allow NIPSCO to continue to install large volumes of renewable energy (which serves the environmental sustainability pillar discussed below) while still maintaining the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when intermittent renewable resources are not available for short or prolonged periods of time.

Finally, we note the CT Project's gas usage will be supported through NIPSCO's gas system, which already contains transportation rates, riders, and pooling options. NIPSCO's gas system is robust, with multiple interconnection points with seven interstate pipelines, which offer an uncommon level of supply diversity as natural gas generators are typically captive to only one interstate pipeline connection. This is an advantage for the CT Project, especially as compared to intermittent resources, and further bolsters its reliability and resiliency.

ii. Affordability. The addition of a large generation resource such as the CT Project will necessarily impact the cost of electric service NIPSCO provides to its customers. This illustrates the tension between the Five Pillars that naturally occurs as a utility invests to ensure the availability and delivery of reliable energy to its customers. The OUCC, IG, and CAC testimony each raised affordability concerns with NIPSCO's proposed CT Project and related cost recovery through the GCT Mechanism. The thrust of their varied concerns is the pillars of reliability, resiliency, and stability should not supplant meaningful consideration of the customer affordability of NIPSCO's request.

Although we are not approving rates as part of this proceeding, we are authorizing NIPSCO to construct a generation facility that will operate for many years and approving a recovery mechanism for costs associated with construction of the facility. Because a utility has limited control over nearly all the external factors that could impact its customers' ability to pay for utility service, the challenge for public utilities in the face of a highly consequential generation transition is to meet its customers' need for electric generation cost effectively. NIPSCO's evidence supports that its proposal for the CT Project does that.

The proposed CT Project originated from NIPSCO's 2021 IRP from which a preferred portfolio was selected as a lower cost option than alternatives. NIPSCO utilized a competitively bid EPC contract event and determined a multi-prime contracting strategy could save $100 million over the viable EPC bid it received. When NIPSCO determined supply chain constraints caused the originally contemplated in-service date to no longer be reasonably achievable, it reevaluated its approach and submitted supplemental direct testimony to shift the in-service date of the CT Project by one year to end of year 2027. This shift in in-service date produced an immediate savings for customers of $65 million over the course of the next five years through delayed rate implementation. In addition to these savings, NIPSCO's proposed GCT Mechanism will further produce gross financial cost savings of approximately $90 million over the life of the CT Project as compared to traditional ratemaking. Finally, the CT Project will not require additional pollution control technology to comply with GHG Rule and offers the flexibility to run as an intermediate load unit, which could serve to reduce NIPSCO's need to procure additional market capacity, which reduces exposure to price volatility to the benefit of NIPSCO's customers. Each of these facts demonstrate the steps NIPSCO took to address affordability as part of its overall project proposal.

While we acknowledge that a project of this size will inevitably lead to an increase in customers rates, we conclude that, when considered in totality, NIPSCO's CT Project supports the goal of utility service costs that are affordable and competitive across the customer classes.

iii. Resiliency. Resiliency is similar to reliability, and much of our discussion above regarding reliability is applicable here. Resiliency represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. The fast start capabilities of the CT Project, especially given the configuration with aeroderivative units are a key component of resiliency. NIPSCO witness Mr. Walter testified NIPSCO has a need for additional winter capacity, and the CT Project will be a key part of ensuring the resiliency of NIPSCO's electric operations. Mr. Austin offered extensive confidential testimony that directly addressed how the CT Project will support resiliency.

In addition to the system's ability to respond to an acute system emergency or unexpected outage, longer-term resiliency can be considered based on evolving market rules, changing weather patterns, or climate-related phenomena. As outlined by NIPSCO witness Mr. Augustine, the 2023 portfolio analysis incorporated market shifts and changes that have occurred since the 2021 IRP, including the MISO seasonal resource adequacy construct. These changes point to an increased need for capacity-advantaged resources in NIPSCO's generation portfolio, a need which the CT Project directly fulfills.

iv. Stability. Stability is defined in the statute as the ability of the electric system to: (a) maintain a state of equilibrium during normal and abnormal conditions or disturbances and (b) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards. Stable sources of power provide a critical backbone to the grid, which is particularly vital during this dynamic time of significant generation transition. With renewable generation being a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, NIPSCO conducted a Reliability Analysis as part of its 2021 IRP, which identified the need for longer-duration, flexible resources additions within its service territory. As gas turbines can operate continuously for extended durations, the CT Project clearly supports system stability. NIPSCO witness Mr. Stanley testified that gas resources have a significant advantage relative to inverter-based (e.g., renewable) resources, as gas resources can provide (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. These characteristics, which were also discussed above in the Reliability discussion, are essential to a stable generation transition, and a stable generation transition drives value for utility customers. Evidence of record supports a finding that the CT Project offers these types of needed attributes and supports system stability for NIPSCO, Indiana, and the broader MISO region.

v. Environmental Stability. Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources. The CT Project fits as part of NIPSCO's overall plan to retire all its coal-fired generation by 2028 and to reduce its carbon emissions from its electric operations by 90% measuring from a 2005 baseline. The CT Project will have the flexibility to run beyond its currently anticipated capacity factors and still maintain compliance with the newly adopted EPA GHG rule. The CT Project fits within an overall portfolio whereby NIPSCO has successfully transitioned away from a portfolio heavily reliant on coal to one that relies on a fleet of wind, solar, and battery energy storage resources. The intermittent capabilities of those renewable resources must be supported by the quick start/fast ramp capabilities of the CT Project.

OUCC witness Mr. Armstrong states that the determination of whether natural gas generation is environmentally sustainable is subjective. The CT Project supports increasing levels of renewable energy in the electric system and replaces capacity from NIPSCO's coal units that are planned to retire by 2025 and 2028. The retirement of coal generation and replacement with zero-emission generation and low/intermediate-load gas generation—such as the CT Project—keeps NIPSCO and NiSource on-track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels. The efficiency of the aeroderivative turbines serves the environmental sustainability pillar. NIPSCO witness Mr. Holcomb explained that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the EPA greenhouse gas rule and be allowed to operate at capacity factors up to 40%, as needed. The frame

unit is not expected to meet the intermediate load emission standard and would, therefore, be limited to a 20% capacity factor. This demonstrates how the proposed CT Project's configuration balances environmental sustainability while also supporting reliability, resiliency, and stability.

6. Confidentiality. NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information on September 12, 2023, January 16, 2024, and April 25, 2024. These motions related to information NIPSCO claimed to be trade secrets and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. Docket entries were issued on September 28, 2023, February 8, 2024, and March 13, 2024, finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the information that is the subject of these motions is confidential pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. NIPSCO is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct an approximately 400 MW natural gas combustion turbine peaking plant to be located at NIPSCO's existing R.M. Schahfer site. This Order constitutes the certificate.

2. NIPSCO's estimated total cost of the CT Project in the amount of $641.2 million (excluding AFUDC) is approved as set forth herein.

3. NIPSCO's request for ongoing review of the CT Project is approved. NIPSCO shall file reports as described herein for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

4. The CT Project is approved as a clean energy project and NIPSCO's request for financial incentives, including timely cost recovery through construction work in progress ratemaking under Ind. Code Ch. 8-1-8.8 is approved.

5. NIPSCO is granted authority to recover costs incurred in connection with the CT Project through its Generation Cost Tracker Mechanism, as proposed, including approval of the specific ratemaking and accounting treatment approved herein. NIPSCO's proposed changes to its Electric Service Tariff relating to the GCT Mechanism are approved.

6. The Confidential Information submitted under seal in this Cause pursuant to the parties' requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED:

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

_____

Dana Kosco
Secretary of the Commission

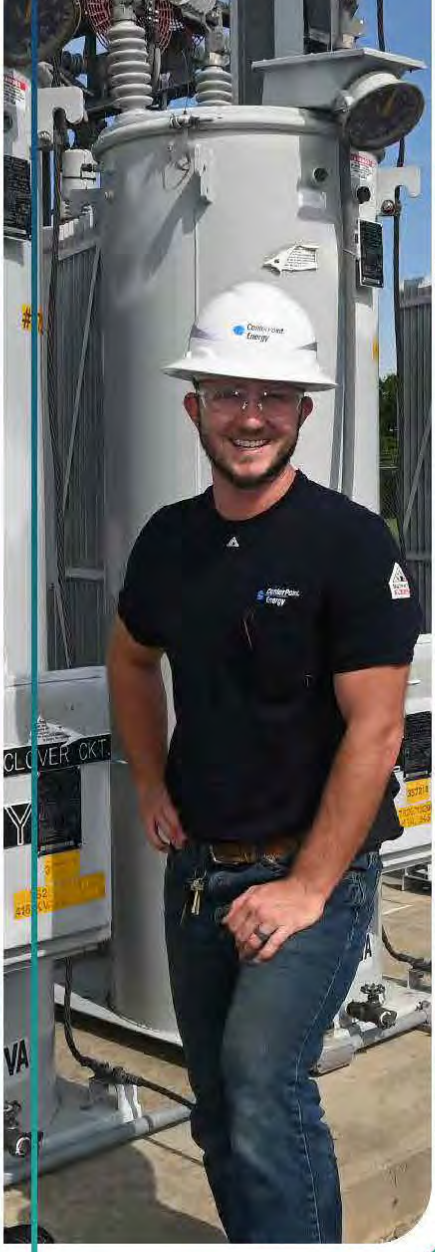
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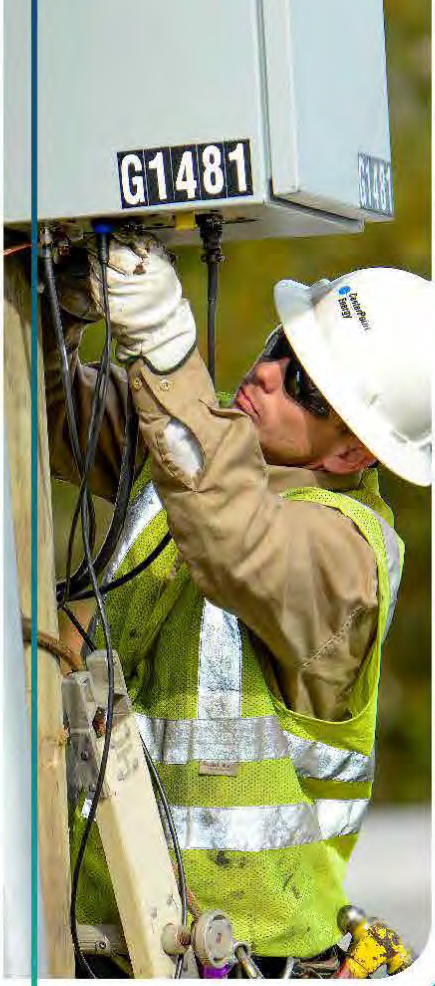
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 21
CenterPoint Indiana 2025 IRP







2025
Integrated Resource Plan

CenterPoint® Energy

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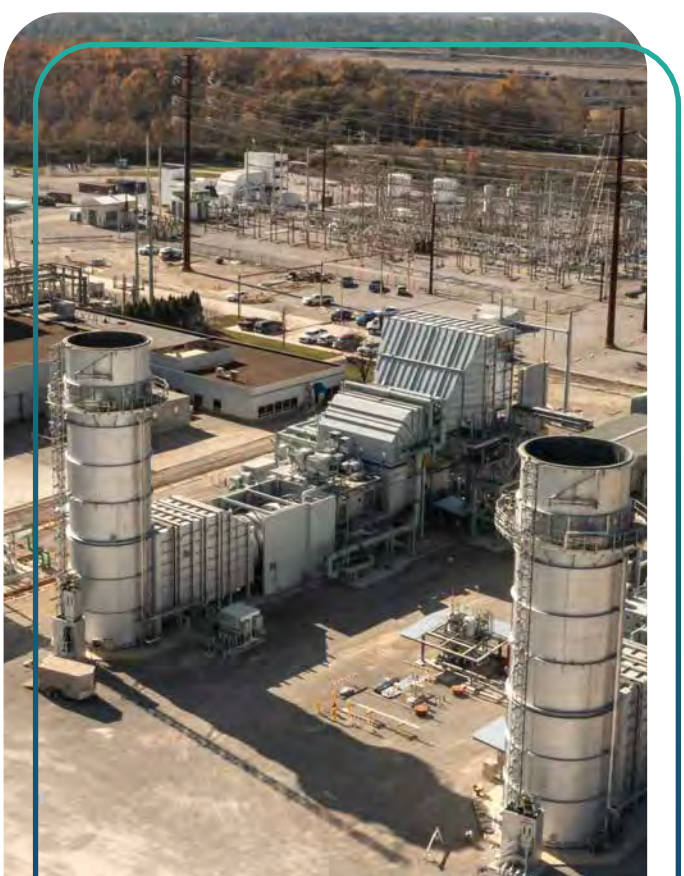
Executive Summary

(Non-Technical Summary)

Introduction

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CEI South"/"CEIS") 2025 Integrated Resource Plan ("IRP") is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's orders related to past Preferred Portfolios described in CEI South's previous IRPs both in the preparation of this IRP and the planning process that preceded the report.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. CEI South's 2022/2023 IRP identified a Preferred Portfolio that included a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with Demand Side Management ("DSM"), wind, and solar resources. CEI South began implementing the 2022/2023 IRP by filing two cases for which CEI South sought and received approval for (1) two signed purchase power agreements ("PPA") for wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project; and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, the IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered their cost relative to what could be acquired in the future, post elimination of Inflation Reduction Act ("IRA") tax incentives for wind and solar resources.



Now in 2025, during this time of unprecedented uncertainty across multiple fronts, the 2025 IRP analysis and its conclusions highlight the prudent decision for CEI South to reevaluate the timing of its generation fleet transition. Amid this time of evolving risk, and following our most recent rate case, there has been feedback from our customers and their advocates to keep bills more affordable. The IRP public meetings allowed us to listen to stakeholders and explain the uncertainty facing the industry.

Therefore, CEI South is reevaluating the timing of its transition to new or upgraded equipment in the near-term with a **focus toward rate stability and system reliability**.



The world looks very different than it did twelve months ago, when this IRP process began. The current pace and amount of change creates a variety of risks that, when weighed together, supports CEI South's decision to reevaluate the generation transition. The figure below summarizes current uncertainties.

Current Uncertainties





In 2023, CEI South filed its first electric base rate case in nearly 14 years. Ultimately, CEI South was approved to recover an additional $80 million from customers to continue to **safely and reliably deliver electricity** to their homes and businesses. While the energy transition CEI South set forth in prior IRPs was more affordable in the long run than continuing to operate its coal units, approximately 80% of the approved rate case increase was related to replacing A.B. Brown coal units 1 & 2 with 191 MW Posey Solar (~$385 million) and 460 MW natural gas combustion turbines (~$287 million). A.B. Brown's aging environmental equipment was required to be updated and replaced at a similar cost by 2024; this fact helps to illustrate the importance of strongly considering near-term affordability within the context of the IRP.

In this dynamic environment, CEI South has remained nimble to allow it to provide affordable and reliable service for its customers. Since the last IRPs were filed, there have been significant challenges in moving forward with key pieces of the last two IRPs' Preferred Portfolios. Several solar projects were terminated due to shifting market dynamics and substantial delays in commercial operation dates—one exceeding four years, with others averaging more than three. These market changes and delays drove project costs beyond the levels approved by the Commission and above what CEI South believed economical for its customers.

As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had upward pricing pressure. After years of negotiation and a re-evaluation of this project, CEI South opted, in this IRP, to abandon this project in an effort to avoid additional customer bill impact.

Also, in early 2025, CEI South announced that it paused the plan to convert F.B. Culley 3 to natural gas, to be re-evaluated in this IRP. Within this analysis, CEI South utilized more refined cost estimates and assumptions based on our preparation to convert the unit. This decision to pause the conversion was not taken lightly and was the direct result of near-term affordability concerns raised by the community, along with the current uncertainties listed in the previous figure.

Although the previous IRP projected long-term cost savings, CEI South estimates that implementing all proposed projects as planned would have resulted in a near-term bill increase of approximately $18 per month over the next few years. CEI South also heard some stakeholders express interest in re-evaluating the

decision to convert F.B. Culley 3 within the context of the transparent IRP process, particularly given the near-term uncertainty driven by changes in the Federal and State administrations. CEI South's decision to reevaluate this path forward proved to be prudent. Under today's market conditions, (elimination of future Federal tax incentives for renewables, declining accreditation from MISO for renewables, increased price pressure on resources based on tariffs/ongoing supply chain issues), converting F.B. Culley 3 to natural gas by 2030 with renewables is projected to be the second highest cost portfolio evaluated, 17% higher than the lowest cost portfolio examined and 14% higher than the Preferred Portfolio.

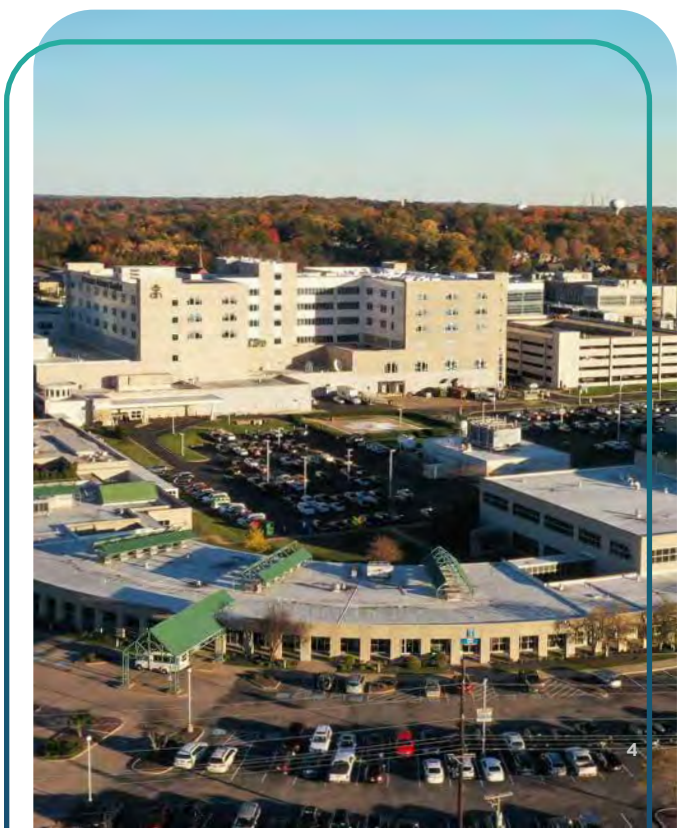
CEI South began its 2025 IRP process in early 2025 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with our 2022/2023 IRP framework as a basis for the 2025 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to, the following:

- expanded sensitivity analysis (distributed solar incentive, large load additions, Demand Response term, etc.);
- increased collaboration with transmission and distribution planning;
- enhanced transmission analysis, unserved energy, capacity risk, etc.;
- inclusion of an expected data release schedule;
- five pillars focused score card with an expanded view of affordability; and
- refreshed IRP layout with enhanced description of analysis and results.

Over the last year, CEI South has participated in active discussions with several large load customers, and there was considerable stakeholder interest in understanding how CEI South would serve a large load addition. In order to maintain maximum flexibility, CEI South responded by including large load sensitivities and adding an alternate reference case to its analysis.

To maintain maximum flexibility and agility in these uncertain times, CEI South has selected both a **Preferred** and an **Alternate Preferred Portfolio**.

The Preferred Portfolio assumes the status quo for our territory. The Alternate Preferred Portfolio was developed should CEI South be in a position to provide power to a large load addition.





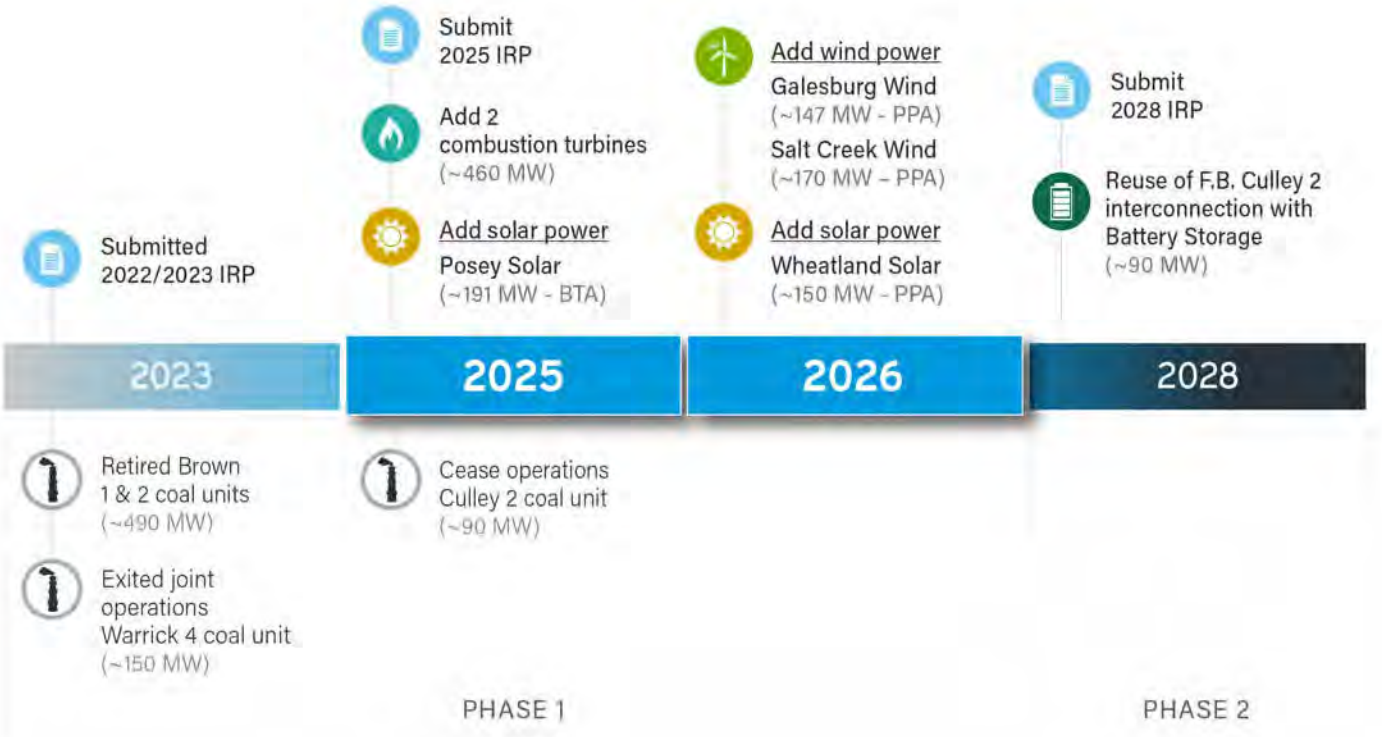
The alternate reference case maintains reference case market conditions but includes a potential large load addition that grows by 250 MWs per year, topping out at 1.5 GWs above CEI South's current retail load. This large load profile is indicative of ongoing discussions/ negotiations with prospective customers. Potential large load customers require utilities to be able to serve their needs quickly, or they will take their economic development, supporting jobs and the tax base for the community, elsewhere.

CEI South plays a proactive role in **advancing economic development** across southwestern Indiana. By developing an Alternative Preferred Portfolio, the company enhances its agility **to better serve and support the region's evolving needs**.

With the need to provide reliable, stable, resilient, affordable, and sustainable energy to our customers, both Preferred Portfolios call for the conversion of A.B. Brown natural gas Combustion Turbine ("CT"), units 5 and 6, to an efficient Combined Cycle Gas Turbine ("CCGT"). The Preferred Portfolio provides customers with near and long-term rate stability and pushes this decision out to future IRPs until there is more clarity on the future while the Alternate Preferred Portfolio moves forward with the conversion by 2030. In either case, the decision on F.B. Culley 3's replacement will be decided in a future IRP. Both portfolios include the remaining solar and wind energy resources—secured prior to this IRP—at significantly lower costs compared to future renewable projects that may not benefit from near- to midterm Federal tax incentives. Both portfolios also include battery storage to replace CEI South's smallest and most inefficient coal unit, F.B. Culley 2. This allows time for CEI South to further evaluate the economics of this option relative to purchasing required capacity to maintain reliability. Finally, both include continued investment in energy efficiency and demand response resources.

The company has signed a contract with a demand response ("DR") aggregator for commercial and industrial DR by 2026. CEI South is also nearing the beginning of a pilot which was approved in its recent rate case to explore time-based rates. The Preferred Portfolio includes indicative DR amounts for IRP planning purposes.

Preferred Portfolio

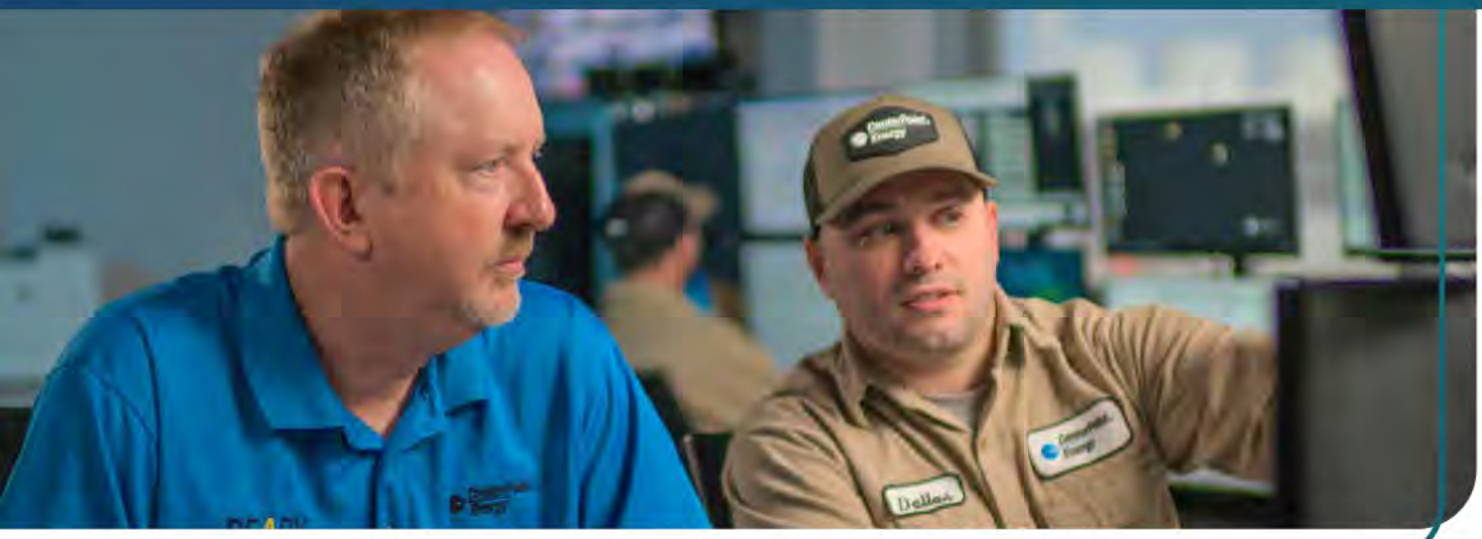


CEI South's Preferred Portfolio takes a more gradual approach to its generation transition, providing time for greater clarity amid today's unprecedented uncertainty. This approach also allows time for transmission system upgrades through CEI South's current TDSIC plan and the MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 projects, which support enhanced reliability and resilience.

The Preferred Portfolio provides for **maximum flexibility** to pivot should the future turn out differently than expected.

This is crucial in this current environment, where developers are less willing to share in cost risk which drives generation project costs higher for utility customers, with uncertainty around how much accreditation resources will receive from MISO to meet reliability requirements, or the direction of future greenhouse gas regulations.

In the short term, the plan maintains the F.B. Culley 2 interconnection, with possible 90 MW battery storage reuse and continues the demand side management programs. In the long-term and to be reevaluated in a future IRP, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit in 2034 to replace F.B. Culley 3 by 2035. The plan also calls for 50 MWs of battery storage in 2040 and 2045 to meet its planning reserve margin requirements.



Preferred Portfolio: **How Did We Get Here**

While current modeling suggests that replacement of F.B. Culley 3 coal with conversion of CEI South's two new CTs to a CCGT by 2030 could save customers money in the long run, locking in this option for CEI South's retail customers could increase bills in the near-term, increase risk, and reduce future flexibility. The conversion of these units would cost approximately $1 billion dollars or more and would likely be included in customer rates by 2030, costing customers up to $21[1] more per month on average in the near term compared to the Preferred Portfolio which delays this decision. Affordability, one of the five pillars, is top of mind for CEI South and its customers following our recent rate case and has also been prominent within IRP stakeholder comments.

By slowing down the generation transition, customers should benefit from rate stability while preserving the flexibility—a critical capability in today's landscape—for CEI South to reevaluate F.B. Culley 3's fate in a future IRP. For example, in its previous IRP, CEI South had planned to convert F.B. Culley 3 to natural gas by 2027 with a continued renewables build out. However, just three years later, shifting external factors—such as reduced MISO accreditation for renewables, increased costs driven by market uncertainty, and diminished federal support following the rollback of key IRA tax incentives—have made this a more costly strategy relative to alternatives (14-17% higher).

Preferred Portfolio: **Overview**

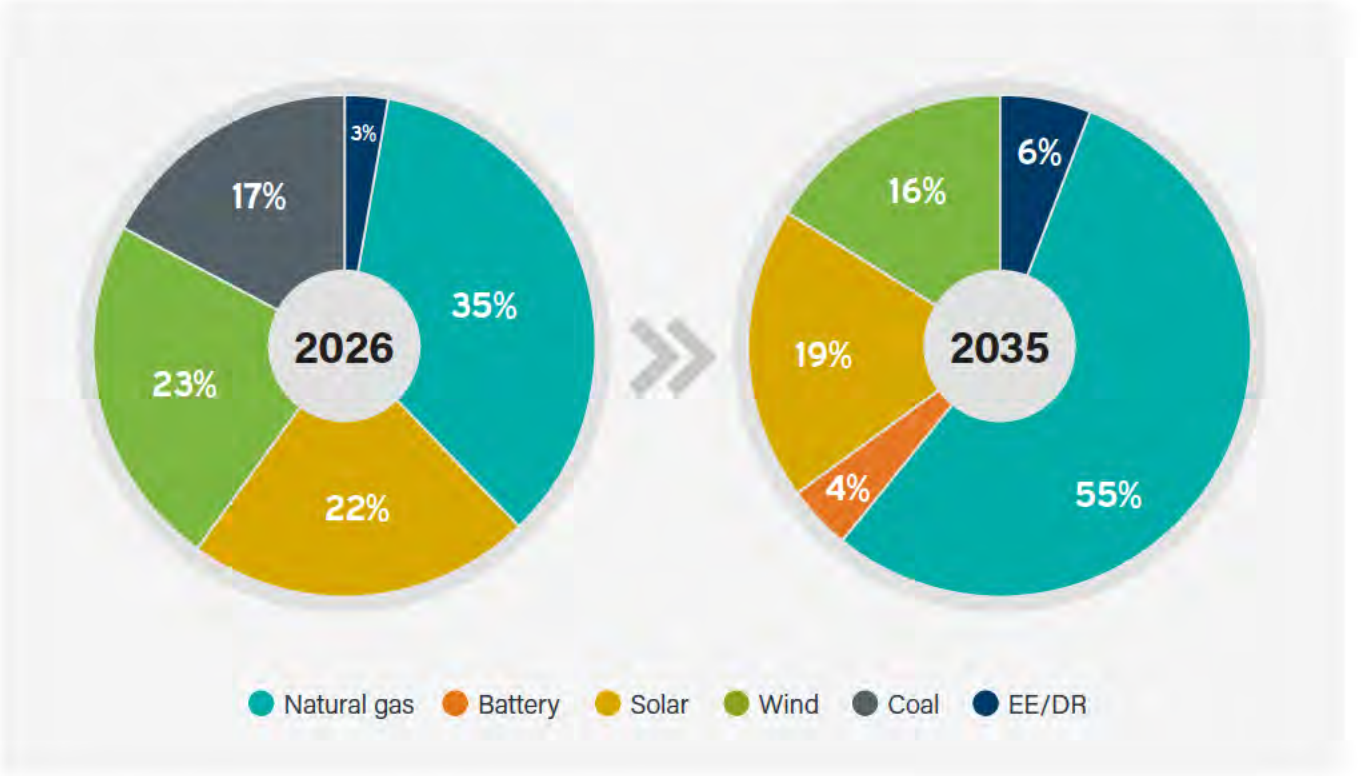
Between now and 2034, the Preferred Portfolio preserves the option to replace F.B. Culley 2 coal plant when it is suspended at the end of 2025 with a 90 MW battery storage unit by the end of 2028. CEI South will conduct another Request for Proposal ("RFP") to determine if the cost of this project has escalated from what was bid in the All-Source RFP and compare the cost to required capacity purchases. Based on the All-Source RFP, the cost of this battery is nearly identical to purchasing an equivalent amount of capacity on the market. Locking in capacity with a battery should help stabilize bills versus purchasing from a volatile capacity market that is expected to see rising prices as MISO's reserve margin continues to decline. It also helps maintain reliability with an on-system resource to help supply stored energy when it is needed most.

The Preferred Portfolio secures cost savings from wind and solar resources identified and acquired through previous IRPs, ahead of the repeal of IRA renewable energy tax incentives under the One Big Beautiful Bill Act ("OBBBA"). It also maintains operational flexibility by allowing F.B. Culley 3 to continue to run on coal, allowing time to reevaluate if conversion to natural gas or earlier retirement makes sense in a future IRP.

[1] *Not including expected offsetting sales revenues*

Preferred Portfolio: **Key Considerations**

CEI South's preferred resource plan reduces risk through continued diversification, lowers the cost to serve load over the next 20 years, and provides flexibility to evaluate and respond to future needs through subsequent IRPs.



The Preferred Portfolio has several advantages, including:

1. Among the least cost options, within **3% of the lowest cost portfolio** in the long term.
2. Provides near-term rate stability for **customer affordability** by delaying large capital investment.
3. Provides **affordable, reliable energy** with a well-balanced mix of **sustainable energy resources** and continued focus on demand side resources.
4. F.B. Culley 2 battery storage **enables avoidance of certain required capacity purchases.**



5. **Maximizes flexibility** to navigate unprecedented uncertainty; **minimizes risk**.

   - Delaying large capital investment also mitigates cost risk, as we live in very uncertain times. Current uncertainty is driving near-term price increases for various resources. It also helps reduce long-term price risk by allowing more time to better understand the direction of Environmental Protection Agency ("EPA") greenhouse gas regulations. Over the last 16 years environmental regulations have flexed and retracted with each administration. It is possible that in the next administration an aggressive greenhouse gas regulation could materialize which could throttle how much an efficient combined cycle gas unit may run, or a more stringent environmental regulatory requirement is finalized that would significantly increase operating costs for a fossil-fuel fired generation unit.

   - Provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. Maximum flexibility is important as demonstrated by the massive amount of change that has been experienced over the last decade. By proactively canceling high-cost renewable projects and securing affordable wind power purchase agreements, CEI South has taken decisive action to avoid increasing customer expenses. This forward-thinking strategy also strengthens CEI South's position ahead of MISO's upcoming accreditation reforms—reforms that are expected to significantly reduce the reliability value of certain resources, particularly solar. Additionally, pausing the conversion of F.B. Culley 3 and reevaluating under current market conditions preserves future flexibility at a lower near and long-term cost to our customers.

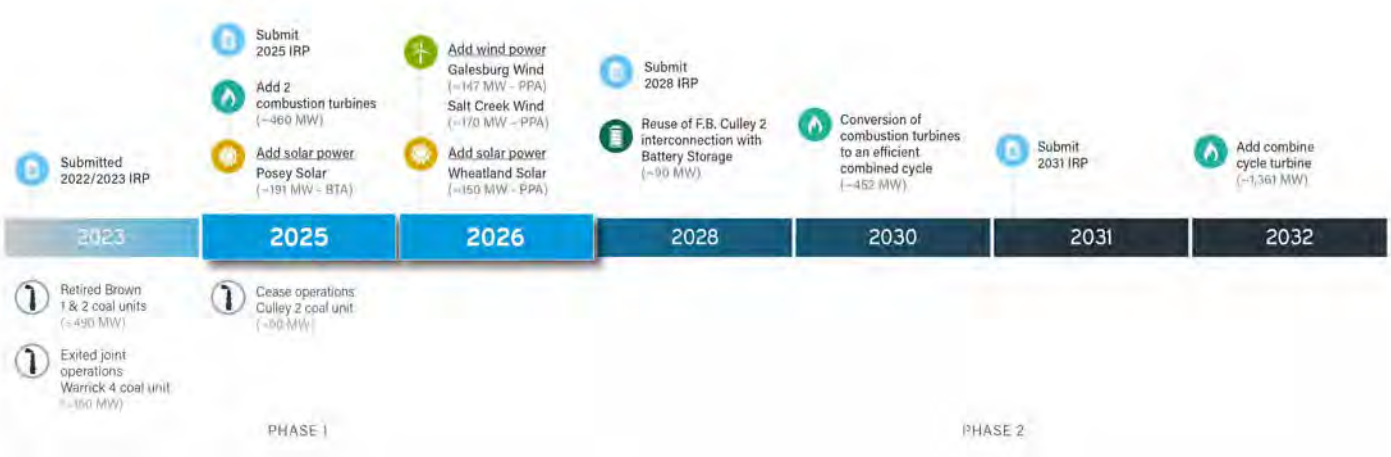
6. **Preserves tax base and jobs in Warrick County.** The replacement of F.B. Culley 2 with a battery storage system provides economic benefit to the community, whereas purchasing this needed capacity from the market does not. It is the equivalent of renting a home vs buying. Allowing F.B. Culley 3 to continue running in the near-term preserves tax base, benefiting the county while it continues to depreciate; it also maintains jobs associated with coal handling. Additionally, the facility uses Indiana-mined coal, preserving mining jobs and supporting the state's economy.

7. Maintains a base load generator on the east side of our system, providing **reliable**, **stable**, and **resilient power**.

   F.B. Culley Unit 3 continues to deliver essential voltage support to our community, providing valuable time for needed transmission expansion and offering flexibility as we await greater clarity on the future of nearby generation facilities that currently play a key role in grid stability.

8. Provides **flexibility** to serve a large load addition, should an **economic development** project materialize (See Alternate Preferred Portfolio).

Alternate Preferred Portfolio



The following Alternate Preferred Portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

To maintain flexibility and stay nimble for potential economic development opportunities for southwestern Indiana, CEI South chose an **Alternate Preferred Portfolio** for a large load addition.

A large load addition scenario was created, starting at 250 MW and scaling up to 1,500 MWs in the early 2030s. Conversion of the new A.B. Brown CTs to a CCGT and F.B. Culley 2 battery storage become the most affordable options in the near-term to support the ramp. The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028 and continues demand side management programs.

Additionally, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit by 2030, continues F.B. Culley 3 on coal, and builds a large natural gas combined cycle unit by 2032 to support the large load addition. This build out is paired with near-term reliance on the market and aligns with system capabilities.

Alternate Preferred Portfolio: **How Did We Get Here**

Per stakeholder feedback, CEI South evaluated the potential for a large load addition that would scale over time. This scenario complements the multiple large load sensitivities conducted during the IRP and reflects insights gained from CEI South's ongoing conversations over the past several years with prospective customers across a range of industries. Commonly, CEI South is asked to determine how fast the system can be ready to accommodate a potential customer's business plan. Timelines have been compressed from what was considered normal in the past. These requests require CEI South's generation planning team to work closely with its transmission planning team. This scenario incorporates feedback from both teams, along with expert third party consultants to evaluate what is possible.



Alternate Preferred Portfolio: **Overview**

In the alternate reference case, all market conditions remain the same as reference case conditions, but load is increased by 250 MWs per year until the cumulative load reaches 1,500 MWs in the early 2030s. Load evaluations from prospective customers of this size were extremely uncommon for economic development projects in the past but are now approaching routine. CEI South selected the optimized, least cost model results as the Alternate Preferred Portfolio.

By including an Alternate Preferred Portfolio, CEI South is preserving necessary flexibility to quickly pivot, keeping southwestern Indiana competitive for economic development and growth. The Alternate Preferred Portfolio adds tax base and jobs to the community, not only from the prospective customer facility, but also from the infrastructure needed to support it. CEI South's analysis shows that generation near the site of the load is necessary to provide stability and avoid a large transmission outlay.

Alternate Preferred Portfolio: **Key Considerations**

The Alternate Preferred Portfolio:

- Preserves maximum future flexibility, keeping southwestern Indiana competitive for economic development and growth (Speed to market is important for most prospective customers),
- Adds tax base and jobs in our community, which helps all customers thrive,
- Aligns with Federal and State goals,
- Utilizes F.B. Culley 3 until replacement/conversion to natural gas is decided, and
- Adds efficient on-system base load generation for **reliability**, **stability** and **resilience**.

CEI South will continue to have ongoing conversations with prospective customers. At this point, no contract has been signed. As we prepare for this potential, CEI South will continue to evaluate possible timelines and costs necessary to serve. While the Alternate Preferred Portfolio provides a possible path, the resource mix to serve will be heavily influenced by a potential customer's need for low-cost power, along with other criteria important to the prospective customer. As such, CEI South modeled alternatives to aid in these conversations. CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations turn into negotiations/contracts.

CenterPoint Energy Overview

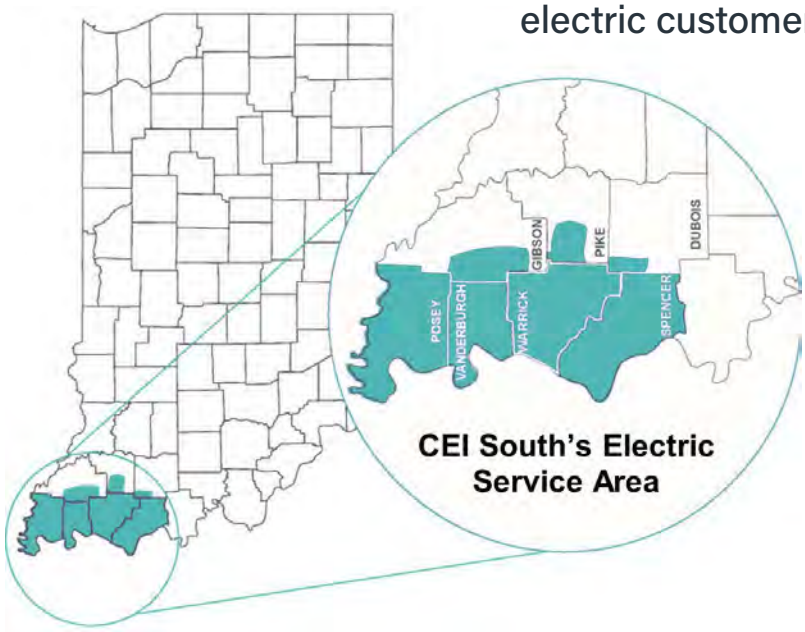
Provides energy delivery services to more than

150,000

electric customers

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in southwestern Indiana. In 2024, approximately 45% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers, and 25% were made to small commercial customers.

The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

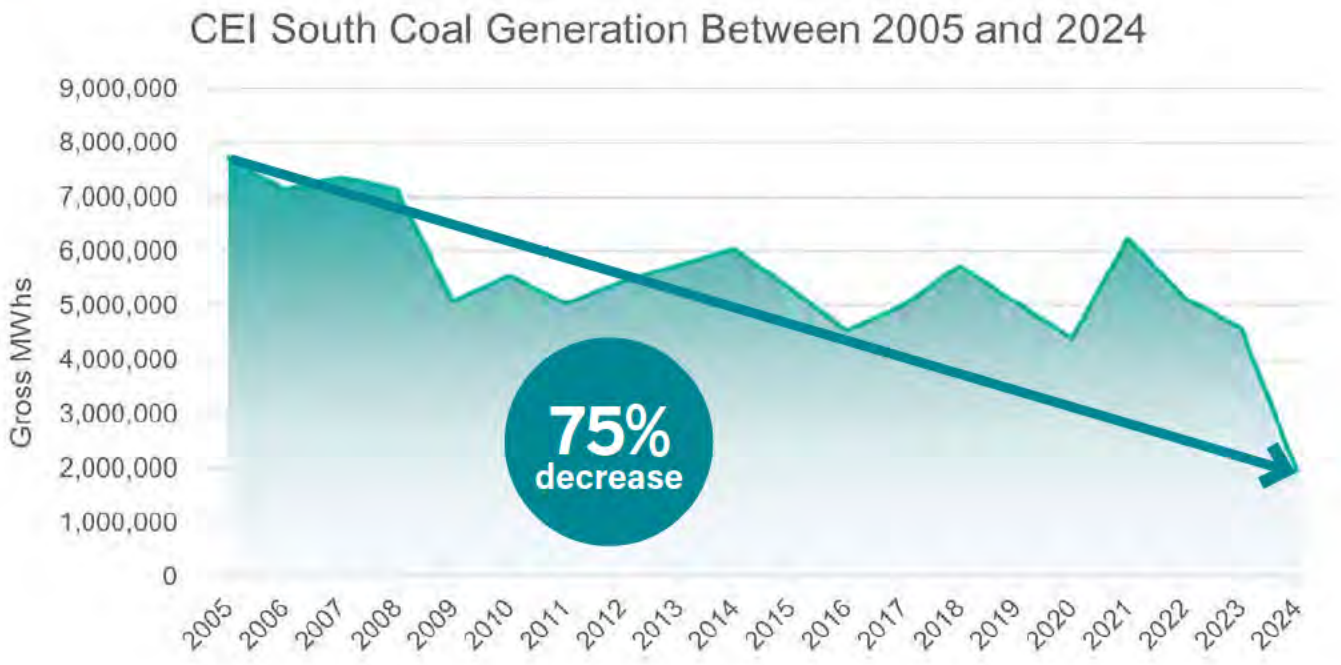


Unit [2]	Installed capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date/Expiration	Unit Age	Coal Unit Environmental Controls [3]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	230	Gas	2025	N/A	<1	
A.B. Brown 6	230	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2026	N/A	N/A	
Salt Creek	170	Wind PPA	2026	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

[2] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

[3] Both Coal units are controlled for Sulfur Dioxide ("SO2"), Nitrogen Oxide ("NOx"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO3") and Sulfuric Acid ("H2S04").

CEI South has largely moved away from coal, with the retirement of A.B. Brown units 1 & 2, exiting the joint operating agreement for Warrick 4, and the planned suspension of F.B. Culley 2 at the end of 2025.



These resources have been replaced with a diverse mix of wind, solar, energy efficiency, demand response, and gas resources. The current analysis demonstrates that customers receive a better balance of near-term and long-term affordability and reliability by continuing to evaluate the opportunity to replace CEI South's smallest and least efficient coal unit, F.B. Culley 2, with battery energy storage while deferring a decision on replacement of CEI South's last remaining coal unit that it operates, F.B. Culley 3, to a future IRP.

Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required. The IRP describes the analysis process used to evaluate the optimal mix of generation, storage, energy efficiency, and demand response resources (resource portfolio) to meet customers' needs for reliable, resilient, stable, affordable, and environmentally sustainable power ("the five pillars") over the next 20 years. The IRP helps set the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

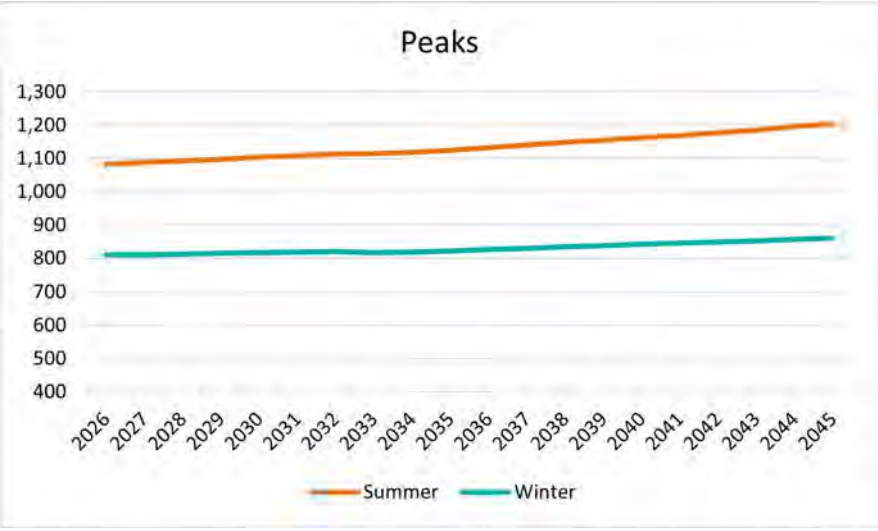
CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, trade associations and environmental advocacy groups. CEI South placed considerable emphasis on the five pillars, rate stability, risk, and resource diversity. The IRP process continues to increase in complexity as MISO continues to implement resource accreditation reforms to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

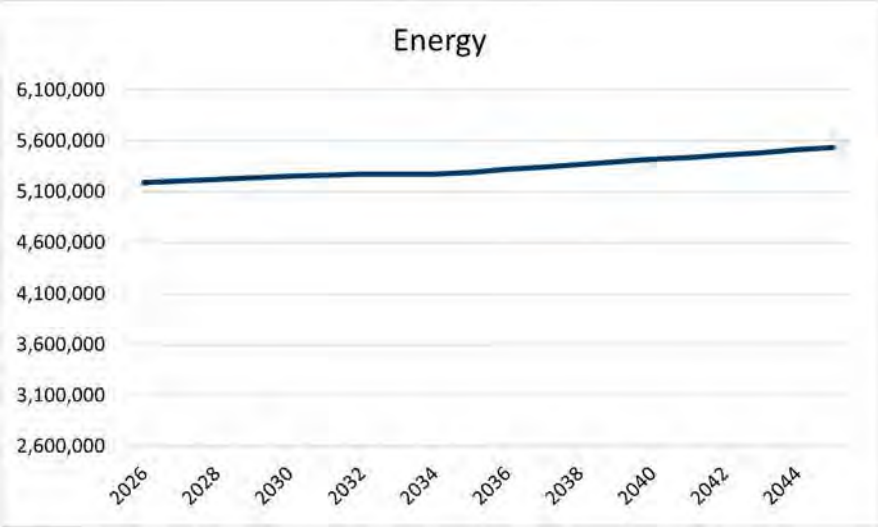
Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Demand is typically measured in Megawatts ("MW"), and energy is typically measured in Megawatt hours ("MWh"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation, demand side (energy efficiency and demand response), and storage resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.



CEI South must meet customer demand in all hours of the year. This has become more challenging, as the regional resource mix changes towards intermittent (variable) renewable generation. MISO functions as the regional transmission operator for 15 midwestern and southern states, including Indiana (also parts of Canada). MISO evaluates how changes in the future resource mix impact reliability. Recently, they have received FERC approval to update the way resources are accredited to the Direct Loss of Load ("DLOL") methodology beginning in 2028, which is projected to have a substantial impact on solar accreditation in the summer and winter when load is at its highest. CEI South has accounted for this change and worked with stakeholders to develop a reasonable accreditation projection given the best available information. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability.





CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles.

Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by **0.5% per year**. Winter peak demand grows at a slightly slower pace of **0.3% per year**.

Resource Options Considered

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 95 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, bio-mass thermal, demand response, and wind. These project bids provided up-to-date, market-based information to inform the analysis. Additionally, CEI South utilized other information sources for long-term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 3 coal unit to natural gas, various other natural gas resources, conversion of A.B. Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries.

Every IRP is a snapshot in time producing a direction based on the best-known information. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the accelerated sunset of wind and solar tax incentives from the IRA with the passage of OBBBA, the rise of Artificial Intelligence ("AI") data centers and onshoring of industrial manufacturing driving unprecedented load growth, state and federal executive orders to maintain existing resources, continued increased costs for renewables projects, new technologies, and rapid changes in the MISO market to adapt and help enhance reliability.

- Battery storage
- Coal
- Energy efficiency/ Demand response
- Hydro electric
- Natural gas
- Nuclear
- Wind and solar





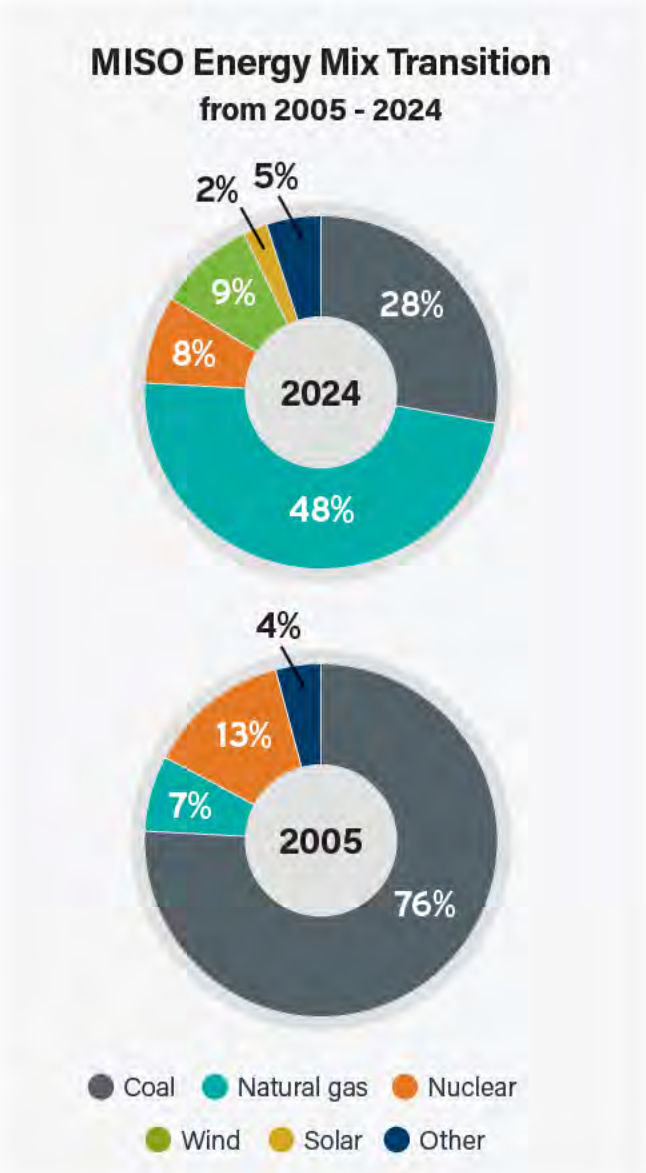


INDUSTRY TRANSITION

The transition to intermittent renewable resources within MISO has continued over the last several years, although at a slower pace. Until the pandemic, renewables costs declined rapidly due to improvements in technology and government incentives. This largely stalled and began an upward climb. Wind and solar resources continue to face increasing price pressure, interconnection delays, and decreasing accreditation from MISO. With the passage of OBBBA, renewable resource tax incentives sunset more quickly than under the IRA placing more pressure on renewable resources.

This comes as load growth to serve data centers supporting AI is projected to ramp very quickly over the next several years. Each data center can use enough energy to power a mid-sized city, and they require power twenty-four hours a day, necessitating dispatchable resources. Additionally, President Trump has made tariffs a core part of his second term. These tariffs are designed to incentivize manufacturing to come back to the United States, thus providing new economic development opportunities, particularly with industries related to national security. For example, his administration has focused on the steel and aluminum industries, which also bring the potential for extremely large loads.

To respond to this challenge, the federal government is working to slash regulations and maintain incentives for baseload (24x7 power) nuclear resources. Additionally, the state of Indiana has responded with incentives for these prospective customers and also with economic development incentives aimed at spurring development in small modular nuclear resources that can provide power intense data centers and large industrial facilities with zero carbon emitting resources, the first of which, in Indiana, is likely to come on-line in the early to mid-2030s.



In the near-term, gas resources are seeing unprecedented demand from utilities to meet increasing near-term load obligations. Installed capacity of wind and solar resources is expected to continue to increase within the MISO footprint, although more slowly than even a few years ago. Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation in 2005, used primarily to meet the needs during peak demand conditions, to approximately 48% of total generation in 2024.[4] Meanwhile, coal has declined but still supplies a little more than a quarter of the energy need within MISO, followed by wind at 9%, nuclear at 8%, and solar at 2%.

[4] *MISO 2024 State of the Market Report, Potomac Economics, June 2025, page 6 https://cdn.misoenergy.org/2021 State of the Market Report625295.pdf https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf*

The move toward renewables and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with EPA regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has also driven unit retirements.

While coal has been declining, it remains an important source of power for our grid, particularly as this capacity-rich resource has seen an uptick in market capacity revenues. Additionally, President Trump has written executive orders aimed at supporting the coal industry in an attempt to preserve remaining plants. With these market changes, coupled with increasing costs for renewable and gas resources, we are more likely to see some coal units remain online longer than they otherwise would have.



CHANGING MARKET RULES TO HELP ENSURE RELIABILITY

MISO recognizes the major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have overproduction (more energy produced than is needed at the time) and other periods will have low-to-no renewable energy production, requiring dispatchable resources to meet real-time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future.

Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing mix of resources, there is an increased importance of ensuring that adequate attributes are available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained, MISO implemented a seasonal resource adequacy construct beginning with the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct, thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("EFORd") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources continues to be challenged as MISO received approval to further revise the accreditation approach in 2028 with the introduction of DLOL methodology. The move to DLOL is expected to most affect renewable resources, particularly solar. For example, solar resources were expected to provide about 25% or more of their total installed capacity to cover MISO's reliability requirement. This is expected to drop over time to approximately 5% or below in the summer, CEI South's tightest season. The practical effect is that more capacity will be needed when fully implemented.

Also, MISO continues to study how demand response resources will be accredited. To date, these reforms have provided more certainty that demand response will be there when called upon; however, there is a much higher bar than in the recent past for industrial customers to participate with annual testing and required faster response times to remain a participant in these programs. MISO reforms will continue as reserve margins continue to tighten and increasingly include intermittent renewable resources that make it more difficult to maintain acceptable voltage and thermal limits on the grid than traditional, dispatchable resources.

CEI South has accounted for these changes by incorporating the seasonal construct and DLOL accreditation approach into the Encompass model, and the portfolios in this analysis provide sufficient resources to meet its MISO obligations in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations.

BATTERY STORAGE AND TRANSMISSION RESOURCES

To support greater reliance on intermittent renewable resources, utilities are increasingly considering the opportunity to add battery storage to resource portfolios to help provide availability and flexibility. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature. In fact, 2024 All-Source RFP bids for battery storage to replace F.B. Culley 2 as a potential CEI South resource were cost effective for the first time.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining the reliability of the transmission system. CEI South has experience operating a 1 MW battery designed to capture energy from an adjacent solar project. This pilot project has provided information that will be helpful in moving forward with a much larger project. The 90 MW battery will be available to discharge energy for four hours and will be available for energy arbitrage and meeting peak load conditions.

Uncertainty/Risk

As demonstrated over the past few years, the future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the preferred resource portfolio mix of generation and demand side resources to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

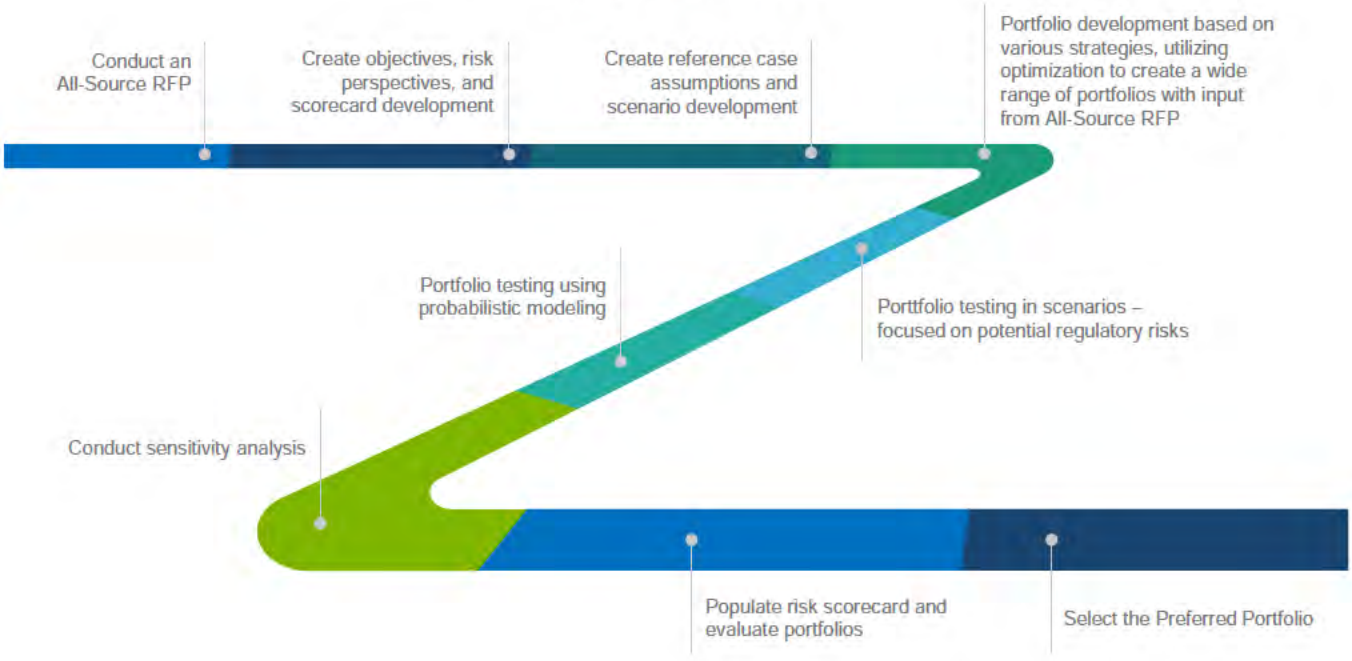


Analysis

CEI South's analysis included a step-by-step process to identify the Preferred Portfolio. The graphic below summarizes the major steps which included the following:

1. Conducted an **All-Source RFP** to better understand resource cost and availability.
2. Worked with stakeholders to develop a **scorecard** as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Worked with stakeholders to develop a wide range of **future states**, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Worked with stakeholders to develop a wide range of **portfolios** for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conducted a **risk analysis,** including deterministic and probabilistic modeling with sensitivity analysis.
6. Utilized the **quantitative scorecard measures** and **judgment** to select the Preferred Portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).

Analysis Process



Stakeholder Process

As in the last IRP, each of the last three stakeholder meetings began with stakeholder feedback. CEI South reviewed requests/comments from the prior stakeholder meeting and provided feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South explained why not. Notes for each meeting were included in question-and-answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (IRP@CenterPointEnergy.com) and with phone calls/meetings in between each public stakeholder meeting by request.

While maintaining the virtual option to participate, CEI South thought it was important to continue face-to-face meetings. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to southwestern Indiana or did not wish to participate in person Dates and topics covered are listed below

CEI South held a series of technical meetings with stakeholder groups willing to sign a Non-Disclosure Agreement ("NDA") and participate in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. These meetings, along with a data release schedule, helped keep technical stakeholders informed throughout the process and provided an opportunity to engage with CEI South in a way that is not always possible during public stakeholder meetings.

CEI South also incorporated feedback from the Director's report on its previous IRP, along with insights from the annual Contemporary Issues Conference hosted by the IURC. The 2025 Conference topics proved especially timely - highlighting considerations for large load coordination and planning. Discussions underscored the importance of flexibility and preparation to account for the impacts of large load within our planning process. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.



Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real-time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the Preferred Portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This, along with providing modeling inputs, helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process.

CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios, including the addition of a possible future, the alternate high regulatory scenario. CEI South updated the scorecard to measure risks in each of the five pillars (Affordability, Environmental Sustainability, Reliability, Resiliency, Stability) with a separate section for other market risks. Per the Director's report, CEI South added the 5th percentile of Net Present Value Revenue Requirements ("NPVRR"). CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding an affordability metric (electric energy burden) that illustrated the 5-10 year incremental impact to energy burden (incremental residential bill impact in 2030 and 2035 divided by Vanderburgh County median household income). This measure highlights near to mid-term price pressure that customers may face for each portfolio. Additionally, CEI South added measures for Dynamic VAR Support ("MVAR") and Short Circuit Ratio ("SCR") from its updated transmission reliability analysis. CEI South also added SOx and NOx emissions and capacity sales/purchases to the scorecard. Adjustments were also made to modeling inputs and assumptions based on direct stakeholder feedback. The following table shows key stakeholder requests made during the process and CEI South's response.



Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scorecard	Under the Environmental Sustainability Objective: Remove CO_2 intensity, keep CO2-e tons	CEI South believes that there is value in keeping CO_2 intensity, as well as CO_2-e metrics. CO_2 intensity allows the reader to compare CO_2 levels across scenarios.
Scorecard	Include metrics for SOx and NOx	CEI South has added metrics that includes combined tons of SOx and NOx.
Scorecard	Under the Affordability Objective: consider adding an energy burden calculation	CEI South proposes to add electric energy burden, defined as the 5-Year [5] residential rate impact as of July 1, 2025 divided by the Vanderburgh County Median Household Income.
Resource Options	Are the Demand Response proposals subject to discussion/change with Demand Side Management (DSM) Oversight Board	CEI South continues to discuss Demand Response with members of the DSM Oversight Board
Resource Options	Is CEI South considering what the resource mix could be if a resource incentive (updated EDG rate) is included in the IRP?	CEI South is conducting a sensitivity considering a $500 per kW incentive for Distributed Generation solar resource.
Load Forecast	Provide a breakout of peaks by customer class	See graph in 3/19/2025 Stakeholder meeting notes posted at www.centerpointenergy.com/irp
Load Forecast	Why is CEI South using historical rather than forecast temperature, e.g., Purdue University temperature forecast?	CEI South used a linear projection of temperature based on historical data; it is not significantly different from the Purdue University study for the IRP period.
Load Forecast	Requested CEI South to revisit the estimated 12,000 miles for EVs used in the forecast	Itron EV assumption for reference forecast. The 12,000 miles per year for EVs was revised to 9,500 miles per year. This revision is noted in the 5/14/2025 Stakeholder meeting slides

[5] *CEI South ultimately added a 5 and 10 year incremental energy burden per stakeholder request.*

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Load Forecast	Does the EV charging profile used for CEI South's load forecast account for remote work at home?	The NREL tool, EVI-Pro, documentation does not specifically state any assumptions regarding work from home. The "EVHome" charging profile on slide 61 of the 3/19/2025 stakeholder slides includes some level of charging between 11am-2pm. (slides posted at www.centerpointenergy.com/irp)
Load Forecast	Does CenterPoint have plans to electrify its fleet?	CenterPoint does have plans to electrify its fleet - please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/
Commodity Inputs	Does the natural gas forecast assume increased drilling under the current administration?	At this time, CEI South is uncertain how the current administration's policies will affect natural gas prices. Our vendors consider multiple factors when developing commodity forecasts. Utilizing a consensus forecast is an approach CEI South has taken in previous IRPs. These various perspectives allow us to capture the diversity in opinions for future market prices.
Generation Timeline	Regarding Salt Creek Wind, is this project going to service CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be service to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?	Please see Witness Swanson's public testimony in Cause No. 46218.
Objectives & Draft Measures	Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?	We'll look at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scenarios	Suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high.	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Scenarios	When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Supply-Side Resource	Can CEIS incorporate real coal price offers made to CenterPoint. The uncertainty variable is not the mining cost as much as the demand.	Due to the confidential and competitive nature of CEIS's contractual coal price this was discussed during the 8/20/2025 Tech to Tech meeting
Supply-Side Resource	How many bids did CEIS receive for storage?	There were 17 standalone storage bids. The 2024 All-Source RFP results were shared during the 3/19/2025 Stakeholder meeting. The presentation is available here: CenterPointEnergy.com/IRP.
Supply-Side Resource	Is CEIS accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?	Health costs are captured within EPA regulations that are included in the applicable scenarios.
Supply-Side Resource	Has CEIS considered the water pressure nuclear option, such as the Westinghouse AP1000?	The general nuclear option included in the Tech Assessment is representative of a variety of future nuclear options. If you have information regarding technology performance or costs that you would like to see in the model, please email IRP@CenterPointEnergy.com

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
MPS	For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?	We performed cost-effectiveness screening using a range of incentives and adoption rates. In all scenarios the Utility Cost Test ratio was less than 1, which is not cost-effective. Results are included in today's (9/11/2025) Stakeholder meeting.
MPS	For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?	We are assuming that the customer would supply their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs
MPS	Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?	When performing cost-effectiveness screening, the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of Demand Response captured in the IRP analysis.
Model Inputs	Is CEIS going to include Scope 3 emissions?	Scope 3 emissions are outside the scope of the IRP as it's related to emissions of the end-user and separate from electricity generation.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Model Inputs	Since CEIS is considering nuclear, does CEIS want to run a stochastic process for uranium?	We are currently using publicly available data sources for uranium pricing forecasts. Uranium pricing is not expected to be a major differentiator in the portfolio risk assessment when compared with other cost drivers. Given this, we do not anticipate that running a stochastic process for uranium will materially change the outcomes of the analysis.
Model Inputs	Is CEIS planning to use the MISO published 2025/2026 indicative DLOL results for the solar and wind accreditation assumptions?	We have revised the accreditation values to interpolate between the first season of DLOL and 2035. Providing a smoother shift in accreditation. Revised Solar and Wind capacity accreditation forecasts are included in the 9/11/2025 presentation's Appendix.
Model Inputs	Recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP	CEI South's evaluated demand response programs that align with the intent of both DCP and VPP programs as well as a DG Solar incentive during the IRP process. Updates on the evaluations are included in today's (9/11/2025) Stakeholder meeting.
Modeling	Scenario Portfolios – Explain why manual modifications applied to scenario portfolios to align with the Reference Case load	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Scenario Portfolios – Request to re-run the capacity expansion simulation instead of the production cost simulation	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Modeling	Scenario Portfolios – Request to share documentation illustrating manual modifications made to the scenario portfolios	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Build Limits – Request for CEI South to consider running scenarios with relaxed limits	CEI South ran a simulation and chose to relax limits to allow more resources to be selected within the capacity expansion model.
Modeling	Consider a study with FB Culley 3 retiring in 2030	Given the unprecedented amount of uncertainty at this time and future transmission upgrades that will help with system reliability and resilience, it would not be prudent to consider retirement prior to 2031/2032, as is being considered within this IRP.
Affordability Measure	Request for energy burden calculation	CEI South will make the energy burden workpaper available to technical stakeholders with a signed NDA.
Rates	Request to provide guidance on bill itemization	Please see the CenterPoint website, where is shows an explanation of the bills. https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in

Meeting materials for each meeting can be found at **CenterPointEnergy.com/IRP** and in Technical Appendix Attachment 4.2 Stakeholder Materials.

Next Steps

CEI South's flexible plan provides two paths forward, depending on what the future holds. If a large load customer agreement is not made prior to the next IRP in 2028, CEI South will move forward with the Preferred Portfolio. With this path, there are a few items that must be done in the short-term action plan.

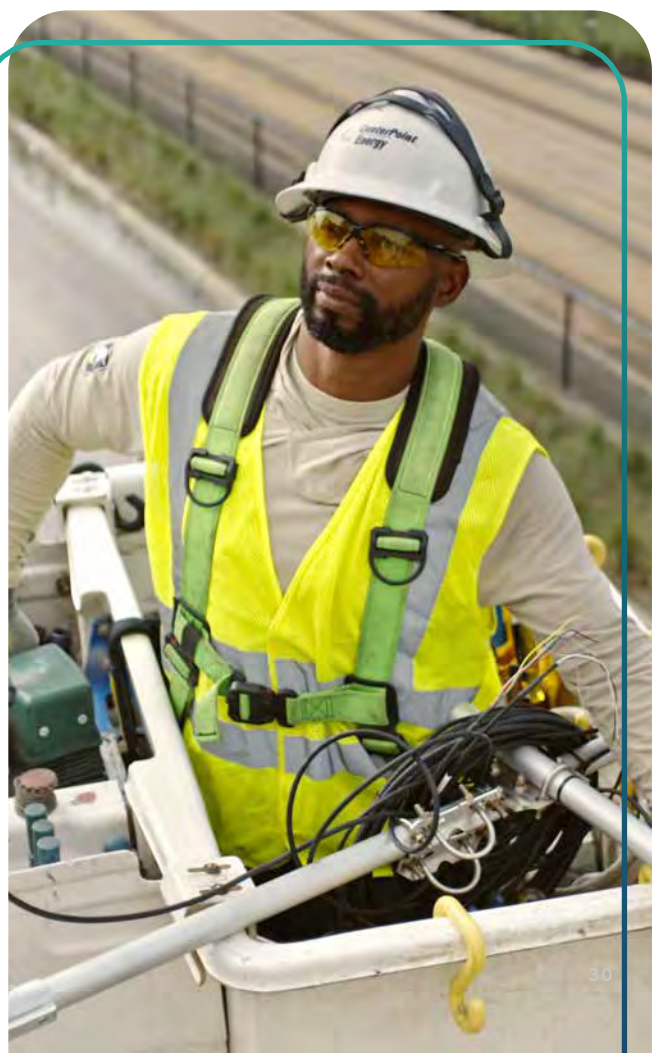
First, CEI South will continue to implement the generation transition that was identified in prior IRPs. CEI South is currently pursuing three renewable projects that are scheduled to be online in 2026: 147 MW Galesburg Wind (approved PPA), 150 MW Wheatland Solar (approved PPA), and 170 MW Salt Creek Wind (approved PPA). These projects will continue to diversify CEI South's generation mix.

Secondly, CEI South will conduct two RFPs to determine current pricing for capacity and battery storage for replacement of F.B. Culley 2 interconnection in the next three years. Having run past its useful life, F.B. Culley unit 2 (coal) is slated for suspension at the end of this year. FERC rules allow for replacement of the interconnection within 3 years of suspension. CEI South will continue to evaluate the proper path forward with consideration for Indiana's five pillars. Should CEI South choose to reutilize the interconnection, it will seek approval in a Certificate of Public Convenience and Necessity ("CPCN") before the IURC and modify its Attachment Y with MISO to an Attachment X.

Third, CEI South will file for a DSM plan, consistent with the results of the Preferred Portfolio.

Finally, CEI South will continue to engage with economic development opportunities to help strengthen southwestern Indiana. Should a large load addition materialize, CEI South would diligently work to implement its Alternate Preferred Portfolio that would potentially require multiple CPCNs and approval of a contract with the IURC. These filings will be consistent with the Preferred Portfolio paths. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the Preferred Portfolio.

CEI South's plan must be flexible, as several items are not certain at this time, including but not limited to: MISO DLOL, EPA greenhouse gas regulations, cost of resources, policy change, the potential for large load additions, and regulatory risk.





Integrated Resource Planning

Chapter 1

1.1. Integrated Resource Planning

CEI South takes integrated resource planning very seriously. The Integrated Resource Plan ("IRP") is used as a guide for how CEI South will serve existing and future customers over the next 20 years in a reliable, affordable, stable, resilient, and environmentally sustainable manner. The integrated resource plan sets the direction for future generation and Demand Side Management ("DSM") options; however, future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

CEI South is required to submit its IRP to the IURC every three years and last submitted it in 2023 with a plan to transition its generation fleet away from a majority reliance on coal to a portfolio of renewable generation, supported by a diverse set of natural gas generation resources. Since that time two new quick start, fast ramping natural gas combustion turbines and the Posey Solar project have come on-line, while the conversion of F.B. Culley 3 to natural gas was paused for re-evaluation within this IRP, and several renewable projects were canceled due to increasing cost.

With a focus on stakeholder input, CEI South began the 2025 IRP process by gathering feedback from stakeholders on the last IRP and the Director's Report for the 2022/2023 IRP. Additionally, CEI South worked closely with IRP stakeholders throughout the process, including multiple tech-to-tech discussions and information sharing between public stakeholder meetings, as discussed in Section 8.6 Public Advisory Process.

Although the future remains uncertain; several factors have set the stage for the 2025 analysis. After many decades of stagnant growth, reindustrialization and the Artificial Intelligence ("AI") race has changed the trajectory and will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power in the near-term. Renewable resources have been slow to come online, many of which are not projected to come on-line at all due to higher than projected interconnection costs, delays in the MISO queue, tariffs, declining accreditation from MISO, changes to state and federal policy, the proposed repeal of EPA greenhouse gas regulation, and the passage of the One Big Beautiful Bill Act ("OBBBA") that accelerated the sunset of IRA tax credits to wind and solar resources.

Despite considerable uncertainty throughout the IRP development, CEI South has remained agile in navigating evolving risk, including but not limited to incorporation of stakeholder feedback on methodology, modeling, and assumptions, adding two additional scenarios per stakeholder feedback, and updating originally proposed scenario assumptions in near real time to account for proposed changes in EPA regulation. This necessitated requesting and receiving approval for an extension to submit the IRP on or before December 5, 2025.

1.1.1. Indiana's Five Pillars

On April 20, 2023, House Enrolled Act 1007 was signed into law by Governor Eric J. Holcomb. Indiana incorporated the Five Pillars of Indiana energy policy into state law in Indiana Code 8-1-20.6, with an effective date of July 1, 2023. The law states that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider the following attributes: reliability, resiliency, stability, affordability, and environmental sustainability. The Indiana Utility Regulatory Commission adopted General Administrative Order ("GAO") 2023-04, which was inclusive of IRPs.

The Five Pillars are Reliability, Resiliency, Stability, Affordability, and Environmental Sustainability. Each has been considered equally within this IRP and are defined below:

Figure 1-1 – Five Pillars



To better account for the five pillars, CEI South structured its portfolio scorecard, a tool to help evaluate risk and tradeoffs, by aligning measures with each of the pillars to aid in the selection of a Preferred Portfolio. While affordability often takes center stage, each pillar is essential in shaping a comprehensive energy strategy. Under the lens of the five pillars, CEI South included the following scorecard updates:

- Incorporated a view into near-term affordability with the inclusion of an energy burden analysis. This complements the traditional long-term affordability measures;
- Conducted a more in-depth evaluation of reliability, resilience, and system stability in this IRP through a dedicated transmission analysis, which informed the development of additional scorecard measures; and
- Enhanced its view into environmental sustainability by adding additional air measures into the scorecard.

1.1.2. State of the World

Over the last year and a half, there has been unprecedented change that directly effects resource planning, including but not limited to:

- Updates to how resources will be accredited to meet reliability requirements,
- Updates to greenhouse gas regulations from the EPA,
- Escalating costs for various resources,
- Policy changes on the state and federal levels,
- Increasing load for the first time in decades, and
- Change in the regulatory environment.

Changes like these have escalated in recent years. Utilities typically face one or two major challenges per planning cycle. These risks demand careful mitigation to ensure the selected resource portfolio remains flexible and capable of adapting to an uncertain future. CEI South and other utilities across the country are required to make long-term planning decisions in a way that mitigates all of the risks that present themselves. This cycle is particularly challenging with at least 6 major unresolved issues, each of which presents a different risk.

1.1.3. Generation Transition (MISO)

MISO is in the midst of a significant transformation in how it plans for and accredits capacity, reflecting both the rapid transition of the generation fleet and the increasing level of system risk. In 2023, MISO shifted from an annual construct to a Seasonal Accredited Capacity (“SAC”) framework, requiring utilities to demonstrate sufficient accredited resources in all four seasons. This shift recognizes that reliability risks no longer occur only in the summer season. Growing penetrations of solar and wind, shoulder-season maintenance outages, and evolving demand patterns have increased exposure to non-summer season peaks. Seasonal planning introduces more precision into capacity

accreditation and compels utilities to build portfolios resilient to reliability challenges year-round.

Looking ahead, MISO is also preparing to replace its current accreditation methods with a more probabilistic approach based on Direct Loss of Load (“DLOL”) modeling. This proposed framework, expected to take effect in the 2028/2029 Planning Year, will assign capacity value to resources based on their performance in avoiding loss-of-load events rather than static assumptions. It builds upon traditional Loss of Load Expectation (“LOLE”) analysis but offers finer granularity by considering not only the probability of shortfall but also the contribution of each resource type in mitigating it. For utilities, the transition means that intermittent resources such as wind and solar will receive capacity credit more directly tied to their effective reliability contribution, while fast-start and dispatchable resources may become even more valuable.

Alongside the move to seasonal and probabilistic accreditation, MISO is also advancing changes in how the Planning Resource Auction (“PRA”) clears capacity through the introduction of the Reliability Based Demand Curve (“RBDC”). The RBDC links capacity prices directly to reliability outcomes by steepening the demand curve as the system approaches shortfall conditions. In effect, it values incremental capacity more highly when the system is at risk, sending stronger price signals for new entry and retention of resources that support reliability. By aligning market prices more closely with the reliability value of capacity, RBDC is designed to help ensure sufficient investment while avoiding undue reliance on emergency procedures.

At the same time, the generation interconnection queue is undergoing substantial reform. With thousands of megawatts of renewable and storage projects proposed, MISO has adopted new cluster-based study processes, standardized timelines, and cost allocation reforms to accelerate development while maintaining fairness and reliability. These reforms are intended to reduce backlog, improve transparency, and align new resource development with regional transmission expansion.

Taken together, the seasonal construct, evolving probabilistic accreditation, implementation of RBDC, and queue reforms reflect the broader generation transition underway in MISO. The system is moving away from static, one-size-fits-all capacity rules toward more dynamic, risk-informed approaches that account for the realities of a rapidly changing resource mix. For utilities like CEI South, these changes require close monitoring and integration into planning processes to ensure that portfolios not only meet today’s requirements but remain reliable and compliant under tomorrow’s market rules.

1.1.4. Political and Regulatory Environment

Since the last IRP, significant shifts have occurred at both the federal and state levels, including the election of Donald J. Trump as President of the United States and Mike Braun as Governor of Indiana.

President Trump immediately rescinded executive orders issued during the Biden administration and replaced them with new directives aligning with his administration's policy agenda. Speaking in broad strokes, these changes were intended to unleash American energy dominance, paving the way to keep existing fossil generation on-line and to put in place barriers to renewable energy generation.

Along with the flurry of executive orders, President Trump signed the OBBBA into law. With his signature, this bill set into motion the core of President Trump's tax and spend agenda. It has had far reaching impacts throughout the energy industry and integrated resource planning. The law rolls back tax incentives for those that purchase electric vehicles, which could have an effect on load projections in the long-term. Additionally, the bill rapidly phases out Inflation Reduction Act ("IRA") tax incentives for wind and solar resources, while nuclear and battery resource provisions from the IRA were largely preserved.

President Trump has also brought in a new era of tariffs in an effort to bring back lost manufacturing by leveling the playing field with foreign countries. While tariffs could bring more load back to the system in the long run, near-term uncertainty and inflation have had the effect of raising costs for new generating resources, often built with materials sourced from all over the world.

Finally, President Trump has worked to appoint those that will promote his agenda through government agencies. These agencies have made shifts that must be accounted for within the IRP, most notably, the potential roll-back of EPA greenhouse gas regulations could ease restrictions on fossil-fueled dispatchable resources needed to support the administration's desire for dominance in Artificial Intelligence.

Although Governor Braun's election has not yet resulted in policy shifts as sweeping as those at the federal level, several notable developments in Indiana warrant attention. Governor Braun is also supportive of maintaining existing fossil fuel generation to support economic development opportunities, and he is a strong proponent of building small modular nuclear reactors in Indiana by the early 2030's. To carry out his energy agenda to ensure affordable and reliable power for current residents and economic development opportunities, Governor Braun named Suzanne Jaworowski Secretary of Energy and Natural Resources. In her position, she oversees the Indiana Department of

Environmental Management, the Indiana Regulatory Commission, the Office of Utility Consumer Counselor, and several other agencies.

In August, Governor Braun named long-time utility consumer advocate Abby Gray as Utility Consumer Counselor and directed her find ways to lower bills for Hoosiers. Additionally, Governor Braun will soon be appointing three new Commissioners to the IURC.

1.1.5. Environmental Regulations

In June of 2025, EPA proposed to rescind greenhouse gas limits for new and reconstructed gas turbines and existing and modified coal fired generating units under Clean Air Act Sections 111(b) and (d). As an alternative, the proposal would withdraw a previous determination that carbon capture and storage is commercially available and cost effective to reduce greenhouse gas emissions. This change had a major effect on modeling assumptions within the current IRP, as the ultimate finalization of either option would rescind the drivers for retirement of uncontrolled (for CO_2) units by 2032. While this is still a proposal, the proposal is an action in response to the Administration's Executive Order 14154, "Unleashing American Energy", which directs EPA to identify rules that "impose an undue burden" on domestic energy resources. CEI South believes that the current requirements applicable to GHG's under 111(b) and (d) will not be the most likely future regulatory scenario and therefore updated its Reference Case. Ultimately, the proposed rule revisions will be litigated, and a new proposal could come from a future administration. CEI South developed scenarios to account for these future regulatory uncertainties and potential boundary conditions.

1.1.6. Large Loads

With the rise of AI data centers and onshoring of industry, the country is facing rapid electric growth that has not been seen in decades, if ever. Depending on the project, these loads can start large and scale very quickly, some of which grow to be larger than a mid-sized city such as Evansville, IN. CEI South has fielded many economic development inquires over the last two years, several of which fit this mold.

As part of this IRP, CEI South initially planned a large load sensitivity that evaluated possible build outs based on conversations. However, stakeholders were understandably very interested in this topic given the implications for our system. In response, CEI South agreed it was prudent to develop a separate scenario to address this realistic possibility. As a result, CEI South built an Alternate Reference Case to evaluate the best path forward should an agreement be reached with a potential large load addition.

1.1.7. CenterPoint Energy Rate Case and Community Engagement

In December of 2023, CEI South filed its first rate case in 14 years. Ultimately, a settlement was approved, increasing revenues by $80 million dollars. The increase was approved to be phased in over a year between February 2025 and March 2026, with the largest increase coming in the summer of 2025 as the Posey solar plant and the first of the two new combustion gas turbines (A.B. Brown unit 6) came on-line. 80% of the requested increase was associated with these generation units, including unit 5, which came online in August. Customer affordability was a key issue throughout the case with our customers and their advocates. With affordability top of mind, CEI South worked to evaluate the bill impact of various portfolios in the near to mid-term, as well as evaluating the long-term affordability of each portfolio. Ultimately, near to mid-term affordability proved to be one of the key differentiators in the selection of the 2025 Preferred Portfolio.

To strengthen communication with customers, CEI South hosted an initial round of Community Connect sessions across its service territory. These events offered customers the opportunity to engage directly with CenterPoint employees about key investments aimed at improving system reliability and enhancing bill transparency. Subject matter experts were on hand to answer questions and address concerns related to CEI South's long-term planning and the IRP Preferred Portfolio. Dates and times of the Community Connect sessions are listed in the table below.

Figure 1-2 – Community Connect Sessions

DATE	TIME	LOCATION
Thursday, 11/6	4 - 7 p.m.	**South Spencer High School** 1142 N. County Road 275 W., Rockport, IN
Saturday, 11/8	9 a.m. - noon	**Vanderburgh County 4H Fairgrounds** 201 E. Boonville-New Harmony Road, Evansville, IN
Wednesday, 11/12	4 - 7 p.m.	**Mount Vernon Junior High School** 701 Tile Factory Road, Mount Vernon, IN
Thursday, 11/13	4 - 7 p.m.	**CK Newsome Community Center** 100 E. Walnut Street #1, Evansville, IN
Saturday, 11/15	9 a.m. - noon	**Ohio Township Phoenix Event Center** 3433 Libbert Road, Newburgh, IN

1.1.8. CEI South Current Generation Portfolio

The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

Figure 1-3 – CEI South Generating Units

Unit[6]	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date / Expiration	Unit Age	Coal Unit Environmental Controls[7]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	232	Gas	2025	N/A	<1	
A.B. Brown 6	232	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2025	N/A	N/A	
Salt Creek	170	Wind PPA	2025	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + Battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

1.1.9. Status on Implementing Prior IRP (Retirements and Additions)

Since the last IRP filing, CEI South has encountered significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several renewable projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable for its customers. The Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025 due to cost increases

[6] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

[7] Both Coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_X"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("$H2S0_4$").

beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. At that time, the Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources was the optimal path forward. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, this IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for suspension at the end of 2025. A key decision in this IRP was to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available and evaluated were small gas units or battery storage.

1.1.10. Culley 3 Conversion

In the last IRP, CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. In light of growing change and uncertainty, CEI South chose to pause its conversion plans and opted not to pursue a Certificate of Public Convenience and Necessity from the Indiana Utility Regulatory Commission at this time. CEI South chose to re-evaluate the F.B. Culley conversion with renewables within this IRP. While the F.B. Culley coal-to-gas conversion may become a viable option in the future, current analysis indicates it is not projected to be cost-effective. As detailed later in this IRP, a conversion paired with renewables is projected to be approximately 14% more expensive than the Preferred Portfolio.



Resource Planning Process

Chapter 2

2.1. Planning Structure

CEI South's IRP was developed using a structured, data-driven planning process that incorporates real-world operating conditions, market signals, stakeholder input, and long-range policy and technology expectations. While uncertainty remains a fundamental characteristic of long-term planning, CEI South's objective is to develop a portfolio that is resilient across a wide range of plausible futures while maintaining affordability, reliability, environmental sustainability, stability, resilience, and operational feasibility. The IRP process is organized around five major planning steps:

1) **Real-World Inputs and Modeling Foundations** – Establishing accurate load forecasts, technology costs, demand-side potential, resource data, and fuel assumptions, supported by market solicitations and expert consultation.
2) **Development of Resource Strategies and Planning Scenarios** – Structuring candidate resource strategies, evaluating transmission deliverability, and modeling a range of policy and demand futures.
3) **Planning Priorities and Guiding Principles** – Defining the core decision-making values that shape portfolio evaluation, supported by stakeholder perspectives and long-term CEI South objectives.
4) **Comprehensive Portfolio Development & Testing** – Using a suite of planning tools to simulate long-term portfolio performance, test sensitivities, and assess operational and financial tradeoffs.
5) **Portfolio Evaluation** – Comparing portfolios using a structured framework aligned with CEI South's long-term planning priorities.

The remainder of this section outlines each step in more detail, highlighting the analytical foundation that supports the Preferred Portfolio selection later in the IRP.

2.2. Real-World Inputs and Modeling Foundations

In Q2 2024, CenterPoint launched an open All-Source Request for Proposals ("RFP") (*Technical Appendix Attachment 2.1 2024 All-Source Request for Proposal*) to solicit capacity and energy resource options from the market, including specifically requesting options to replace the F.B. Culley 2 generator and reuse the existing transmission interconnection. This broad solicitation was essential for capturing current, technology-specific costs and operational characteristics. The 2024 All Source RFP yielded a diverse set of project proposals, including renewables, storage, thermal resources, and demand-side offerings. These responses informed both near-term procurement strategies and were also translated into representative long-term modeling inputs.

In addition to the All-Source RFP, CEI South worked with 1898 & Co. to conduct a detailed technology assessment (*Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential)*) to support the evaluation of a wide range of

resources and to supplement the All-Source RFP. Resource-specific cost assumptions were based on a combination of historical operations data and forward-looking financial models. Fixed and variable O&M, depreciation, book life, and capital recovery factors were incorporated to reflect the true economic impact of maintaining or replacing legacy assets. Each resource type was reviewed for cost, performance, availability, and operational viability, which informed the resources that were included in modeling.
CEI South continued its long-standing partnership with Itron, a recognized leader in energy forecasting to produce 20-year energy and demand forecasts. The resulting load forecasts incorporated recent trends in fleet electrification, trended weather, customer behavior, economic growth, customer-owned rooftop solar, and appliance efficiency. This foundational input was used across all planning scenarios.

To evaluate the long-term potential of customer energy savings, CEI South worked with GDS Associates to conduct a comprehensive Market Potential Study (*Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*) focused on demand-side management ("DSM"). The study assessed achievable impacts across the planning horizon by analyzing customer segmentation, end-use technologies, cost-effectiveness, and adoption potential. These results were integrated into portfolio modeling to reflect Demand Response ("DR") and Energy Efficiency ("EE") as resource options on a consistent and comparable basis with supply-side alternatives.

Supporting these major studies was a rigorous data development effort. CEI South used publicly available datasets, averaged confidential vendor information in order to incorporate multiple perspectives and to allow for public viewing, and internal data to populate a robust suite of assumptions. For instance, CEI South utilized industry forecasts for natural gas and other fuels, including NYMEX futures, third-party consultant projections, and public sources such as the EIA. These assumptions were scenario-specific and reflected differing regulatory environments and market conditions.

This work helped ensure that resource modeling was grounded in transparent and realistic expectations.

2.3. Development of Resource Strategies and Planning Scenarios

CEI South developed a set of generation strategies to reflect plausible pathways based on CEI South's existing fleet, known constraints, and evolving regulatory and market dynamics. For example, as part of evaluating the future of existing coal-fired generation, CEI South modeled multiple resource conversion and replacement strategies to test how the system responds to retirement timing, capacity shortfalls, and differing replacement technology mixes.

These deterministic generation strategies served as a foundational planning step, representing different strategic postures. Some explored early retirement and rapid decarbonization; others maintained legacy assets longer to evaluate affordability or for fuel diversity. To support this process, CEI South created several fixed resource configurations, including storage options, new gas replacements, continuation of existing resources, conversion of existing resources, and renewable heavy alternative, to observe how the capacity expansion model responded. These “what-if” inputs were used to test the system’s flexibility and better understand which technologies filled capacity gaps most effectively under different assumptions.

In parallel, CEI South initiated a transmission study (*Technical Appendix Attachment 2.3 Transmission Study (Confidential)*) to examine the deliverability, reliability, and cost implications of these generation strategies. This was a critical component of planning, as the viability of new generation, especially renewable resources, often depends on transmission availability and local system limitations. Transmission constraints, upgrade needs, and regional challenges were modeled alongside generation expansion to ensure that the resulting portfolios were not only economically viable but also physically feasible on an electric transmission basis. The findings from the transmission study were used to:

- Identify system constraints that might require upgrades or lead to curtailment risks;
- Quantify the cost of transmission upgrades associated with portfolio sensitivities; and
- Refine resource strategies and modeling assumptions where needed.

This integration of transmission and generation modeling ensured that resource portfolios were built on a technically sound foundation, which attempts to minimize the risk of stranded assets or overlooked system limitations.

2.4. Stakeholder Engagement

Stakeholder engagement is a cornerstone of integrated resource planning, as input is shared on all portions of the analysis. The stakeholder process functions as a collaborative forum – providing a diverse range of views with multiple opportunities to provide input on the assumptions, inputs, and methodologies to inform CEI South’s IRP development. Over the past twelve months, CEI South has provided many engagement opportunities to a diverse audience of CEI South customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials. Throughout the 2025 IRP, stakeholders were encouraged to engage and participate in the development of the Integrated Resource Plan. Engagement opportunities included public meetings, technical meetings, and direct communication

channels via CEI South's IRP website and the IRP-specific email address, irp@centerpointenergy.com. CEI South has also engaged in written correspondence in response to data requests from several stakeholders.

CEI South hosted four public meetings in Evansville, Indiana – with in-person and virtual participation options (Figure 2-1). An average of 70 individuals, representing over 30 organizations, registered for the public meetings. Meeting agendas focused on a broad range of IRP topics, including the overall process, timelines, impactful industry factors, resource evaluations, modeling inputs and methodologies, scenarios and sensitivities. To ensure ample opportunity for stakeholder feedback and questions, Q&A touchpoints were scheduled throughout each meeting. Public meeting presentations and summaries were shared with stakeholders on CEI South's IRP website, www.centerpointenergy.com/irp.

Figure 2-1 – 2025 Stakeholder Meeting Schedule



In addition to public meetings, CEI South hosted three technical meetings. These meetings included detailed and often confidential discussions of modeling inputs and assumptions. Interested stakeholders, with a signed NDA, were able to participate in the technical meetings as well as access confidential modeling data provided throughout the process through a secure file share site. These meetings offer a forum to discuss detailed assumptions and evaluation criteria to gain insight from multiple perspectives.

Section 8.6, Public Advisory Process, further details CEI South's public engagement, including a robust description of the process, key issues discussed, stakeholder feedback, data requests and stakeholder impact on the development of the IRP.

2.5. Planning Scenarios

To ensure CEI South's Preferred Portfolio performs reliably under a broad range of future conditions, the IRP includes a suite planning scenarios. Each scenario reflects a distinct

"worldview" shaped by key uncertainties in environmental regulation, load growth, technology costs, fuel markets, and federal policy implementation. Together, they test the durability of candidate portfolios across plausible futures rather than anchoring planning decisions to any single forecast.

These scenarios share a consistent modeling foundation, using the same optimization tools, reliability targets, and engineering constraints, but differ in the external forces shaping utility operations. This framework allows CEI South to explore how shifts in demand, policy, and market conditions could alter resource needs, economic outcomes, and implementation feasibility.

2.6. Reference Case

The Reference Case represents CEI South's best estimate of future conditions and serves as the baseline for portfolio development and scenario evaluation. It reflects current law along with recent policy developments, specifically, developments in the proposed repeal of carbon regulation and modified elements of certain Inflation Reduction Act ("IRA") provisions. These assumptions were selected to reflect CEI South's planning judgment about the most likely regulatory, market, and economic trajectory over the 20-year horizon. To develop this scenario, CEI South worked with 1898 & Co. and other technical consultants to establish consistent and transparent assumptions across all major inputs:

- **Load Forecast:** CEI South's long-term energy and demand forecast was developed by Itron and reflects residential, commercial, and industrial usage patterns. It incorporates appliance efficiency trends, fleet electrification, long-term weather normalization, continued expansion of customer owned solar panels, and modest economic growth across the service territory.
- **Fuel Prices:** The Reference Case uses a consensus forecast approach for natural gas and coal, averaging inputs from sources such as S&P Global, Wood Mackenzie, Hitachi, and EVA. This reduces bias from any single forecast and reflects a transparent, market-aligned view of future commodity prices.
- **MISO Capacity Prices:** Scenarios include a forecast of MISO Zone 6 capacity prices, based on available projections from Hitachi, S&P Global, and Wood Mackenzie. These help inform portfolio revenue requirements and cost competitiveness resource portfolios, whether buying or selling excess capacity[8].

[8] Note that portfolios were not able to sell capacity in capacity expansion modeling runs. This helped prevent building more resources than needed for the purpose of selling capacity into the market.

- **CO_2 Price Proxy:** With the proposed repeal of Environmental Protection Agency ("EPA") Clean Air Act ("CAA") 111, the Reference Case only includes costs for compliance upgrades under framework modeled a proxy utilizing the Affordable Clean Energy ("ACE") Rule for existing coal resources, providing an efficiency requirement without assuming a carbon price.
- **Capital Costs:** Where available, baseline resource capital costs were developed utilizing a blend of All-Source RFP results and National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") curves, with adjustments made for inflation and supply chain constraints. These inputs ensure new technologies are evaluated on realistic, market-informed economics.
- **Resource Cost and Performance:** All-Source RFP data was supplemented with a comprehensive technology assessment by 1898 & Co., which was used to validate the capital, fixed and variable O&M, and operational performance assumptions of all resource types under consideration. Where data was not available from the All-Source RFP, the technology assessment was utilized. For example, CEI South utilized the technology assessment for several gas options, advanced nuclear, etc.
- **Demand-Side Resources:** A Market Potential Study ("MPS") developed with GDS Associates informed energy efficiency and demand response potential. These demand-side inputs were modeled on a consistent and comparable basis with supply-side resources to capture full system cost and performance tradeoffs.
- **Transmission Planning:** CEI South conducted a focused transmission study in parallel with generation strategy development to evaluate deliverability, upgrade needs, and local system constraints. The study identified areas where interconnection limitations or thermal constraints could impact various portfolios and ensured that Reference Case portfolios reflect realistic transmission system capabilities.

Portfolio modeling under the Reference Case was conducted using EnCompass, which performed a capacity expansion analysis to identify the least-cost resource mix, followed by chronological dispatch modeling to assess operational feasibility and system performance. The Reference Case was also used as the central comparison point in risk and scorecard evaluation to test how alternative portfolios perform under expected conditions.

2.7. Alternative Scenarios

While the Reference Case provides an outlook on likely future conditions, CEI South recognizes that long-term resource planning must account for the inherent uncertainty in regulatory policy, technology costs, economic development potential, and customer

demand. To stress-test portfolios across a broad range of possible futures, the IRP included four Alternative Scenarios that were each structured to represent distinct, plausible deviations from the Reference Case.

These alternative scenarios are not forecasts or policy goals; instead, they serve as analytical “bookends” that help reveal how portfolios perform when challenged by differing policy mandates, commodity prices, demand growth rates, or environmental regulation.

Each scenario alters multiple input drivers simultaneously, such as fuel prices, load trajectories, capital costs, and environmental policy, to reflect a coherent and internally consistent worldview. Together, they provide insight into how different futures affect system needs, cost exposure, and implementation risk.

Alternate Reference Case
This scenario retains the same policy and regulatory assumptions as the Reference Case but introduces high load growth and is representative of several potential economic development opportunities. It explores the impact of potential large-scale developments such as emerging technologies like AI data centers, metal smelting plants, etc. that could rapidly accelerate electricity demand. This high-demand future was set up to evaluate potential portfolios to maintain affordability, operability, and resource adequacy under increased load conditions on an accelerated timeline. It also tests the responsiveness of transmission and interconnection pathways under fast buildout.

High Regulatory
The High Regulatory scenario reflects a future shaped by progressive federal or state decarbonization mandates. This includes a consensus carbon price utilizing Hitachi, EVA, and S&P forecasts as source data, faster fossil retirements, and tighter compliance obligations under the Clean Air Act and other environmental statutes. Clean energy deployment is further accelerated through economic incentives including the renewable tax credits under the IRA, supporting rapid expansion of renewables and storage. Portfolios in this future must accommodate a faster transition away from legacy assets while preserving reliability and cost control under accelerated timelines and regulatory pressure.

Alternate High Regulatory
This variation on the high regulatory scenario was created due to stakeholder input; it assumes continued regulation under the Clean Air Act, without direct carbon pricing, but introduces elevated load growth tied to electric vehicle adoption, enhanced electrification incentives, and economic expansion. While regulatory pressure is still present, the primary driver of change in this scenario is demand growth, coupled with slightly less regulation than the high regulatory scenario. Supply chain constraints and development

bottlenecks amplify the complexity of meeting new load, increasing capital costs and siting challenges. Energy efficiency program costs are assumed to continue at baseline levels; as there is greater opportunity for EE under increased load conditions. This scenario tests portfolios for their ability to scale under load and capital pressure while maintaining regulatory compliance.

Low Regulatory

The Low Regulatory scenario represents a future with further repeal of progressive environmental rules. CAA 111(b) and (d) are repealed, and no new decarbonization mandates are introduced. IRA provisions are cancelled, and resource decisions are driven primarily by market forces and asset-level economics. This Low Regulatory scenario emphasizes affordability and system stability, favoring legacy asset utilization and measured adoption of new technologies. This scenario helps identify portfolios that remain viable in policy-light conditions with limited external drivers for transition.

Scenarios Summary

The following graphic provides a side-by-side comparison of the five planning scenarios used in this IRP. Each scenario reflects a distinct set of assumptions related to environmental regulation, federal policy, demand growth, fuel pricing, capital costs, and technology adoption. This visual summary highlights the key drivers that differentiate these futures and illustrates how CEI South tested the robustness of candidate portfolios across a wide spectrum of uncertainties.

Figure 2-2 – Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
Alternate Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Much Higher	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Together, these five scenarios form the analytical backbone of CEI South's deterministic portfolio development and evaluation processes. Four of these worldviews, core scenarios (Reference Case, High Regulatory, Alternate High Regulatory, and Low Regulatory), served as the primary analytical foundation for this IRP. By modeling a range of regulatory, economic, and operational conditions, the IRP attempts to capture the spectrum of challenges that may emerge over the planning horizon. Each scenario was constructed to test how resource decisions could change relative to key drivers, as well as providing a view into how each portfolio would perform if applied to a different future. It also helps ensure that no single set of assumptions determines the outcome.

The fifth scenario, the Alternate Reference Case was developed as an alternate parallel analysis, providing additional perspective on the unique impact of a large load addition within CEI South's service territory. Since the load forecast and overall system need significantly differ from those found in the other scenarios, this worldview was modeled separately. This is discussed further in Section 6, The Alternate Preferred Portfolio.

This scenario-based framework enhances transparency and decision-making confidence. It enables CEI South to identify portfolios that are not only cost-effective under expected conditions but also resilient in the face of disruptive change. The insights from scenario modeling directly inform the risk evaluation and scorecard comparison process that follows, ultimately helping shape the selection of a Preferred Portfolio that balances affordability, reliability, resilience, stability, and environmental sustainability, and implementation feasibility across all plausible futures.

2.8. Planning Priorities and Guiding Principles

To bring clarity to how CEI South evaluates potential resource portfolios, this IRP is organized around the five pillars, into three overarching evaluation layers. These layers reflect the practical structure of utility decision-making; first, establishing whether a portfolio is technically viable, second, determining which feasible portfolios best align with customer priorities, stakeholder values, and long-term policy uncertainty, and third, ensuring all risks such as market, policy, and execution risks are accounted for.

Technical Requirements

Reliability – Reliability is foundational to electric system planning and refers to the ability of a portfolio to maintain sufficient generation capacity to meet peak demand. CEI South assessed resource adequacy using capacity expansion modeling that enforced MISO Planning Reserve Margin Requirements ("PRMR"), along with seasonal and annual load shape variation. Resource accreditation was modeled according to MISO's seasonal capacity valuation methodologies and included the transition to direct-loss-of-load

accreditation methodology beginning in 2028. Portfolios that failed to maintain reserve adequacy were not included for consideration.

Stability – Grid operability refers to the capacity of a portfolio to maintain real-time and near-term system stability, including frequency regulation, voltage support, inertial response, and ramping adequacy. To evaluate operability, CEI South leveraged production cost modeling that simulated hourly dispatch and reserve commitment over the full planning horizon. These simulations tested portfolios for ability to manage renewable intermittency, net load variability, and contingency events while complying with reliability standards. Dispatchable thermal resources, fast-ramping assets, DR, and renewable generation were all critical to ensuring operability in modeled futures.

Resilience – Resilience reflects the ability of the electric system to prepare for, absorb, and recover from disruptive events, such as extreme weather, prolonged fuel supply limitations, correlated renewable shortfalls, and simultaneous generation derates. CEI South evaluated resilience through scenario-based and probabilistic-based modeling. Portfolio resilience was quantified through the total installed capacity of resources capable of fast start and spinning reserve benefits. Beyond the metrics, the inclusion of resources that offer black start capability were considered. Through price fluctuations, capacity factor limitations, and other variations in market conditions and assumptions, the portfolios were stress-tested and the system-wide response capability was evaluated.

Strategic Differentiators

Affordability – Affordability is evaluated using the Net Present Value of Revenue Requirements (“NPVRR”), which captures all generation-related costs, including but not limited to the following: capital, O&M, fuel, and market purchases – discounted over the 20-year planning horizon. This metric enables consistent comparison of portfolios with differing investment profiles and cost timing. CEI South examined NPVRR three ways: the mean value, and the 95^{th}/5^{th} percentile across 200 stochastic iterations. The 5^{th} and 95^{th} percentile represent possible boundary conditions for the 20-year costs, helping to measure cost risk. In addition to system-level costs, CEI South considered Incremental Electric Energy Burden, defined as total electric costs as a percentage of household income, to evaluate near to mid-term affordability of portfolio decisions on customer bills.

Environmental Sustainability – Environmental sustainability was assessed by analyzing portfolio emissions relative to expected environmental regulations and policy drivers. Modeling included assumptions around IRA incentives, potential Clean Air Act regulatory requirements, and carbon prices in the high regulatory scenario. Portfolios were also reviewed for alignment with stakeholder values around decarbonization, public health, and long-term climate risk mitigation.

Risk Management

MISO Market – Participation in the MISO market provides valuable flexibility, but increased reliance on market purchases introduces cost and reliability risks, especially as regional conditions evolve. Thermal retirements and rising renewable penetration may reduce capacity market liquidity and heighten price volatility during system stress.

To help illustrate tradeoffs, CEI South modeled energy market exposure across all scenarios, applying purchase limits mirroring system constraints and requiring portfolios to have a minimum level of self-sufficiency. This approach helps ensure resource adequacy even when market conditions are unfavorable.

Federal Policy – The Inflation Reduction Act included significant tax credits that enhance the economics of renewables, storage, and low-carbon technologies. While these incentives improve portfolio affordability and emissions performance, they also introduce planning risk due to evolving regulatory guidance, compliance complexity, and potential policy reversals. Scenarios were constructed with and without IRA tax incentives to evaluate boundary conditions, the One Big Beautiful Bill Act repeal and reinstatement of IRA incentives.

Execution and Supply Chain – Implementing large-scale resource transitions requires coordination across permitting, procurement, interconnection, and construction, each vulnerable to delays and cost escalation. National supply chain constraints, equipment lead times, and labor shortages present material risk to project execution.

CEI South incorporated these risks into modeling through cost sensitivities and contingencies, while also qualitatively assessing the scale and complexity of each portfolio. Portfolios with phased buildouts, technology diversity, and distributed development timelines were favored to reduce execution risk and support achievable, cost-effective implementation.

The final definitions of the objectives and metrics that were provided in the fourth Stakeholder meeting can be reviewed in the following table.

Figure 2-3 – Objectives, Measures, & Metrics

Objective	Measure	Metrics
Affordability: Consider portfolios' impact on the retail electric utility service providers' ability to provide affordable power across residential, commercial, and industrial customer classes	20-year NPVRR across 200 dispatch iterations under varying market conditions	millions$
	95th percentile of NPVRR across 200 dispatch	millions$

Objective	Measure	Metrics
	iterations under varying market conditions	
	5th percentile of NPVRR across 200 dispatch iterations under varying market conditions	millions$
	Incremental Electric energy burden (2030 – 2035)	% HH Income
Environmental Sustainability: Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation	CO_2 Intensity	Tons/ CO_2/kwh
	CO_2 Equivalent Emissions	Tons CO_2e
	SO_x and NO_x Emissions	Tons
Reliability: Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times and withstand sudden disturbances **Resiliency:** Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions **Stability:** Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters	Unserved energy across 200 dispatch iterations under varying market conditions	MWh
	Spinning Reserve	Portfolio MW's that offer spinning reserve
	Fast Start Capability	Portfolio MW's that offer fast start
	Transmission reliability analysis	Dynamic VAR support ("MVAR") Short Circuit Ratio ("SCR")
Risk/Other:	Energy market purchase and sales	% (average, near/long-term)
	Capacity sales and purchases	$

2.9. Comprehensive Portfolio Development & Testing

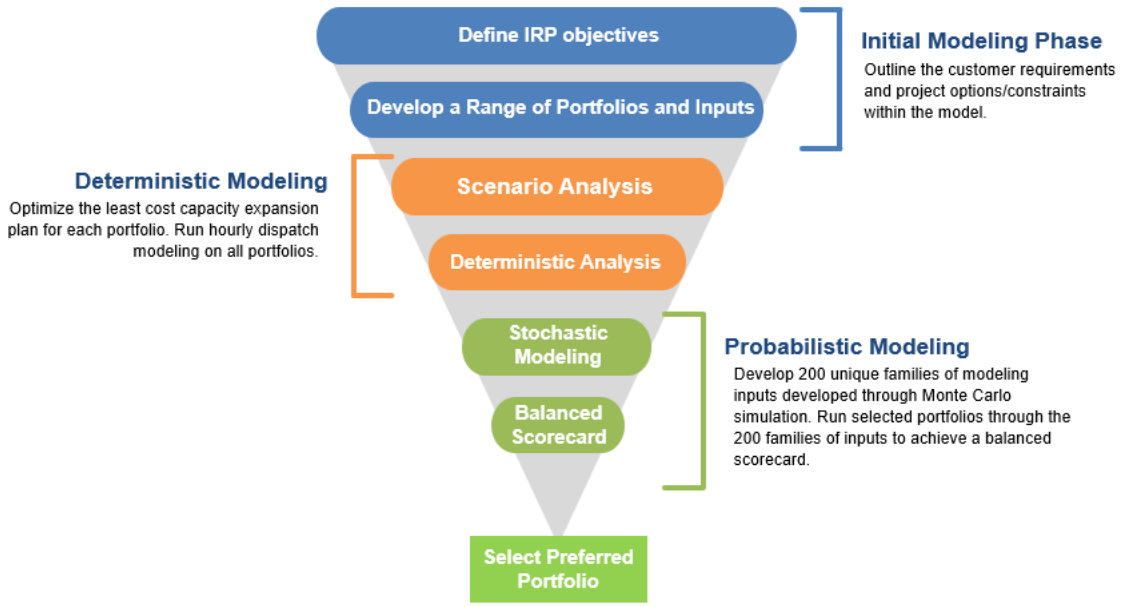
Following the completion of scenario design and modeling setup, CEI South initiated an iterative portfolio development process to explore and evaluate long-term resource pathways. Three major decisions were evaluated within this IRP: replacement of F.B. Culley 2 interconnection, the next three-year DSM Plan, and evaluation of F.B. Culley 3,

CEI South's last remaining coal unit that it operates. For portfolio development, economic decisions for DSM programs were locked in prior to building out the final 12 portfolios. Then, the process began with initial runs of the primary scenarios designed to identify common themes across load, policy, and cost conditions. Resources that consistently emerged across scenarios, such as early storage or demand-side measures, were considered for inclusion in a "going-in" resource position to anchor subsequent modeling. Then CEI South focused on capacity need and built around various resource options to replace or maintain F.B. Culley 3.

Building from this foundation, CEI South constructed a broad set of candidate portfolios that reflect diverse planning priorities and technology pathways. These portfolios were then evaluated against CEI South's predefined criteria, including but not limited to technical performance, customer affordability, emissions outcomes, and implementation feasibility.

Figure 2-4 below illustrates the structured, multi-step approach used to refine, test, and compare resource strategies before selecting a final Preferred Portfolio. Note that with the inclusion of the Alternate Reference Case, this multi-step approach was performed once with the core scenarios and then again with the Alternate Reference Case inputs.

Figure 2-4 – Portfolio Development Process



Modeled Portfolios

Each portfolio represents a distinct pathway for meeting future energy needs, varying by generation mix, retirement timing, renewable adoption, and storage deployment. These resource portfolios test specific planning themes, and while some emphasize emerging resource types, others prioritize system flexibility. Several explore the role of legacy resources under evolving market and regulatory conditions. By modeling a wide range of options, CEI South was able to evaluate tradeoffs and performance across multiple dimensions, including reliability, cost, emissions, and implementation risk, under the four core planning scenarios. Twelve portfolios were evaluated in the final risk analysis. These portfolios and the selection process will be discussed further in Section 4, Portfolio Development and Evaluation.

The modeling framework included EnCompass and PSSE software packages to support both long-term system development and near-term operational analysis. These tools allowed CEI South to capture cost, reliability, and policy tradeoffs with appropriate technical rigor.

Capacity Expansion Modeling

For each scenario, capacity expansion modeling was used to identify optimal long-term resource plans that met planning reserve margins, and reliability criteria, while minimizing system cost. Fixed generation strategies, such as early coal retirement or prescribed storage additions, were used in certain runs to explore how portfolio configurations responded under controlled planning assumptions. Additionally, this strategy was used to create portfolios with a wide range of potential technologies to maintain needed capacity.

Production Cost Modeling

Once expansion plans were established, system dispatch and production costs were simulated on an hourly basis. This allowed CEI South to assess operational dynamics, including renewable integration, unit starts, expected unserved energy, and emissions output. These production cost insights ensured that modeled portfolios were not only cost-effective in theory but also viable under real-world system conditions.

Probabilistic Analysis

Recognizing the uncertainty inherent in long-term planning, CEI South performed targeted sensitivity analyses to test portfolio robustness. Key variables including fuel prices, load growth, carbon costs, energy sales, and capital expenses were varied within reasonable bounds. This helped identify portfolios that consistently performed well across multiple risk dimensions, even under adverse conditions.

Sensitivity Analysis

Sensitivity analysis is conducted to evaluate certain risks. It includes changing only one

variable at a time to understand the impact of a single risk factor. In some cases, the sensitivity is used as a screening tool for ideas to see if the risk is worth further exploration within more comprehensive modeling. In other cases, it was used to provide more insight into the impact of one cost driver or explore potential differences in resource build out. Sensitivity analysis is particularly helpful in explaining isolated impacts that stakeholders or the company is interested in.

Together, these modeling efforts produced a well-rounded view of how candidate portfolios would perform across regulatory, economic, and operational contexts.

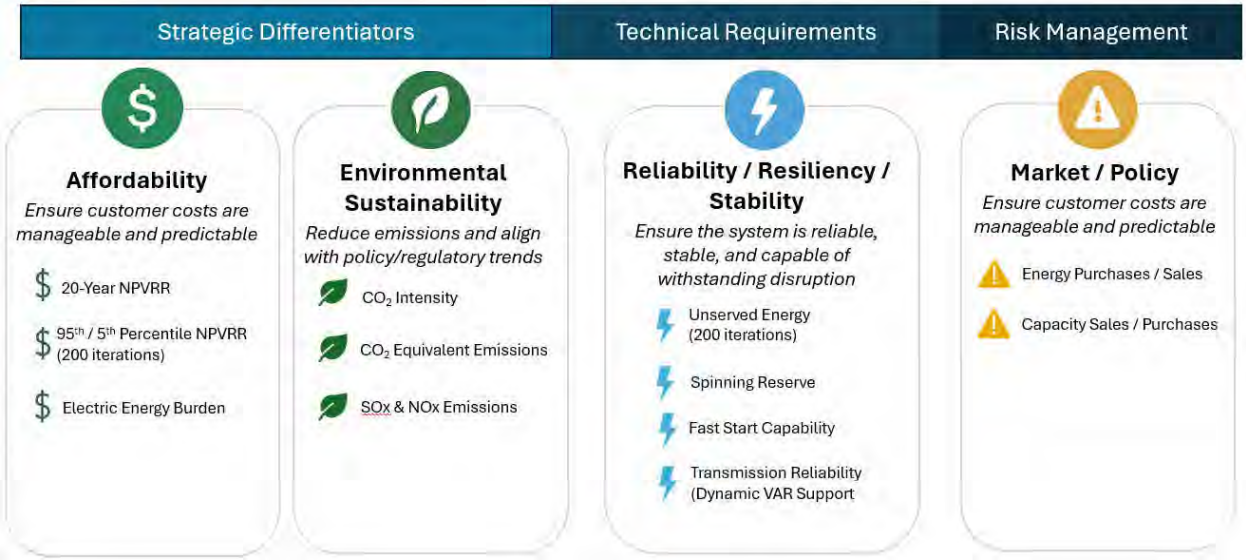
2.10. Portfolio Scorecard Evaluation

Once candidate portfolios were developed and tested, CEI South used a scorecard-based framework to compare performance across the three evaluation layers outlined above. This approach translated complex modeling outputs into a structured decision-making tool, allowing CEI South to balance technical feasibility with strategic value.

Evaluation Framework Summary

Figure 2-5 summarizes how CEI South's evaluation criteria are organized into the three assessment layers, Technical Requirements, Strategic Differentiators, and Risk Management. The image also illustrates the specific pillars, objectives, and performance metrics considered within each layer. This structure enables transparent, side-by-side comparison of portfolios across operational, economic, environmental and risk dimensions.

Figure 2-5 – Evaluation Objectives, Measures & Metrics



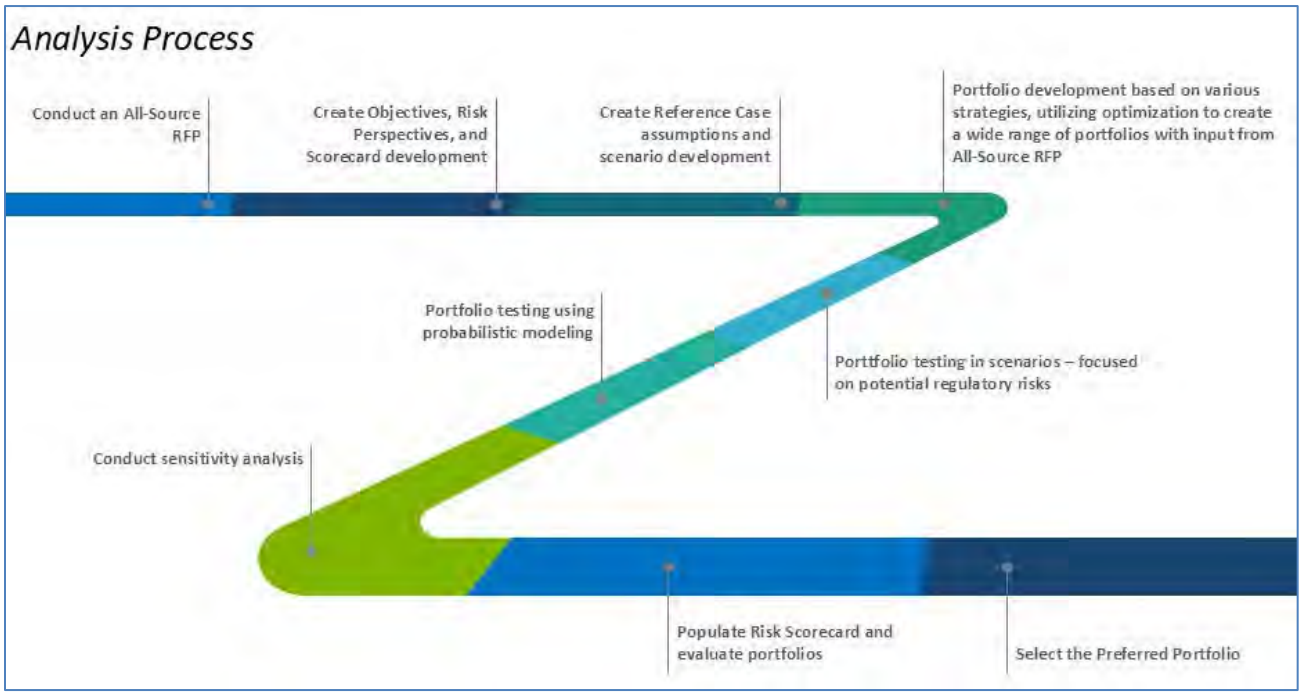
Together, this method ensures that CEI South's Preferred Portfolio is not only technically sound and cost-effective, but also robust under a range of future uncertainties. By integrating operational standards, long-term strategic objectives, and explicit risk considerations, the framework supports balanced decision-making and reflects CEI South's commitment to reliable, affordable, resilient, stable, and environmentally sustainable service for its customers. This structured approach also provides transparency and an opportunity for stakeholder engagement, reinforcing confidence in the IRP process and its outcomes.

2.11. Analytical Process & Tools

2.11.1. Analytical Roadmap

As shown in Figure 2-6, CEI South initiated the IRP process with the 2024 All-Source RFP (*Technical Appendix Attachment 2.1*), which provided current market data on resource availability and pricing. Following the 2024 All Source RFP, CenterPoint developed key evaluation metrics, perspectives, and scenario worldviews based on stakeholder input and existing knowledge. These scenarios, combined with additional planning considerations, were used to create potential future portfolios. Each portfolio was then evaluated through probabilistic modeling and various sensitivity analyses to quantify risk and performance under varied market conditions. Finally, the results were evaluated, and a Preferred Portfolio was selected.

Figure 2-6 – Analytical Roadmap



2.11.2. Modeling Tools

The primary modeling software used to assist in portfolio development, probabilistic modeling, and sensitivity analysis was the EnCompass capacity expansion and production cost simulation software package, licensed from Yes Energy. The National Database provided by Horizons Energy was used to represent the broader power grid beyond CEI South's service territory.

In parallel with generation system planning, a comprehensive transmission assessment was performed using the PSS/E software, licensed from Siemens. This analysis incorporated the MISO Transmission Expansion Planning ("MTEP") 2024 dataset to reflect the current state of the regional transmission network, supplemented with system-specific insights provided by CEI South.

2.11.3. Process Enhancements

Several enhancements were made to the IRP process in alignment with feedback from the previous IRP cycle and stakeholder requests. These updates included refinements to objectives and metrics, expanded sensitivity analysis, improvements to probabilistic

modeling, and other process modifications intended to increase transparency and stakeholder engagement throughout the IRP development.

2.11.3.1. Enhancements to Objectives and Metrics

Additional scoring measures were introduced across the pillars to provide a more comprehensive assessment of the impacts evaluated in this study. Under the affordability metric, the 5th percentile of the NPVRR was added to the final scorecard, in addition to the traditional 95th percentile, to better represent the potential range of customer cost outcomes under varying future conditions. In response to stakeholder requests, electric energy burden was also incorporated as a new affordability metric. Accordingly, 5- and 10-year incremental electric energy burdens were calculated by dividing the bill impact in those years by the median household income in Vanderburgh County. This metric is intended to illustrate the potential near to mid-term impacts to customers associated with portfolio decisions made in this IRP cycle.

To strengthen the evaluation of environmental sustainability, new scoring measures were added to capture criteria air pollutants not previously reported in the scoring process. Specifically, cumulative tons of sulfur oxides ("So_x") and nitrogen oxides ("No_x") emitted were added to the environmental metrics. While previously captured in the broader CO_2 equivalent emissions intensity metric, this explicit inclusion provides greater transparency into portfolio environmental performance.

The transmission reliability analysis was conducted to assess system stability measuring the available dynamic reactive power ("VAR") support and short circuit ratio ("SCR"). Both metrics were evaluated under single element outage (N-1) conditions. The dynamic VAR support metric quantifies the maximum available reactive power on the system during an outage event by summing the total system VAR capability and accounting for each generator's reactive power contribution. Scenarios with lower dynamic VAR support may indicate potential voltage stability concerns. The SCR represents the ratio of the apparent power available at a given system bus following a fault to a benchmark apparent power value of 100 MW. Scenarios exhibiting lower SCR values are indicative of potential stability limitations. Together, these metrics help identify locations or scenarios where the system may require additional reactive support or reinforcement to maintain reliable operation.

Finally, in the risk category, capacity sales and purchases were added to the scorecard to better capture exposure associated with interactions in the market. This metric is intended to quantify the potential risks tied to capacity sales, particularly given their influence on the overall affordability results and customer cost outcomes. Moreover, highlighting reliance on

capacity purchases in this way clearly demonstrates the risks related to market capacity availability and price volatility.

2.11.3.2. Enhancements to Probabilistic Modeling

One key enhancement to the probabilistic modeling framework involved the addition of energy sales variability within the stochastic analysis. To better reflect a range of potential market conditions, the model varied the limits of allowable energy sales across the 200 probabilistic iterations. These limits were implemented at the current transfer capability of 660 MW as well as reduced limits of 330 MW and 165 MW, with each limit applied to one-third of the total draws. This improvement provides a more realistic representation of operational flexibility and market exposure, while also preventing portfolio overreliance on market energy sales revenues to offset costs.

Another improvement expanded the probabilistic modeling of capital costs beyond renewables and storage to include all resources in the model. Each resource type was assigned high, base, and low capital cost forecasts to reflect a realistic range of potential outcomes. This addition allows the model to better capture uncertainty in future costs and improves the understanding of how capital cost changes influence overall portfolio performance.

2.11.3.3. Stakeholder Scenario Input

Throughout the IRP process, stakeholders were continually offered the opportunity to provide feedback and input for incorporation into the analysis. For example, during the initial stakeholder meeting, draft scenarios were presented, prompting stakeholders to request an additional scenario with substantially different key drivers. In response, CEI South developed an Alternate High Regulatory worldview, in which environmental regulations become more stringent, while load continues to grow a rapid pace due to electrification of heating equipment and vehicles, resulting in upward pressure on capital costs. Stakeholders also proposed the development of an Alternate Low Regulatory scenario—mirroring the original Low Regulatory scenario but incorporating lower projected load growth. This latter case was included as a sensitivity analysis rather than a new scenario.

2.11.3.4. Alternate Reference Case

This IRP coincides with a period of unprecedented uncertainty in the industry, particularly related to the rapid emergence of large loads seeking interconnection to the power grid. Following stakeholder interest surrounding the impacts of potential large load additions in CEI South territory and continued interest from multiple industries to locate in CEI South's territory, CEI South introduced an Alternate Reference Case. This analysis utilized IRP capacity expansion modeling to develop multiple portfolios for further evaluation using

probabilistic modeling and selection of an Alternate Preferred Portfolio. More information on the Alternate Reference case can be found in Section 6, The Alternate Preferred Portfolio.

2.11.3.5. Expanded Sensitivity Analysis

To provide a more comprehensive understanding of portfolio performance under varying conditions, CEI South expanded the scope of sensitivity analyses performed in this IRP. These sensitivities examined the effects of several key factors, including the distributed solar incentive, large load additions, A.B. Brown 5 and 6 conversion costs, inclusion of F.B. Culley 2 storage, demand response term, and the Alternate Low Regulatory case. Together, these analyses provided greater insight into how changes in resource costs, load levels, distributed generation, and market conditions could influence portfolio development and overall system reliability.



Forecasts and Key Modeling Assumptions

Chapter 3

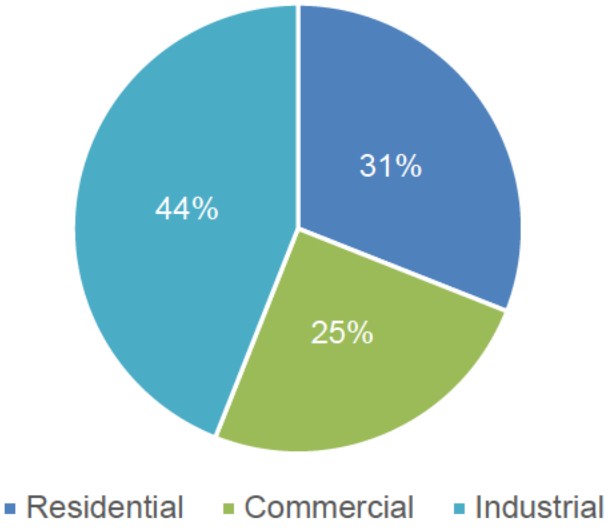
3.1. Load Forecast

3.1.1. Methodology

CUSTOMER TYPES

CEI South serves more than 150,000 electric customers in Southwestern Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of energy sales in 2024. The residential class accounts for 31% of sales with approximately 133,000 customers and the commercial class is 25% of sales; there are approximately 19,000 nonresidential customers. System 2024 energy requirements were 5,032 GWh with non-weather normalized system peak reaching 1,065 MW. Figure 3-1 shows 2024 class-level sales distribution.

Figure 3-1 – 2024 CEI South Annual Sales Breakdown



3.1.2. Forecast Drivers and Data Sources

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used more than 10 years of historical energy and demand data within the energy and demand forecasts. This data is maintained by CEI South in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting.

There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer ("AUPC"). Similarly, small to large commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by S&P Global (formerly IHS Markit), which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

Weather is also a driver of electric consumption. CEI South's peak demand is traditionally in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast to capture recent weather activity. The trended weather picks up the 0.06 degree annual increase in temperature the Evansville area has experienced since 1988.

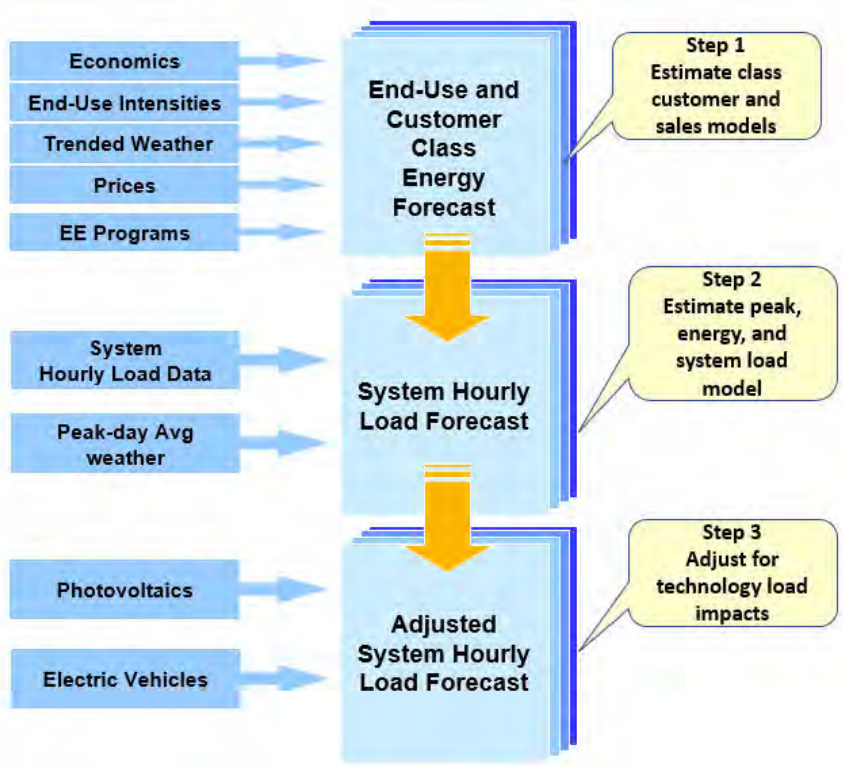
Itron provides regional Energy Information Administration ("EIA") historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to CEI South's service territory based on the appliance saturation survey data.

3.1.3. Model Framework

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts.

Figure 3-2 shows the general framework and model inputs.

Figure 3-2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use ("SAE") model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price and weather. Both residential and commercial sales are forecasted using an SAE specification. Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

3.1.4. Reference Case

ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, energy requirements increasing 0.3% per year, summer peak demand increases of 0.5% per year and winter peak demand increases 0.3% per year growth over the next 20 years. The table below shows CEI South's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on CEI South long-term energy and demand forecasts, including load shapes, see *Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report, Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs/Outputs (Confidential)*, and *Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load.*

Figure 3-3 – Energy and Demand Forecast

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2025	5,201,610		1,083		813	
2026	5,191,351	-0.2%	1,083	0.0%	810	-0.4%
2027	5,203,796	0.2%	1,088	0.5%	811	0.1%
2028	5,222,633	0.4%	1,093	0.5%	813	0.2%
2029	5,235,038	0.2%	1,098	0.5%	815	0.2%
2030	5,251,045	0.3%	1,104	0.5%	817	0.2%
2031	5,262,958	0.2%	1,108	0.4%	818	0.1%
2032	5,275,867	0.2%	1,113	0.4%	819	0.2%
2033	5,271,139	-0.1%	1,115	0.2%	818	-0.2%
2034	5,272,156	0.0%	1,118	0.3%	818	0.0%
2035	5,288,369	0.3%	1,124	0.5%	821	0.4%
2036	5,321,526	0.6%	1,133	0.8%	826	0.6%
2037	5,342,859	0.4%	1,140	0.6%	830	0.4%
2038	5,367,527	0.5%	1,148	0.7%	834	0.5%
2039	5,391,397	0.4%	1,155	0.6%	838	0.5%
2040	5,422,019	0.6%	1,163	0.7%	842	0.6%
2041	5,438,402	0.3%	1,169	0.5%	846	0.4%
2042	5,460,741	0.4%	1,177	0.7%	849	0.4%

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2043	5,483,087	0.4%	1,186	0.7%	852	0.4%
2044	5,512,360	0.5%	1,196	0.9%	857	0.5%
2045	5,535,614	0.4%	1,204	0.7%	860	0.4%
CAGR 25-45		0.3%		0.5%		0.3%

3.1.5. Alternate Scenarios

Itron developed three alternative scenario load forecasts as part of the IRP, one for each core scenario; they include a Low Regulatory, High Regulatory, and Alternate High Regulatory with electrification forecast. These forecasts are developed by altering the model inputs such as the EV/PV forecasts, economics, and end-use saturations and efficiencies. In addition to scenario forecasts, Itron developed four large load forecasts, three for the large load sensitivity and one for the alternate reference case. These forecasts assume the additional of a large load such as an industrial customer or data center.

Figure 3-4, Figure 3-5, and Figure 3-6 show the scenario, large load, and Alternate Reference Case forecasts.

Figure 3-4 – Alternate Scenario Forecasts

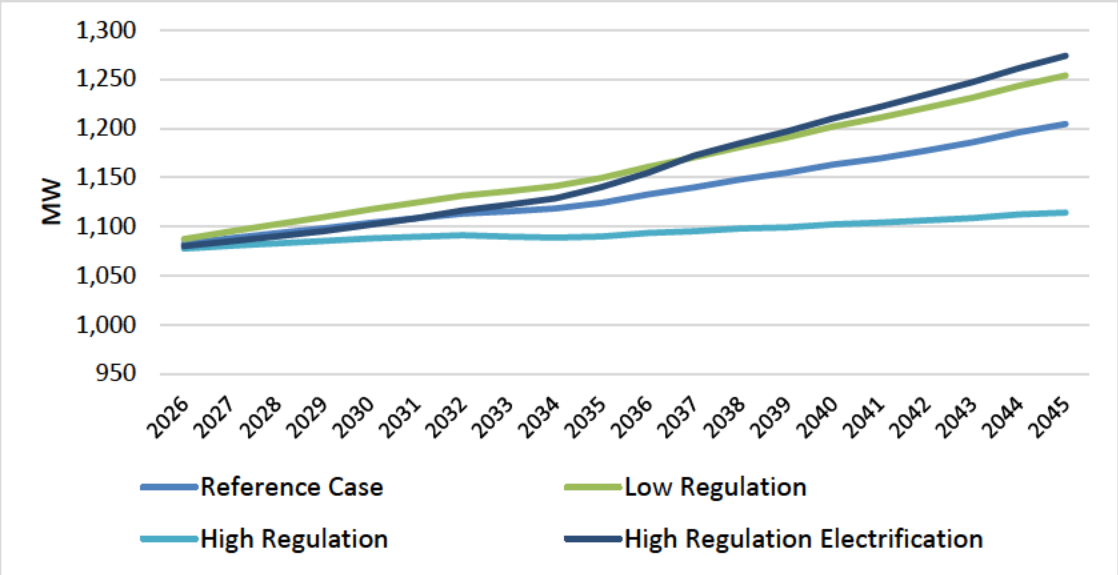


Figure 3-5 – Sensitivity Forecasts

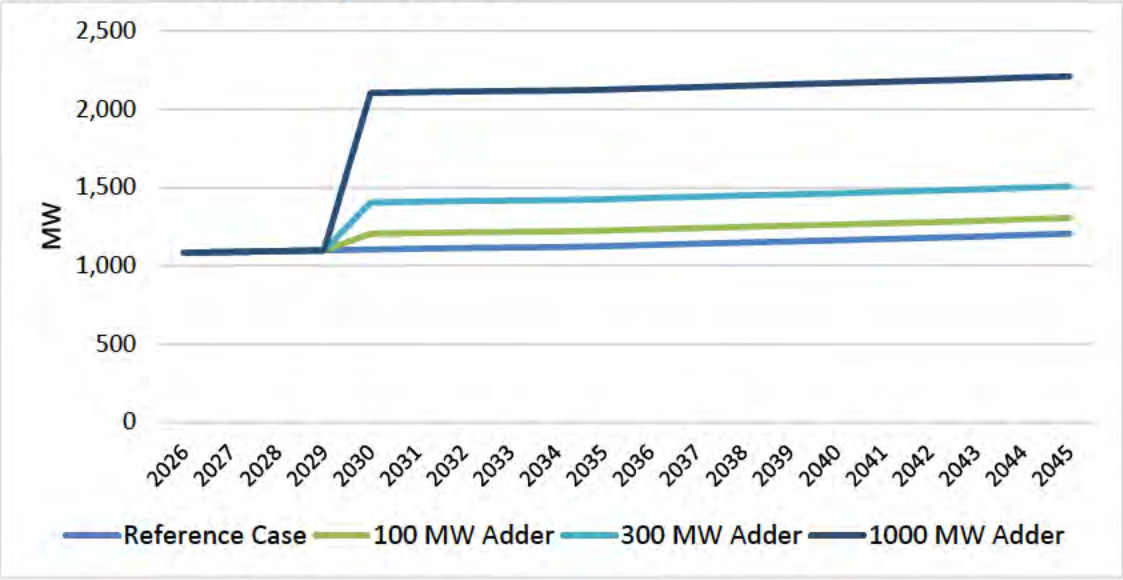
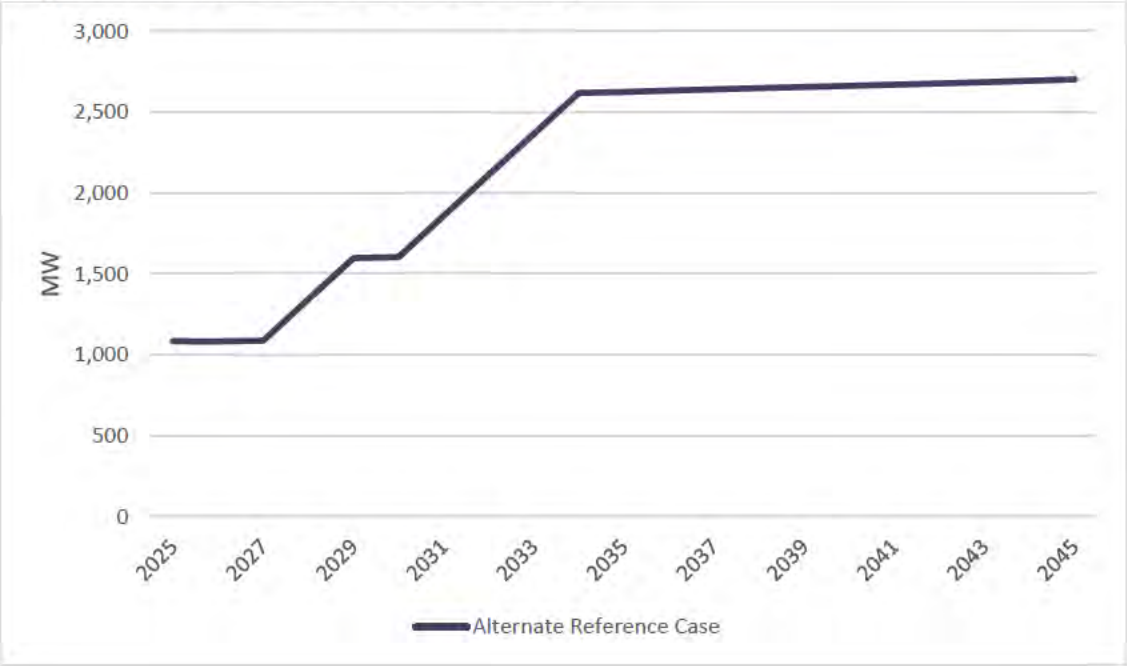


Figure 3-6 – Alternate Reference Case



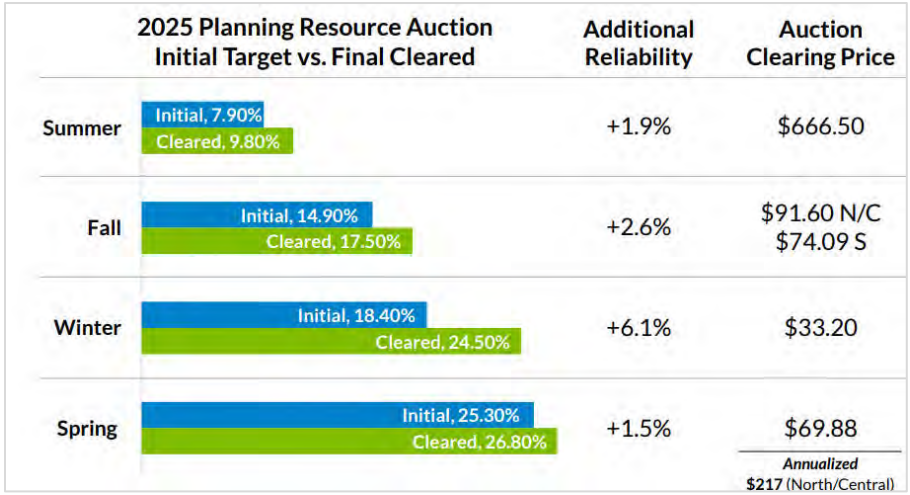
3.2. MISO

3.2.1. Planning Reserve Margin Requirement

MISO's Planning Reserve Margin ("PRM") is the percentage of additional capacity that Load Serving Entities ("LSEs"), including CEI South, must maintain above their forecasted peak demand to ensure grid reliability. The Planning Reserve Margin Requirement ("PRMR") is calculated based on the LSE's peak load forecast and the applicable PRM. The PRMR is further detailed by the Local Clearing Requirement ("LCR") which mandates how much of a LRZ PRMR must be met by generation resources physically located within that LRZ for each respective season. In recent years the number of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend is continuing as more baseload units are projected to retire in the coming years.

In 2024, FERC approved MISO's transition from a vertical demand curve to a reliability-based demand curve ("RBDC") for its capacity market, characterized by a sloped design, it is intended to improve MISO's capacity market by assigning value to surplus capacity based on its contribution to reliability, while also stabilizing prices, reducing volatility, and encouraging long-term investment in dependable energy resources. For LSE's the introduction of the RBDC adds complexity as each season has an initial PRM, but the final PRM can shift based on auction outcomes—requiring LSEs to estimate their potential final PRMR. The illustration in Figure 3-7[9] shows the impact of the RBDC on the 2025/2026 Planning Auction PRM.

Figure 3-7 – 25/26 RBDC Impact on the Planning Resource Auction



[9]"MISO Resource Adequacy PY 25-26: 2025 PRA Results Posting 20250529_Corrections". MISO Energy. May 29, 2025. https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf, page 5

3.2.2. Capacity Price

MISO's PRA is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 3-8 below. These large swings have made it difficult to forecast prices. Outside of the 2022-2023 anomaly, prices were relatively low for MISO's Zone 6 market participants. However, in the last three Planning Years, since the implementation of the Seasonal Construct, prices have been steadily increasing. RBDC prices are in line with MISO expectations and send more accurate price signals that properly value incremental capacity.

Figure 3-8 – MISO Capacity Prices



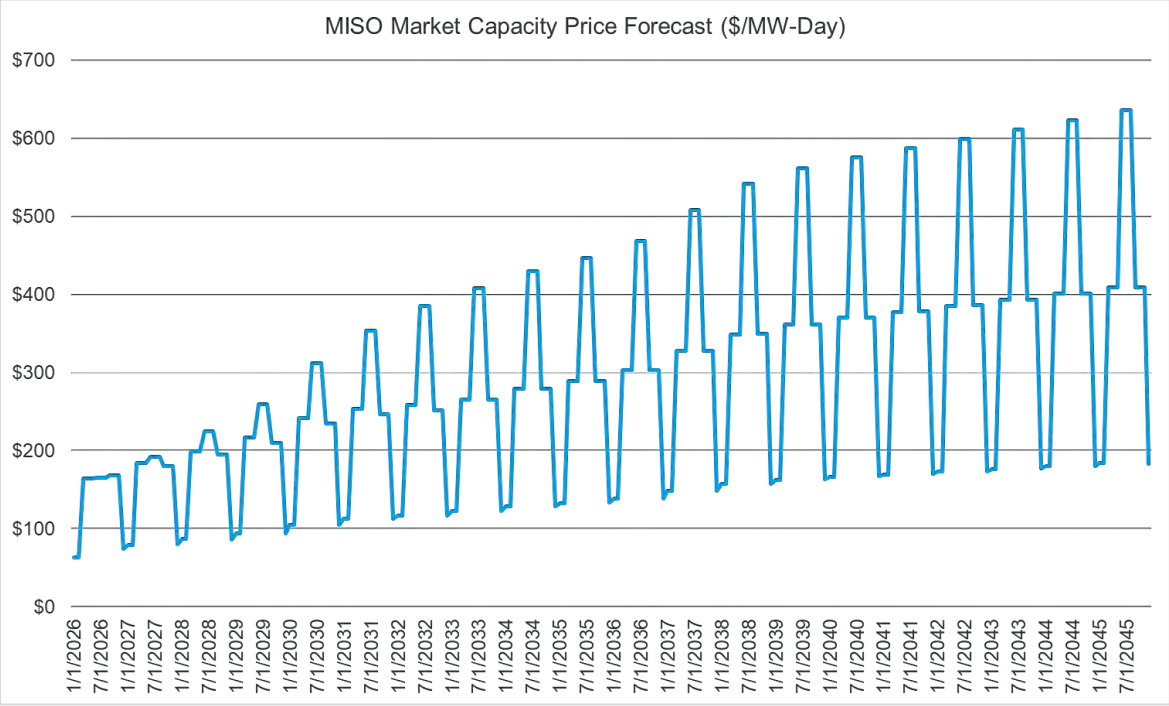
In Figure 3-9, the 2025-2026 seasonal PRA zone 6 cleared at $666.50 in the Summer, $91.60 in the Fall, $33.20 in the Winter, and $69.88 in the Spring, all in $/MW-Day.

Figure 3-9 – 2025-2026 MISO Seasonal Capacity Prices

Planning Year	Highest Clearing Price for MISO-region per MW-Day	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-Day
Summer	$666.50	$666.50
Fall	$91.60	$91.60
Winter	$33.20	$33.20
Spring	$69.88	$69.88

Forward-looking capacity prices were modeled using a consensus forecast from their sources, Hitachi, S&P Global, and Wood Mackenzie. This limits reliance on a single forecast and captures views from several experts. Seasonal capacity price forecasts are given in Figure 3-10. As illustrated below, the capacity price in all seasons is increasing over time, with the summer capacity price increasing at the quickest pace.

Figure 3-10 - MISO Market Capacity Price Forecast



3.2.3. Addressing Resource Adequacy and Reliability Challenges

To address escalating reliability risks and resource adequacy challenges, MISO is executing a series of strategic reforms guided by its Reliability Imperative—a framework launched in 2020 that defines the shared responsibility among MISO, its members, and states to ensure grid reliability amid rapid change. The Reliability Imperative is structured around four pillars: Market Redefinition, Transmission Evolution, System Enhancements, and Operations of the Future, each driving targeted initiatives to manage uncertainty, integrate new technologies, and modernize planning and operations.

Key reforms have included the transition to a seasonal PRA in Fall 2022, the implementation of the RBDC effective June 3, 2024, and resource accreditation reforms scheduled for full rollout by the 2028–2029 planning year. These changes improve capacity valuation, align planning with seasonal risks, and incentivize reliable resource performance. MISO's interconnection reforms, including the Expedited Resource Addition Study ("ERAS") process launched in May 2025, aim to accelerate critical resource deployment, with the first Definitive Planning cycle beginning January 2026.

Additionally, FERC Order 881, effective December 31, 2028[10], requires utilities to implement ambient-adjusted transmission line ratings, enhancing grid efficiency and transparency, which may require improved forecasting tools and data integration to reflect dynamic transmission capabilities. FERC Order 2222 mandates the integration of Distributed Energy Resources ("DERs") into wholesale markets. MISO's compliance efforts in 2025 have involved building new workflow models and structuring communication frameworks for key roles that CEI South will incorporate into future IRPs as it becomes clearer how DER aggregation, visibility, and dispatchability affects our system. The impact of these regulatory changes is addressed in more detail below.

3.2.3.1. Direct Loss of Load ("DLOL") Resource Accreditation

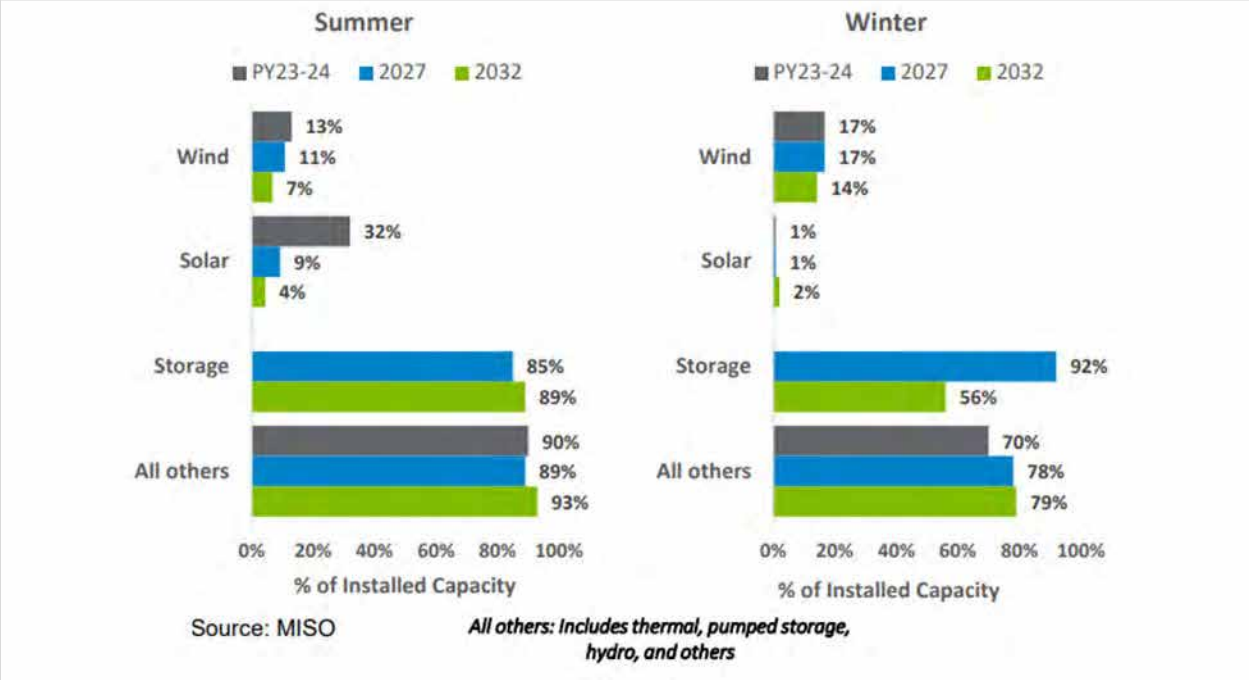
MISO is undergoing a pivotal transformation in its resource portfolio. A substantial portion of dispatchable thermal generation is approaching retirement, while being replaced by a growing share of weather-dependent, intermittent wind and solar resources. This shift combined with the increasing penetration of variable generation and the rising frequency of extreme weather events is fundamentally altering the nature of system risk and presenting new challenges to maintaining reliable grid operations, as part of MISO's broader Resource Availability and Need ("RAN") initiative (2019) and Market Redefinition, MISO proposes a two-step accreditation framework, known as the DLOL-based methodology, to address emerging reliability challenges and ensure a balanced, diverse resource mix. This approach also builds on recent reforms, including FERC's approval of Seasonal Accreditation ("SAC") and the shift to a seasonal PRA.

MISO's proposed DLOL-based resource accreditation methodology involves two steps. First, it uses a probabilistic assessment to estimate a resource's expected contribution to reliability by analyzing class-level performance during high-risk periods, based on 30 years of weather and load data through Monte Carlo simulations. Second, it applies a

[10] "Commissioner Rosner's Concurrence on Order Granting Extension of Time re MISO, Inc. under ER22-2363 | Federal Energy Regulatory Commission". FERC News. June 6, 2025. https://www.ferc.gov/news-events/news/commissioner-rosners-concurrence-order-granting-extension-time-re-miso-inc-under.

deterministic assessment that evaluates each resource's historical performance during critical reliability hours to assign accreditation within its resource class. Seasonal and resource-specific impacts under MISO's DLOL based resource accreditation methodology reflect a shift in reliability risk from summer to winter, which significantly affects solar and wind resources. Solar accreditation declines as penetration increases due to reduced effectiveness during evening risk hours, while both wind and solar receive lower proposed accreditation values compared to current methods. In contrast, thermal and storage resources maintain more stable accreditation levels, though they are still influenced by probabilistic risk modeling. The DLOL methodology began a three-year transition starting September 1, 2024, with full implementation targeted for the 2028/29 Planning Year.

Figure 3-11 – MISO DLOL Accreditation Forecast



3.2.3.2. Demand and Emergency Resources Accreditation Reforms

MISO's Demand and Emergency Resources Accreditation Reforms introduce a performance-based approach to resource accreditation, emphasizing availability during high-risk reliability periods. Utilities must now account for seasonal and hourly availability rather than static nameplate capacity and adjust planning reserve margins accordingly. With emergency DR programs being phased out starting in 2025 and full implementation of the reforms by Planning Year 2028–2029, IRPs developed during this transition must

reflect evolving accreditation values and anticipate reduced capacity credits for certain demand-side resources[11].

3.2.4. Generation Interconnection Process

Before a new generating facility can connect to the MISO-controlled transmission network, the new energy source is evaluated and approved through the MISO Generator Interconnection Process. The Generator Interconnection Process ("GI") defines the steps an interconnection customer and MISO take to move interconnection requests through the interconnection queue[12].

The three steps are: Pre-Queue, Application Review and Definitive Planning.

Pre-Queue: Provides interconnection customers with an overview of the Generator Interconnection process, including timelines and output expectations.

Application Review: MISO reviews the request, checks customer readiness, and conducts a mandatory scoping meeting.

Definitive Planning Phase ("DPP"): The final phase of MISO's generator interconnection study process where MISO conducts reliability and deliverability studies that determine whether there is available transmission capacity to accommodate the interconnection of a new, proposed generation facility or whether network upgrades are needed.

Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. After satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate, and receive full accreditation in the MISO energy and capacity markets.

3.2.4.1. Interconnection Reforms

In parallel to MISO's strengthening of system reliability and resource adequacy initiatives, MISO is advancing key interconnection reforms to meet the 373-day processing timeline per MISO's Tariff. This includes implementing a queue volume cap to manage the surge

[11] "IRP Contemporary Issues Technical Conference". IN.GOV-IURC. June 6, 2024. https://www.in.gov/iurc/files/MISO-Resource-Accreditation-Reform-IRP-Contemporary-Issues-Technical-Conference-06062024.pdf

[12] Midcontinent Independent System Operator, Inc., Generator Interconnection and Retirement, available at https://www misoenergy.org/planning/resource-utilization/generator-interconnection/

in interconnection requests, limiting new proposals to 50% of each region's non-coincident peak load to reduce delays and improve study accuracy. Alongside this, financial reforms have increased milestone payments and introduced penalties for late-stage withdrawals from the queue to discourage speculative projects and streamline the process. SUGAR (Suite of Unified Grid Analyses with Renewables) is MISO's advanced automation tool developed to streamline and accelerate interconnection studies. SUGAR significantly reduces engineering time from months to minutes by automating tasks like base case creation, voltage and thermal violation detection, and contingency analysis. It has demonstrated a 99.2% match rate with legacy MISO studies and is being used to support Phase 1 of the DPP. Together, these coordinated initiatives reflect MISO's commitment to efficient resource integration and maintaining system reliability[13].

3.2.4.2. Expedited Resource Addition Study ("ERAS")

Resource adequacy is the cornerstone of MISO's FERC-approved ERAS process, which was established to accelerate the interconnection of generation resources deemed critical for near-term reliability. ERAS enables states or load-serving entities like CEI South to nominate projects that directly address resource adequacy needs such as meeting planning reserve margins or replacing retiring capacity allowing these projects to bypass the traditional queue. Designed as a temporary mechanism to mitigate emerging reliability risks until broader queue reforms are implemented by 2028. ERAS is limited in scope and duration, concluding by August 31, 2027, with a cap of 68 projects and a maximum of 15 per quarter[14].

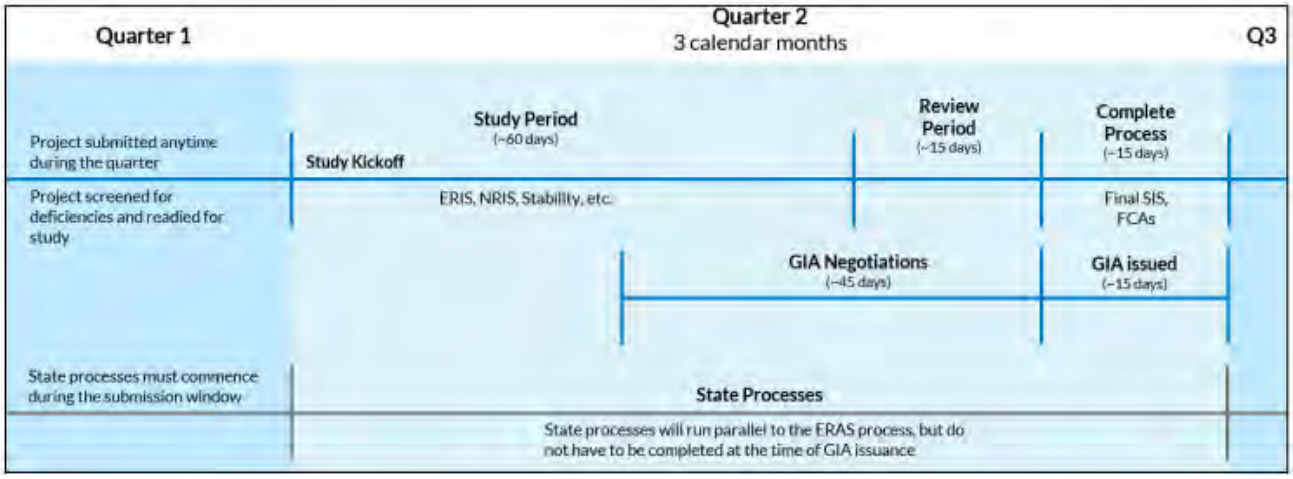
Eligible projects must resolve a specific load addition or resource adequacy deficiency, be commercially operable within 3–6 years of submission, and receive interconnection service capped at 150% of the identified need within the same Local Resource Zone. Each nomination must be verified by the Relevant Electric Retail Rate Authority ("RERRA") to confirm the necessity of the project. As of September 2025, MISO has received 47 ERAS applications totaling 27 GW of capacity. These projects represent a diverse mix of energy sources—primarily gas (74%), followed by nuclear (15%), solar and wind (each 4%), and storage (3%). The applications span multiple states, indicating a

[13]"MISO Dashboard". MISO Energy. June 26, 2025. https://www misoenergy.org/engage/MISO-Dashboard/generator-interconnection-queue-improvements/

[14] 2025-11-25_193 FERC ¶ 61,168_Docket No. ER25-3543-000729602.pdf. FERC Order approving MISO's September 2025 request to increase from ten projects to fifteen projects per quarter.

broad geographic interest in expedited resource development[15]. Under the ERAS process GIAs are expected to be executed as early as Q4 2025.

Figure 3-12 – ERAS Timeline



3.2.5. Impact of Regulatory Changes

Recent FERC orders 2023, 2222, and 881 introduce significant changes led by MISO. It also requires transmission providers to evaluate Grid Enhancing Technologies ("GETs") to improve system efficiency These orders may promote more agile, data-driven, and distributed approaches to resource planning in the future, requiring adaptation to evolving grid realities and regulatory requirements.

FERC Order 2023:

Requires MISO and other Regional Transmission Operators to overhaul their generator interconnection processes. It mandates MISO to modernize its generator interconnection process by adopting a "first-ready, first-served" cluster study model, enhancing transparency, and enforcing stricter timelines. It calls for MISO to prioritize commercially viable projects, streamline queue management, and evaluate Grid Enhancing Technologies to optimize transmission capacity. The order also reinforces cost allocation principles, ensuring developers fund necessary upgrades[16]. These reforms aim to reduce interconnection delays, support renewable integration, and align MISO's procedures with

[15]"Board of Directors – System Planning Committee". MISO Energy. June 10, 2025. https://cdn misoenergy.org/06_2025-09-16_SPC_Open_Long%20Term%20Resource%20Adequacy%20%20Interconnection%20Queue%20Update_FINAL717559.pdf., page 6

[16] "Fact Sheet – Improvements to Generator Interconnection Procedures and Agreements". FERC. July 27, 2023. https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements

FERC's national standards. Compliance filings were submitted in April and May 2024, and continuing through 2026. MISO continues to work with stakeholders to enhance transparency and align its processes with FERC's expectations for Transmission Evolution initiatives.

FERC Order 2022:

Issued in September 2020, requires RTOs/ISOs to allow DERs to aggregate and participate in wholesale markets. MISO submitted its second compliance filing in early 2025, which FERC accepted, allowing full market integration of DER aggregators by 2030. Utilities will adapt IRPs by integrating DERs more explicitly into planning models, potentially revising forecasting methods to include aggregated DER impacts, and coordinating more closely with distribution system operators and aggregators. Intermediate steps may allow limited participation under demand response models between 2027 and 2029. MISO is currently upgrading its market platform and settlement systems, with major milestones expected in 2025–2028.[17]

FERC Order 881:

Mandates that all U.S. transmission providers—including RTOs, ISOs, and utilities implement Ambient Adjusted Ratings ("AARs")[18]. This order requires CEI South to develop a Facility Rating Methodologies, ensuring hourly electronic updates of line ratings based on forecasted ambient temperatures, and maintaining secure databases of rating methodologies. This shift enhances grid efficiency by unlocking unused transmission capacity based on real-time weather data.

Overall, Order 881 drives more accurate, cost-effective, and flexible transmission resource planning. Originally set for July 2025, MISO requested and received an extension to December 31, 2028, citing vendor delays and software readiness issues. Despite the delay, stakeholders and FERC encourage MISO to implement components of AARs ahead of schedule to reduce congestion costs and improve reliability.

3.3. Fuel

The thermal units in this analysis are fueled by three main sources: natural gas, coal, and uranium. Fuel forecasts were obtained from a variety of sources in order to capture perspectives from multiple industry experts, allowing CEI South to be more transparent and

[17] "Distribution Energy Resource Task Force (DERTF)". MISO Energy. April 11, 2024. https://cdn.misoenergy.org/2024%20Order%202222%20Compliance%20Framework631391.pdf

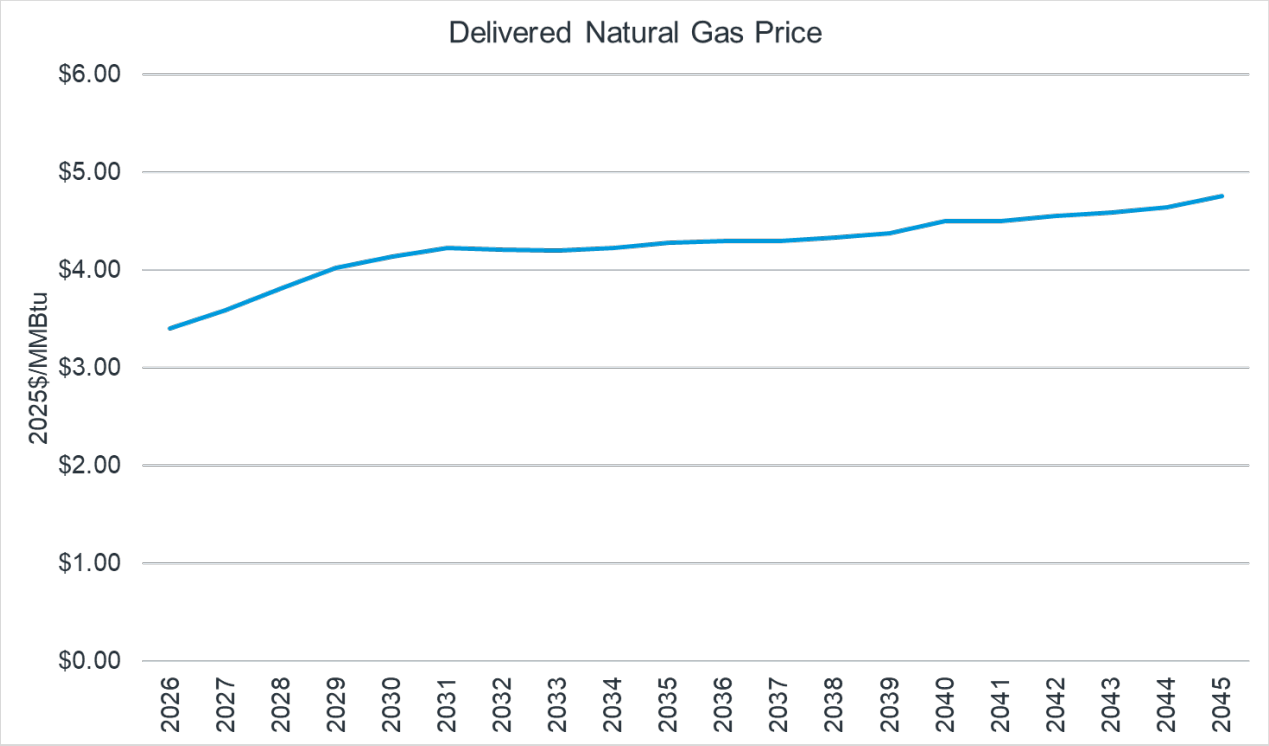
[18] "FERC Rule to Improve Transmission Line Ratings Will Help Lower Transmission Costs". FERC. December 16, 2021. https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs

less reliant on a single perspective in the planning process. For natural gas and coal, forecasts from Wood Mackenzie, Hitachi, S&P Global, and EVA were averaged.

3.3.1. Natural Gas

In addition to the sources mentioned above, CEI South utilized NYMEX data to adjust the Henry Hub price based on historical price separation between Henry Hub and delivered gas prices to the CEI South system. Figure 3-13 displays the delivered natural gas price forecast for the Reference Case.

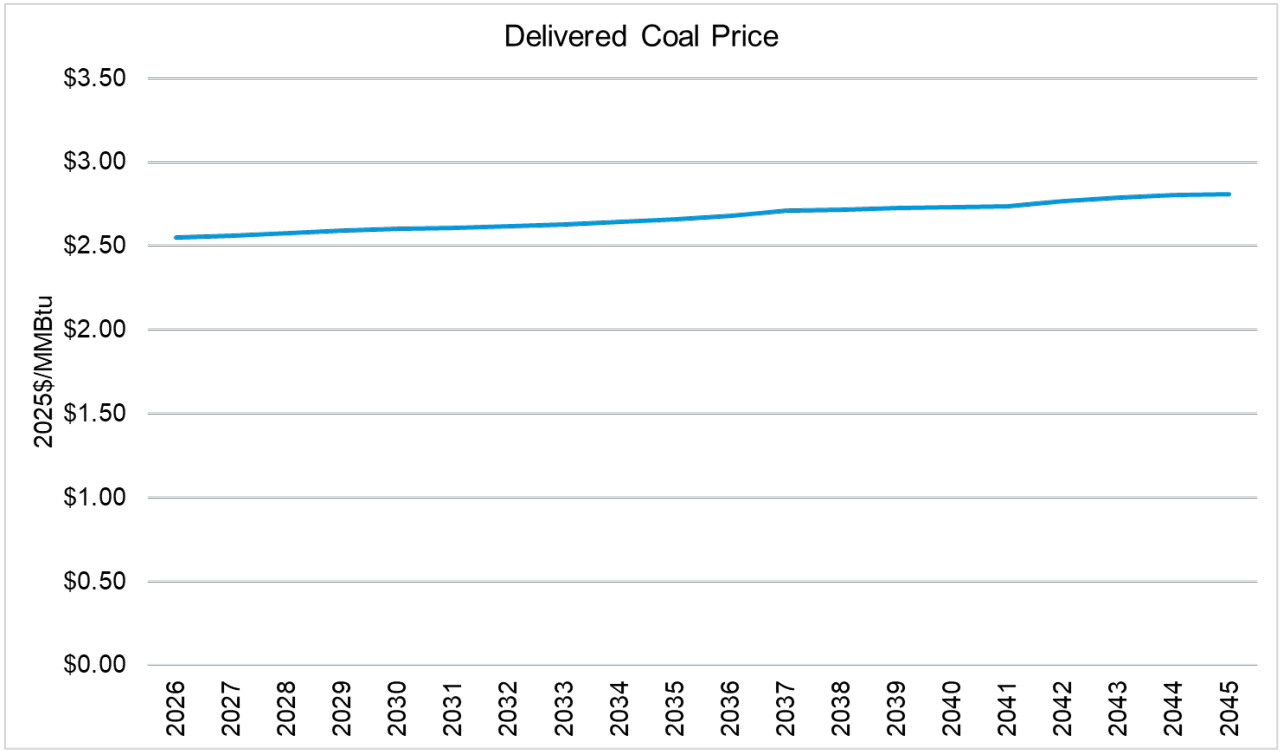
Figure 3-13 – Reference Case Natural Gas Price Forecast (2025$/MMBtu)



3.3.2. Coal

CenterPoint's coal facility is fueled by Indiana-mined coal. Similar to natural gas, a transportation adder based on historical data was included to obtain a price for coal delivered to CEI South. Figure 3-14 displays the consensus coal price forecast for the Reference Case.

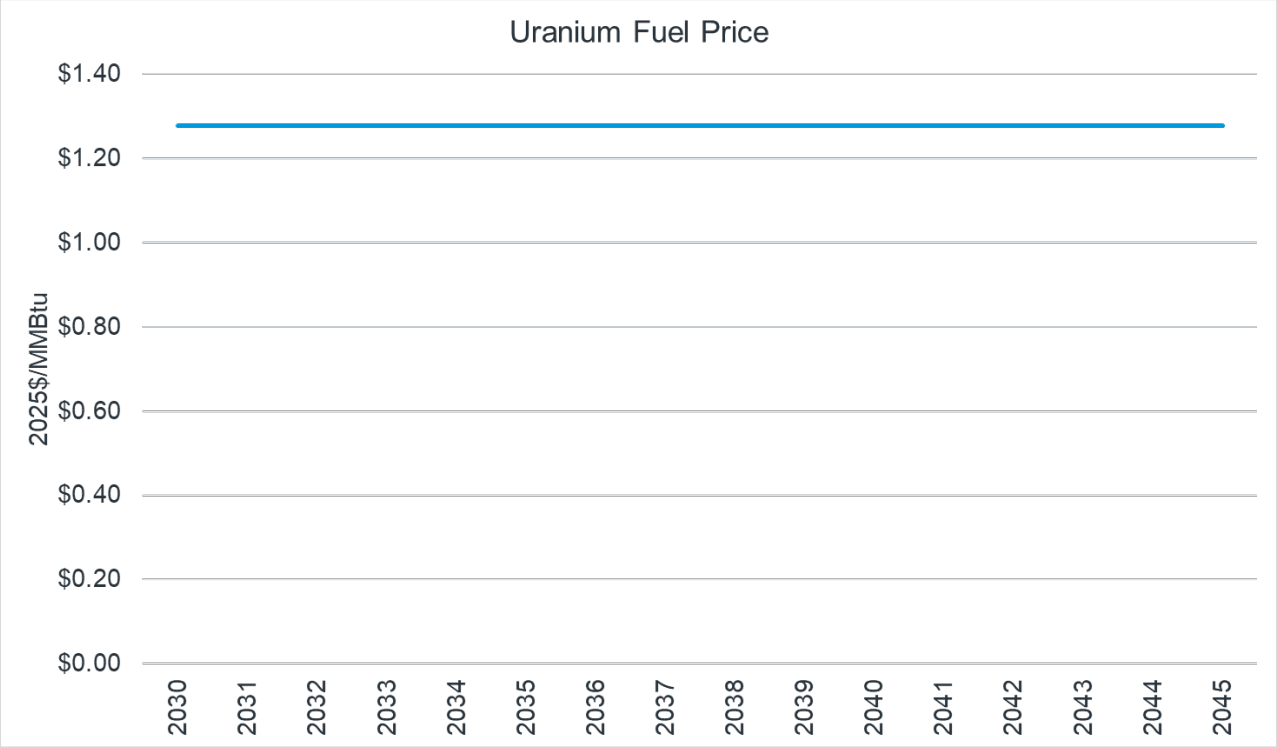
Figure 3-14 – Reference Case Coal Price Forecast (2025$/MMBtu)



3.3.3. Uranium

Nuclear power plants use uranium fuel to produce heat. The uranium price forecast, shown in Figure 3-15, was sourced from the 2024 Annual Technology Baseline published by the NREL[19]. Because uranium is a fuel associated with an emerging technology in NREL's dataset, the forecast begins in 2030 and assumes a constant price throughout the study period.

Figure 3-15 – Reference Case Uranium Price Forecast (2025$/MMBtu)

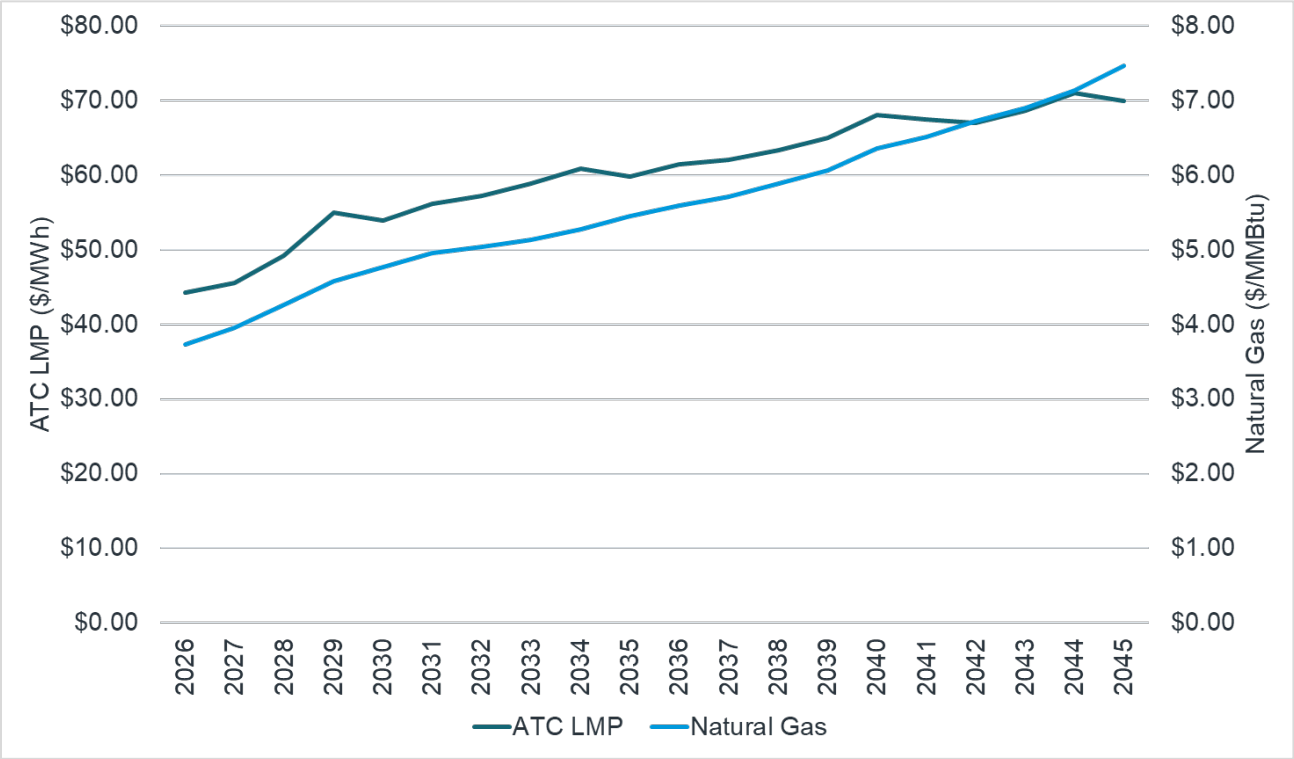


3.4. Power Prices

Energy prices as an input into the IRP model were developed by 1898 & Co. using the EnCompass software. The starting model for the analysis was the national database licensed from Horizons Energy, LLC. Updates to the National Database were made to specifically align the input assumptions with the IRP Scenario assumptions. A summary of around the clock ("ATC") power price forecast can be seen below in Figure 3-16 which also illustrates the macro correlation to natural gas prices over the study period.

[19] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Uranium fuel costs were taken from the "Nuclear" tab. The moderate forecast for a small nuclear facility was used.

Figure 3-16 – Reference Case Power Price Forecast (Nominal $)



3.5. Environmental Regulations

The current modeling analysis includes relevant costs primarily focused on evaluation of alternatives to comply with the ELG, 316(b), and ACE rule proxy requirements where applicable. The costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications, permit requirements, and vendor bids. It should be noted that environmental regulatory requirements represent one of the areas presenting significant uncertainty with respect to the current administration's activities related to regulatory reform and potential future requirements related to greenhouse gas emissions from fossil fuel-fired generating units.

3.5.1. Effluent Limitations Guidelines ("ELG")

F. B. Culley Unit 3 is equipped with dry fly ash and dry bottom ash handling systems, thereby eliminating ash transport water discharges in compliance with the current requirements of the ELG rule. The Spray Dryer Evaporator Zero Liquid Discharge system

has been completed and is online, timely meeting the ELG requirements that are incorporated into the NPDES permit and eliminating the discharge of FGD Wastewater. F.B. Culley Unit 2 still utilizes bottom ash transport water and is slated for retirement on December 31, 2025, in compliance with the requirements of its NPDES permit.

In May 2024, EPA published updated Effluent Limitation Guidelines rule, which contains a provision that requires Zero Liquid Discharge ("ZLD") of unmanaged Combustion Residual Leachate ("CRL") for facilities that do not permanently cease combustion of coal by the end of 2034. This technology is factored into scenarios that include operating Culley Unit 3 on coal past 2034.

3.5.2. Coal Combustion Residuals ("CCRs")

Company continues to close its ash ponds in timely compliance with the requirements of the CCR rule, which was first promulgated in 2015 and has undergone multiple revisions since implementation. The timing of the closures is based on forced closure (i.e., exceedance of Ground Water Protection Standard ("GWPS") and failure of aquifer location restriction) and compliance with the Site-Specific Alternatives to Initiate Closure plans that were submitted to U.S. EPA under the requirements of the CCR Part A rule. The base cost for the closures does not change regardless of future generation and closure cost for CCR units is not part of the IRP modeling.

3.5.3. Greenhouse Gas Regulations

As noted previously, the federal regulation of greenhouse gases is an area of significant uncertainty stemming from years of litigation and continual swings in requirements between federal administrations. In June 2019 the first Trump administration finalized the ACE rule, which replaced the 2015 Clean Power Plan (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels) with a requirement that existing fossil fuel-fired generating units meet certain efficiency targets. This rule was referred to as the Affordable Clean Energy Rule ("ACE"). The ACE rule was repealed and replaced by the Biden administration's New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units which was effective on July 8, 2024 (Biden Rule). The Biden Rule is currently in effect; however, on June 17, 2025, the second Trump administration has proposed revisions to the Biden Rule. The current proposal would rescind greenhouse gas emissions targets as they related to fossil fuel-fired EGUs, or in the alternative declare carbon capture and sequestration technology. We believe it is unlikely that we will cease to have any regulatory requirements applicable to greenhouse gas emissions from fossil fuel-fired generating units, so CEI South used ACE as a proxy for

carbon legislation in the reference case (see Figure 3-17). Since F.B. Culley 2 is planned for suspension in 2025, no ACE costs were included for this unit.

Figure 3-17 – ACE Proxy Cost

Unit	Total ACE Update Cost (2025$)
F.B. Culley 3	$32 Million

3.5.4. 316(b)

In 2014 EPA issued its final rule regarding Section 316(b) of the Clean Water Act which seeks to mitigate impacts to aquatic life from large water intake structures. The rule establishes requirements for Cooling Water Intake Structures ("CWIS") at existing fossil fuel-fired generating facilities and applies to the Culley generating facility which employs a once-through cooling water system. The 316(b) rule requirements are implemented through the facility's NPDES permit. Company is currently in the final stages of finalizing the selected technology and estimated costs for compliance at the Culley facility is included in the current IRP modeling scenarios as appropriate.

3.6. Tax Incentives

3.6.1. Inflation Reduction Act ("IRA") and One Big Beautiful Bill Act ("OBBBA")

The IRA was signed into law by President Biden on August 16, 2022. The $500 billion legislation was intended to mitigate the effects of climate change by offering numerous incentives to promote investment in clean energy production and included tax credits for households to offset energy costs. A substantial portion of the funding was directed toward reshaping the nation's energy infrastructure. Key provisions of the IRA included the extension of wind Production Tax Credits ("PTC"), the allowance of solar production tax credits, the continuance of solar Investment Tax Credits ("ITC"), funding for energy efficiency, the introduction of the ITC for stand-alone battery storage, and incentives for electric vehicle charging.

Vast portions of the IRA were eliminated with the passage of the OBBBA, signed into law on July 4, 2025. The legislation repeals most clean energy provisions and includes eligibility conditions that effectively disqualify clean energy projects that are not shovel-ready. The OBBBA includes a dual-condition eligibility test; a project must begin construction (start physical work or incur at least 5% of total project costs and maintain continuous progress)

within 60 days of the bill's enactment and be placed into service by December 31, 2028. Projects that do not meet these criteria will no longer be eligible for the PTC or ITC. Additionally, the law removes consumer energy incentives for distributed energy adoption after 2025 and repeals electric vehicle tax credits after 2026. Credits for carbon capture and storage, clean fuels credit, and zero emissions nuclear power production credits remain in place.

These updates to the renewable tax credits were incorporated into the modeling assumptions based on the description of the scenarios. In the Reference Case and Alternate Reference Case, solar ITC and wind PTC eligibility expires at the end of 2029, while nuclear and storage resources retain their full credits through 2033, followed by declining values in 2034 and 2035. Figure 3-18 shows the updated tax credits included in the reference and alternate reference case scenarios.

Figure 3-18 – Reference and Alt Reference Scenario Tax Credits

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Solar	ITC	30%	30%	30%	30%	30%	0%	0%	0%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	30%	23%	15%	0%
Wind	PTC	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Nuclear	PTC	100%	100%	100%	100%	100%	100%	100%	100%	100%	75%	50%	0%

For the High Regulatory and Alternate High Regulatory worldviews, the previous legislation governing tax credit eligibility was retained. Under these scenarios, solar and storage resources qualify for the full ITC through the end of 2032 and wind resources qualify for full PTC through 2029, with a reduced credit from 2030 through 2032. Figure 3-19 shows the pre-OBBBA tax credits that are included in the High Regulatory and Alternate High Regulatory scenarios.

Figure 3-19 – High Reg and Alt High Reg Scenario Tax Credits

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Solar	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Wind	PTC	100%	100%	100%	100%	100%	100%	100%	100%	0%	0%	0%	0%

3.7. Resource Options

3.7.1. Current Resource Mix

Thermal generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more.

F.B. Culley 3 has historically operated as a base load unit but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. F.B. Culley 3, CEI South's last coal unit that it plans to operate past 2025, more recently has operated more like an intermediate unit, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. CEI South's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, CEI South's small gas turbines, units 3 and 4, are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on. Most recently, CEI South has added two new combustion turbines and one solar array. These assets will provide necessary support for grid stability following the retirement of A.B. Brown coal units 1 and 2 in 2023.

3.7.1.1. Generation

CEI South's current and expected generation mix consists of approximately 1,807 MW of installed capacity. This capacity currently consists of approximately 360 MW of coal-fired generation from F.B. Culley 2 & 3. Following the suspension of F.B. Culley 2, which is scheduled for the end of 2025, the installed capacity of coal-fired generation in CenterPoint's fleet will drop to 270 MW. CEI South's existing generation also includes 624 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 397 MW of wind procured through Power Purchase Agreements ("PPAs"), 391 MW of solar (with 150 of that total coming from PPAs), and a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

3.7.1.2. Existing Resources

Figure 3-20 references both Installed Capacity ("ICAP") and Seasonal Accredited Capacity ("SAC"). Installed capacity is also referred to as nameplate capacity. Seasonal accredited capacity is the amount of capacity that can be relied upon to meet load during tight operating hours. MISO now uses SAC for planning purposes. The SAC accreditation recognizes all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year operating history and a weather normalized capability verification to determine the SAC accreditation of each unit. CEI South used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO seasonal planning reserve margin requirements (7.9% for summer, 14.9% for fall, 18.4% for winter, and 25.3 in spring[20]) in the current IRP. This information was utilized to help ensure all portfolios met MISO obligations on a seasonal basis.

Figure 3-20 – CEI South's Owned Generating Units (2026/2027 Planning Year)[21]

Unit	Installed Capacity (MW)	Summer - Seasonal Accredited Capacity (SAC - MW)	Fall - SAC (MW)	Winter -SAC (MW)	Spring - SAC (MW)	Primary Fuel	Initial Service Year
F.B. Culley 3	270	181.4	248.8	231.6	269.6	Coal	1973
A.B. Brown 3	80	67.4	72.1	91.7	75.8	Gas	1991
A.B. Brown 4	80	70.5	67.3	89.2	80.3	Gas	2002
A.B. Brown 5	232	209.1	195.1	183.5	195.1	Gas	2025
A.B. Brown 6	232	209.1	195.1	183.5	195.1	Gas	2025
Posey Solar	191	85.0	66.7	48.7	89.2	Sun	2025
Troy Solar	50	22.25	17.5	12.75	23.35	Sun	2021
Blackfoot	3	N/A	N/A	N/A	N/A	Landfill Gas	2009
Oak Hill Solar	2	N/A	N/A	N/A	N/A	Sun	2018
Volkman Rd. Solar	2	N/A	N/A	N/A	N/A	Sun	2018

[20] "Loss of Load Expectation Working Group (LOLEWG)". MISO Energy. October 24, 2024. https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf, Slide 2

[21] CEI South plans to place F.B. Culley 2 into suspension by December 31,2025.

3.7.1.2.1. Energy Efficiency

CEI South utilizes a portfolio of Demand Side Management ("DSM") programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

Since 1992, CEI South has operated a Direct Load Control ("DLC") program called Summer Cycler which can reduce residential and small commercial air-conditioning and water heating electricity loads when needed during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. CEI South's Summer Cycler program has served CEI South and its customers well for more than three decades, but more recent technology is now making the program obsolete. Between 2010 and 2024, CEI South's DSM programs reduced demand by approximately 97,000 kW and provided annual incremental gross energy savings of approximately 521,000,000 kWh.

Figure 3-21 below outlines the estimated program penetration on an annual basis since CEI South programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 3-21 – Gross Cumulative Savings[22] [23]

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2010	5,617	2.53	0.00051	0.04%
2011	5,595	19.40	0.00331	0.35%
2012	5,465	66.95	0.01212	1.23%
2013	5,459	128.64	0.02416	2.36%
2014	3,499	175.98	0.03215	5.03%
2015	3,224	202.82	0.03698	6.29%
2016	3,256	236.40	0.04222	7.26%
2017	3,281	268.86	0.04861	8.20%
2018	3,491	309.28	0.05624	8.86%

[22] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.
[23] Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting out of DSM programs effective July 1, 2014.

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2019	3,135	352.76	0.06455	11.25%
2020	3,176	398.16	0.07411	12.54%
2021	3,174	428.56	0.08102	13.50%
2022	3,209	454.79	0.08638	14.17%
2023	3,265	490.01	0.09265	15.01%
2024	3,285	521.50	0.09717	15.87%

3.7.1.2.1.1.1. 2025-2027 Plan Overview

Consistent with the 2022/2023 IRP, the framework for the 2025-2027 EE Plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential, as well as commercial and industrial programs offered in 2025-2027. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2025-2027 EE Plan detail found in the *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*.

Residential Programs

- Residential Prescriptive
- Residential Midstream
- Home Energy Assessment
- In Store Discount
- Multi Family Energy Solutions
- Community Connections
- Residential New Construction
- Income Qualified Weatherization
- Energy Efficiency Store (Marketplace)
- Residential Behavior Savings
- Smart Cycle (“DLC Change Out”)
- Bring Your Own Thermostat (“BYOT”)
- Conservation Voltage Reduction (“CVR”) Residential

Commercial and Industrial Programs

- Commercial and Industrial Prescriptive
- Commercial and Industrial Midstream
- Commercial and Industrial Custom

- Small Business Energy Solutions
- Building Optimization
- Conservation Voltage Reduction ("CVR") Commercial

The 2025-2027 plan was included as an existing resource in the 2025 IRP and has an assumed average measure life of 13 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*).

Figure 3-22 – Energy Efficiency Savings[24]

	2025		2026		2027	
Sector	Net kWH Energy Savings	Net kW Demand Savings	Net kWH Energy Savings	Net kW Demand Savings	Net =kWH Energy Savings	Net kW Demand Savings
Residential	13,259,256	7,818	14,814,287	8,854	14,732,977	7,874
C&I	19,224,000	2,528	21,344,251	2,982	21,570,750	2,757
Total	**32,483,256**	**10,345**	**36,158,538**	**11,836**	**36,303,727**	**10,631**

3.7.1.3. Demand Response

CEI South's tariff currently includes five Demand Response ("DR") programs:

- Direct Load Control Rider ("DLC"),
- Thermostat Load Control Rider ("TLC"),
- Two interruptible options for larger customers (Interruptible Contract Rider and Interruptible Option Rider),
- Aggregation Demand Response Rider ("ADR") and
- MISO Demand Response Rider.

Demand response programs allow CEI South to curtail load for reliability purposes. CEI South's MISO DR tariff and interruptible tariffs have no customers currently enrolled and registered with MISO. CEI South has recently contracted a third-party DR aggregator from the All-Source RFP to begin a DR aggregation program based on CEI South's customer load and industry demographics.

[24] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

3.7.1.3.1. Current DLC (SUMMER CYCLER)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, and electric water heating through radio-controlled load management receivers. Under the program, CEI South compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. CEI South can initiate a load control event for several reasons, including to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

CEI South manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. CEI South also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2024, Cadmus predicted that the DLC Program was capable of generating approximately 8 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control during MISO load curtailment events during the summer season. This figure will continue to decrease over time with the increasing occurrence of switch failures.

Until recently, DLC switches have been the default choice for residential load control programs. CEI South has had a DLC program since the early 1990's and as of 2024 had approximately 16,000 residential customers with 22,250 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CEI South has begun replacing DLC switches with smart thermostats, and the DLC program is closed to new customers as of February 13, 2025.

3.7.1.3.2. Current Interruptible Load

CEI South makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. CEI South previously had three customers who were participating for a total demand reduction of approximately 31 MW. MISO issued a curtailment on June 10, 2021. CEI South's largest interruptible customer at approximately 30 MW elected to no longer participate in the interruptible tariff after the event. CEI South worked with stakeholders to help update its interruptible tariffs to streamline language, open them up to a wider number of potential participants, and bring in line with MISO's on-going updates to the Load Modifying Resource ("LMR") rules to derisk this segment of resources. CEI South requested and received approval from the Commission to update these tariffs

accordingly in its most recent rate case in Cause No. 45990. Even with these updates, CEI South still has no customers on the tariff registered as a resource with MISO. See section 3.7.1.3.4 for more information on how CEI South is working to partner with customers to maximize its demand response potential with this segment of C&I customers.

3.7.1.3.3. SMART THERMOSTATS

CEI South launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning ("HVAC") settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats than DLC switches. As such, CEI South has designed a program to replace switches with smart Wi-Fi thermostats, a strategic option for cost-effective load control. The Smart DLC Change-out program focuses on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, CEI South will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement. This change-out program is reflected in IRP modeling.

CEI South also launched the Bring your Own Thermostat program as a DR program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2025-2027 Plan provides for approximately 1,430 kW demand each year from the BYOT program based on approximately 1,300 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in the Thermostat Load Control program. By taking advantage of two-way communicating smart/Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events. Smart thermostat DR programs provide approximately 1 kW per thermostat in load reductions during a DR event.

3.7.1.3.4. Aggregation Demand Response

CEI South received approval to launch the Aggregation Demand Response program in Cause No. 45590. CEI South recently executed a contract with a third-party aggregator for C&I customers which allows the third-party aggregator to provide customers with a

customized energy reduction plan specific to customer's needs based on customer type, such as the following: commercial office building, public school systems, and manufacturing. Aggregators often have the metering and controls technology to allow customers to see and manage their load reduction in real time.

CEI South has included 12 MWs in 2026 ramping up to 25 MWs in 2027 through 2045 based on a market potential analysis during the bidding process. CEI South is one of the first utilities to offer a new Aggregation program in Indiana within approximately the last 10 years. CEI South put this program in place in recognition of stakeholder interest, providing more optionality for C&I customers than CEI South alone can provide.

Aggregation provides long-term affordability by allowing participating customers to earn payments, improve resilience by allowing customers to receive advance notification of grid stability issues, protecting facilities from potential power outages, and supporting the community by helping to maintain reliable, low-cost energy. Aggregation allows for energy industry experts to work with customers to define strategies that leverage existing assets, manage enrollment and execution, and helps maximize revenue for participants.

3.7.2. Potential Future Resource Options

CEI South evaluated a broad range of supply-side technologies, including natural gas, renewable energy, storage technologies, and advanced nuclear. Operational inputs for all supply-side resources were developed from the technology assessment conducted by 1898 & Co., while capital costs were primarily sourced from CEI South's 2024 All-Source RFP results to reflect current market conditions. Where RFP data was not available, capital costs from the technology assessment were used, unless otherwise noted. Detailed information for the All-Source RFP and the technology assessment can be found in *Technical Appendix Attachments 2.1* and *2.2 (Confidential)*, respectively.

The following section details supply-side resource options including conversion opportunities at existing sites, followed by new natural gas, renewables, advanced nuclear, and storage technologies. Then, demand-side resources are outlined including Energy Efficiency and Demand Response programs. Finally, innovative rate designs are also considered.

3.7.2.1. Existing Site Conversions

CEI South evaluated two existing sites, F.B. Culley 3, and A.B. Brown 5 and 6, for potential conversion of existing units to provide additional capacity and energy to meet system needs. F.B. Culley 2 interconnection replacement was also explored in this IRP.

F.B. Culley 2:

At the F.B. Culley 2 site, three power generation technologies were evaluated: reciprocating engines, aeroderivative engines, and storage. The option to let the interconnection agreement at F.B. Culley 2 expire without reuse was also considered. The three resource types were selected based on available space at the site, available infrastructure, regulations on timing of a replacement resource, and CEI South's system needs. Operational parameters of all stated resource options, as well as the capital costs of the natural gas resources, were sourced from the technology assessment. The capital investment of a storage resource at the F.B. Culley 2 site was informed by the 2024 All Source RFP. The gas transportation costs included in all existing site conversions are for firm gas supply and were informed by vendor and internal estimates. Additional detail surrounding gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)*. Figure 3-23 displays the operational and financial parameters for these potential resources.

Figure 3-23 – F.B. Culley 2 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Reciprocating Engines	Aeroderivative Engines	Storage
Technology Description	Five 18-MW Engines	Two 50 MW Engines	4-Hour Lithium-Ion Storage
Base Load Net Output (MW)	91.5	104.4	90
Base Load Heat Rate (HHV Btu/MWh)	8,340	9,310	N/A
Capital Expenditures (2025$/kW)	$2,650	$3,440	$1,573
Fixed O&M (2025$MM/year)	$2.6	$3.2	$3.2
Gas Transportation Costs (2025$MM/yr)	$10.2	$9.6	N/A
Variable O&M (2025$/MWh)	$4.0	$0.90	N/A

F.B. Culley 3:

At the F.B. Culley 3 site, CEI South analyzed three potential operating pathways for the existing coal plant: continue operating on coal until retirement, convert to operating on natural gas, or co-fire with 40% natural gas. For the first two options, multiple implementation dates were studied. Potential retirement dates for F.B. Culley 3 included December 31, 2031, December 31, 2034, and beyond the planning horizon of this IRP. For conversion to natural gas, start dates of January 1, 2030 and January 1, 2035 were analyzed. Portfolios that included unit conversion also assumed a four-month outage prior to the conversion to allow for necessary construction. The co-fire pathway was modeled with only a single implementation date, primarily driven by the former Clean Air Act 111(d) rule. This includes beginning co-fire operation on January 1, 2030, followed by unit retiring by the end of 2038. These pathways are described in Figure 3-24. Converting F.B. Culley

3 to natural gas will likely result in the unit operating at a lower capacity factor compared to its current coal-fired operation, more similar to that of a peaking resource. The capital costs for this option were developed using vendor estimates, historical data, and internal calculations.

Figure 3-24 – F.B. Culley 3 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Operate on Coal	Conversion to Natural Gas	Convert to Co-Fire
Description of Available Options	• Continue through 2045 • Retire on 12/31/2031 • Retire on 12/31/2034	• Start Gas Fired operation on 1/1/2030 • Start Gas Fired operation on 1/1/2035	• Start Co-Firing operation on 1/1/2030, followed by unit retirement on 12/31/2038
Base Load Net Output (MW)	270	270	270
Base Load Heat Rate (HHV Btu/MWh)	10,560	10,560	10,560
Gas Transportation Costs (2025$MM/yr)	N/A	$15.5MM	$8.9MM

A.B. Brown:

At the A.B. Brown site, the simple cycle gas turbines ("SCGT") placed in service in 2025 (A.B. Brown Units 5 and 6) were evaluated for conversion to a 2x1 combined cycle gas turbine (CCGT), which would improve thermal efficiency, increase generation capacity, and transition the primary use of the facility to be a baseload resource. In this configuration, the exhaust heat from each existing combustion turbine would be captured by a Heat Recovery Steam Generator ("HRSG") which converts the waste heat into steam. This steam then drives a steam turbine generator to produce additional electricity without additional fuel input. Furthermore, this combined cycle configuration was investigated with and without duct firing. In the duct-fired CCGT, natural gas burners are installed in the HRSG to inject supplemental fuel directly into the exhaust steam, raising the temperature and causing the production of more steam. This design provides approximately 150 MW of additional output compared to the non-duct fired configuration. Both options were included to evaluate the tradeoff between increased output and higher capital investments, fuel usage and slightly lower efficiency when operated in this mode. Two implementation dates were considered for this conversion, with the unit being fully operational as a combined cycle at the start of 2030 or 2034. Figure 3-25 depicts the operational and financial parameters of this option.

Figure 3-25 – A.B. Brown Potential Future Conversion Options

Operating Characteristics and Estimated Costs	2x1 F Class SCGT to CCGT Conversion, Unfired	2x1 F Class SCGT to CCGT Conversion, Fired
Base Load Net Output (MW)	735	734
Base Load Heat Rate (HHV Btu/MWh)	6,430	6,440
Duct Fired Net Output (MW)	N/A	893
Duct Fired Heat Rate (HHV Btu/MWh)	N/A	6,830
Capital Expenditures (2025$/kW)	$1,050	$950
Fixed O&M (2025$MM/yr)	$6.2	$6.2
Gas Transportation Costs (2025$MM/yr)	$37.7	$37.7
Variable O&M (2025$/MWh)	$1.5	$1.5

3.7.2.2. Natural Gas

Natural gas power plants are characterized by igniting natural gas and transforming the heat generated from combustion into electrical energy. In addition to the natural gas projects at existing sites, CEI South evaluated a wide range of natural gas technologies including peaking resources such as simple-cycle turbines and reciprocating engines, and intermediate and baseload options such as combined cycle units. This wide range of available natural gas-powered alternatives allow for the evaluation of the tradeoffs between cost effectiveness, reliability, and environmental sustainability.

3.7.2.3. Simple Cycle Gas Turbines

SCGTs utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 3-26 for further details on the simple cycle gas turbine technologies evaluated.

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. An average pipeline cost (in dollar per MW) was developed from the F.B. Culley and A.B. Brown site estimates and then applied to the maximum capacity of all evaluated generic thermal resources. More detail on the estimated gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimate (Confidential)*.

Figure 3-26 – Simple Cycle Gas Turbine Technologies

Operating Characteristics and Estimated Costs	1xF-Class SCGT	1xJ-Class SCGT
Base Load Net Output (MW)	235	426.4
Base Load Net Heat Rate (HHV Btu/kWh)	9,930	8,940
Base Project Costs (2025$/kW)	$1,520	$1,190
Fixed O&M Costs (2025$MM/year)	$2.5	$2.6
Gas Transportation Costs (2025$MM/year)	$17.7	$32.2
Variable O&M (2025$/MWh)	$0.9	$1.2

3.7.2.4. Combined Cycle Gas Turbines

CCGTs utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator and to also use the hot exhaust gases from the gas turbine to produce steam in a HRSG. This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, seven different configurations were evaluated: a 1x1 F class (unfired and fired), 2x1 G/H class (unfired and fired), 1x1 J class (unfired), and 2x1 J class (unfired and fired), as shown in Figure 3-27 and Figure 3-28. A 1x1 CCGT is configured with one gas turbine and one steam turbine where a 2x1 CCGT is configured with two gas turbines and one steam turbine. General Electric (“GE”) turbines were used as representative CCGT technologies for the operational and financial parameters. The F class is based on the GE 7FA.05 turbine, the J class is based on the GE 7HA.03, and the G/H class is based on the GE 7HA.01 turbine.

Figure 3-27 – Combined Cycle Gas Turbine Technologies (Unfired Configuration)

Combined Cycle Gas Turbines - Unfired				
Operating Characteristics and Estimated Costs	1x1 F-Class	2x1 G/H-Class	1x1 J-Class	2x1 J-Class
Base Load Net Output (MW)	366	848	620	1,254
Base Load Net Heat Rate (HHV Btu/kWh)	6,470	6,260	6,150	6,080
Base Project Costs (2025$/Unfired kW)	$2,271	$1,961	$2,039	$1,695
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.1	$6.8
Gas Transportation Costs (2025$MM/year)	$27.5	$63.9	$46.7	$94.6
Variable O&M (2025$/MWh)	$1.6	$1.6	$1.6	$1.5

Figure 3-28 – Combined Cycle Gas Turbine Technologies (Fired Configuration)

Combined Cycle Gas Turbines - Fired			
Operating Characteristics and Estimated Costs	1x1 F-Class	2x1 G/H-Class	2x1 J-Class
Base Load Net Output (MW)	365	847	1,244
Total Duct-Fired (Peaking) Net Output (MW)	445	1,034	1,454
Base Load Net Heat Rate (HHV Btu/kWh)	6,490	6,260	6,120
Total Duct-Fired Heat Rate (HHV Btu/kWh)	6,843	6,682	6,569
Base Project Costs (2025$/Fired kW)	$2,518	$2,070	$1,808
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.8
Gas Transportation Costs ($MM/year)	$33.5	$78.0	$109.7
Variable O&M ($/MWh)	$1.6	$1.6	$1.5

3.7.2.5. Aeroderivative and Reciprocating Engines

Aeroderivative and reciprocating internal combustion engines represent smaller-scale, highly flexible natural gas technologies. Aeroderivative turbines are adapted from jet engine technology, while reciprocating engines are most technologically similar to the engine found in a car. These technologies are well-suited to provide peaking and balancing services during periods of system stress or low renewable output. Both engine types have smaller unit sizes, fast start-up times, and strong operational flexibility when compared to large heavy-frame gas plants. Figure 3-29 explains the operating and financial characteristics of these natural gas units.

Figure 3-29 – Aeroderivative and Reciprocating Engines

Operating Characteristics and Estimated Costs	Aeroderivative Engines	Reciprocating Engines
Base Load Net Output (MW)	52 MW (single engine)	110 MW (six 18-MW engines)
Base Load Net Heat Rate (HHV Btu/kWh)	9,310	8,340
Base Project Costs (2025$/kW)	$3,440	$2,650
Fixed O&M Costs (2025$MM/year)	$2.1	$3.1
Gas Transportation Costs (2025$MM/year)	$3.9	$8.3
Variable O&M ($/MWh)	$0.90	$4.0

3.7.2.6. Renewables

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic ("PV"), and hydroelectric. Our base assumptions for renewable tax credits reflect the updates specified in the OBBBA, including the end of solar and wind tax credits by 2030. Wind resources were modeled to include Production Tax Credits, while solar resources included discounts for the Investment Tax Credit. Under the IRA solar resources have the option to choose between the investment tax credit and the production tax credit. Based on the assumed capacity factor of solar resources, the investment tax credits are anticipated to provide more value and therefore were used in the model.

3.7.2.6.1. Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 3-30 for further details on wind technologies evaluated. Aside from the hybrid storage price, the following assumptions were based on the 1898 & Co. technology assessment.

Figure 3-30 – Wind Technologies

Operating Characteristics and Estimated Costs	Wind	Wind + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	200	200 + 100
Base Project Costs (2025$/kW) + ($/kW for Storage)	$2,194	$2,194 + $1,436
Fixed O&M Costs (2025$MM/year)[25]	$10.5	$10.5 + $3.3
Annual Capacity Factor	37%	37%

[25] Variable O&M costs are included in the Fixed O&M estimate in this table.

3.7.2.6.2. Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a relatively mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar PV technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 3-31 for further details on the solar PV technologies evaluated. Base project costs are informed by the 2024 All Source RFP data where available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

Figure 3-31 – Solar Technologies

Operating Characteristics and Estimated Costs	10 MW Solar PV	100 MW Solar PV	100 MW Solar PV + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	10	100	100 + 50
Base Project Costs (2025$/kW) + (2025$/kW for Storage)	$2,560	$2,351	$2,504 + $1,626
Fixed O&M Costs (2025$MM/year)[26]	$0.1	$1.2	$1.2 + $1.8

3.7.2.6.3. Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 3-32 for further details on the hydroelectric technology evaluated.

[26] Variable O&M costs are included in the Fixed O&M estimate.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed that, when taking economics into consideration, both dams combined had an average potential output near 50 MW, which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 3-32 – Hydroelectric Technologies

Operating Characteristics and Estimated Costs	John T. Myers	Newburgh
Base Load Net Output (MW)	36	22
Base Project Costs (2025$/kW)	$6,901	$6,901
Fixed O&M Costs (2025$MM/year)	$3.8	$2.3

3.7.2.7. Storage

In addition to storage resources paired with renewable technologies, standalone storage was evaluated in this IRP. Short duration Lithium-Ion batteries as well as more nascent long duration technologies were considered. These are summarized in Figure 3-33 and Figure 3-34.

Lithium-ion technology represents a significant majority of utility scale, stationary energy storage projects being developed and installed in the current market. It is the most commercially and technically mature battery storage solution in today's market and is commonly the most cost-effective option for grid-scale applications/use cases with a 1-4 hour discharge duration at rated power. Cost and performance information for these resources are informed by the 2024 All-Source RFP where data was available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

In effort to consider a wide range of resources, additional emerging energy storage options were also considered as long duration (>4 hours) storage. There are numerous technologies of varying commercial and technical maturity, and while CEI South recognizes the desire for technology diversity, two representative technologies were selected to represent the broader category of long duration energy storage ("LDES"). Compressed Air Energy Storage ("CAES") is a maturing technology that is suitable for large, utility scale projects. While CAES will be limited in implementation depending on

certain geologic characteristics, it generally represents the lower end of today's LDES capital cost range and is therefore a representative technology for resource planning. Additionally, following requests from stakeholders, iron-air energy storage technology was also included in this analysis. The cost and performance estimates for the 100 MW/ 100 Hour storage technology is shown in Figure 3-34.

Figure 3-33 – Lithium-Ion Energy Storage

Operating Characteristics and Estimated Costs	Lithium Ion 50 MW / 200 MWh	Lithium Ion 100 MW /400 MWh	Lithium Ion 100 MW /800 MWh
Base Load Net Output (MW)	50	500	100
Storage Duration (hours)	4	4	8
Round-Trip Cycle Efficiency	85%	85%	85%
Base Project Costs (2025$/kW)	$2,461	$2,273	$4,067
Fixed O&M Costs (2025$MM/year)[27]	$2.0	$3.5	$6.3

Figure 3-34 – Emerging Energy Storage Technologies

Operating Characteristics and Estimated Costs	Compressed Air Representative Technology	Iron Air Representative Technology
Base Load Net Output (MW)	100	100
Storage Duration (hours)	10	100
Round-Trip Cycle Efficiency	68%	34%
Base Project Costs (2025$/kW)	$5,020	$2,840
Fixed O&M Costs (2025$MM/year)[27]	$4.2	$5.0

3.7.2.8. Advanced Nuclear

Nuclear power generation technology has been a dependable, carbon-free power resource in the United States for many decades. In a nuclear power plant, nuclear fission, or the splitting of atoms, occurs. This process creates heat energy which is used to generate steam and spin a turbine, which in turn produces electricity. The nuclear technology considered in this evaluation is a small modular reactor ("SMR") design, which is characterized by compact reactor modules that can be deployed individually or in groups to match system needs. The design incorporates passive safety systems, simplified plant configurations, and high thermal efficiency, which enable lower operating costs and enhanced safety as compared to traditional nuclear generators. The assumed economic and operational data can be found in Figure 3-35.

[27] Variable O&M costs are included in the Fixed O&M estimate.

Although commercial SMR projects are still under development, evaluating a nuclear option provides insight into potential long-term strategies for reliable, sustainable power generation. In the near-term, CEI South views the technology as a future-facing resource rather than a near-term build candidate. For the purposes of this IRP, it is assumed that 2035 is the earliest possible in-service date for this technology.

Figure 3-35 – Advanced Nuclear Technology

Operating Characteristics and Estimated Costs	Nuclear
Base Load Net Output (MW)	100
Base Load Net Heat Rate (HHV Btu/kWh)	11,580
Base Project Costs (2025$/kW)	$15,812
Fixed O&M Costs (2025$MM/year)	$21.6MM
Variable O&M Costs (2025$/MWh)	$2.8

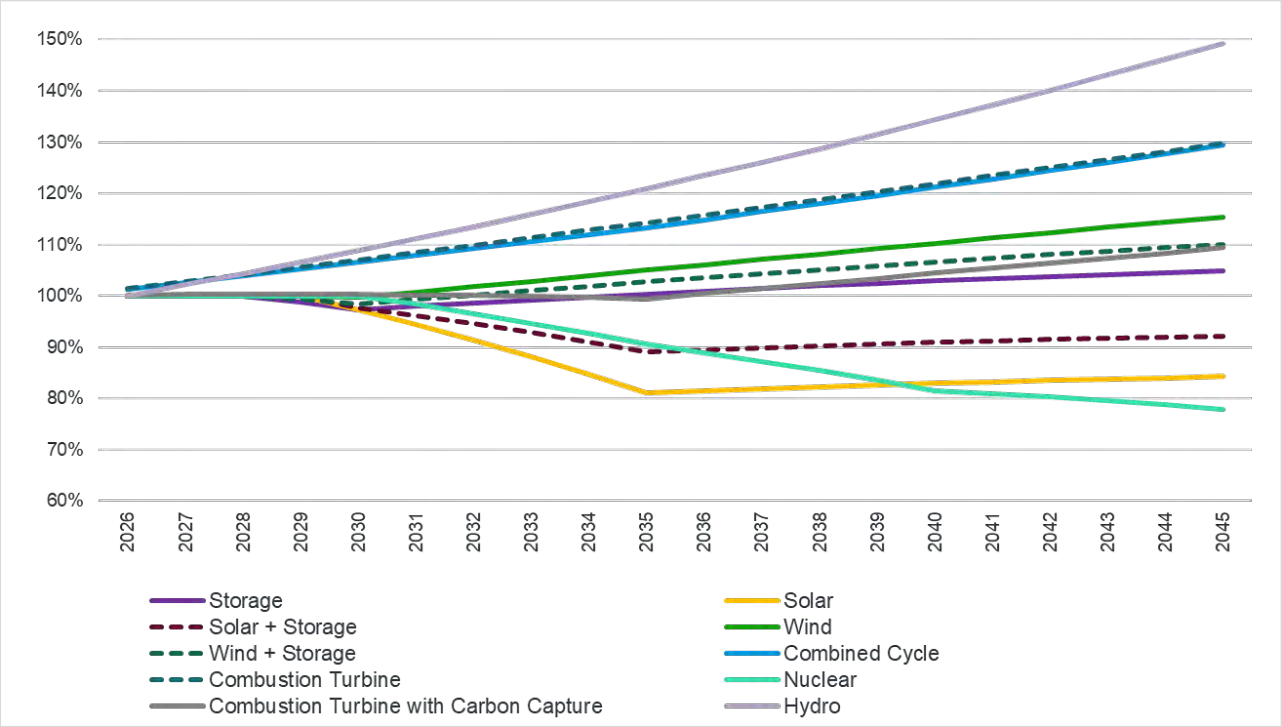
3.7.2.9. Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2025 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 3-36.

Technologies whose capital costs do not decline significantly over the IRP time period, such as wind, natural gas, and coal are generally more mature, while technologies such as advanced nuclear, solar, and hybrid solar plus storage are less mature and expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies for nuclear, solar, and hybrid solar plus storage are expected to decrease capital costs over time. Due to uncertainty associated with these less mature technologies, CEI South relied upon information collected as part of the 2024 All Source RFP as well as cost curves provided by the NREL in their 2024 Annual Technology Baseline ("ATB") Workbook[28] to help project capital costs over the study period.

[28] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Capital cost curves were pulled from the "CAPEX ($/kW)" of each included technology.

Figure 3-36 – Forward Looking Capital Cost Curves– Forward Looking Capital Cost Curves



3.7.2.10. Energy Efficiency

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of DSM options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:
> (1) Rate design as a resource in meeting future electric service requirements.
> (2) Demand-side resources. For potential demand-side resources, the utility shall include the following:
> (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters.
> (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.
> (C) The customer class or end-use, or both, affected by the demand-side resource.

(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.
(F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers."

In addition, this process aligns with IAC 8-1-1.5-3 which requires energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

3.7.2.10.1. DSM Market Potential Study

The first step in the process is a Market Potential Study ("MPS"). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decision makers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[29] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource. Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: societally, all customers, the program administrator, program participants and utility rates.

CEI South's MPS completed in 2025 was utilized to both to inform the IRP and support the development of a DSM Action Plan for CEI South, see *Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*. The study included a comprehensive review of current

[29] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf ; November 2017; page ES-1

programs, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study leveraged new primary market research from the *Technical Appendix Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey* in the CEI South service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. New primary market research from the 2025 study was also leveraged to estimate customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints and other barriers the “program intervention” is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- **Maximum Achievable** Potential estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- **Realistic Achievable** Potential estimates achievable potential with CEI South paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

It is important to also note the estimates of potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in CEI South's energy efficiency programs. In the CEI South service area, approximately 5% of commercial energy sales and 72% of industrial energy sales are associated with customers who have elected to opt-out.

In addition to the energy efficiency potential study, a demand response potential study was also conducted. The methodological approach to the demand response potential study closely mirrored the energy efficiency analysis, with an assessment of the calculation of the demand response technical, economic, and achievable potential. The demand response study analyzed existing programs, such as the Smart Cycle and Residential BYOT programs, as well as potential new programs, such as DR Aggregation, DLC Grid-Enabled Water Heating, DLC Electric Vehicle, Battery Storage, Commercial BYOT, and Critical Peak Pricing rates. The demand response study shows the amount of potential demand that could be realized if customers shift their electric usage from on-peak to off-peak periods.

3.7.2.10.2. Energy Efficiency – IRP Reference Case

Energy Efficiency for the 2025 through 2027 IRP years were informed directly from CEI South DSM Settlement Agreement (2025-2027). These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the realistic achievable potential identified in the MPS as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team initially provided the energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2025-2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely prevent its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program

planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the initial sector-level bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the energy efficiency achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of CEI South's programs. Net savings were calculated by applying CEI South's most current Net to Gross ("NTG") ratios to the MPS estimates of gross achievable savings.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on peak system line loss rate of 8.4% to convert savings from the meter level up to the generator level. Figure 3-37 provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided transmission and distribution ("T&D") benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

3.7.2.11. Demand Response

CEI South, after working with stakeholders, expanded the number of DR bundles to be included for selection in the IRP Reference Case, from five bundles in the 2022/2023 IRP to thirteen bundles. In the 2025 IRP, to align with MISO's new seasonal structure, cumulative demand MW savings were calculated per the four seasons (Summer, Winter, Spring and Fall).

CEI South included two fixed bundles representing CEI South's DR capabilities for DLC switches on residential air conditioning units and hot water heaters in the CEI South service area. Over the IRP time frame, CEI South anticipates replacing existing DLC switches with smart thermostats that integrate DR capabilities (via the Smart Cycle Program). As CEI focuses on converting switches to smart thermostats, the estimated annual DR savings for the fixed residential air conditioner switch bundle drop from approximately 1.45 MW in 2028, to 0.13 MW by 2045. The estimated annual impacts for the fixed residential water heater switch bundle of DR are approximately 0.41 MW in 2028, decreasing to 0.05 MW by 2045.

Bundles three and four, both selectable resources, represent DR saving capabilities for CEI South's residential DR-enabled smart thermostats. The third bundle represents the Smart Cycle Program, anticipating DR savings from replacing DLC switches with smart thermostats. DR capabilities within the Smart Cycle bundle represents 13.68 MW of peak reduction capabilities in 2028 decreasing to 12.74 MW in 2045. The fourth bundle represents DR savings for customer self-installed DR-enabled smart thermostats in our BYOT program. This bundle represents an additional 12.85 MW of peak reduction capabilities in 2028 increasing to 17.85 MW by 2045.

A fifth bundle also represents DR savings for smart thermostats, but this is a new bundle focused on the commercial sector. CEI South commercial customers wanting to enroll their BYOT thermostats could achieve approximately 0.37 MW in 2028, as historical devices would not yet contribute to DR savings. As participation increases, this bundle shows a potential of 3.56 MW in 2045.

Bundles six and seven, consists of DR savings attributable to a time of use ("TOU") rate option with a critical peak price ("CPP") rate. This program is expected to start in 2026 and build slowly a pilot program through 2030. The sixth bundle, representing residential DR potential from TOU with CPP is expected to achieve approximately 0.57 MW in 2028 and increase to 5.71 MW in 2045. The seventh bundle, accounting for commercial DR savings from TOU with CPP, can achieve around 0.24 MW in 2028 and 2.07 MW in 2045.

Bundles eight and nine, both selectable resources, are new inputs in the 2025 IRP. These bundles represent DR savings for residential and commercial grid-enabled water heaters. Residential grid-enabled water heaters represent an additional 0.63 MW of peak reduction capabilities in 2028 and increases to 5.7 MW in 2045. Commercial grid-enabled water heaters represent an additional 0.31 MW in 2028 and increases to 2.6 MW in 2045.

Per stakeholder requests, two more new bundles for this IRP represent DR savings from EV chargers. One bundle represents residential DR achievable potential and the other represents commercial DR capabilities. Bundle ten, residential EV, represents 0.02 MW in 2028 and increases to 1.2 MW in 2045. The eleventh bundle shows there is very little DR savings potential in CEI South's territory for commercial EV charging, with 0.00003 MW in 2028 increasing to 0.001 MW in 2045.

The final two bundles, also new selectable resources per stakeholder requests, represent inputs for residential battery and commercial battery DR saving potential. The residential battery DR saving inputs provided in bundle twelve, represent 0.03 MW in 2028 and increase to 0.68 MW in 2045. The commercial battery DR potential in bundle thirteen

represents an additional 0.01 MW in 2028 and increases to approximately 0.37 MW in 2045.

3.7.2.12. DSM Resources Optimization Process

Energy Efficiency for the 2026 and 2027 IRP years were informed directly from CEI South DSM Plan (*Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan)* approved in Cause No. 46100. These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the achievable potential identified in the MPS[30] as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team provided energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2026/2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely limit its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of CEI South's programs. Net savings were calculated by applying CEI South's most current NTG ratios to the MPS estimates of gross achievable savings.

[30] The IRP inputs used the Enhanced RAP identified in the MPS for the C&I sector, and the RAP for the residential / income-qualified sectors.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on a multiplier of 1.092 to convert savings from the meter level up to the generator level. The table below provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided T&D benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

Figure 3-37 – MPS versus Initial IRP Bundles Comparison – Sum of Incremental MWh

	Vintage 1: MPS	Vintage 1: IRP	Vintage 2: MPS	Vintage 2: IRP	Vintage 3: MPS	Vintage 3: IRP
Residential	46,733	45,343	58,227	55,643	310,420	287,399
C&I	76,079	69,786	75,949	69,666	260,052	238,540
IQW	4,640	4,458	6,284	5,895	31,734	29,130

Following an early review of the residential and commercial/industrial energy efficiency savings and costs inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2), and low/mid cost measure (Tier 1) across each vintage time-series due to concerns that an aggregate residential sector bundle would not get selected. Residential behavioral energy efficiency savings were included in the Tier 1 bundle. Figure 3-38 summarizes the final bundle incremental savings for energy efficiency and associated levelized utility cost per lifetime savings.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each EE resource bundle were provided to CEI South to permit the IRP model to assess the value of energy savings on an hourly basis. These 8,760 shapes were based on residential and commercial end-use load shapes for Indiana from NREL's End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each EE sector and vintage bundle.

Figure 3-38 – Annual MWh EE Savings and Levelized Costs per Lifetime MWh Saved by Bundle

EE Bundles	Enhanced C&I		Res Tier 1 + HER		Res Tier 2		IQW		IQW_HEAR	
	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh
2028	22,839	$37.87	10,879	$30.27	2,708	$84.06	1,042	$166.76	293	$332.49
2029	23,439	$38.72	11,893	$31.52	3,257	$85.49	1,120	$174.99	368	$339.69
2030	23,507	$39.63	12,849	$32.69	3,757	$87.40	1,185	$184.76	451	$347.49
2031	24,198	$40.73	13,495	$33.93	4,222	$89.49	1,319	$201.48	539	$355.87
2032	23,406	$41.66	13,938	$35.04	4,673	$91.91	1,347	$213.36	628	$364.92
2033	22,062	$42.43	14,157	$36.20	5,159	$94.47	1,349	$226.10	712	$374.82
2034	23,008	$44.03	15,372	$34.12	6,097	$94.80	1,411	$244.11	786	$385.39
2035	21,998	$45.14	15,487	$35.20	6,499	$97.62	1,377	$257.84	849	$396.47
2036	20,511	$45.88	15,293	$36.12	6,854	$100.57	1,315	$271.91	899	$407.87
2037	19,500	$47.06	15,061	$37.04	7,131	$103.51	1,327	$289.87	936	$419.72
2038	20,898	$49.15	16,246	$36.40	7,624	$106.04	1,565	$268.04	962	$431.29
2039	20,087	$49.89	17,636	$37.43	7,846	$108.39	1,581	$275.56	981	$442.33
2040	19,772	$51.05	17,724	$38.03	7,998	$111.09	1,628	$287.22	993	$452.74
2041	18,773	$51.85	17,550	$38.81	8,004	$113.26	1,569	$295.52	1,000	$462.96
2042	17,685	$52.27	17,369	$39.67	7,996	$115.36	1,520	$303.39	1,005	$472.25
2043	19,434	$50.86	17,234	$40.50	7,904	$118.38	1,539	$316.34	1,000	$480.82
2044	18,923	$51.04	16,825	$40.97	7,639	$121.56	1,477	$322.91	997	$488.83
2045	17,951	$51.39	16,484	$41.61	7,528	$123.45	1,419	$329.24	994	$497.27

3.7.2.13. DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2022/2023 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2028 and 2031 and then evaluates the remaining years beginning in 2034 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences and resource needs across the short, mid and long run.

The characterization of the EE and DR bundles included in the IRP modeling was based on a collaborative process with the stakeholders. This led to re-evaluating the sector level budling approach included in the 2022/2023 IRP. CEI South bundled the measures by sector for residential and non-residential consistent with the 2022/2023 IRP to account for

high savings behavioral based efficiency measures to be bundled with low to medium cost measures to help ensure the maximum amount of realistic achievable potential was economically selected. CEI South included the income qualified bundle and added an income qualified HEAR bundle to account for savings through the Indiana Energy Saver program (which will occur outside of DSM filings). CEI South bundled C&I sector savings at an enhanced realistic achievable potential, which allows incentives for some measures to be decreased while increasing incentives for measures that would deliver additional adoption and savings. An improvement to the 2022/2023 IRP was adding more emerging technology measures to be included in bundles across all sectors. Additional sector and end-use specific hourly load shapes were included to more accurately estimate the timing of the energy efficiency impacts throughout the year. Also, based on feedback in the Director's report and working with the OSB, DR bundles were expanded to include six (6) additional DR products as selectable resources even though most were not cost-effective in the MPS.

CEI South also modeled Aggregation as the program is currently being implemented. CEI South explored options and strategies for C&I customers to participate in the program. The aggregator will utilize DR products based on customers industry type and will deploy appropriate curtailment strategies such as process controls and equipment. The aggregator has implemented DR strategies such as lighting controls, thermal energy storage, irrigation controls across utility partners nationwide.

Pricing options modeled in the IRP were based on an opt-in time of use and critical peak pricing design that aligns with CEI South's current pilot program, assuming a broader role out of the rate. Peak time rebates were not modeled as the evaluation, measurement and verification of savings is complex and is specific to each individual customer. Further, such a design would cause CEI South to undergo significant and costly changes to the billing system. Figure 3-39 contains a summary of EE & DR bundles modeled in the 2022/2023 and 2025 IRP with a description of enhancements.

Figure 3-39 – EE and DR Bundle Comparison and Enhancements

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Energy Efficiency	Res Tier 1	Res Tier 1 + Behavioral	Bundled Behavioral with Low/Medium cost Tier 1 to capture large savings high-cost measure
Energy Efficiency	Res Tier 2	Res Tier 2	Introduced an expanded emerging tech measure list for consideration
Energy Efficiency	Res Behavioral		
Energy Efficiency	Res Income Qualified	Res Income Qualified	
Energy Efficiency		Res Income Qualified HEAR	Introduced new bundle to capture impacts of OED IN Energy Saver program, will not be included in utility EE programs
Energy Efficiency	Non-Res Enhanced RAP	Non-Res Enhanced RAP	Modeled the enhanced RAP, where some incentives were decreased for measures and other were increased to drive participation
Demand Response	Res Switches	Res AC Switch	Modeled AC Switch as a "going in" resource, water heater switches were modeled as a separate DR product
Demand Response		Res WH Switch	
Demand Response	Res Smart Cycle & BYOT	Res Smart Cycle	Modeled Smart Cycle as a selectable resource, BYOT thermostats were modeled as a separate DR product
Demand Response		Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Res Rates	Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with pilot approval in Cause No. 45990

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Demand Response	Non-Res BYOT	Non-Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Non-Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Non-Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Non-Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Non-Res Rates	Non-Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with Residential pilot approval in Cause No. 45990. Modeling will help inform if TOU & CPP rates are selected for Non-Res
Demand Response	Aggregation	Aggregation	Modeled as a "going in" resource, Aggregation received approval in Cause. No. 45990. CEI South is in the beginning stages of implementing the program and expect 12.5 MWs in 2026 and 25 MWs for 2027-2045

3.7.2.14. Innovative Rate Design

CEI South included innovative rate design in its Preferred Portfolio in its 2022/2023 IRP and the 2025 IRP. Following the IRP, CEI South proposed a CPP with Time of Use ("TOU") pilot in its recent rate case in Cause No. 45990. The Commission approved the pilot, and CEI South has been actively working to develop the program that is set to begin in Q2 2026.

CEI South's approved CPP TOU pilot provides an economic price signal for participating customers to lower their energy usage during peak times through rates. The TOU rate will be available to participating customers in the CEI South pilot between June and September with higher prices during the day and lower prices during nights and weekends. Most likely during times of highest usage, CEI South may call a CPP event, similar to a demand response event where prices are raised to the extent that a reduction in demand is induced. The Automated Metering Infrastructure provides the backbone for this program.

CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if successful. An expansion of the CPP TOU pilot is included within this IRP, utilizing indicative amounts developed in its most recent Market Potential Study. The CPP pilot will help inform the potential expansion of an innovative rate design for the commercial sector, included in this IRP.

3.8. Transmission Planning & Distribution Planning

CEI South continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of CEI South's planning process can be summarized as follows:

- Developing an electric system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet CEI South customers' needs during normal conditions and during a system contingency (loss of a system asset) or set of contingencies;
- Minimizing thermal loadings on transmission and distribution facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
- Analyzing the dynamic stability of the transmission system under various contingency conditions;
- Ensuring the available system fault current imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
- Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
- Coordinating transmission planning activities in broader regional evaluations with the MISO, ReliabilityFirst ("RF") and neighboring transmission owners;
- Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
- Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
- Analyzing the performance of the distribution system to ensure reliability, adequacy to meet future load growth, DER penetration, and to address age/condition of existing facilities; and
- Ensuring compliance with FERC, NERC and RF Reliability Standards.

3.8.1. Transmission Planning Process

At a high level, CEI South's transmission performance planning models include existing facilities at or above 69 kV, critical system conditions, and study years. Modeled Facilities represent, at a minimum, required upgrades and could include future facilities not yet in service. The models may include distribution circuits and substations. The models aid in analyzing More Probable, Less Probable and Extreme Contingency events. The studied time periods may be for near-term (1 to 5 years) or long-term (6 to 10 years) and for peak and off-peak demand periods; however, the planning horizon may be increased to include transmission or generation plans. Using these models, CEI South may study system growth, generator interconnections, transmission interconnections, Load Serving Entity ("LSE") interconnections, and other studies as needed. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria (*Technical Appendix Attachments 3.9 VEC-008 Electric Transmission Planning Criteria*).

3.8.2. Existing Transmission System

CEI South's transmission system is comprised of 64 miles of 345 kV lines, 430 miles of 138 kV lines, and 563 miles of 69 kV lines.

The existing Transmission system has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (345kV-138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station and Duff Substation, a 345kV interconnection to Big Rivers' Coleman Substation, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at AES/IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at CEI South's Newtonville Substation.

3.8.3. Import and Export Capability Assessment

As mentioned above, CEI South's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 660 MW in peak demand periods and approximately 750 MW in off-peak demand periods (or approximately 35-40% of peak demand). The current import capabilities were used as a maximum threshold for the energy purchases and sales during the Risk Analysis.

Although CEI South has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs
- Real-time binding constraints

Transmission planning's most recent analysis in its internal long-range planning study looked at a sensitivity on import capability around MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 and concluded that the maximum import capability in 2031/2032 would increase to 1,280 MW in the peak demand periods.

3.8.4. Transmission Facilities as a Resource

As part of this year's IRP, CEI South retained 1898 & Co to perform transmission planning analyses evaluating 14 potential resource futures (or "Transmission Study Scenarios"). The resulting study report is included in the *Technical Appendix Attachment 2.3, Transmission Study (Confidential)*.

Study Overview:

The Transmission Study Scenarios included analyzing:

- the retirement of additional coal generation and partial replacement of these retirements with Battery Energy Storage System ("BESS"),
- the addition of a synchronous condenser,
- the addition of an aeroderivative, and
- import from the MISO market.

Each of these cases also included the addition of various levels of renewable resources.

The study (Steady-State analysis only) was performed for the Summer peak, Shoulder (off-peak), and Winter peak demand periods. The five-year and ten-year models utilized were from the latest 2024 MISO Transmission Expansion Plan ("MTEP") model series, which includes future transmission system projects and approved generation interconnections. The ten-year models and transmission scenarios were inclusive of MISO's LRTP Tranche 2.1 portfolio for the region. Additionally, given uncertainty of LRTP project #35 meeting the 2032 in-service date prescribed by MISO, a ten-year sensitivity study removing this project from the models was performed. Modeling parameters for the new renewable resource additions were utilized from the latest cycle of the MISO generation interconnection process. These generation projects included known generation replacement projects and those in final negotiations to execute generation interconnection agreements with MISO. Incorporating these projects ensured the use of

the most up-to-date modeling data for generation resources within CEI South's service area. The analysis incorporated renewable resources already in the MISO queue and modeled within MISO systems, along with the new combustion turbines at the A.B. Brown power plant and the Posey Solar project.

Study Results:
Evaluation of the Transmission Study Scenarios found several issues primarily tied to less generation on the system and a shift of additional issues arising in the Shoulder over the Summer period. Under heavy import conditions, severe voltage reinforcements are required in the Shoulder period. The highest magnitude of reinforcement costs is shown in the Winter period under heavy import conditions. Network upgrades needed to mitigate violations observed across all demand periods ranged from $0 million to $242.6 million depending on the transmission scenario.

Under Shoulder and Summer demand periods in the five-year planning horizon, the Culley G2 BESS or aeroderivative conversions evaluated (Transmission Study Scenarios 6 and 9) required no system reinforcements. Under the same demand periods and planning horizon for Culley G3 BESS conversion (Transmission Study Scenario 7), an additional $22.6 million in thermal and voltage reinforcements were required. When evaluating both Culley G2 and G3 BESS conversion (Transmission Study Scenario 8), additional thermal and voltage violations are produced which increases system reinforcements to $39.9 million. Considering the Culley G2 or G3 BESS conversions under heavy import (Transmission Study Scenarios 11 and 12), the system reinforcements ($56.6 million) required for Culley G2 BESS conversion were less severe than under Culley G3 BESS conversion ($156.8 million). In summary, Culley G2 BESS conversion causes less thermal and voltage impacts than Culley G3 BESS conversion.

The magnitude of system reinforcements was the most significant during the five (5) year Winter demand period, driven by heavy import condition. Heavy import conditions represent transmission scenarios when CEI South's dispatchable resources (F.B. Culley 2 and 3, and A.B. Brown CTs) are offline or unavailable. The reinforcements were estimated between $22.1 million and $242.6 million. Major upgrades on the high-end included rebuilding several transmission lines on the 69 kV and 138 kV system, two (2) additional 345/138 kV transformers at A.B. Brown, a 62.4 MVAr capacitor bank at Culley 69kV sub, and an additional 249.6 MVAr of reactive support spread across CEI South's footprint. The need for additional VAR support across the system is correlated to dispatchable generation being unavailable. A new 40-mile Ameren Norris City (IL) 345kV to A.B. Brown 345 kV line was considered as a potential reinforcement and the

preliminary estimate for this potential project is $136 million, accounting for over half of the $242.6 million mentioned above.

Converting Culley Unit 2 to a Synchronous Condenser was reviewed as an option for VAR support and was determined to be unfeasible due to the design of this particular unit.

IRP Impact:
For capacity expansion modeling, CEI South accounted for uncertainty and price volatility by incorporating conservative estimates for transmission upgrades caused by each potential technology added to the F.B. Culley 2 site. In the case that there are no additional units brought online (Transmission Study Scenario 3), the total upgrade cost was $47.9 million. This value was used to represent the cost of transmission system upgrades if a storage resource was assumed to be placed in service (Transmission Study Scenario 2), as well as in the case that the F.B. Culley 2 site interconnection rights were allowed to expire. Because Scenario 2 represents only the shoulder months, the summer transmission cost from Transmission Study Scenario 3 was used as a conservative estimate of the maximum potential upgrade cost. For the addition of a reciprocating engine or aeroderivative engine at the F.B. Culley 2 site, the highest seasonal costs associated with the Culley G2 aeroderivative (Transmission Study Scenario 4) were estimated at $22.8 million.

3.8.5. Distribution Planning Process

In 2025, Transmission Planning and Distribution Planning teams both completed separate but coordinated Long Range Planning reports which assessed future impacts to each system. Both analyses are coordinated to review load growth, generation changes, and overall system limitations and capabilities.

Furthermore, the Distribution Long Range Planning Report discusses further details on CEI South distribution planning criteria used in system analysis. The public version of the Distribution Long Range Planning Report is included in the *Technical Appendix Attachment 3.8*. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria, see *Technical Appendix Attachment 3.9.*

3.8.6. Evolving Technologies and System Capabilities

Transmission Capacity Investments:
MISO's 2024 Transmission Expansion Plan identified numerous Multi-Value Projects aimed at increasing regional transmission capacity throughout the central portion of MISO's footprint. MISO's Board of Directors approved these transmission investments in

December of 2024. MISO's approved plan includes transmission capacity additions in CEI South's footprint.

FERC Order 881 - Ambient Adjusted Line Ratings:

CEI South is actively engaged in implementing ambient-adjusted transmission facility ratings (AARs). FERC Order 881 was issued in December 2021 and directed Regional Transmission Operators (such as MISO) and Transmission Owners (such as CEI South) to implement AARs. CEI South actions taken to date include:

- Working collectively with MISO and other Transmission Owners on AAR implementation;
- Conducting monthly internal stakeholder meetings to review implementation status;
- Implementation of an advanced facility ratings database (software that enables the use of ambient adjusted ratings); and
- Completing Energy Management System upgrades required to manage ambient adjusted ratings in real-time operations and communicate those values to MISO.

Historically, transmission facility ratings have been static and only adjusted seasonally. AARs provide additional real-time capacity on transmission facilities when outdoor temperatures are lower. Implementing AARs may reduce or alleviate transmission facility congestion by allowing system operators to apply the increase in the facility's rating, when applicable.

FERC Order 2222 - Distributed Energy Resources:

FERC Order 2222 requires Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") to allow aggregated distributed energy resources ("DERs") to participate in wholesale electricity markets. In an effort to prepare for MISO's implementation of order 2222, CEI South has created an internal task force to ensure compliance with FERC's mandate and MISO's tariff. The task force will coordinate with MISO, IURC, and other authorities to align internal DER processes, registration, system readiness, tariffs, and compliance with reliability and cybersecurity standards.

3.9. Other Modeling Assumptions

3.9.1. Resource Availability

A key model input is the availability of new generation resources, which signals how quickly resources can be brought online. For all scenarios except for those with large load additions (large load sensitivity analysis and the alternate reference case), resource availability assumptions remained constant over the modeling period. As shown in Figure 3-40, renewable build constraints were intentionally aggressive as requested by stakeholders.

Resource availability was also informed by the 2024 All-Source RFP, which indicated that solar and storage were more readily accessible than wind facilities in or near Indiana. Finally, it is important to note that 2035 was identified as the earliest reasonable in-service date for advanced nuclear technology, as informed by the technology assessment.

Figure 3-40 – Resource Availability for Core Scenarios[31]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	1 Project, 246 MW	1 Project, 246 MW
J Class CT	2030	2 Projects, 874 MW	2 Project, 874 MW
Reciprocating Engine	2030	2 Projects, 220 MW	4 Projects, 440 MW
Aeroderivative	2030	2 Projects, 114 MW	4 Projects, 228 MW
1x1 F Class CC	2032	1 Project, 454 MW	1 Project, 454 MW
1x1 J Class CC	2032	1 Project, 624 MW	1 Project, 624 MW
Renewables			
Solar	2028	4 Projects, 400 MW	18 Projects, 1,800 MW
Solar + Storage	2028	3 Projects, 300 + 150 MW	10 Projects, 500 + 250 MW
Wind	2030	4 Projects, 800 MW	10 Projects, 2,000 MW
Wind + Storage	2030	3 Projects, 600 + 300 MW	5 Projects, 1,000 + 500 MW
Hydro	2032	2 Projects, 58 MW	2 Projects, 58 MW
Storage			
4-hour 50 MW Storage	2028	5 Projects, 250 MW	10 Projects, 500 MW
4-hour 100 MW Storage	2028	5 Projects, 500 MW	10 Projects, 500 MW
8-hour 100 MW Storage	2028	3 Projects, 300 MW	5 Projects, 500 MW
Nuclear			
Nuclear	2035	1 Project, 100 MW	1 Project, 100 MW

For the simulations that included a large load addition, such as the alternate reference case and the large load sensitivity runs, resource build constraints were expanded. As shown in Figure 3-41**,** the constraints for most technologies were expanded to at least twice their base levels. After running the simulations, it was confirmed that these cumulative limits were not binding for either the core scenarios or in the large load addition cases as the model did not select the maximum number of any units.

[31] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

Figure 3-41 – Resource Availability for Large Load Addition Cases[32]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	3 Projects, 737 MW	6 Projects, 1,475 MW
J Class CT	2030	3 Projects, 1,311 MW	6 Projects, 2,623 MW
Reciprocating Engine	2030	4 Projects, 439 MW	8 Projects, 878 MW
Aeroderivative	2030	4 Projects, 228 MW	8 Projects, 457 MW
1x1 F Class CC	2032	2 Projects, 908 MW	2 Projects, 908 MW
2x1 G/H Class CC	2032	4 Projects, 3,825 MW	4 Projects, 3,825 MW
1x1 J Class CC	2032	2 Projects, 1,248 MW	2 Projects, 1,248 MW
2x1 J Class CC	2032	4 Projects, 5,477 MW	4 Projects, 5,477 MW
Renewables			
Solar	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
Solar + Storage	2028	6 Projects, 600 + 300 MW	20 Projects, 2,000 + 1,000 MW
Wind	2030	8 Projects, 1,600 MW	20 Projects, 4,000 MW
Wind + Storage	2030	6 Projects, 1,200 + 600 MW	10 Projects, 2,000 + 1,000 MW
Hydro	2032	4 Projects, 116 MW	4 Projects, 116 MW
Storage			
4-hour 50 MW Storage	2028	10 Projects, 500 MW	20 Projects, 1,000 MW
4-hour 100 MW Storage	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
8-hour 100 MW Storage	2028	6 Projects, 600 MW	10 Projects, 1,000 MW
Nuclear			
Nuclear	2035	2 Projects, 200 MW	2 Projects, 200 MW

3.9.2. MISO Direct Loss of Load Modeling

Beginning with the 2028/2029 Planning Year, MISO is transitioning its capacity accreditation methodology from the SAC construct to the DLOL framework. The DLOL approach represents a significant evolution in how MISO measures resource adequacy, shifting from fixed, technology-specific capacity factors to a probabilistic model based on each resource's performance during periods of highest reliability risk. Under this construct, accreditation is determined by a resource's contribution to avoiding loss-of-load events rather than its average seasonal availability.

[32] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

3.9.2.1. Data Sources and Modeling Approach

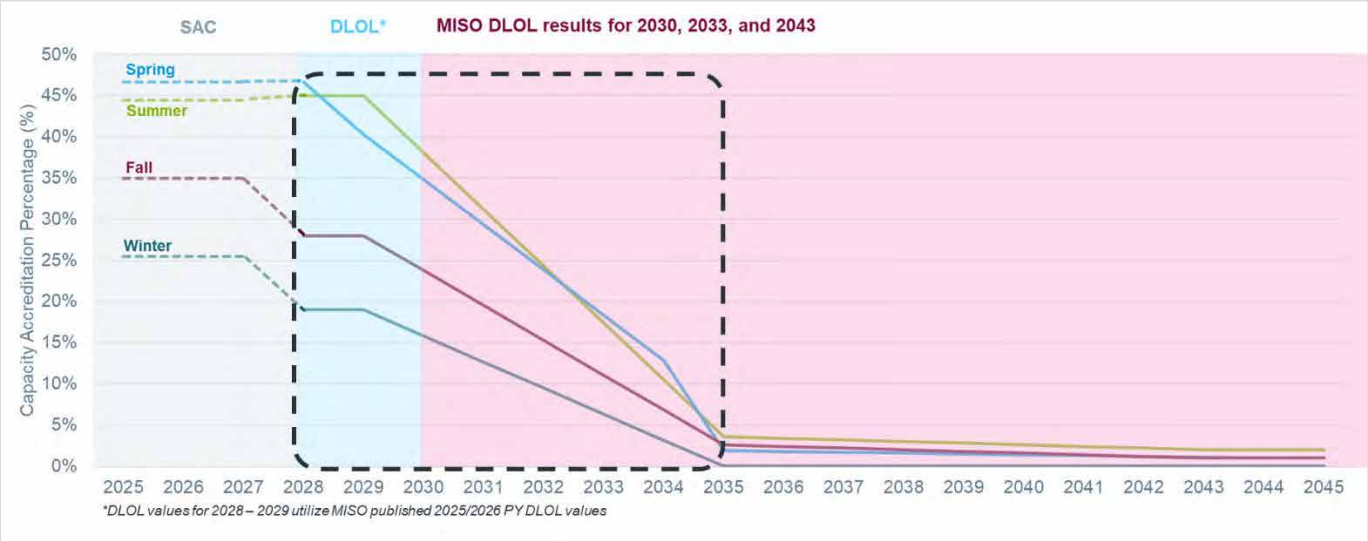
CEI South incorporated MISO's updated DLOL methodology into its 2025 IRP modeling to ensure consistency with the evolving regional framework. The most current publicly available MISO sources were used to obtain capacity accreditation values for each technology type. SAC accreditation percentages for wind and solar were taken from MISO's 2025/2026 Planning Year ("PY") Loss of Load Expectation ("LOLE") Report[33], while accreditation for all other technologies was sourced from MISO's 2023/2024 PY Effective Load Carrying Capability ("ELCC") data[34]. SAC values were applied through Summer 2027, after which DLOL implementation is expected to begin in Summer 2028. MISO's 2025/2026 PY Indicative DLOL Results[35] were used from 2028 through 2030. DLOL values for 2030, 2033, and 2043 were obtained from MISO's Regional Resource Assessment ("RRA") Technical Appendix[36], with interpolation used to determine values for intermediate years, and post-2043 values held constant through 2045.

3.9.2.2. Transition from SAC to DLOL

To ensure a consistent and realistic transition from SAC to DLOL accreditation, CEI South applied a smoothing process to the DLOL values across all resource types. Initial DLOL results from MISO indicated steep accreditation declines during the early implementation years. Following stakeholder feedback regarding this shift, CEI South introduced a moderated adjustment between 2028 and 2035. Figure 3-42 shows the change to the solar capacity accreditation. This smoothing approach preserves the overall downward trend observed in MISO's published data while providing a more stable near-term trajectory for planning and cost modeling purposes.

[33] Planning Year 2025 – 2026 Loss of Load Expectation Study Report. MISO. https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401. March 2025. Page 21.
[34] Market Redefinition: Accreditation Reform. MISO. https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf. February 28, 2024. Page 33.
[35] Planning Year 2025 – 2026 Indicative Direct Loss of Load (DLOL) Results. MISO. https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf. April 2025. Page 3.
[36] Technical Appendix: 2024 Regional Resource Assessment Assumptions and Methodology. MISO. https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf. November 2024. Page 11. Accreditation values between 2028 and 2035 were adjusted for the smoothing process; the 2030 values were not utilized, and the 2033 values were incorporated in 2035.

Figure 3-42 – Example of Smoothed Transition from SAC to DLOL for Solar Resources





Portfolio Development and Evaluation

Chapter 4

4.1. Portfolio Development

CEI South developed a wide range of portfolios for scenario modeling in the dispatch module of EnCompass and ultimately for the probabilistic modeling portion of this IRP process. In collaboration with external stakeholders and informed by feedback provided in the IURC Director's Report on the 2022/2023 IRP, CEI South developed 12 portfolios for final evaluation. These included a status quo case, where F.B. Culley 3 continues to run on coal throughout the study period for benchmarking purposes, scenario-based portfolios optimized under varying market conditions, portfolios focused on existing resource decisions, diversified portfolios with a balanced mix of generation technologies, and renewables-focused portfolios incorporating stakeholder input. Each portfolio was designed with the flexibility to include near-term solar, wind, and battery storage resources identified through the All-Source RFP. Mid- and long-term resource options were drawn from both the 2024 All Source RFP and a comprehensive technology assessment performed by 1898 & Co., which provided cost and performance data for technologies not represented in the 2024 All Source RFP. Values trended forward using available NREL cost curves. All portfolios were designed to include energy efficiency and demand response programs. DSM programs were selected for cost-effectiveness during the first stage of deterministic runs; runs that were selected 95% of the time were then included in all portfolios. All near-term programs included in the previously approved 2025-2027 plan were included in the model.

4.1.1. Optimization Runs

4.1.1.1. Deterministic Portfolio Results

Deterministic modeling was conducted to evaluate individual conversion options at existing CEI South generation sites. In each case, the model was directed to include a specific conversion configuration and optimize a portfolio surrounding that decision. This approach allowed CEI South to compare the cost, performance, and operational outcomes of each option under Reference Case conditions, establishing baseline expectations for cost, capacity, and operational performance across all conversion and retirement pathways.

Several consistent trends emerged from these model runs. In more than half of the simulations, the model selected the conversion of the existing A.B. Brown 5 and 6 combustion turbines to a 2x1 Combined Cycle, indicating the capacity and energy need, as well as the high firm capacity value associated with the thermal units. At the F.B. Culley 3 site, the model generally favored retirement of the unit, although this outcome is heavily influenced by the path selected at the A.B. Brown site.

4.1.1.1.1. F.B. Culley 2 Replacement

In anticipation of the suspension of F.B. Culley 2 at the end of 2025, CEI South evaluated four potential replacement options for this unit: installing natural gas aeroderivative or reciprocating engines, building a lithium-ion storage facility, or allowing the interconnection rights to expire. Each option was modeled individually under Reference Case assumptions to assess relative cost and system performance. The results of these model optimization runs are summarized below in Figure 4-1.

The deterministic analysis showed that allowing the interconnection rights to expire resulted in the lowest-cost outcome, within approximately one percent of the cost of constructing a lithium-ion storage facility. Due to the similar portfolio cost of each pathway, the decision for future pathways at F.B. Culley 2 remained unconstrained in subsequent model runs and portfolio development, with the exception of portfolio 12, the delayed reference case.

Figure 4-1 – F.B. Culley 2 Deterministic Model Results

Year	F.B. Culley 2 Aeroderivative	F.B. Culley 2 No Interconnect Re-Use	F.B. Culley 2 Reciprocating Engines	F.B. Culley 2 Storage
2028	+1 FBC2 Aero (86 MW)	1 FBC2 Do Nothing	+1FBC2 Recip Engines (110 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031				
2032	-1 FB Culley:3 Retire 2032 (-270 MW) +1 50 MW 4 Hour Storage (50 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033		+1 100 MW 4 Hour Storage (100 MW)		+1 50 MW 4 Hour Storage (50 MW)
2034				
2035				
2038				
2039				
2040				
2041	+1 Non IRA Solar PV (100 MW)		+1 50 MW 4 Hour Storage (50 MW)	
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)		
2043				+1 50 MW 4 Hour Storage (50 MW)
2044				
2045	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	
% Delta to Min NPV	**8.1%**	**0.0%**	**5.3%**	**1.0%**

4.1.1.1.2. Demand Side Management Deterministic Runs

Deterministic model runs conducted for conversion decisions at existing sites, together with the reference case and scenario-based runs, were used to evaluate the selection frequency of Energy Efficiency and Demand Response programs. In total, 15 runs were analyzed to identify which DSM programs were most consistently selected by the model. The Near-term ("NT") programs shown in Figure 4-2, which cover the years 2025 through 2027, were part of the previously approved plan and were included as fixed programs in this analysis. In addition, other programs, such as the Demand Response Aggregator program ("DR

Industrial") approved in Cause No. 45990, were also fixed programs consistent with the approved plan.

Figure 4-2 summarizes how frequently each program was selected across the DSM Deterministic runs. Programs that were selected more than 95% of the time were deemed consistently cost-effective and subsequently treated as a fixed resource in all future portfolio optimizations. The remaining programs were allowed to be selected, but not fixed, in each portfolio.

Figure 4-2 – Demand Side Management Deterministic Results

Program Name	Fixed or Selectable	Selection Frequency	Selection Percent
DR Industrial (DR Aggregation Program)	**Fixed**	**19/19**	**100%**
DR_CI Battery	Selectable	0/19	0%
DR_CI BYOT	**Selectable**	**19/19**	**100%**
DR_CI EV	Selectable	0/19	0%
DR_CI TOU CPP	Selectable	18/19	94%
DR_CI WH Grid	Selectable	9/19	47%
DR_Res AC Switch	**Fixed**	**19/19**	**100%**
DR_Res AC Switch_NT	**Fixed**	**19/19**	**100%**
DR_Res Battery	Selectable	1/19	5%
DR_Res BYOT	Selectable	4/19	21%
DR_Res BYOT_NT	**Fixed**	**19/19**	**100%**
DR_Res EV	Selectable	1/19	5%
DR_Res Smart Cycle	Selectable	1/19	5%
DR_Res Smart Cycle_NT	**Fixed**	**19/19**	**100%**
DR_Res TOU CPP	**Selectable**	**19/19**	**100%**
DR_Res WH Grid	Selectable	1/19	5%
DR_Res WH Switch	**Fixed**	**19/19**	**100%**
DR_Res WH Switch_NT	**Fixed**	**19/19**	**100%**
EE_CI_ERAP_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_IQ HEAR_NT, V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_IQW_V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_Res_HER_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier 1_HER_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_Res_Tier1_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier2_V1, V2, V3	Selectable	2/19 - 3/19	11-16%

A supplemental sensitivity analysis was also conducted to assess the impact of a shorter program horizon for Demand Response programs. This case evaluated only the first six

years of cost and production, relative to the 18-year study period used in the deterministic runs. No additional DR programs were selected when evaluated based on the first 6 years.

4.1.1.1.3. Distributed Generation Resource Portfolios

CEI South also evaluated a potential distributed generation solar incentive program intended to encourage customers to install behind-the-meter solar resources, thereby reducing system energy requirements. CEI South worked with Itron to update its solar payback model to include a $500 per kW incentive, to increase the adoption rate of behind-the-meter solar. Based on a solar PV adoption forecast developed by Itron, the program was estimated to reduce system load by a cumulative 137 MW (non-coincident) by 2045 and increase the net present value of portfolio revenue requirements by approximately $34.6 million.

When the IRP EnCompass model performed an optimized capacity expansion simulation under Reference Case conditions with this reduced load, the resulting portfolio was nearly identical to the Reference Case. The only difference was a one-year delay in the addition of storage resources, from 2039 to 2040 and from 2042 to 2043. This result indicates that while the incentive program would reduce energy requirements, long-term planning needs remain primarily driven by capacity. Furthermore, cost savings from reduced operational costs to serve the reduced load were insufficient to offset the cost of the incentive program, as the all-in cost of the optimized distributed generation portfolio was approximately $10 million higher than the Reference Case portfolio. Therefore, a distributed generation portfolio was excluded from the risk analysis.

4.1.1.2. Scenario-Based Portfolios

Scenario-Based portfolios (Reference Case, Low Regulatory, High Regulatory, Alternate High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions, and levels of electricity demand. The scenario-based portfolios move from Low to High Regulatory, with increasing levels of regulation and higher or lower economic drivers. While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to produce and test portfolios in plausible future states that differ from the reference case.

Following stakeholder feedback, the exact model outputs from these scenario optimization runs were used to produce scenario-driven portfolios. Note that these portfolios are developed under varying load conditions (as per the scenario definitions) but are then simulated using the same load inputs as all other portfolios during the risk analysis. These scenario-based portfolios are shown in Figure 4-3.

Figure 4-3 – Scenario Optimization Model Outputs

Year	Optimized Reference Case *(Portfolio 1)*	Optimized Low Reg *(Portfolio 8)*	Optimized High Reg *(Portfolio 9)*	Optimized Alt High Reg *(Portfolio 10)*
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)			
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)		
2040	+1 50 MW 4 Hour Storage (50 MW)			
2042		+1 50 MW 4 Hour Storage (50 MW)		
2043	+1 50 MW 4 Hour Storage (50 MW)			
2045		+1 Non IRA Solar PV + Storage (100 + 50 MW)		

4.1.2. Final Portfolios for Risk Analysis

With these early modeling results in mind, additional portfolios and iterations were developed based on 1) stakeholder feedback, 2) lessons learned from preliminary portfolio optimization results, and 3) examining tradeoffs in different existing resource decision timing. Once all twelve of these diverse portfolios were created, they were run through the EnCompass model to be considered in the Risk Analysis portion of this IRP.

Figure 4-4 summarizes the resource buildouts for the portfolios selected for inclusion in the risk analysis[37].

[37] Portfolio 12 (Delayed Reference Case) was updated from the fourth stakeholder meeting held on 10/23/2025. In that meeting, the 50 MW 4-hour storage resource was presented to come online in 2042; the table entry was corrected to 2040. The slide deck on the CenterPoint IRP website (Integrated Resource Plan (IRP)) reflects this update.

Figure 4-4 – Final Risk Analysis Portfolios

Year	Portfolio1_Reference Case Portfolio	Portfolio2_Convert FBC3 to NG by 2035	Portfolio3_FBC3 on Coal without ABB7	Portfolio4_FBC3 on Coal to SMR	Portfolio5_FBC3 to Simple Cycle Gas Turbine	Portfolio6_Renewable Heavy Portfolio
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	1 ABB5/6 Continue
2032	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 100 MW 4 Hour Storage (100 MW)			-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)		+2 100 MW 4 Hour Storage (200 MW)		+1 100 MW 4 Hour Storage (100 MW)	+2 100 MW 4 Hour Storage (200 MW)
2034						
2035		+1 FB Culley:3 NG 2035 (270 MW)		-1 FB Culley:3 Retire 2035 (-270 MW) +1 Nuclear - SMR (100 MW)	-1 FB Culley:3 Retire 2035 (-270 MW) +1 J Class SCGT (385 MW)	
2038						
2039						
2040	+1 50 MW 4 Hour Storage (50 MW)					
2041					+1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind (200 MW)
2042			+1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW)		+1 Non IRA Wind + Storage (200 + 100 MW)
2043	+1 50 MW 4 Hour Storage (50 MW)					
2044						
2045			+1 FB Culley:3 thru 2045 (270 MW) +2 Non IRA Solar PV (200 MW) +1 Non IRA Wind (200 MW)		+1 Non IRA Wind (200 MW)	

Year	Portfolio7_FBC3 Gas Conversion with Renewables	Portfolio8_Low Reg Approach	Portfolio9_High Reg Approach	Portfolio10_Alt High Reg Approach	Portfolio11_FBC3 Co-Fire 2030	Portfolio12_Delayed Reference Case
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2030	+1 FB Culley:3 NG 2030 (270 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)	+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	
2032		-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)		
2033	+2 100 MW 4 Hour Storage (200 MW) +1 50 MW 4 Hour Storage (50 MW)					
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)		+1 AB Brown7: Fired CCGT 2034 (850 MW)
2035						-1 FB Culley:3 Retire 2035 (-270 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)			-1 FB Culley:3 Retire (270 MW)	
2039					+2 50 MW 4 Hour Storage (100 MW)	
2040	+1 Non IRA Wind (200 MW)				+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)
2041						
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)				
2043						
2044					+1 50 MW 4 Hour Storage (50 MW)	
2045	+1 100 MW 4 Hour Storage (100 MW) +2 Non IRA Wind (400 MW)	+1 Non IRA Solar PV + Storage (100 + 50 MW)				+1 50 MW 4 Hour Storage (50 MW)

Moreover, Figure 4-5 explicitly states the motivation behind the development of these twelve portfolios. The first group includes the portfolios informed by the deterministic optimization results and explores various existing unit decisions. The second group, as mentioned in Section 4.1.1.2, is the scenario-based portfolios. The final group reflects portfolios shaped by stakeholder input. These portfolios include the two portfolios with an increased renewable penetration in CEI South's resources mix as well as a portfolio with a Small Modular Reactor as a potential resource option.

Figure 4-5 – Description of Portfolio Motivations

Portfolio Name	Motivation
2-Convert FB Culley 3 to NG by 2035	Deterministic Portfolios (economically optimized model given fixed existing site decisions and potential replacement options for F.B. Culley 3)
3-Continue FB Culley 3 on Coal through 2045	
5-FB Culley 3 to Simple Cycle Gas Turbine	
11-FB Culley 3 Co-Fire	
12-Delayed Reference Case	
1-Reference Case Portfolio	Scenario-Based Portfolios (economically optimized model for each scenario)
8-Low Regulatory Approach	
9-High Regulatory Approach	
10-Alternate High Regulatory Approach	
4-FB Culley 3 to Small Modular Reactor	Stakeholder Input Portfolios
6-Renewable Heavy	
7-FB Culley 3 Gas Conversion with Renewables	

4.2. Evaluation Of Portfolio Performance

Each of the risk analysis candidate portfolios were subjected to two different forms of risk modeling. One was scenario-based (deterministic), and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard. The inputs into the EnCompass model that were used to generate the following results are given in the *Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)*.

4.2.1. Scenario Risk Analysis (Simulated Dispatch in Each Scenario)

The IRP requires scenario-based modeling be performed as a part of the risk analysis. In the scenario-based risk analysis, the twelve candidate portfolios selected for further analysis were modeled under each of the four core scenarios with their respective market inputs. The following provides a summary of the results of this scenario-based risk analysis. The results shown in Figure 4-6 and Figure 4-7 are NPVRR and the cumulative carbon-dioxide emissions of each portfolio under each scenario. In the alternative high regulatory and high regulatory scenarios, capacity factor limitations associated with the CAA 111(b) and (d) legislation tend to increase the operating costs of portfolios while also limiting the portfolio emissions. The Preferred Portfolio performs fairly consistently across all four scenarios, avoiding extreme outcomes while allowing time for re-evaluation in a future IRP before the F.B. Culley 3 decision must be finalized.

Figure 4-6 – Portfolio NPVRR (Million $)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	$3,455	$4,613	$4,093	$3,458
2-FBC3 NG 2035	$3,430	$4,338	$4,119	$3,338
3-FBC3 on Coal	$3,959	$4,639	$4,435	$4,211
4-FBC3 to SMR	$4,126	$5,164	$4,464	$4,433
5-FBC3 to SCGT	$4,145	$5,009	$4,620	$4,128
6-Renewable Heavy	$4,144	$5,417	$4,315	$4,536
7-FBC3 NG with Renewables	$4,174	$5,336	$4,604	$4,193
8-Low Reg	$3,497	$4,572	$4,047	$3,431
9-High Reg	$4,247	$4,185	$2,970	$4,721
10-Alt High Reg	$3,960	$4,057	$3,294	$4,389
11-FBC3 Co-Fire	$3,556	$4,557	$4,181	$3,485
12-Delayed Reference	$3,625	$4,572	$4,175	$3,572

Figure 4-7 – Portfolio Total CO_2 Emissions Over Study Period (Million Tons)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	61	46	39	63
2-FBC3 NG 2035	69	55	46	72
3-FBC3 on Coal	69	78	57	70
4-FBC3 to SMR	66	53	44	66
5-FBC3 to SCGT	51	61	46	58
6-Renewable Heavy	35	44	34	39
7-FBC3 NG with Renewables	42	49	36	50
8-Low Reg	61	46	39	63
9-High Reg	34	43	32	38
10-Alt High Reg	51	44	37	53
11-FBC3 Co-Fire	68	50	43	69
12-Delayed Reference	62	52	43	65

4.2.2. Probabilistic Risk Analysis (Simulated Dispatch 200 Runs Scorecard)

After selecting the twelve portfolios for further consideration and completion of the scenario-based risk assessment, the remaining steps are to conduct the 200 iteration stochastic risk assessment, complete the balanced scorecard, and consider "other" relevant factors to select the Preferred Portfolio.

A comprehensive risk analysis using 200 iterations provides a more thorough understanding of how the different portfolios perform under a range of scenarios. As with any analysis, the risk assessment and subsequent balanced scorecard do not provide CEI South with an answer but instead offer insights into tradeoffs associated with the portfolios across a range of possible future conditions. Among other things, the results of this evaluation help CEI South get a clearer picture of the balance between total portfolio cost, the cost uncertainty (measured by the 5^{th} and 95^{th} percentile of cost outcomes over the planning horizon), the carbon equivalent profile, the percentage dependence on energy and capacity purchases and sales, and the stability, reliability, and resilience of the portfolios based on the probabilistic range of potential outcomes.

A color-coded comparison (shaded automatically by the Microsoft Excel spreadsheet) of the balanced scorecard is shown below in Figure 4-8[38]. The color coding represents the relative ranking among the portfolios. Green generally indicates scoring well relative to other portfolios within the same metric, and red generally indicates scoring poorly relative to other portfolios within the same metric. The color scheme is purely for illustrative purposes to show where differences between the best-performing portfolio and the worst-performing portfolio for that metric. Since the color coding is purely relative to the other portfolios, red does not necessarily mean that a portfolio performed poorly on that metric, but relatively worse than other portfolios. For more information on this analysis, please see the final stakeholder presentation in *Technical Appendix Attachment 4.2 Stakeholder Materials*.

[38] The Capacity Purchases NPV ($M) shown in the scorecard and presented during the fourth stakeholder meeting held on 10/23/2025 have been updated and posted to the CenterPoint IRP website.

Figure 4-8 – IRP Portfolio Balanced Scorecard Color-Coded Comparison

Objective	Affordability					Environmental Sustainability				Reliability/Resiliency/Stability					Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	Incremental Energy Burden (%) 2030 - 2035	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (1000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Transmission Reliability Analysis MVAR	Transmission Reliability Analysis SCR	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
2-FBC3 NG 2035	$3,718	0%	$2,941	$4,464	0.13% - 0.22%	0.368	48,696	18,017	13,091	119	1,031	253	753	3.5	26%	9%	$217	$6
1-Reference Case	$3,726	0%	$2,963	$4,439	0.11% - 0.25%	0.346	44,302	12,877	10,650	61	842	340	665	3.5	26%	10%	$140	$14
8-Low Reg	$3,764	1%	$2,983	$4,475	0.15% - 0.20%	0.345	44,199	12,908	10,582	49	842	366	665	3.5	26%	10%	$167	$6
12-Delayed Reference	$3,836	3%	$3,195	$4,467	0.16% - 0.26%	0.391	46,535	21,885	14,539	56	701	444	665	3.5	23%	12%	$115	$18
11-FBC3 Co-Fire	$3,854	3%	$3,064	$4,587	0.18% - 0.17%	0.354	46,317	14,397	11,812	61	937	308	753	3.5	26%	10%	$192	$12
3-FBC3 on Coal	$4,034	8%	$3,511	$4,630	0.03% - 0.29%	0.522	53,636	51,793	25,931	43	302	835	626	3.5	15%	19%	$117	$22
10-Alt High Reg	$4,211	13%	$3,444	$4,829	0.17% - 0.48%	0.280	34,415	14,226	10,985	29	660	486	665	3.5	25%	9%	$159	$19
9-High Reg	$4,297	15%	$3,543	$4,926	0.43% - 0.44%	0.234	25,913	13,701	12,322	15	113	935	605	3.5	20%	14%	$128	$23
5-FBC3 to SCGT	$4,306	16%	$3,857	$4,770	0.14% - 0.59%	0.408	41,016	22,763	16,698	73	154	955	665	3.5	14%	21%	$93	$26
6-Renewable Heavy	$4,309	16%	$3,756	$4,723	0.10% - 0.62%	0.329	28,966	14,385	14,597	38	113	985	605	3.5	11%	30%	$95	$22
7-FBC3 NG with Renewables	$4,375	17%	$3,912	$4,771	0.26% - 0.49%	0.357	34,642	8,289	18,780	76	302	802	626	3.5	14%	23%	$106	$24
4-FBC3 to SMR	$4,456	20%	$3,674	$5,185	0.15% - 0.76%	0.342	45,224	18,653	11,950	52	938	273	665	3.5	26%	9%	$171	$13

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Increase in residential bill impact since 2026 as a percentage of median Vanderburg county resident forecasted annual income in 2030 and 2035
6: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
7-9: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
10: Total emergency unserved energy purchased from 2026 to 2045
11: Capacity from “spinning” thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
12: Capacity from “fast start” assets that can be dispatched quickly (combustion turbine, battery)
13-14: Dynamic VAR support and short circuit ratio from transmission reliability analysis
15: Total energy sales as a percentage of total energy generation from 2026 to 2045
16: Total energy purchases as a percentage of total load from 2026 to 2045
17-18: Net present value of capacity sales and purchases from 2026 to 2045

4.3. Results By Portfolio

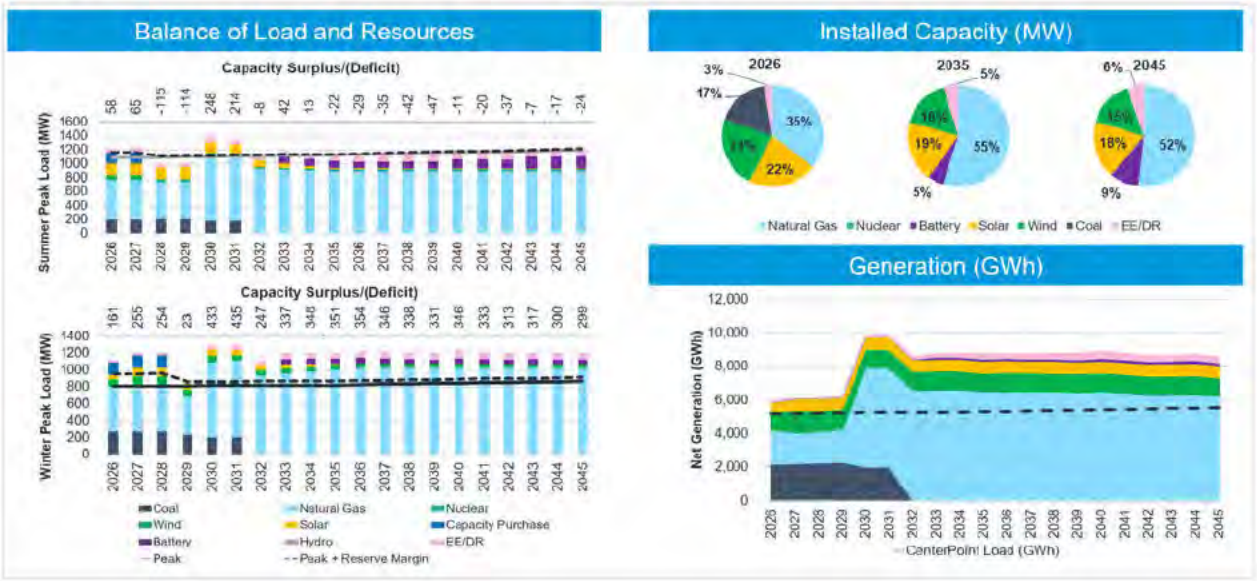
4.3.1. Reference Case Portfolio

The Reference Case portfolio represents the capacity expansion results from the Reference Case scenario. While this portfolio is the least cost in the capacity expansion (reference case) run, the portfolio becomes the second-lowest cost during the Risk Analysis (200 runs) portion of the analysis, as previously seen in Section 4.2.2. This portfolio allows for the expiration of interconnect rights at F.B. Culley 2 ("FBC2 Do Nothing"), conversion of the A.B. Brown 5 and 6 combustion turbines into a 2x1 Duct-Fired Combined Cycle ("A.B. Brown 7"), and retires CEI South's last remaining coal unit that it operates, F.B. Culley 3, at the end of 2031. In addition, the model builds a cumulative 200 MW of 4-hour battery energy storage resources beginning in 2033 through the end of the study period. The selection of batteries in the model is indicative of the need for long-term capacity on CEI South's system, especially following the implementation of MISO's DLOL methodology, which reduces the accreditation of intermittent resources.

The retirement of F.B. Culley 3 and the conversion of A.B. Brown 5 and 6 result in a highly efficient and relatively environmentally friendly portfolio, achieving among the lowest NO_x emissions compared to other portfolios. However, the early investment in A.B. Brown's conversion also necessitates a near-term rate increase, and the trend of increased demand for HRSGs and turbines creates a near-term price risk. The early A.B. Brown conversion and loss of the F.B. Culley 2 and F.B. Culley 3 interconnections also make the portfolio relatively inflexible, as it is less adaptable to changes in regulations, market conditions, and fuel costs.

The results dashboard for the reference case, shown in Figure 4-9, displays the Balance of Load and Resources on the left-hand side. This figure shows the need for capacity in the near-term, which makes the A.B. Brown conversion favorable, as it adds about 400 MW of firm capacity to the system. The installed capacity pie charts on the top right of the figure display the diverse mix of renewable, thermal, and demand-side resources included in the reference case. For all portfolio dashboards, the 32 MW of coal generation from Kyger Creek Generating Station, owned by the Ohio Valley Electric Corporation ("OVEC") and purchased by CenterPoint, is assumed to convert to natural gas in 2030. Finally, in the bottom left, it is observed that for the two years that A.B. Brown 7 and F.B. Culley 3 are online, CEI South's system produces significant excess energy, which it can sell to the MISO market and lower portfolio costs, ultimately benefiting CenterPoint customers but also introduces revenue risk if market conditions change.

Figure 4-9 - Reference Case Portfolio Results Dashboard



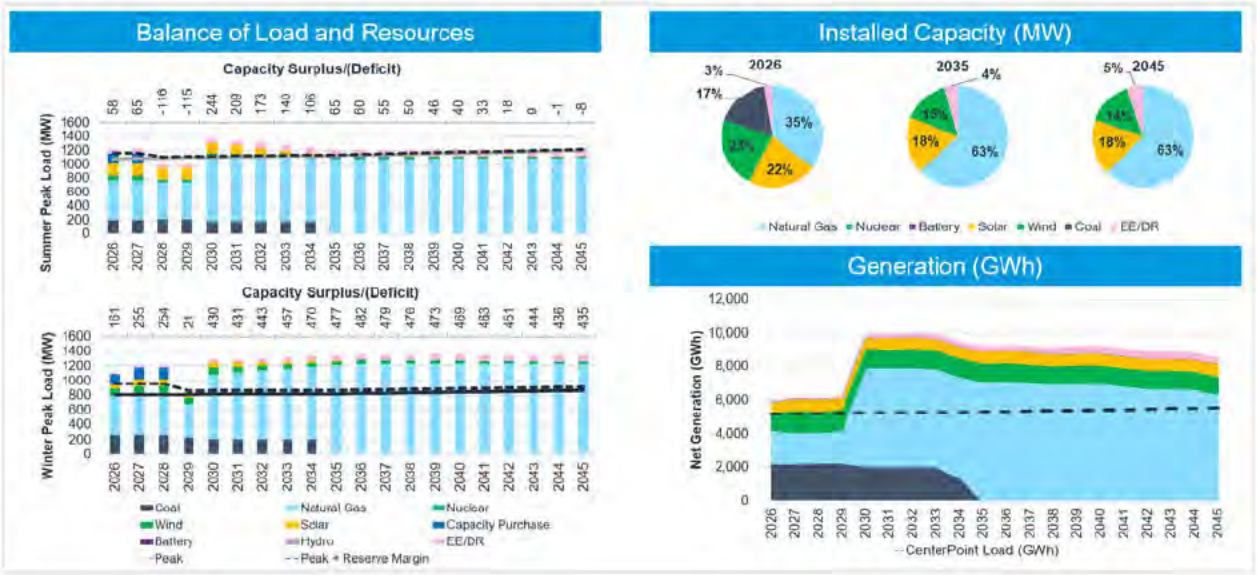
4.3.2. Convert F.B. Culley 3 to Natural Gas by 2035

This portfolio was designed to include the conversion of F.B. Culley 3 from a baseload coal-fired plant to a natural gas peaking plant beginning in 2035 and continuing through the end of the study period. This conversion preserves and repurposes much of the existing site infrastructure while maintaining valuable firm capacity on CEI South's system and lowering CO_2 emission rates. While the model was optimized around the conversion of F.B. Culley 3 to natural gas and the conversion of A.B. Brown 5 and 6 to A.B. Brown 7, no additional resources were necessary to meet all energy and capacity needs.

As seen in Figure 4-10, the inclusion of F.B. Culley 3 and A.B. Brown 7 results in CEI South being long on both capacity and energy, which can be sold to the MISO market to reduce the NPVRR and provide opportunities for economic development. While this portfolio has the lowest NPVRR across 200 draws of varying market conditions, it also relies on the highest levels of both energy and capacity sales, creating a revenue risk if market conditions differ. Moreover, the conversion of A.B. Brown in 2030 necessitates a potential near-term rate increase and introduces price risk from the increased demand for HRSGs and turbines, which could challenge the overall affordability of this portfolio. With natural gas resources comprising over 60% of total installed capacity, this portfolio is sensitive to changing regulations and volatility in fuel costs. Moreover, during the Risk Analysis, this portfolio showed the greatest amount of unserved energy along with the lowest amount of

fast start resources, suggesting potential challenges for the reliability and resiliency of the system, absent potential mitigations.

Figure 4-10 – Convert F.B. Culley to Natural Gas by 2035 Results Dashboard



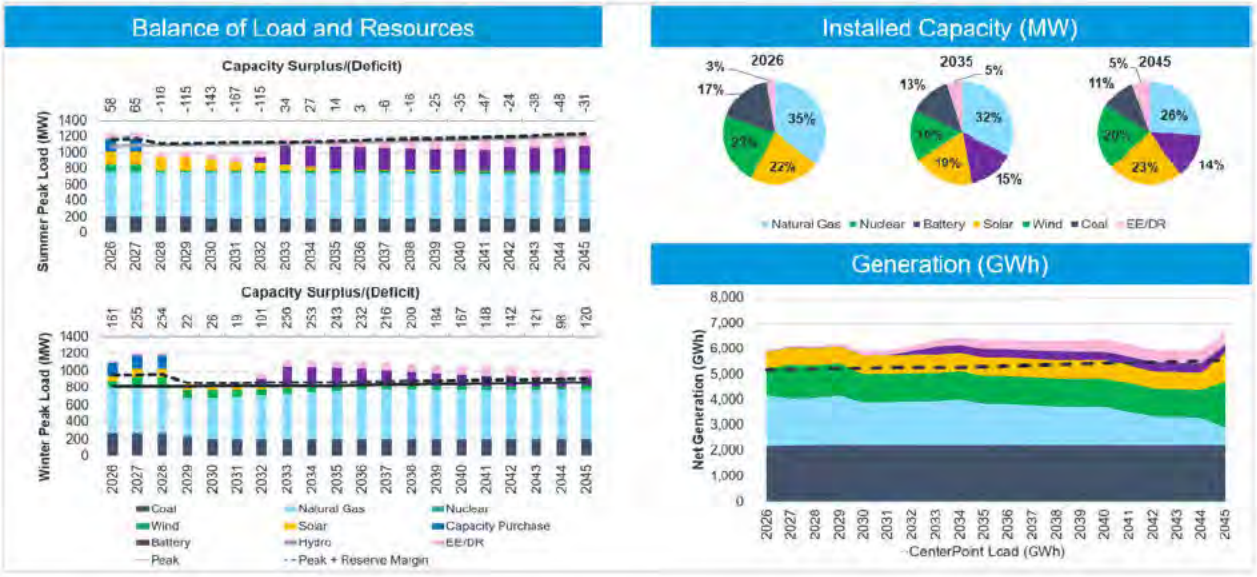
4.3.3. Continue F.B. Culley 3 on Coal through 2045

The F.B. Culley 3 on Coal portfolio serves as a Business As Usual ("BAU") case as it assumes no conversion of existing units and allows for the expiration of the interconnection rights at F.B. Culley 2. Without the conversion of the existing A.B. Brown units, the model chooses to build a cumulative 350 MW of storage facilities to maintain resource adequacy requirements. Moreover, in the final year of the planning horizon, additional solar and wind units are built to address energy needs. As shown in Figure 4-11 this portfolio relies on a significant amount of near-term capacity purchases until the additional storage resources are built.

The continuation of F.B. Culley 3 and the A.B. Brown CTs through the rest of the study period minimizes the need for near-term capital investment, which provides relative rate stability. To conform with environmental regulations included in the reference case, running F.B. Culley 3 on coal throughout the entire study period would require costly efficiency upgrades. Since this portfolio is unique in running F.B. Culley 3 on coal through 2045, the upgrades raise the base year (2026) revenue requirement, making the 2030 incremental energy burden appear lower than other portfolios in the near to midterm. Overall, this portfolio has a moderate NPVRR, approximately 8% greater than the least cost portfolio. As shown in the installed capacity graphs below, this portfolio is well diversified and

therefore less susceptible to cost risk from fuel prices. However, the reliance on inefficient coal generation makes this portfolio environmentally unsustainable, with the highest emissions rates for all considered environmental scoring metrics. These high emissions present a regulatory risk if state and federal objectives change to focus on emissions reduction.

Figure 4-11 – F.B. Culley 3 on Coal through 2045 Results Dashboard



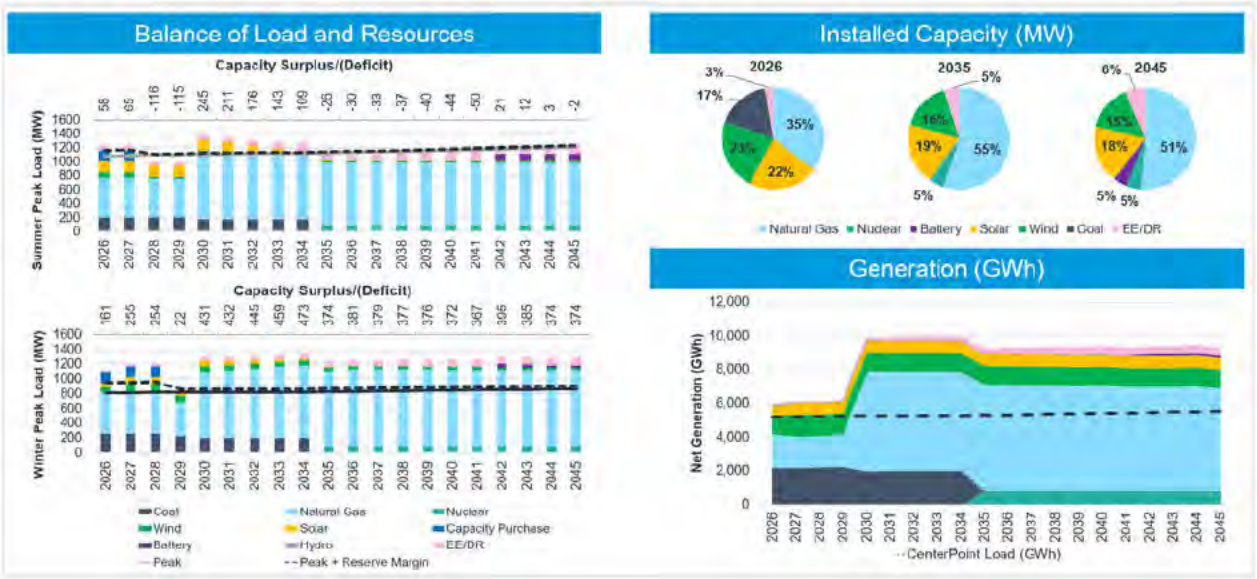
4.3.4. F.B. Culley 3 on Coal to Small Modular Reactor ("SMR")

Including an advanced nuclear portfolio allows CEI South to evaluate a long-term, zero-carbon firm resource that could support reliability as conventional coal resources continue to retire. Therefore, this portfolio retires F.B. Culley 3 at the end of 2034, while assuming that a small modular reactor ("SMR") would be brought online at the beginning of 2035. As shown in Figure 4-12, this portfolio is long on capacity from 2030 through 2034 as both F.B. Culley 3 and the A.B. Brown 7 are online.

This portfolio aligns with state and federal desire for nuclear energy, but the SMRs are also a new and unproven technology, which introduces significant long-term cost risk. The conversion of A.B. Brown 5 and 6 to a CCGT in 2030 would increase costs, making a rate increase necessary in the near-term. Moreover, the inclusion of the SMR in 2035 with CEI South as an off taker makes this portfolio the highest cost portfolio, approximately 20% higher than the least cost portfolio. The temporary capacity surplus from 2030 to 2034 allows the opportunity for significant capacity and energy sales, helping offset a portion of the cost of this advanced nuclear technology. This portfolio is among the highest ranking

in terms of capacity and energy sales, thus representing a significant cost risk with potential for the NPVRR to increase even further if revenues do not materialize.

Figure 4-12 – F.B. Culley 3 on Coal to Small Modular Reactor Results Dashboard



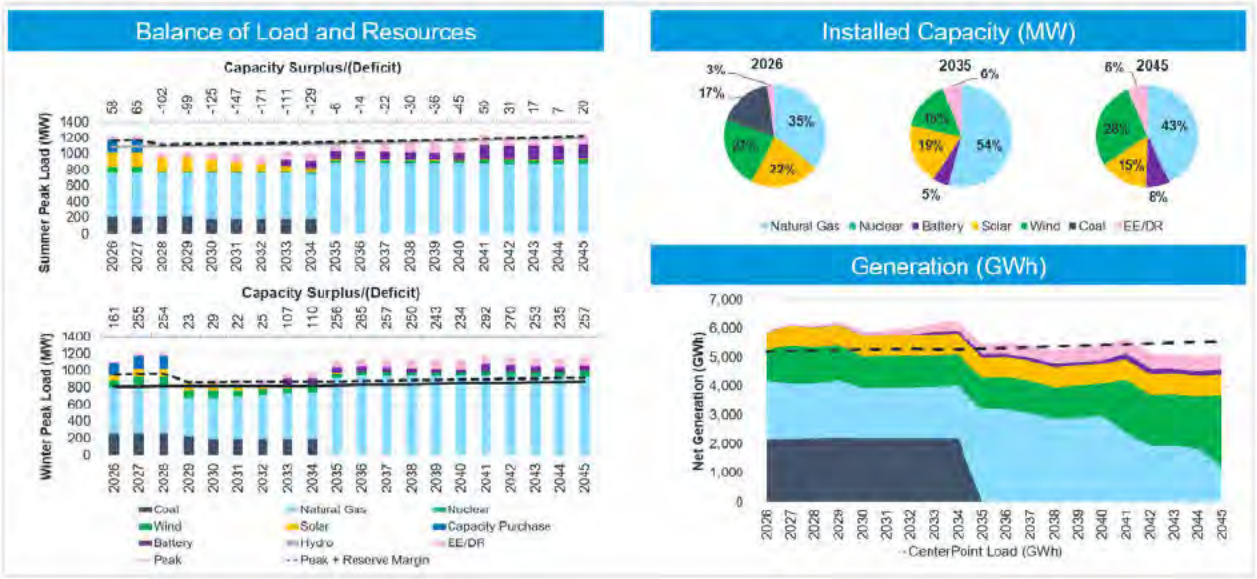
4.3.5. F.B. Culley 3 to Simple Cycle Gas Turbine

This fifth portfolio examines the replacement of CEI South's final coal-fired generating unit that it operates, F.B. Culley 3, with a new 385 MW SCGT. The retirement of F.B. Culley 3 at the end of 2034 is intentionally aligned with the in-service date of the new gas unit, which would begin operation in early 2035. In the absence of converting A.B. Brown 5 and 6 to a combined-cycle configuration (A.B. Brown 7), the portfolio experiences a temporary capacity shortfall that is addressed through the addition of a 100 MW battery storage resource in 2033. Additional wind and battery resources are introduced in the later years of the study to meet growing energy and capacity requirements. Figure 4-13 summarizes the simulated results for this portfolio under Reference Case conditions.

This portfolio maintains flexibility by keeping A.B. Brown 5 and 6 units as combustion turbines and deferring the replacement of F.B. Culley 3 to the beginning of 2035. This reduces risk from changes in regulations and market conditions, reduces the need for near-term investment, and keeps the near-term incremental energy burden low. The addition of storage and wind resources to meet capacity and energy needs over time allows for increased renewable reliance but also increases cost in the long-term, leading to a 20-year NPVRR that is 16% greater than the least-cost portfolio. Because the portfolio is highly reliant on gas combustion turbines, it faces risk associated with gas cost, capacity,

availability of gas, and pipeline regulations that could potentially increase the portfolio's already high long-term cost.

Figure 4-13 – F.B. Culley 3 to Simple Cycle Gas Turbine Results Dashboard



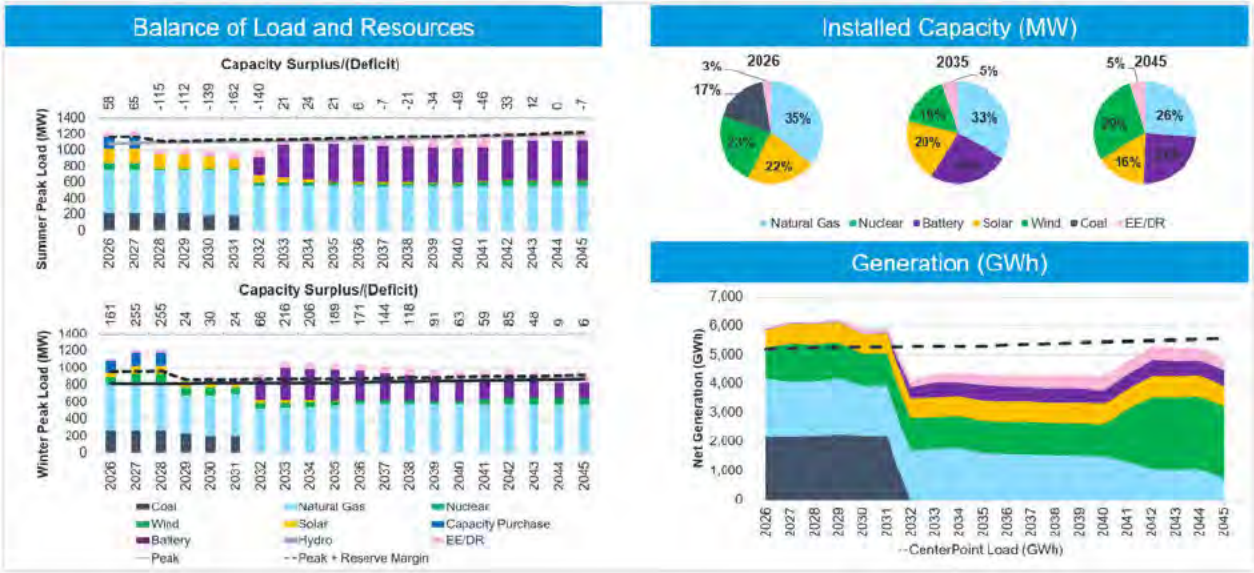
4.3.6. Renewable Heavy Portfolio

This portfolio examines a pathway in which CEI South meets its long-term capacity and energy needs primarily through renewable and storage resources while still maintaining existing thermal gas units. In this portfolio, F.B. Culley 3 retires at the end of 2031, and the model immediately replaces that capacity with 300 MW of 4-hour storage resources in 2032. As the study period continues, the model adds additional storage and wind resources for a cumulative total of 600 MW of storage capacity and 400 MW of wind capacity. The balance of load and resources shown in Figure 4-14 illustrates that this portfolio is generally short on capacity during the summer despite substantial renewable additions. This reflects the declining capacity accreditation of intermittent technologies, which is accelerated under MISO's Direct-Loss-of-Load methodology. The figure also shows that the portfolio is reliant on energy purchases from the retirement of F.B. Culley 3 at the end of 2031 until the end of the planning horizon.

While the rate impact of this portfolio is limited until 2032 due to minimal capital investments and the inclusion of tax incentives before IRA sunset, the long-term cost and cost risk in this portfolio are high. The portfolio is heavily reliant on market capacity purchases in the near-term and energy market purchases in the long-term, a major risk associated with this portfolio. Future uncertainty around MISO's accreditation could result in even greater

capacity deficits. The portfolio is relatively environmentally friendly with low CO_2 emissions, but that comes with execution risk from procuring the amounts of storage and wind needed for this portfolio to function. The loss of interconnections at F.B. Culley 2 and F.B. Culley 3 also make this portfolio inflexible and less able to adapt to regulatory and market conditions.

Figure 4-14 – Renewable Heavy Portfolio Results Dashboard



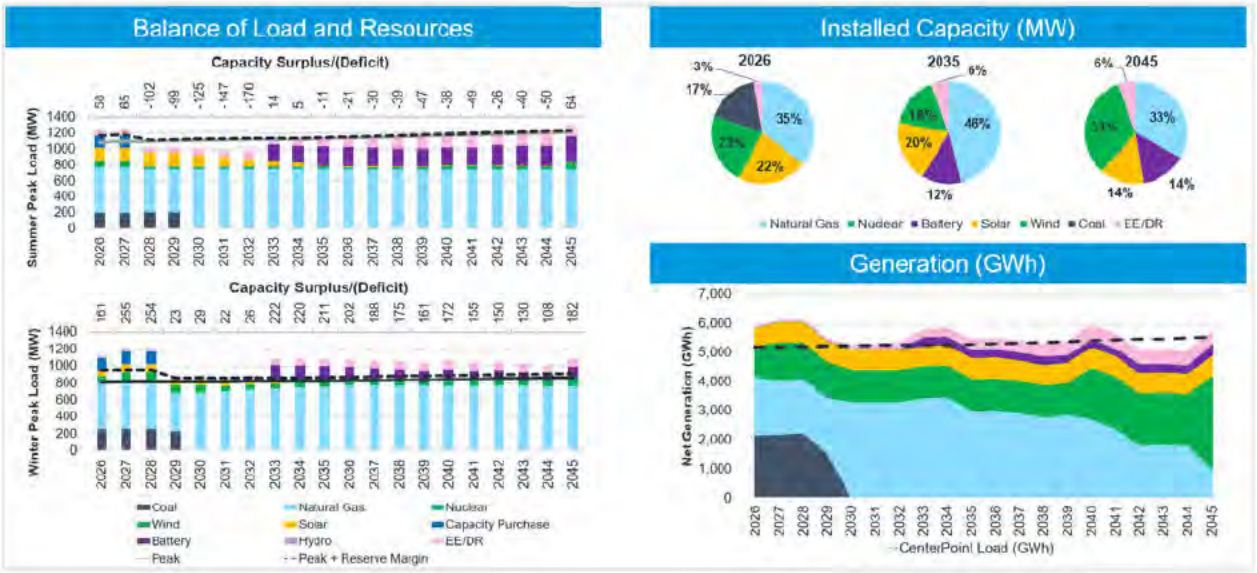
4.3.7. F.B. Culley 3 Gas Conversion with Renewables

This portfolio evaluates the conversion of F.B. Culley 3 from a coal resource to a natural gas-fired unit at the beginning of 2030. This portfolio does not utilize the interconnect at F.B. Culley 2 and does not convert the A.B. Brown 5 and 6 combustion turbines to A.B. Brown 7. Without additional capacity at those existing sites, this portfolio adds firm capacity to the portfolio through additional storage resources in 2033. Similar to previous portfolios, additional wind and storage resources are built in the later years of the study period to meet future energy and capacity needs. As shown in Figure 4-15, as the new resources continue to come online, the generation from F.B. Culley 3 generally declines.

This portfolio has moderate overall emissions released, with the lowest SO_x emissions but the second highest NO_x emissions. Despite the high NO_x emissions, the portfolio is generally well positioned in case environmental regulations change because of its renewable emphasis and the early conversion of F.B. Culley 3. However, the portfolio is among the highest cost portfolios with a high incremental energy burden in both the near and long-term. Additionally, for most years of the planning horizon, this portfolio falls short

on accredited capacity, which exposes CEI South to capacity market price swings and represents a risk as renewable accreditation continues to change.

Figure 4-15 – F.B. Culley 3 Gas Conversion with Renewables Results Dashboard



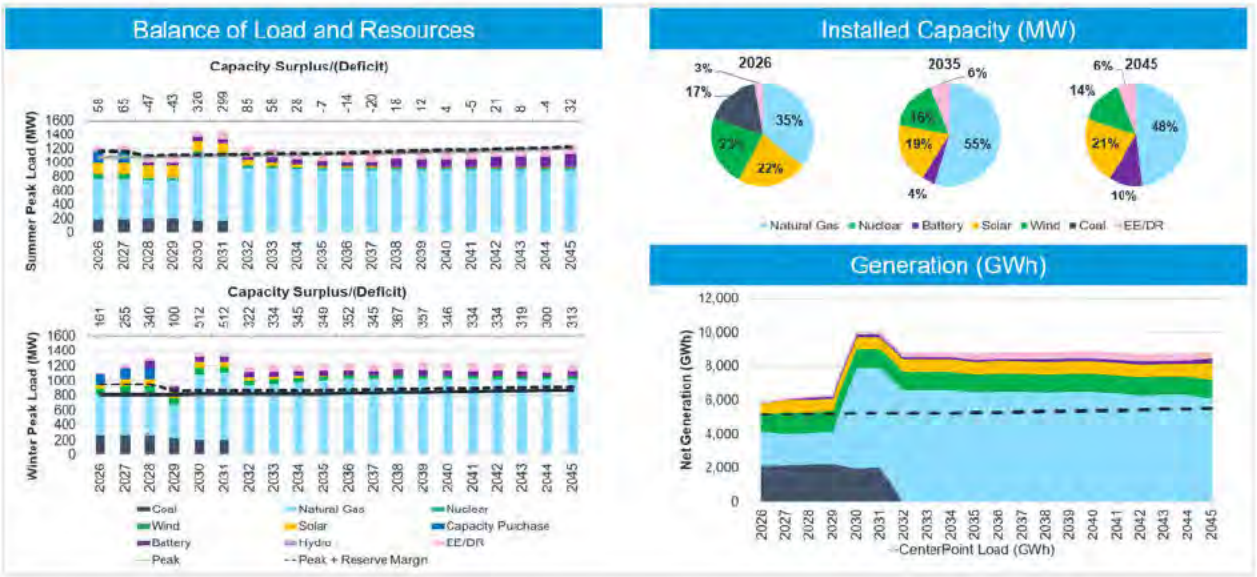
4.3.8. Low Regulatory Portfolio

As mentioned previously, there are three scenario-driven portfolios that are the optimized model results from running the various scenarios. This portfolio represents the optimized outcome under the Low Regulatory scenario, which assumes higher load growth and lower capital costs relative to the Reference Case, driven by reduced regulatory pressure and stronger economic forecasts. Under this scenario, natural gas prices grow modestly while capital cost curves for new construction remain comparatively low.

This portfolio reuses the interconnection at F.B. Culley 2 for a 90 MW battery storage project, which comes online at the beginning of 2028. This portfolio also selects to convert the A.B. Brown 5 and 6 to A.B. Brown 7 in 2030 while retiring F.B. Culley 3 at the end of 2031. Similar to the reference case, additional storage resources are added to the system in 2038 and 2042, indicating the need for long-term capacity on CEI South's system. Finally, in the last year of the study, the model selects a hybrid solar plus storage resource to address the accelerated load growth in this scenario. Pairing the solar resource with storage allows for additional solar produced during the midday hours to be stored and used during peak times. Figure 4-16 displays the results of how the low regulatory portfolio performs under reference case assumptions.

Because it relies heavily on a highly efficient combined cycle gas turbine ("CCGT") at A.B. Brown and reuses the F.B. Culley 2 interconnection for storage, portfolio 8 is relatively inexpensive. Although its NPVRR is only 1% greater than the lowest NPVRR portfolio, the early conversion of A.B. Brown does necessitate a near-term rate increase. The portfolio has among the highest energy sales, which introduces a risk that NPVRR could increase if MISO energy market conditions change. This portfolio has moderate overall emissions, though it has the lowest NO_x emissions rate.

Figure 4-16 – Low Regulatory Portfolio Results Dashboard



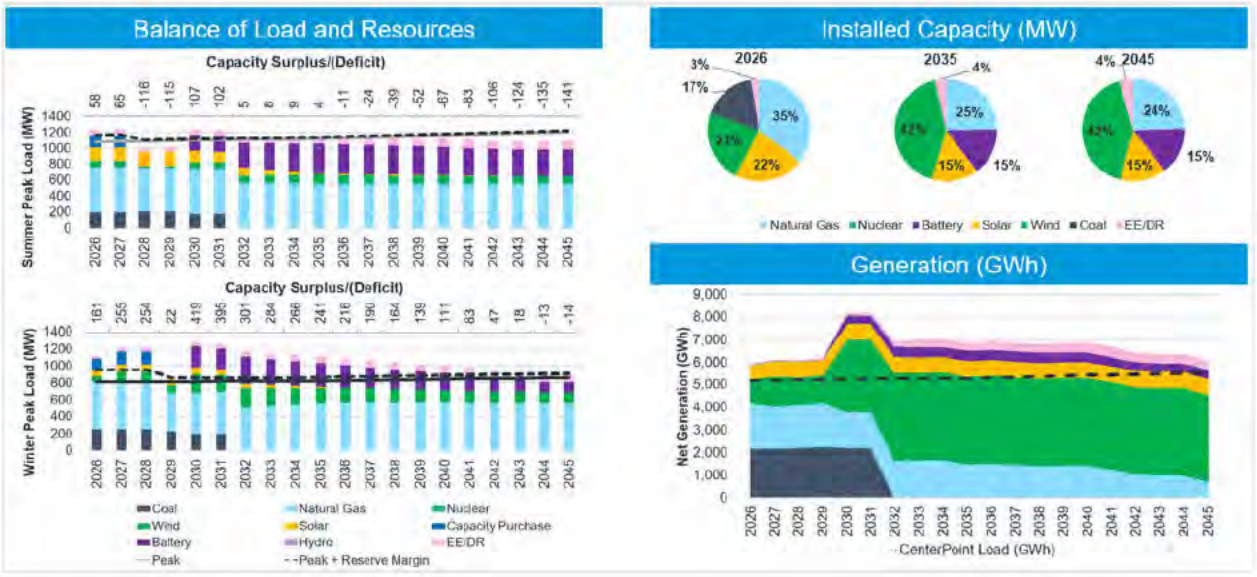
4.3.9. High Regulatory Portfolio

In the High Regulatory scenario, load is assumed to grow at a reduced rate compared to the Reference Case. It has increased fuel prices and lower capital costs for generation resources. Additionally, this scenario includes environmental regulation based on the Clean Air Act (CAA) 111(b) for new gas resources and includes its expansion to existing gas resources, limiting all new and existing gas resources to a 40% annual maximum capacity factor. Moreover, the inclusion of the CAA 111(d) restricts the options for F.B. Culley 3 to either co-fire or convert to natural gas by 2030 or retire by 2032. During the optimization under this scenario, the model selected to retire F.B. Culley 3 at the end of 2031 and continue operating A.B. Brown 5 and 6 without a conversion. The model chooses to fill the capacity and energy gap entirely through hybrid wind and storage resources, for a cumulative total of 800 MW of wind and 400 MW of storage by 2032. Figure 4-17 shows the performance of the high regulatory portfolio under reference case assumptions. Note that since this portfolio is developed to meet a lower load growth, when it is simulated with

Reference Case assumptions, it has a significant shortfall on capacity in the later years of the study.

The High Regulatory portfolio is environmentally friendly with the lowest CO_2e emissions rate and CO_2e intensity. It is well positioned in case environmental regulations change with minimal fuel cost and regulatory compliance risk because of its strong renewable emphasis and F.B. Culley 3 retirement. With 400 MW of storage resources, this portfolio high relatively high fast start capabilities. However, this portfolio is expensive across all affordability metrics, with a high near- and long-term incremental energy burden and NPVRR. Moreover, the inclusion of such large additions (800 MW of wind and 400 MW of storage) across two years brings a significant execution risk, capacity accreditation risk, and likely congestion risk.

Figure 4-17 – High Regulatory Portfolio Results Dashboard



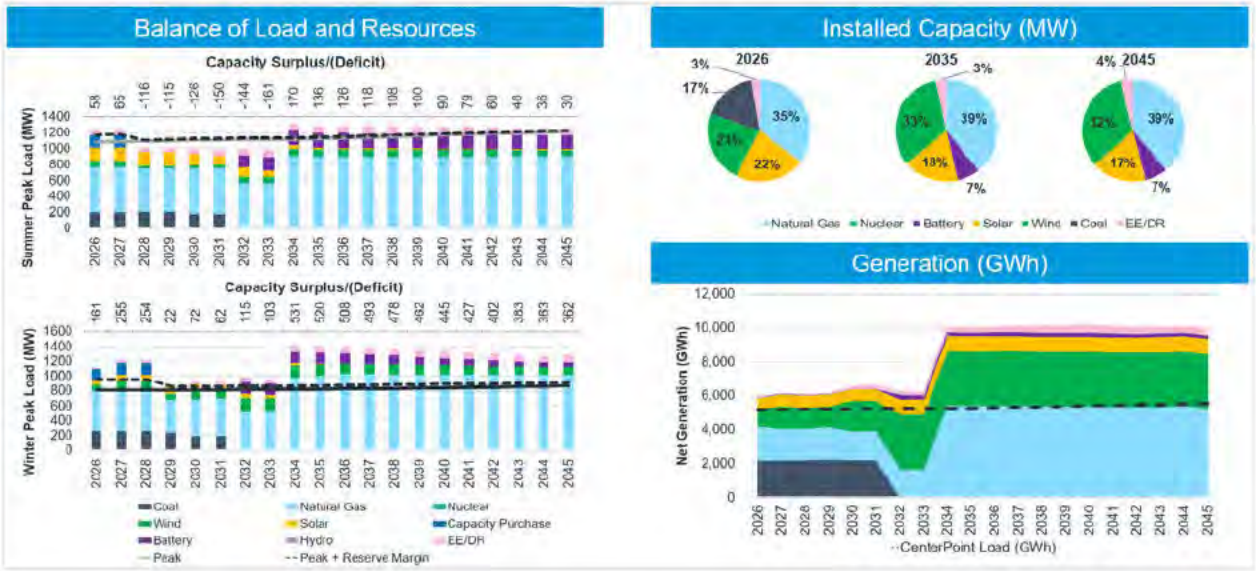
4.3.10. Alternate High Regulatory Portfolio

This portfolio reflects the optimized outcome under the Alternate High Regulatory scenario, which assumes the highest load growth among the scenarios, combined with elevated fuel prices and new resource capital costs. In this portfolio, the interconnection rights expire at F.B. Culley 2 and F.B. Culley 3 retires by 2032 without replacement. The A.B. Brown 5 and 6 combustion turbines are selected to convert to A.B. Brown 7 at the beginning of 2034. To meet long-term energy and capacity needs, the model also selects additional renewable resources, specifically, 600 MW of wind, 200 MW of storage, and 100 MW of solar. As shown in the Balance of Load and Resources chart given in Figure 4-18, the portfolio is

long on capacity when simulated under Reference Case assumptions, reflecting the lower load forecast relative to the Alternate High Regulatory scenario.

The Alternate High Regulatory portfolio is moderately high in cost in both near-term energy burden and 20-year NPVRR. It has the third lowest total CO_2e emissions and second lowest CO_2e intensity because of the renewable emphasis and efficiency of the CCGT at A.B. Brown, minimizing environmental regulatory risk. The need for renewables and storage in the near-term does present execution risk, and the portfolio is generally reliant on capacity purchases until the A.B. Brown conversion takes place in 2034.

Figure 4-18 – Alternate High Regulatory Results Dashboard



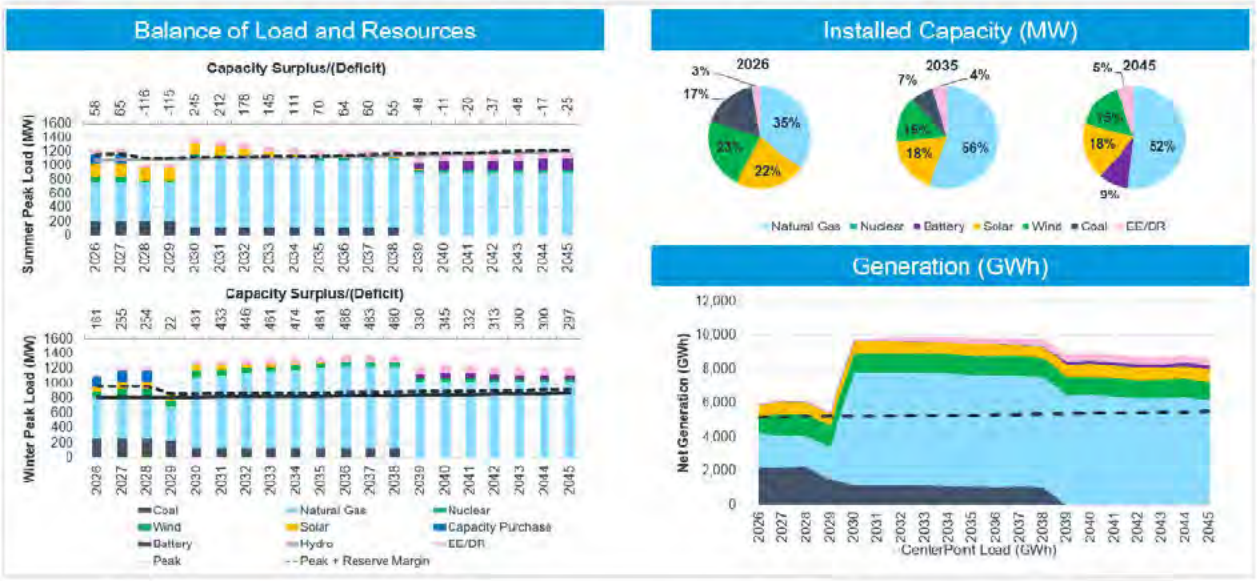
4.3.11. F.B. Culley 3 Co-Fire Portfolio

This portfolio, largely inspired by the regulatory requirements with the Clean Air Act 111, investigates retrofitting F.B. Culley 3 to co-fire with 40% natural gas and 60% coal, until its retirement at the end of 2038. A.B. Brown 5 and 6 convert to A.B. Brown 7 in 2030, which adds additional dispatchability and firm capacity to the portfolio. As illustrated in Figure 4-19, there is excess capacity on the system during the 8 year period in which F.B. Culley 3 is online with A.B. Brown 7. Following the retirement of F.B. Culley 3, the model fills the capacity need with storage resources.

This portfolio is relatively inexpensive as its NPVRR is within 3% of the least-cost portfolio. It is the only portfolio where the incremental energy burden decreases from 2030 to 2035,

so while it has a moderate energy burden in 2030, it has the lowest energy burden by 2035. Despite the low overall costs, the two conversion projects are susceptible to execution risk as well as near-term rate increases due to the large capital investments. While the portfolio is consistent with current state and federal near-term objectives to maintain coal, the continuation of F.B. Culley 3 on coal renders this portfolio exposed to future regulatory risk. Additionally, there are operational risks associated with blending fuels.

Figure 4-19 – F.B. Culley 3 Co-Fire Portfolio Results Dashboard



4.3.12. Delayed Reference Case Portfolio

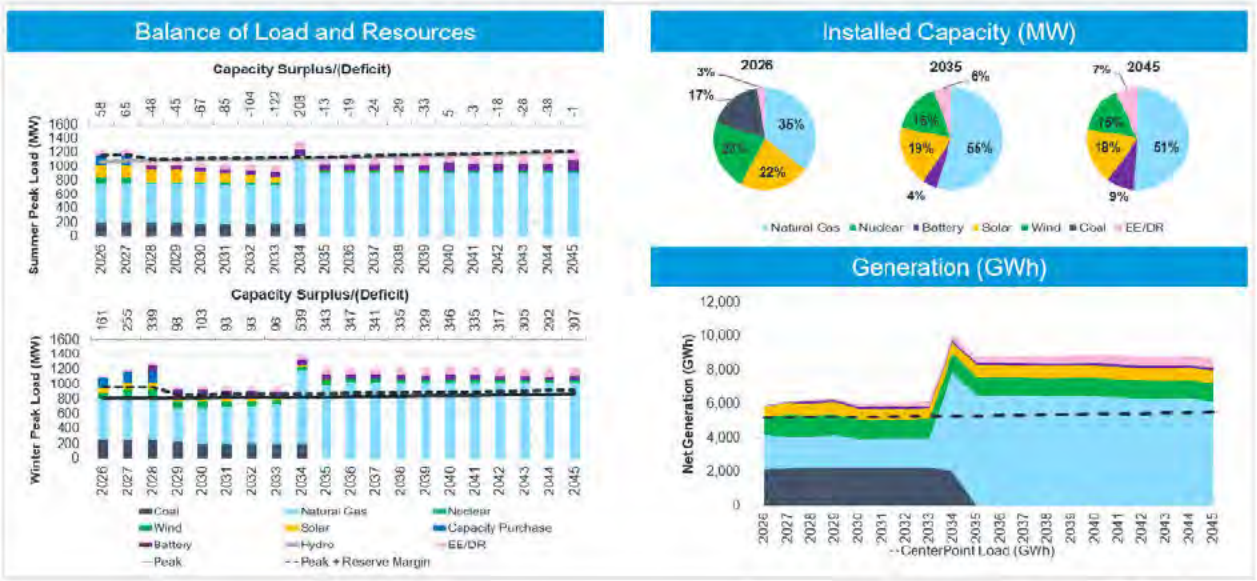
This final portfolio reflects a similar resource plan to the reference case but with delayed timing for major resource decisions to be determined in a future IRP, particularly A.B. Brown 7 which begins operations in early 2034 and F.B. Culley 3 that retires at the end of that same year. By aligning the A.B. Brown 7 conversion date to occur within the same year as the retirement of F.B. Culley 3, the delayed conversion minimizes near-term capital spending and results in less overbuild than the reference case, as illustrated in the Balance of Load and Resources in Figure 4-20.

Additionally, installing a 90 MW battery energy storage resource at F.B. Culley 2 in 2028 leverages existing site infrastructure and interconnection, avoiding future cost risk, while deferring the need for additional capital expenditures for capacity resources until 2040, seven years after the Reference Case begins investing in additional storage. The inclusion of the 4-hour battery at F.B. Culley 2 was tested through a sensitivity analysis, which found that storage resources are more cost-effective than gas options at the site. Furthermore,

pursuing a battery at F.B. Culley 2 or a generic storage resource later in the study period resulted in less than a 0.1% difference in total portfolio costs. As such, the F.B. Culley 2 battery project is included in this portfolio.

The delayed reference case is relatively inexpensive with an NPVRR within 3% of the reference case. It has a moderately low incremental energy burden in the near-term and a moderate CO_2e emissions rate. The delay of the conversion for A.B. Brown and retirement of F.B. Culley 3 makes this portfolio highly flexible, awarding additional time to reassess and adapt to changing regulatory, economic, and market landscape.

Figure 4-20 – Delayed Reference Case Portfolio Results Dashboard





The Preferred Portfolio

Chapter 5

5.1. Preferred Portfolio Recommendation

Based upon several factors, CEI South's Preferred Portfolio is the Delayed Reference Case.

5.1.1. Description of the Preferred Portfolio

The Preferred Portfolio includes a combination of new and existing supply- and demand-side resources designed to balance affordability, reliability, and environmental performance. Supply-side additions include a 90 MW battery at F.B. Culley 2 by 2028, conversion of A.B. Brown 5 and 6 (850 MW) in 2034, and retirement of F.B. Culley 3 (270 MW) by 2035, along with an additional 100 MW of storage between 2040 and 2045. These supply-side resources are complemented by demand-side resources: demand response and energy efficiency. These demand-side resources include seven near-term programs (2026–2027) from the approved plan, along with twenty additional programs across the commercial, residential, and income-qualified sectors over the remainder of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and increase steadily to 156 MW by 2045.

The Preferred Portfolio (Delayed Reference Case) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The Preferred Portfolio was within 3 percent of the lowest-cost portfolio. It ranked 3rd out of 12 portfolios in the 95th percentile cost risk metric. It does not over-rely on purchases or sales of energy or capacity. The Preferred Portfolio maintains 270 MW of reasonably low-cost, dispatchable capacity to support CEI South customers during the worst weeks of each season, providing a physical hedge against high energy prices during peak periods. It also capitalizes on the ability to reuse the interconnection at F.B. Culley 2 while allowing time to reassess regulatory and market conditions during the next IRP.

Importantly, it provides flexibility and optionality as MISO adapts to higher future levels of renewables across the system, allowing more time for other technologies, like long-duration battery storage and small modular reactors, to be commercialized. The ability to retire F.B. Culley 3 provides CEI South with a structured pathway to shift toward a lower-carbon portfolio as technology and regulatory conditions evolve.

The Preferred Portfolio is among the best performing portfolios across multiple measures on the scorecard and provides several additional benefits to CEI South customers and other stakeholders, including that it:

- Presents an affordable portfolio for customers as it limits near-term capital investment resulting in a relatively low incremental energy burden. Of the top five

least-cost portfolios, the Preferred Portfolio shows the smallest range of expected revenue requirements, indicating that it has less price volatility.

- Includes a diverse mix of resources—solar, wind, and energy efficiency—supported by dispatchable generation, storage, and demand response resources; protects against overreliance on the market for energy and capacity.
- Maintains flexibility with multiple off-ramps to adapt to a rapidly evolving industry, including a multi-year resource buildout across several sites and the option to replace F.B. Culley 3 as technology and market conditions change. This flexibility also enables CEI South to respond to new economic development opportunities.
- Hedges against future cost risks and uncertainty by maintaining the F.B. Culley 2 and F.B. Culley 3 interconnection rights.
- Maintains tax base in Warrick County, which is particularly important to the local school system in that county. Moreover, the Preferred Portfolio adds jobs and tax base to Posey County in 2034.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of CPP Time-of-Use rates beginning in 2028; note that the residential pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

5.1.2. Reliability

Reliability is commonly measured by the ability of a system to meet load without unserved energy. In the probabilistic Risk Analysis, the Preferred Portfolio was tested through Reference Case assumptions as well as different elements from the three alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load, and capital costs. In each of these simulations, the Preferred Portfolio consistently met MISO's seasonal PRMR and experienced negligible hours of unserved energy. These results confirm that the portfolio provides reliable service under both expected and stressed operating conditions over the 20-year study horizon.

In the near-term, the portfolio contains two highly dispatchable combustion turbines totaling 460 MW. These units provide fast-ramping capability and can reach full output within ten minutes, offering essential backup to variable renewable generation and serving as a hedge against volatility in both the energy and capacity markets. Following the conversion of these combustion turbines to a combined cycle in 2034, ramp times will lengthen to about 30 minutes, but overall thermal efficiency will increase significantly and have the ability to follow load.

Complementing these units is 90 MW of storage beginning in 2028 along with an additional 100 MW of storage by the end of the study period. These storage resources can dispatch at full output in less than one minute, providing immediate response to fluctuations in renewable output or system contingencies. The portfolio also retains 180 MW of existing combustion turbines, one of which provides black start capability, ensuring resilience during grid restoration or multi-day low-renewable conditions. Collectively, these resources enable the system to meet peak demand during periods of limited solar and wind production and to maintain service during seasonal high-risk weeks.

While not an explicit objective in the balanced scorecard, resource diversity supports reliability by reducing dependence on any single fuel or technology. The Preferred Portfolio achieves a balanced mix of peaking and baseload natural gas, solar, wind, battery storage, and demand-side resources. This diversity mitigates risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline that could otherwise compromise system reliability.

CEI South has signed a contract with Enel X to add commercial and industrial demand response resources through the approved Aggregation Demand Response rider. 12 MW were included in the Preferred Portfolio in 2026, increasing to 25 MW in 2027, and CEI South has received twenty customer letters of authorization to begin sharing interval meter data for potential program enrollment. Additionally, CEI South’s AMI system is being further developed to allow for a time-based rate. CEI South is currently developing a pilot program for a voluntary critical peak pricing rate. CPP better aligns the price customers pay for electricity with the cost of producing it by varying the price of electricity based on the time it’s consumed. Customers are charged more for electricity during certain periods of peak demand, encouraging customers to use less energy during critical times. Customers who participate have the opportunity to lower their overall electricity spending by shifting load to lower cost hours. As generation becomes more intermittent and less controllable, it will be more important to shape load in the future. These demand-based options will help to further diversify CEI South’s resource mix.

The Preferred Portfolio also includes a significant amount of local resources, namely the assets at the F.B. Culley and A.B. Brown sites. Local projects provide voltage support, physical hedging against high market prices, and reliability for CEI South's large industrial customers, who comprise nearly half of total load. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

CEI South worked with 1898 & Co. to conduct an analysis and review reliability for several alternative paths at existing CenterPoint sites. This near-term assessment reviewed thermal loadings, voltage, VAR support, and transfer capability. Minimal mitigations were identified in the case of F.B. Culley 2 storage, F.B. Culley 3 remaining operational, and the A.B. Brown generation conversion to a combined cycle. For additional study details, see *Technical Appendix Attachment 2.3 Transmission Study (Confidential)*.

5.1.3. Resilience

The Preferred Portfolio offers CEI South customers a blend of renewable energy along with highly efficient, dispatchable thermal generation to maintain system reliability under a range of operating conditions. The combustion turbines currently at A.B. Brown will continue to offer fast ramping capability when needed. When they transition to baseload resources, following the conversion, they will provide additional spinning reserve benefits by supporting system frequency and replacing generation during sudden outages. The continuation of F.B. Culley 3 through the end of 2034 enhances near-term resilience by supplying dependable, dispatchable capacity and spinning reserve benefits. These dispatchable resources are critical to grid resilience, particularly when intermittent resources experience long duration droughts, periods of sustained high demand, or potential future winter weather events. The Preferred Portfolio also includes a combustion turbine with black start capability, offering an additional degree of increased resiliency and operational flexibility.

The chosen portfolio also maintains both of the existing interconnection rights at F.B. Culley 2 and 3, for 90 MW and 270 MW, respectively. This protects customers from untimely delays associated with a generation resource at another location, especially with the extensive MISO queue delays in recent years due to the record amount of interconnection requests submitted. In addition, it shields customers from potential transmission upgrade costs because the increase in interconnection requests is exhausting available transmission capacity. In addition to preserving these rights for future replacement resources, the continued operation of F.B. Culley 3 provides valuable spinning mass on

CEI South's system, supporting local grid frequency. This makes the local grid more resilient to sudden system disturbances.

5.1.4. Stability

A transmission analysis was performed on four unique groups defined by the operational status of F.B. Culley 3 (retirement or continued operation) and A.B. Brown 5 and 6 (conversion or no conversion). As described in Section 2.8.3.1, short circuit ratio ("SCR") and dynamic reactive power ("VAR") support were used as the primary transmission metrics to assess system stability. The Preferred Portfolio, which includes the conversion of A.B. Brown 5 and 6 at the beginning of 2034 as well as the retirement of F.B. Culley 3 at the end of that same year, performed well in both stability metrics. Notably, the Preferred Portfolio has the second highest dynamic VAR support, indicating strong voltage stability during and after major grid disturbances.

In addition to the scoring assessment, a more detailed transmission study evaluated the system impacts of individual unit retirements and additions. The study found that if F.B. Culley 2 were to retire and no other units were brought online, the transmission system would require about $47.9 million in upgrade costs. These upgrade costs were incorporated into the Preferred Portfolio's NPVRR, recognizing that these expenses could be incurred if the site's planned battery storage remains idle. Including this assumption ensures that the Preferred Portfolio reflects a prudent estimate of potential transmission investment needs.

5.1.5. Environmental Sustainability

The Environmental Sustainability objective was evaluated utilizing the stochastic analysis and is quantified using four metrics:

- CO_2 equivalent emissions (stack emissions) intensity (tons of CO_2e/kWh)
- CO_2 equivalent emissions (tons of CO_2e)
- SO_x emissions (tons of SO_x)
- NO_x emissions (tons of NO_x)

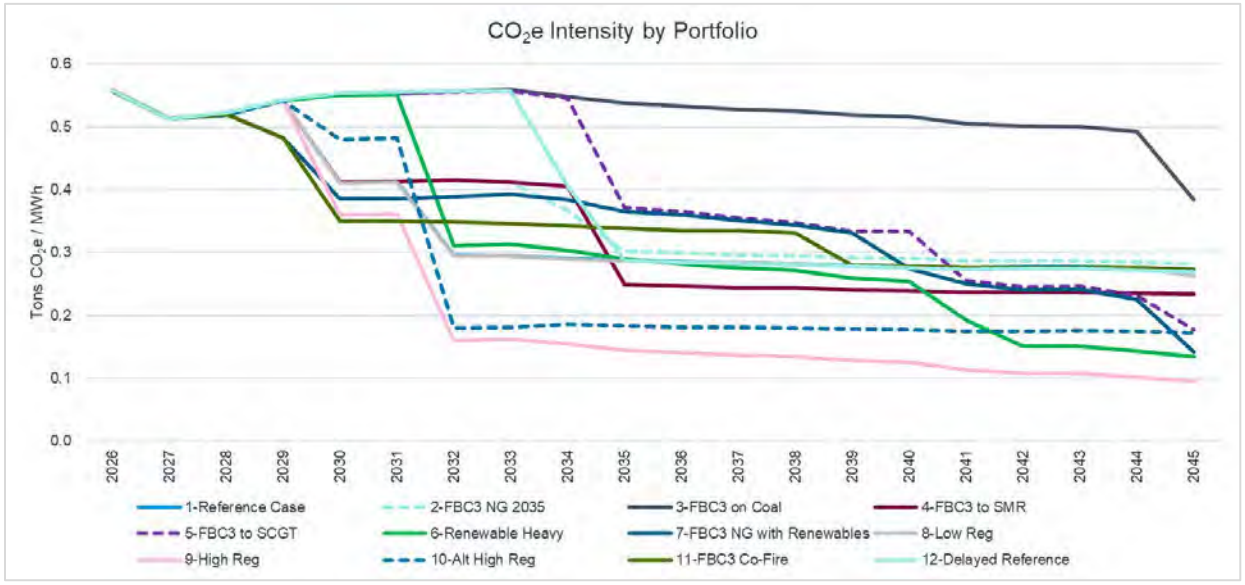
The inclusion of CO_2e is useful as it measures not only CO_2 but other emissions, such as methane and nitrous oxide. Conversion factors were applied to CO_2 from the Electronic Code of Federal Regulations ("eCFR")[39,40] to convert to CO_2 equivalence. All metrics measure the total amount of pollutants that go into the atmosphere over the 20-year planning period rather than at a given point in time.

[39] Methane (CH4) and nitrous oxide (N2O) emission factors for coal (bituminous) and natural gas taken from Table C-1 to Subpart C of 40 CFR Part 98. December 9, 2016.
[40] Chemical-specific Global Warming Potentials ("GWPs") taken from Table A-1 to 40 CFR Part 98 Subpart A for a 100-year time horizon. December 11, 2014.

The Preferred Portfolio performs moderately well in the Environmental Sustainability objective, reducing annual CO_2e emissions by more than 7 million tons over the 2026-2045 study period compared to the BAU portfolio (Portfolio 3). As illustrated by Figure 5-1, the retirement of F.B. Culley 3 at the end of 2034 causes a significant drop in total emissions. During the same year, the conversion of A.B. Brown 5 and 6 combustion turbines to a highly efficient combined cycle also contributes to declining emissions.

By 2035, the Preferred Portfolio was found to reduce CO_2 emissions in the reference case by approximately 72% compared to the baseline year of 2005. This represents an annual reduction of approximately 7.5 million tons of CO_2 from the baseline of 9.6 million tons of CO_2, with the small remainder driven mostly by the A.B. Brown units.

Figure 5-1 – Average CO_2e Emissions Intensity across 200 Draws



5.1.6. Affordability

Affordability is a key objective in the balanced scorecard that is measured as part of the stochastic analysis. The primary measure for affordability is the 20-year NPVRR, which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is simulated in the dispatch model under varying market conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenues, and capacity market purchase costs. Each annual cost category is then summed

into a total portfolio cost and discounted by CEI South's weighted average cost of capital to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be to recoup the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

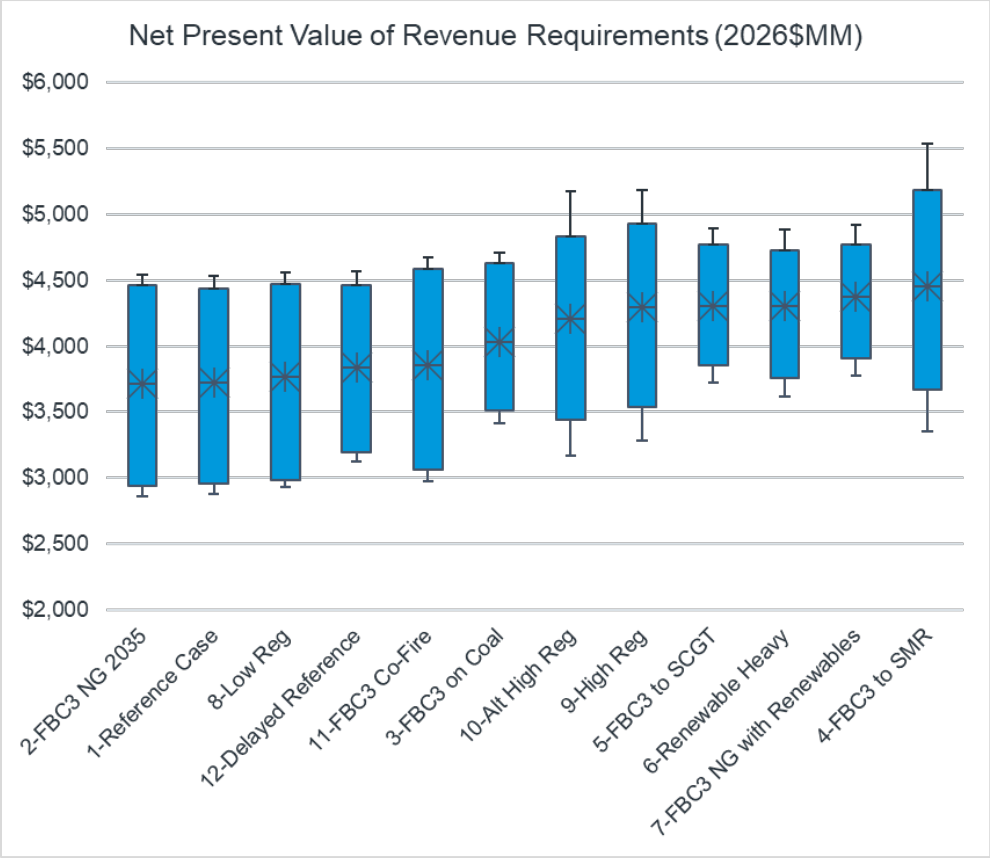
The Preferred Portfolio is within the least-cost portfolios and performs well in the other quantitative affordability metrics including 5th and 95th percentiles of NPVRR and incremental energy burden. Beyond the NPVRR, the Preferred Portfolio mitigates future cost risk through moderate reliance on energy and capacity market sales and using local resources, which have an additional benefit.

5.1.6.1. Portfolio Cost Comparison

Figure 5-2 summarizes NPVRR outcomes from 200 stochastic iterations for each portfolio, showing the minimum, the fifth percentile, the average (indicated by the star), the ninety-fifth percentile, and the absolute maximum. As illustrated in the figure, the Preferred Portfolio has the narrowest range of possible NPVRRs of the top 5 least-cost portfolios. This indicates less variability in future portfolio costs, revealing cost stability among changing market conditions. The 5th percentile of costs is approximately $3.2 billion while the 95th percentile is approximately $4.5 billion, meaning that 90% of the 200 runs created a total net present value of revenue requirements between those two values.

The Preferred Portfolio is among the lowest cost portfolios across the 12 candidates, with a 20-year average NPVRR of $3,836 million. This NPVRR is within 2.9% of the Reference Case portfolio and 3.2% of the least cost portfolio. The Preferred Portfolio is nearly $200 million less expensive than BAU which continues F.B. Culley 3 on coal (the sixth most expensive portfolio in this objective category), which saves customers money in the long-term. Moreover, if sales revenues come in as modeled, the incremental energy burden shows a minimal increase in affordability over both the near and long-term.

Figure 5-2 – Net Present Value of Revenue Requirements for All Portfolios



5.1.6.2. Future Affordability

Moreover, of the top 5 least-cost portfolios, the Preferred Portfolio shows the least reliance on future energy and capacity market sales to lower the NPVRR and make the portfolio more competitive. The greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the CEI South fleet.

Figure 5-3 displays the near-term maximum, short-term maximum, and planning horizon average energy market sales expressed as a percent of total generation as well as the net present value of total capacity market sales in dollars. As seen in the Figure 5-3, four of the top five portfolios have an average of 26% of generation contributing to sales and a near-term maximum of 32%. As explained above and validated by the Indiana Commission in

Cause No. 45052, this is a risky proposition for a company of this size. In contrast, CEI South's Preferred Portfolio (12-Delayed Reference) sells a maximum of 17% of total generation in the near-term and averages 23% over the entire study period. Thus, even with lower energy market sales exposure, the Preferred Portfolio's total cost (NPVRR) remains within 3% of the least-cost portfolio.

Figure 5-3 – Portfolio Exposure to Market Sales

Portfolio	Energy Market Sales (%)			Capacity Sales NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	26%	32%	31%	$217
1-Reference Case	26%	32%	30%	$140
8-Low Reg	26%	32%	30%	$167
12-Delayed Reference	23%	17%	31%	$115
11-FBC3 Co-Fire	26%	32%	31%	$192
3-FBC3 on Coal	15%	18%	18%	$117
10-Alt High Reg	25%	20%	32%	$159
9-High Reg	20%	26%	23%	$128
5-FBC3 to SCGT	14%	17%	18%	$93
6-Renewable Heavy	11%	16%	13%	$95
7-FBC3 NG with Renewables	14%	17%	19%	$106
4-FBC3 to SMR	26%	32%	31%	$171

In contrast, overreliance on market purchases also carries inherent risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk, if capacity market prices are lower than forecasts the NPV reduction from capacity sales would be lower.

As shown in Figure 5-4, the Preferred Portfolio is moderately reliant on energy market purchases, which, on average over the planning horizon, was about 12% of total generation. While the other least-cost portfolios only had about 10% of total generation from market sales, this is due to the earlier conversion of A.B. Brown, which necessitates

a near-term rate increase. With regard to capacity market purchases, the Preferred Portfolio also performs moderately well. In the first four years of the study, this portfolio has the smallest capacity deficit, largely due to the addition of the firm capacity associated with the F.B. Culley 2 battery. While the ten portfolios that allow for the interconnection rights to expire at F.B. Culley 2 are forecasted to purchase nearly $5 million worth of capacity in 2028 and 2029, the Preferred Portfolio purchases are about half of that during the same time period. Thus, while the Preferred Portfolio includes moderate capacity purchases over the long-term, CEI South will continue to evaluate this path and prioritize affordability following submission of this IRP.

Figure 5-4 – Portfolio Exposure to Market Purchases

Portfolio	Energy Market Purchases (%)			Capacity Purchases NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	9%	16%	9%	$6
1-Reference Case	10%	17%	11%	$14
8-Low Reg	10%	17%	11%	$6
12-Delayed Reference	12%	21%	11%	$18
11-FBC3 Co-Fire	10%	22%	11%	$12
3-FBC3 on Coal	19%	21%	26%	$22
10-Alt High Reg	9%	17%	5%	$19
9-High Reg	14%	17%	16%	$23
5-FBC3 to SCGT	21%	20%	29%	$26
6-Renewable Heavy	30%	37%	40%	$22
7-FBC3 NG with Renewables	23%	26%	30%	$24
4-FBC3 to SMR	9%	16%	8%	$13

5.1.6.3. Broader Affordability Impacts

Moreover, since the Preferred Portfolio proposes a significant amount of resources located within CEI South's service territory, the customers benefit from reduced congestion cost risk and additional tax base and jobs. Local generation helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When

power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system.

Investing in local projects also helps produce tax base and jobs, which directly benefit the communities CEI South serves. Currently, CEI South primarily operates generation assets in two counties, generating tax revenues in Posey and Warrick counties. The Preferred Portfolio replaces F.B. Culley 2 with a battery storage system, which provides economic benefit to the local community, whereas simply purchasing the capacity from the market does not. Moreover, the Preferred Portfolio provides additional tax base in Posey County due to the A.B. Brown 5 and 6 conversion. Communities where CEI South customers live can utilize this money to support school systems, police, parks and recreation, and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy. Finally, the continued operation of F.B. Culley 3 on coal preserves the local tax base and contributes to Indiana's economy through the use of Indiana-mined coal and the associated mining employment.

5.1.7. Other

5.1.7.1. Future Flexibility

The Preferred Portfolio provides a low-cost plan with a great deal of forward-looking flexibility. The inclusion of the battery storage resource at F.B. Culley 2 addresses CEI South's capacity need while also maintaining a valuable MISO interconnection. Maintaining the interconnection avoids future cost risk. This portfolio provides time for other technologies to advance and potentially become more cost competitive as CEI South will reevaluate decisions at F.B. Culley 3 and at A.B. Brown 5 and 6, in a future IRP. This time also allows CEI South to adapt to changing regulatory and market conditions. Until such time, CEI South customers will benefit from the minimal capital investments in the near-term, providing rate stability.

5.1.7.2. Operational Flexibility

In the near term, the Preferred Portfolio includes Variable Energy Resources ("VER") in the form of nearly 400 MW each of solar and wind, balanced by 190 MW of energy storage resources and two 230 MW natural gas combustion turbines that transition into an 850 MW combined cycle gas turbine in 2034. The CT units, batteries, and CCGT can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that fast-start resources perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Moreover, the dispatchable CCGT will

provide critical baseload and load-following capability along with a lower emission profile. The high thermal efficiency and quick ramping capability of the unit will stabilize the net load variability and deliver reliable power during extended periods of low wind or solar production. This portfolio is expected to meet all operational flexibility requirements.

Following the conversion of the A.B. Brown combustion turbine units 5 and 6 to a CCGT, CEI South will retain a diverse and flexible set of natural gas units as it will maintain its' existing two 80 MW CT's. These peaking units can be brought online relatively quickly to address short-term fluctuations in demand, complementing the steady output of the CCGT. One of the two peaking units includes black start capability, providing operational flexibility. Maintaining both technologies strengthens operational flexibility, ensuring reliable service across a range of potential market and system conditions.

CEI South considers maintaining an adequate amount of dispatchable generation essential to ensuring reliable service for customers throughout all seasons and operating conditions. CEI South's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output. Given the healthy number of dispatchable resources in the Preferred Portfolio, CEI South is not only able to meet current system needs but is positioned well to continue to investigate the addition of more intermittent generators on the system should the need arise.

5.1.7.3. Economic Development

The Preferred Portfolio positions CEI South well to provide relatively low-cost power to industrial customers and other large load users. The current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, CEI South must remain nimble and dynamic for prospective industrial customers and planning for the conversion of A.B. Brown 5 and 6 to a CCGT in 2034 provides this agility. CEI South aggressively pursues manufacturing opportunities which have direct, indirect, and induced economic benefits for the region and state of Indiana. CEI South's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunities for residents and at the same time raises state revenue and tax base. Additionally, large power users can assist all CEI South customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

For industrial customers to maintain their required voltage level, the CEI South system must be able to supply an adequate amount of reactive power ("VARs"). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power

supplying facilities, such as local synchronous generation. The CTs in the Preferred Portfolio provide reactive power support. Even when they are not dispatched normally, CTs are able to be started and brought online quickly if needed for CEI South system reliability. Moreover, when the A.B. Brown CTs are converted to a baseload combined cycle in 2034, the dynamic reactive power on the system increases. The A.B. Brown CTs as well as the CCGT also prevents CEI South from entering into Reactive Power Payments through the MISO market, which would impact CEI South customers' bills.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in CEI South's ability to provide safe, reliable, and cost-effective service. CEI South's generation strategy is an essential service for customers and the region's economic growth capability.

5.1.8. Fuel Inventory and Procurement Planning

Prices for commodities such as coal and natural gas are influenced by market conditions and can vary significantly over time, introducing uncertainty into long-term planning. CEI South manages short-term price volatility through coal contract strategies that lock in prices to stabilize costs. Coal suppliers and transportation providers generally require firm commitments on quantities; however, CEI South coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently CEI South utilizes non-firm pipeline delivery and gas storage for the existing 80 MW peaking units and firm pipeline delivery and gas storage for the new A.B. Brown CTs. It is planned that the combustion turbines at A.B. Brown, if converted, will continue to utilize firm pipeline supply contracts.



The Alternate Preferred Portfolio

Chapter 6

6.1. Alternate Reference Case Portfolio Development

Following stakeholder feedback, the Alternate Reference Case was developed to evaluate the potential for a large load addition that scales over time. In this scenario, the new, additional load increases in 250 MW increments until it reaches 1,500 MW, while all other market assumptions remain consistent with the Reference Case. To support potential economic development opportunities in Southwestern Indiana, CEI South developed multiple portfolios to explore different pathways for serving future large load growth.

Specifically, five portfolios were considered, each designed to test alternate development pathways under the large load growth assumptions included in the Alternate Reference Case. One portfolio, similar to the scenario-based portfolios discussed earlier, was produced by allowing the model to freely optimize resource additions to create the least-cost portfolio that meets input assumptions. The remaining four portfolios were developed to explore different ways to serve an increased load by directing the model toward specified resource selections and then allowing optimization around those decisions.

The resulting portfolios are summarized in Figure 6-1. Across all portfolios, the model selected to reuse the interconnection rights at F.B. Culley 2 to construct a 90 MW storage facility in 2028, securing capacity to meet load growth and taking advantage of the investment tax credit benefits. The model also exclusively chose to convert the A.B. Brown 5 and 6 CTs to a 2x1 CCGT at the earliest opportunity (2030). This conversion is favorable as it converts the peaking CTs to an efficient CCGT that can serve as a baseload resource, while adding nearly 400 MW of firm capacity to the portfolio. Finally, all portfolios also preferred to keep F.B. Culley 3 operational in some capacity, either as a baseload coal resource or a peaking natural gas unit.

Figure 6-1 – Alternate Reference Case Portfolios

Year	1: Optimization Run	2: 1x1 J Class in 2032	3: Renewables + CT's	4: FB Culley 3 NG Conversion 2030	5: FB Culley 3 NG Conversion 2035
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031			+1 Non IRA Wind + Storage (200 + 100 MW)		
2032	+1 2x1 J Class Fired CCGT (1361 MW)	+1 1x1 J Class Unfired CCGT (568 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 2x1 J Class Fired CCGT (1361 MW)	+1 2x1 J Class Unfired CCGT (1144 MW)
2033			+5 Non IRA Wind + Storage (1,000 + 500 MW)		+1 2x1 J Class Fired CCGT (1361 MW)
2034		+1 2x1 J Class Unfired CCGT (1144 MW)	+2 Non IRA Wind + Storage (400 + 200 MW)		
2035	+1 J Class SCGT (385 MW)		+1 J Class SCGT (385 MW)	+1 J Class SCGT (385 MW)	+1 FB Culley:3 NG 2035 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)
2036					
2037			+1 50 MW 4 Hour Storage (50 MW)		
2039		+1 50 MW 4 Hour Storage (50 MW)			
2040	+1 50 MW 4 Hour Storage (50 MW)		+1 F Class SCGT (222 MW)	+1 Non IRA Wind (Battery) (100 MW) +1 Non IRA Wind (Hybrid) (200 MW)	
2041					+1 50 MW 4 Hour Storage (50 MW)
2042	+1 100 MW 4 Hour Storage (100 MW)	+1 50 MW 4 Hour Storage (50 MW)			
2043					+1 50 MW 4 Hour Storage (50 MW)
2044		+1 50 MW 4 Hour Storage (50 MW)	+1 Non IRA Wind (200 MW)		
2045	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Solar + Storage (100 + 50 MW) +1 Reciprocating Engine (110 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)

6.2. Portfolio Performance

The five portfolios were evaluated through a similar risk analysis framework as the traditional portfolios in order to test operational performance and affordability under a range of potential market conditions. The market conditions that were varied include fuel costs, capital costs, inclusion of a CO_2 tax, market prices, and allowable energy sales. The methodology and calculations underlying these variations are described in the Risk Appendix section Risk Appendix. The relative performance of each portfolio across these conditions is detailed in Figure 6-2. The inputs into the EnCompass model that were used to generate the following results is given in the *Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)*.

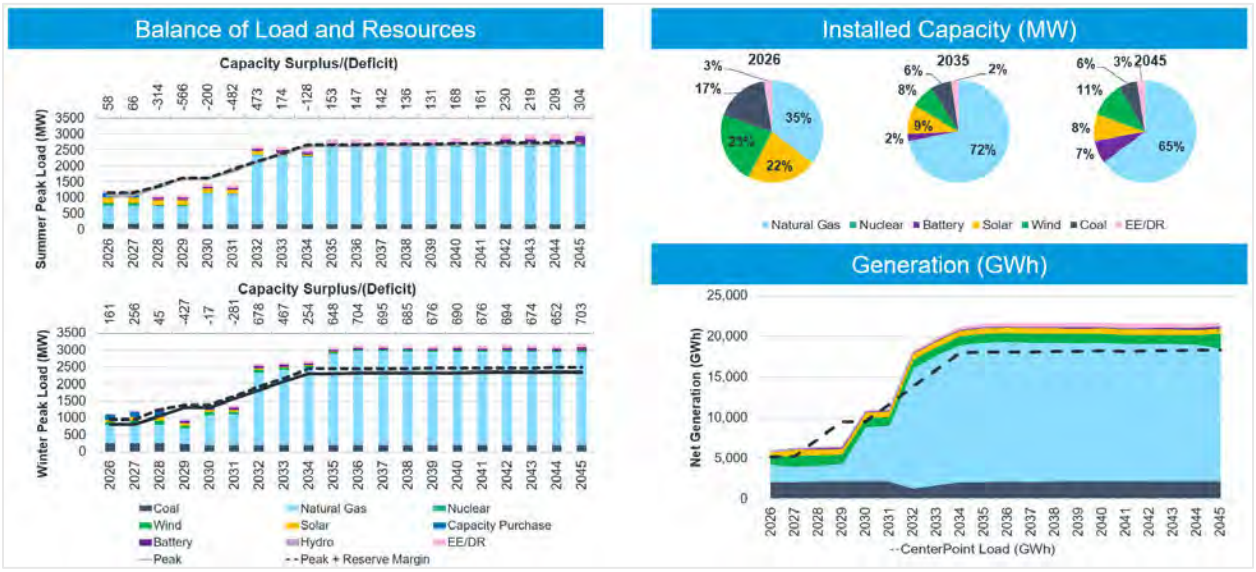
Figure 6-2 – Alternate Reference Case Risk Analysis Scorecard

Objective	Affordability				Environmental Sustainability				Reliability/Resiliency/Stability			Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
1- Optimized Case	$11,652	0%	$10,197	$13,257	0.427	121,201	47,708	26,303	33,860	2,063	614	10.1%	14.2%	$163	$80
2- 1x1 J Class 2032	$12,242	5%	$10,899	$13,674	0.304	93,487	8,890	17,617	41,307	2,227	371	9.7%	14.8%	$122	$112
3- Renewables + CT's	$12,024	3%	$10,510	$13,288	0.335	84,915	51,563	26,813	5,386	1,031	1,269	7.5%	18.1%	$45	$120
4- FBC3 NG 2030	$11,893	2%	$10,573	$13,355	0.304	92,840	9,123	17,187	38,787	2,063	612	9.7%	14.9%	$168	$79
5- FBC3 NG 2035	$11,659	0%	$10,401	$13,119	0.296	82,899	21,563	10,358	25,466	1,868	556	9.7%	14.3%	$130	$100

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
6-8: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
9: Total emergency unserved energy purchased from 2026 to 2045
10: Capacity from “spinning” thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
11: Capacity from “fast start” assets that can be dispatched quickly (combustion turbine, battery)
12-13: Dynamic VAR support and short circuit ratio from transmission reliability analysis
14: Total energy sales as a percentage of total energy generation from 2026 to 2045
15: Total energy purchases as a percentage of total load from 2026 to 2045
16-17: Net present value of capacity sales and purchases from 2026 to 2045

The optimized portfolio (Preferred Portfolio) developed for the Alternate Reference Case ranks as the least-cost option for meeting rapid load growth. This portfolio retains the F.B. Culley 2 interconnection rights by installation of a battery energy storage resource by 2028, avoiding future cost risk and providing additional reliability to the system. It also maintains the operation of F.B. Culley 3 on coal throughout the entire study period. Though this outcome is less favorable from an environmental perspective, it preserves flexibility for CEI South to revisit this critical decision point in a future IRP cycle as regulatory, market, and technology conditions evolve. The 2030 conversion of A.B. Brown 5 and 6 provides benefits beyond energy and capacity, including the creation of additional jobs and tax base in Posey County. As seen in Figure 6-3, the portfolio, similar to all alternate reference case portfolios, relies on market capacity and energy purchases in the short-term. These needs would most likely be filled by fixed capacity or energy contracts.

Figure 6-3 - Alternate Reference Case Preferred Portfolio Results Dashboard



6.2.1. Transmission System Impact of the Large Load Additions

To assess system reliability, a thorough transmission study evaluated the shoulder, summer, and winter scenarios for various possible large loads. This includes a near-term addition of 300 MW and a 1,000 MW on the West side of the transmission system along with a long-term study of 300 MW and a 1,500 MW on either the West or East side of the system. Similar to previously mentioned studies, this was performed using the MTEP 2024 model, PSS/E software for power flow analysis, and the MISO MTEP 2025 cost guide for component price estimates.

The results indicated that the addition of a 300 MW load on either side of CEI South's system did not require upgrades to the transmission system, while the larger loads did necessitate transmission mitigation (See *Technical Appendix Attachment 6.2 Large Load Study Results (Confidential)*). The Preferred Portfolio's inclusion of the A.B. Brown 2x1 combined cycle and additional large thermal resources located on CenterPoint's system led to required transmission mitigation and upgrade costs of $15.2 to $16.4 million. In contrast, if a large thermal resource were not added to the local system, transmission costs would increase roughly tenfold due to the need for major system reinforcements to accommodate heavy power imports from neighboring regions. Specifically, on the West side of the system, a cost of $152 million would be required to serve a near-term 1,000 MW load while a cost of $147 million would be required to serve a long-term 1,500 MW load. These estimates are for the transmission upgrade costs studied in the transmission portfolio and do not include the costs associated with on- or off-system generation needed to meet the energy and capacity needs of the large load.

For a large load located on the East side of the system, there are unresolvable low-voltage issues, indicating a need for a large generator on the system. The costs resulting from this transmission analysis were not factored into the NPVRR, as the location and timing of the load are speculative. Since the costs would affect all generation portfolios evenly, the relative ranking of portfolio performance stands.

6.2.2. Generation Planning for Large Loads

In addition to the Alternate Reference Case portfolios, a series of large load sensitivities were also conducted to evaluate how the timing and magnitude of new load additions influence resource decisions. Load increases of 100 MW, 300 MW, and 1,000 MW were evaluated. The sensitivities were constructed primarily to provide insight into model behavior and were not included in the Risk Analysis. Three important trends emerged during this sensitivity analysis:

1. In all cases, the model selected the conversion of A.B. Brown from combustion turbines to a combined cycle natural gas plant. This conversion adds nearly 400 MW of firm capacity and provides a reliable baseload resource to support opportunities for economic development.
2. For future load additions greater than 300 MW, the preferred pathway at F.B. Culley 3 shifted from retirement to continued operation throughout the entire study period, preserving flexibility for future replacement or conversion.
3. For future load additions greater than 1,000 MW, the decision to install a battery at F.B. Culley 2 became part of the least-cost portfolio. The early procurement of additional capacity increases system flexibility and contributes valuable firm capacity to CEI South.

6.3. Description of the Alternate Reference Case Preferred Portfolio

The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028, calls for the conversion of A.B. Brown units 5 and 6 gas turbines to an efficient CCGT unit by 2030, and continues to operate F.B. Culley 3 on coal. Beyond these resources, the portfolio calls for the addition of a large natural gas combined cycle in 2032 as the load continues to rapidly increase. In the latter years of the planning horizon, a smaller simple cycle gas unit is added in 2035, and a cumulative 150 MW of standalone storage is procured. In the final study year, an additional hybrid wind plus storage facility is brought online to fill energy and capacity needs.

This generation fleet is complemented by energy efficiency and demand response programs. These demand-side resources include the seven near-term (2026-2027) programs included in the previously approved plan, as well as nineteen additional programs across the commercial, residential, and income-qualified sectors throughout the rest of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and scale up to 118 MW by 2045.

The alternate preferred portfolio offers a least-cost and extremely flexible pathway to meeting additional load. The critical decisions at existing assets match those made in the Preferred Portfolio: F.B. Culley 2 storage, A.B. Brown conversion, and maintaining the F.B. Culley 3 interconnection. This consistency between the two preferred pathways highlights the flexibility in the plan.

It provides a number of benefits to CEI South customers and other stakeholders, beyond what is seen on the balance scorecard, including that it:

- Preserves maximum future flexibility, keeping Southwestern Indiana competitive and able to quickly adapt to support economic development and growth.
- Adds tax base and jobs in our community, helping customers thrive. Both the addition of prospective customers and the additional infrastructure necessary to support it drives economic growth.
- Aligns with current Federal and State goals.
- Utilizes the existing asset at F.B. Culley 3 until future replacement or conversion to natural gas is decided, which will be re-analyzed in subsequent IRPs.
- Adds efficient on-system base load generation through the conversion of A.B. Brown 5 and 6 to a CCGT, which promotes system reliability and provides competitively priced energy that is projected to be consistently lower than market prices.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry and includes a multi-year build out of resources on several sites,

maintaining the option to replace Culley 3 in the future when appropriate, based on continual evaluation of changing technology and conditions.

- Maintains tax base in Warrick County, which is particularly important to the local school system in that county.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to energy efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of Residential CPP Time-of-Use rates; the pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

At this time, no contract to secure a large load has been executed. CEI South will continue ongoing conversations with prospective customers. This large load analysis will continue to evolve as the company continues to evaluate possible load additions, timelines, and costs necessary to serve. While the alternate preferred portfolio provides great insight into a possible path, the resource mix used to serve the potential customer will be heavily influenced by the balance of the customer's needs and priorities. As discussions continue, CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations advance to negotiations or contracting.



Short Term Action Plan

Chapter 7

7.1. Differences Between the Last Short Term Action Plan from What Transpired

Since the last IRP was filed there have been significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several solar projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable for its customers. As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible in the near to mid-term.

CEI South conducts the IRP process every three years and each IRP, necessarily builds on the previous IRP and the generation resource investments that have come before. The Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project. (2) CEI South sought and received approval for the 2025-2027 DSM Plan. Each of these filings was consistent with the 2022/2023 IRP, and as noted below, this IRP affirms the direction taken by CEI South. These remaining renewable resources from prior IRPs still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for retirement at the end of 2025, consistent with the last IRP. A key decision in this IRP is to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available, meeting limited space requirements, were small gas units (reciprocal engines or aero derivative) or battery storage.

7.1.1. Culley 3 Conversion

In the last IRP CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. As CEI South observed increased change and uncertainty, it decided to pause on the conversion and not seek a certificate of convenience and necessity to gain approval from the IURC. CEI South chose to re-evaluate this option within this IRP. While coal to gas conversion may make sense in the future, it does not today. As discussed in this IRP, the conversion with renewables today is projected to be 14% higher cost than the Preferred Portfolio. CEI South will reevaluate this option in its next IRP.

7.1.2. Posey Solar and Two New CTs

CEI South brought Posey solar (191 MW) and A.B. Brown unit 6 (230 MW) online at the end of May 2025. A.B. Brown unit 5 (230 MW) came online at the end of August, consistent with expectations from the last IRP. All three new units have been performing well since coming online.

7.1.3. DSM

The 2022/2023 IRP did support continued energy efficiency programs designed to save 1.1% of eligible retail sales. CEI South proposed the 2025-2027 Electric DSM Plan (*Technical Appendix Attachment 3.4*) to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 26, 2025 in Cause No. 46100. Consistent with the 2022/2023 IRP, the framework for the 2025-2027 filed plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% eligible load. Additionally, CEI South updated all of its DR tariffs in Cause No. 45990 to provide more consistency, to open them to a wider range of potential customers, and to align with changes in the MISO Business Practices Manual. Additionally, CEI South received approval in the same cause to offer DR aggregation to C&I customers and have signed a contract to begin working with Enel X as the program implementer. Enel X began outreach and enrollment in October and has signed a letter of authorization with twenty customers to begin sharing meter data to explore energy plans and contracts and has five customers with a signed contract.

7.2. Discussion Of Plans For The Next 3 Years

7.2.1. Procurement of Resources

CEI South has continued to diversify its portfolio of resources with two wind projects identified in its last IRP. On November 5, 2005 the Commission approved the Salt Creek Wind Project purchase power agreements (“PPA”). That, along with the Galesburg Wind

PPA is expected to come online in 2026, bringing a total of 317 MW of additional clean renewable wind energy to serve our customers. Additionally, the Wheatland solar PPA project is expected to come online at the end of Q1 2026.

7.2.2. RFPs and Continued Evaluation of F.B. Culley 2 interconnection

At the end of 2025 CEI South will place F.B. Culley 2 in suspension with the plans of transferring the interconnection to a 90 MW battery storage unit before the end of 2028. This will require CEI South to replace its existing Attachment Y with an Attachment X. CEI South plans to utilize the results of RFPs for capacity and for a new RFP for battery storage unit to further evaluate the economics and reliability attributes of this option relative to purchasing required capacity to maintain reliability. Pending the results of this analysis, CEI South may file a CPCN for a 90 MW battery storage unit at F.B. Culley and have a COD by the end of 2028.

7.2.3. DSM

CEI South filed for and received approval on March 26, 2025 for a 3-year DSM Plan for 2025-2027 with energy efficiency savings guided by the 2022/2023 IRP process. The CEI South Oversight Board, including the OUCC, CAC and CEI South, will oversee the implementation of energy efficiency programs. CEI South will file a 3-year DSM Plan for 2028-2030 the first half of 2027 consistent with energy efficiency savings guided by the Preferred Portfolio in the 2025 IRP. The Aggregation Demand Response Rider is a 5-year contract and will be ongoing until the end of the contract in 2030, at which time the program will be re-evaluated.

7.2.4. Other Innovative Rate Design

CEI South has been actively working to develop a TOU CPP Pilot program that is set to begin in Q2 2026. CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot, including development of a new system to execute CPP events and help facilitate customer enrollment. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if the pilot is successful. Results of the pilot will be included in the next IRP; if the pilot is successful and the next IRP continues to indicate that the program is beneficial for customers, CEI South will propose to expand the rate to the majority of its residential customers in the next general rate case following the next IRP.

7.2.5. Demand Response

CEI South will continue to work with its demand response aggregator in the hopes of attracting C&I customers to participate. This IRP included an indicative amount of industrial DR for this program.

7.2.6. Ability to Finance the Preferred Portfolio

The Company expects to have sufficient funds to finance the Preferred Portfolio through a combination of internally generated cash flow from operations, external capital markets activity, and capital contributions from its parent company. CEI South's secured debt ratings are currently A1/A with a stable outlook from Moody's Investors Services and S&P Global Ratings, respectively.

7.2.7. Continuous Improvement

CEI South works hard on continuous improvement and will take the feedback that we receive on this IRP into consideration as we develop the next IRP. We appreciate formal or informal comments from active stakeholders and what is received through the Director's report. They will be used as the basis for continuous improvement going forward.

7.3. Schedule

Below is a general timeline for implementation of the Preferred Resource Portfolio, subject to change.

Figure 7-1 - Implementation Schedule

Timing	Activity Type	Actions
Q3 2025	Demand Response	Initiation of DR aggregator program
Q1 2026	Generation Transition	Salt Creek Wind (170 MW PPA) online Wheatland Solar (150 MW PPA) online
Q1 – Q2 2026	Storage RFP	Conduct an RFP for storage at F.B. Culley 2. If determined to be affordable, submit a Certificate of Public Convenience and Necessity (CPCN) for 90 MW battery storage in Q3.
Q1 – Q2 2026	Demand Response	Planned implementation of DR aggregator program
Q2 2026	Rate Design	Planned implementation of TOU CPP Pilot program
Q2 – Q3 2026	Generation Transition	Galesburg Wind (147 MW PPA) online
Q1 – Q2 2027	DSM Plan	File a 3-year DSM plan for 2028 through 2030 informed by the 2025 IRP in the first half of 2027
Ongoing	Large Load Addition	Continue to work through due diligence for possible large load addition



Technical Appendix

Chapter 8

8.1. Load Forecast Appendix

8.1.1. Forecast Inputs

8.1.1.1. Energy Data

Historical CEI South sales and revenues data were obtained through the billing system. The billing system contains detailed customer information including rate, service, North American Industrial Classification System ("NAICS") codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

8.1.1.2. Economic and Demographic Data

Economic and demographic data was obtained from S&P Global (formerly IHS Markit) for the state of Indiana and the Evansville Metropolitan Statistical Area ("MSA"). S&P Global is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to CEI South contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

8.1.1.3. Weather Data

Historical and normal Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") are derived from daily temperature data for the Evansville airport. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above a base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.4% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.4% over the forecast period while CDD increased 0.5% per year through 2045. Figure 8-1 and Figure 8-2 show historical and forecasted monthly HDD and CDD.

Figure 8-1 - Heating Degree Days

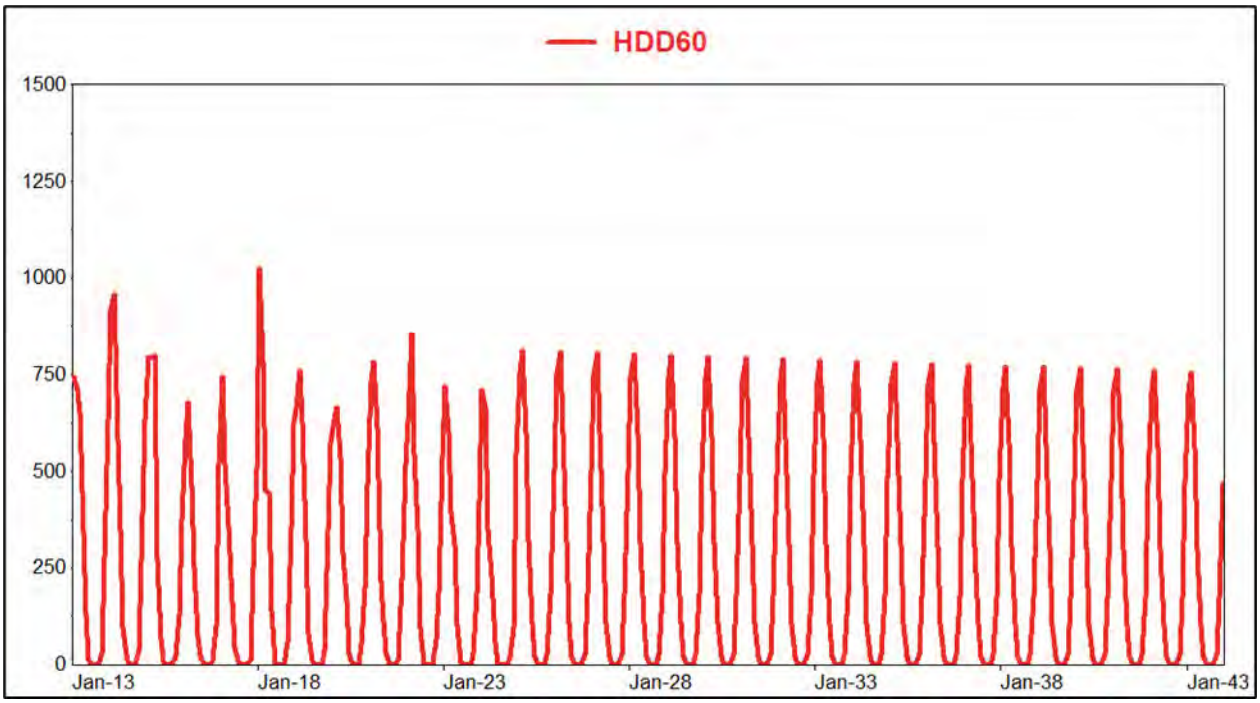
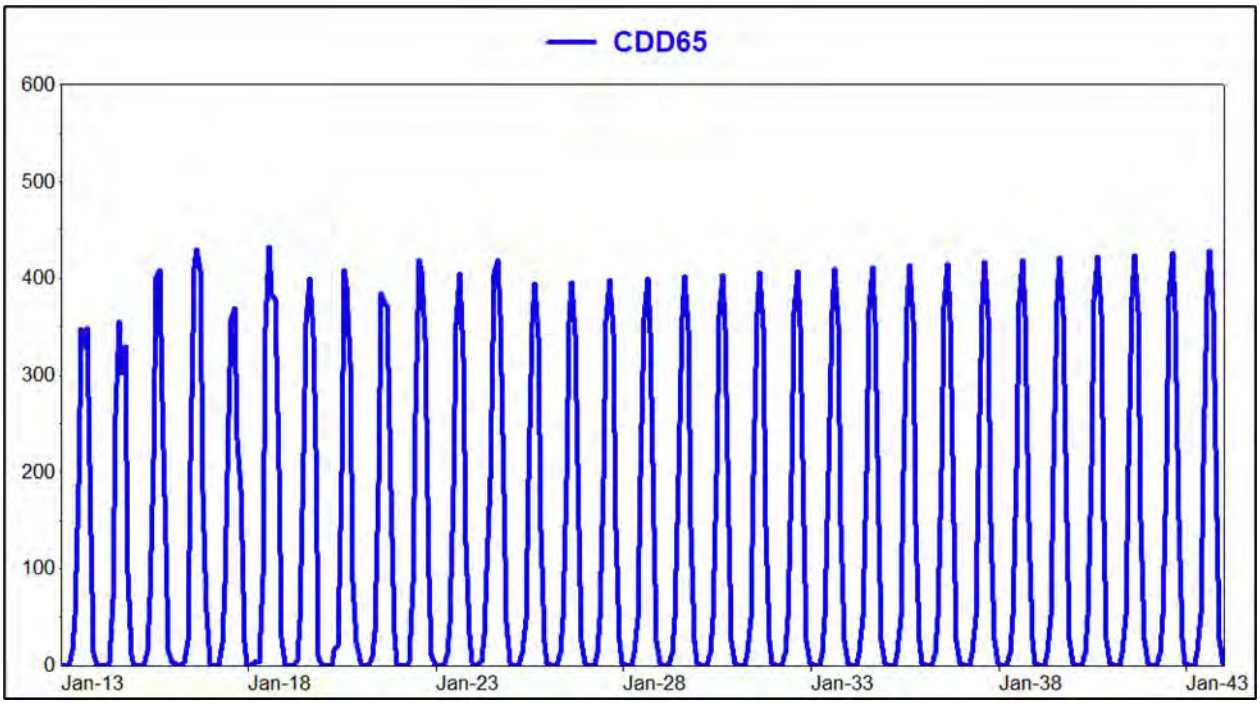


Figure 8-2 - Cooling Degree Days



8.1.1.4. Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional EIA historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. CEI South conducted an Electric Baseline survey in the third quarter of 2016 of CEI South's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. To increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of CEI South's actual territory.

8.1.1.5. Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE modeling framework. In addition to annually updating efficiency and saturation projections with the latest estimates from the EIA the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate. The CEI South forecast now considers emerging technologies: customer distributed generation and electric vehicles. Customer owned PV adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the EIA's forecast of vehicle stock. The EIA's has robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type: gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, CEI South continually stays up to date with load forecasting topics in a variety of ways. First, CEI South is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Forecasters typically attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. CEI South forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, CEI South discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. CEI

South compares CEI South model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

8.1.2. Overview of Past Forecasts

The following tables outline the performance of CEI South's energy and demand forecasts over the last several IRPs by comparing Weather Normalized ("WN") sales and demand figures to IRP forecasts from 2015-2024.

Weather-normalization is performed each month in order to analyze the variance from the forecast without the impact of weather. This is done by combining customer count, meter read schedule, billing month sales and daily temperature with estimates of the impact of changes in usage to variations of temperature. Underlying the estimates are average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data. Actual weather data from NOAA is used to generate daily use per customer estimates for the revenue classes. The results are used to predict daily use estimates and are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures.

The following tables show the WN[41] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[41] Note that large sales are not weather normalized.

Figure 8-3- Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (MW)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,155				1,113	-3.8%			
2016	1,156				1,087	-6.3%			
2017	1,113	1,082			1,038	-7.2%	-4.3%		
2018	1,109	1,086			1,006	-10.2%	-7.9%		
2019	1,106	1,085			1,039	-6.4%	-4.5%		
2020	1,106	1,088	1,106		990	-11.8%	-9.9%	-11.7%	
2021	1,106	1,084	1,107		998	-10.8%	-8.5%	-10.8%	
2022	1,107	1,083	1,129		1,013	-9.2%	-6.9%	-11.4%	
2023	1,107	1,083	1,168	1,010	1,052	-5.2%	-2.9%	-11.0%	4.0%
2024	1,107	1,084	1,172	1,087	1,070	-3.5%	-1.3%	-9.5%	-1.6%
Mean Absolute Error						7.4%	5.8%	10.9%	1.2%

Figure 8-4- Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	5,914				5,773	-2.4%			
2016	5,936				5,725	-3.7%			
2017	5,514	5,257			5,073	-8.7%	-3.6%		
2018	5,503	5,290			5,139	-7.1%	-2.9%		
2019	5,494	5,294			4,965	-10.6%	-6.6%		
2020	5,497	5,319	5,400		4,788	-14.8%	-11.1%	-12.8%	
2021	5,492	5,302	5,405		4,923	-11.6%	-7.7%	-9.8%	
2022	5,494	5,303	5,527		4,834	-13.7%	-9.7%	-14.3%	
2023	5,494	5,308	5,755	4,725	4,793	-14.6%	-10.7%	-20.1%	1.4%
2024	5,496	5,320	5,784	5,164	5,096	-7.9%	-4.4%	-13.5%	-1.3%
Mean Absolute Error						9.5%	7.1%	14.1%	0.0%

Figure 8-5- Residential Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,404				1,444	2.8%			
2016	1,394				1,416	1.5%			
2017	1,383	1,407			1,398	1.1%	-0.6%		
2018	1,377	1,395			1,375	-0.2%	-1.5%		
2019	1,374	1,384			1,372	-0.1%	-0.9%		
2020	1,373	1,375	1,386		1,408	2.5%	2.3%	1.5%	
2021	1,370	1,366	1,376		1,417	3.3%	3.6%	2.9%	
2022	1,373	1,362	1,378		1,378	0.4%	1.2%	0.0%	
2023	1,377	1,359	1,382	1,433	1,402	1.8%	3.1%	1.4%	-2.2%
2024	1,383	1,359	1,390	1,453	1,446	4.3%	6.1%	3.9%	-0.5%
Mean Absolute Error						1.7%	1.7%	1.9%	1.4%

Figure 8-6- Commercial (GS) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,304				1,321	1.3%			
2016	1,320				1,281	-3.0%			
2017	1,315	1,315			1,278	-2.9%	-2.9%		
2018	1,311	1,324			1,235	-6.1%	-7.2%		
2019	1,308	1,326			1,184	-10.5%	-12.0%		
2020	1,311	1,325	1,280		1,117	-17.4%	-18.7%	-14.7%	
2021	1,310	1,321	1,284		1,165	-12.4%	-13.4%	-10.1%	
2022	1,313	1,322	1,290		1,156	-13.5%	-14.3%	-11.6%	
2023	1,315	1,324	1,294	1,186	1,124	-17.0%	-17.8%	-15.1%	-5.5%
2024	1,320	1,330	1,300	1,186	1,179	-12.0%	-12.9%	-10.3%	-0.6%
Mean Absolute Error						9.4%	12.4%	12.3%	3.1%

Figure 8-7- Industrial (Large) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	2,916				2,722	-7.1%			
2016	2,932				2,722	-7.7%			
2017	2,546	2,211			2,097	-21.4%	-5.5%		
2018	2,547	2,252			2,182	-16.7%	-3.2%		
2019	2,546	2,270			2,073	-22.8%	-9.5%		
2020	2,549	2,312	2,348		1,971	-29.3%	-17.3%	-19.1%	
2021	2,550	2,317	2,360		2,041	-25.0%	-13.5%	-15.6%	
2022	2,550	2,322	2,464		2,015	-26.5%	-15.2%	-22.2%	
2023	2,549	2,329	2,670	1,793	1,986	-28.4%	-17.3%	-34.5%	9.7%
2024	2,546	2,334	2,682	2,189	2,244	-13.5%	-4.0%	-19.5%	2.5%
Mean Absolute Error						19.8%	10.7%	22.2%	6.1%

8.1.3. Actual and Weather Normalized Energy and Demand Levels

Figure 8-8- Historic Peak Demand

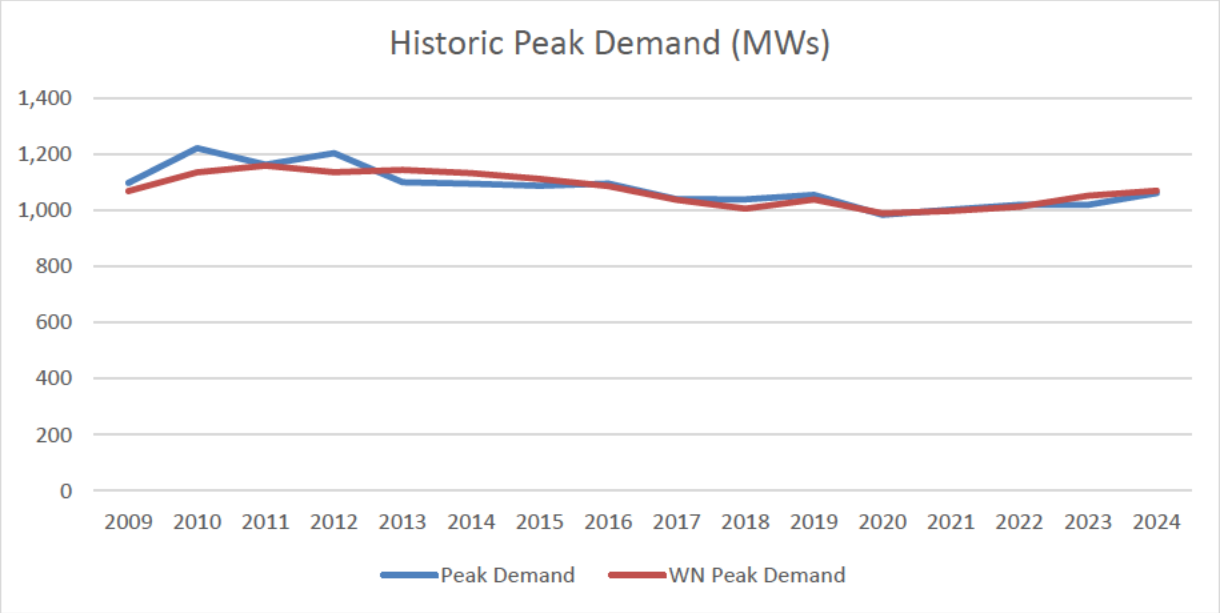
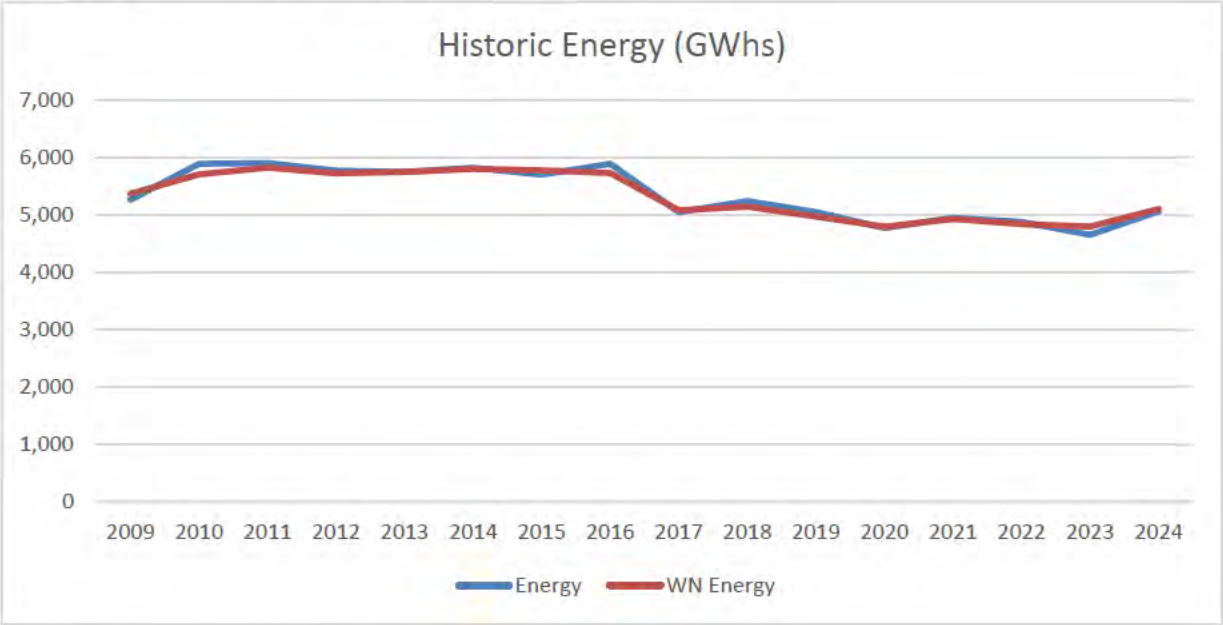


Figure 8-9- Historic Energy



8.1.4. Load Shapes

Figure 8-10- Historic Annual Load Shape

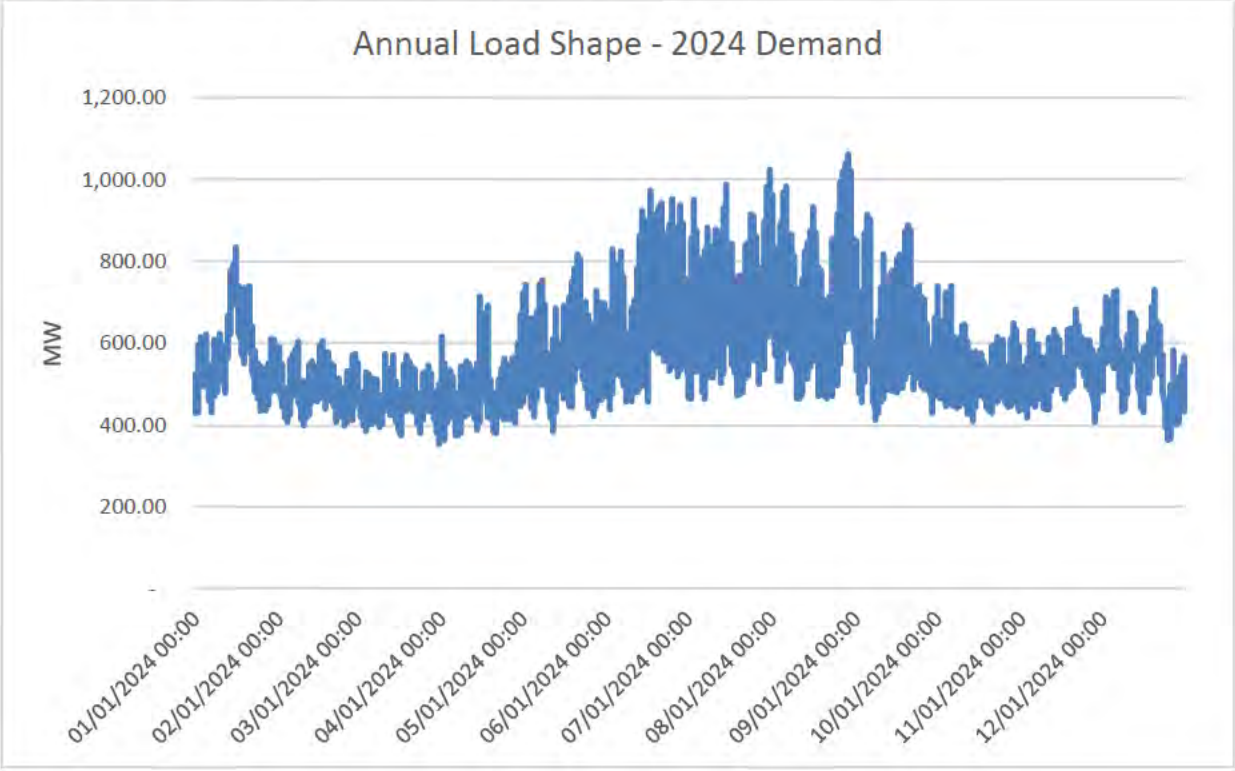


Figure 8-11- Summer Peak Day

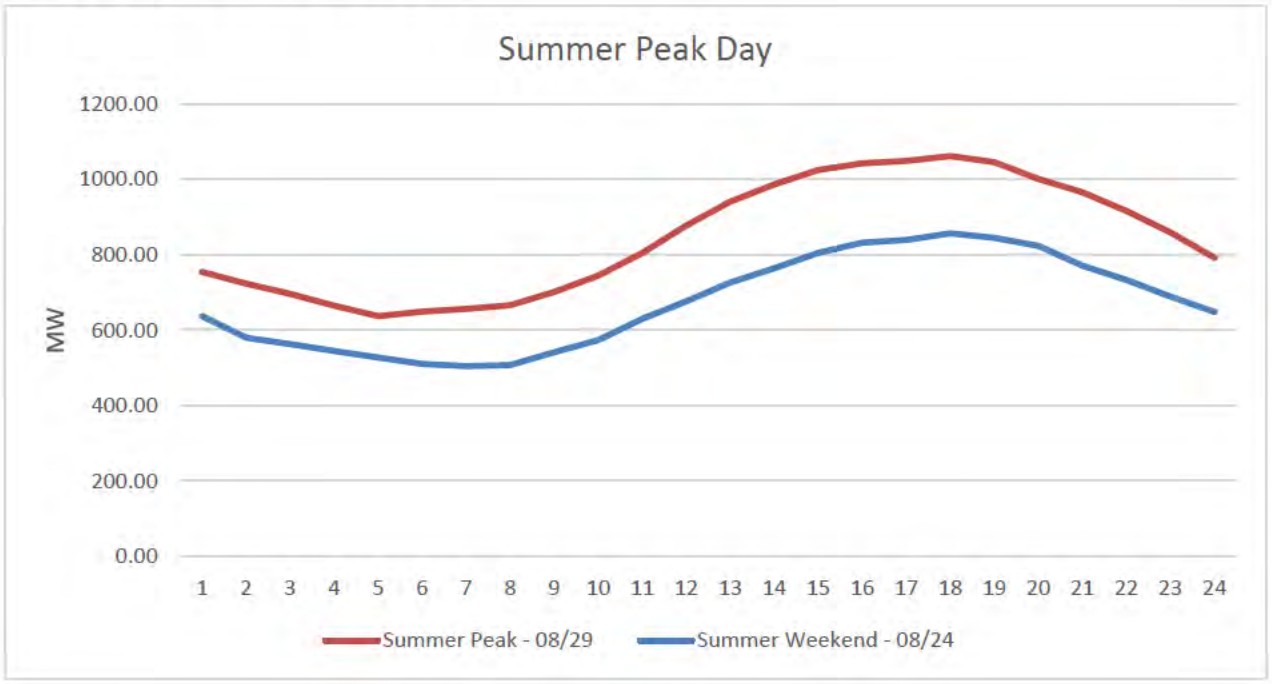


Figure 8-12- Typical Fall Day

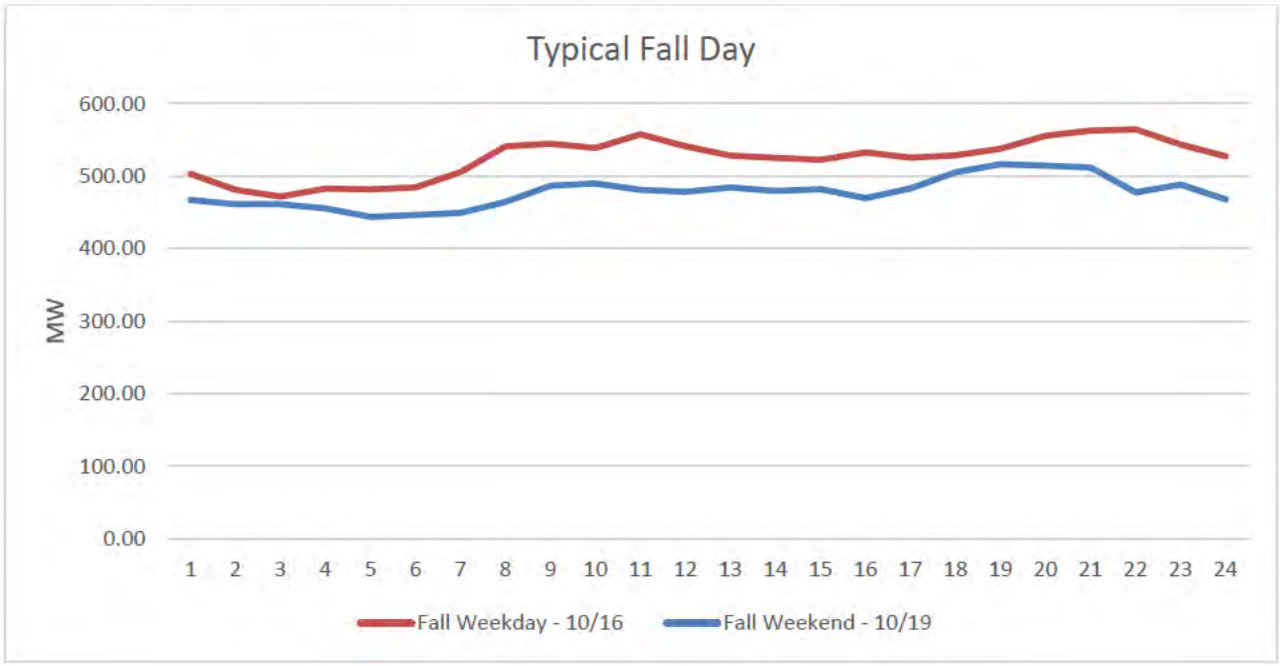


Figure 8-13- Winter Peak Day

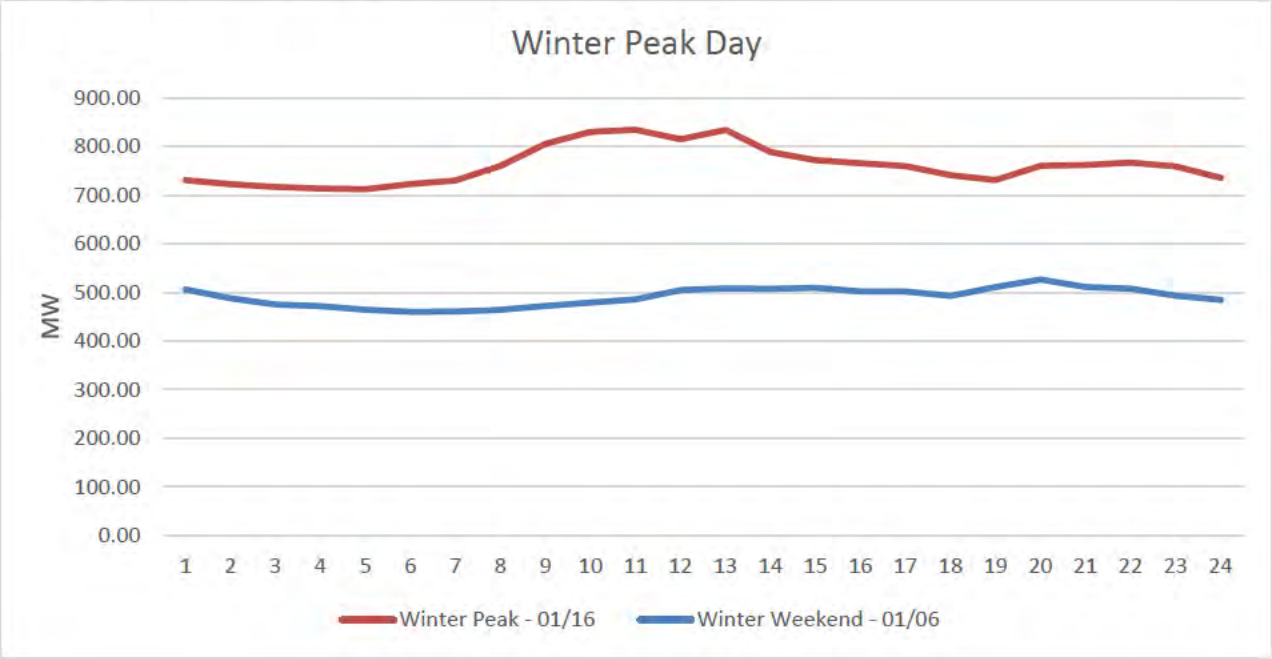


Figure 8-14- Typical Spring Day

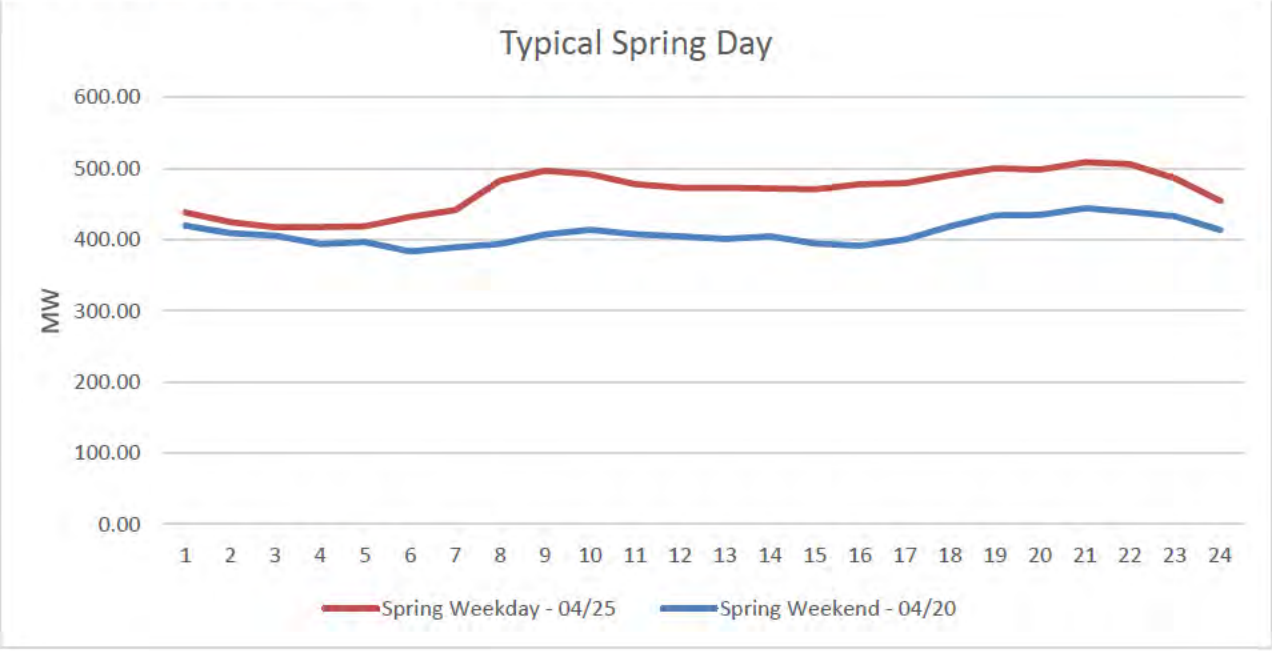


Figure 8-15- January Load



Figure 8-16- February Load

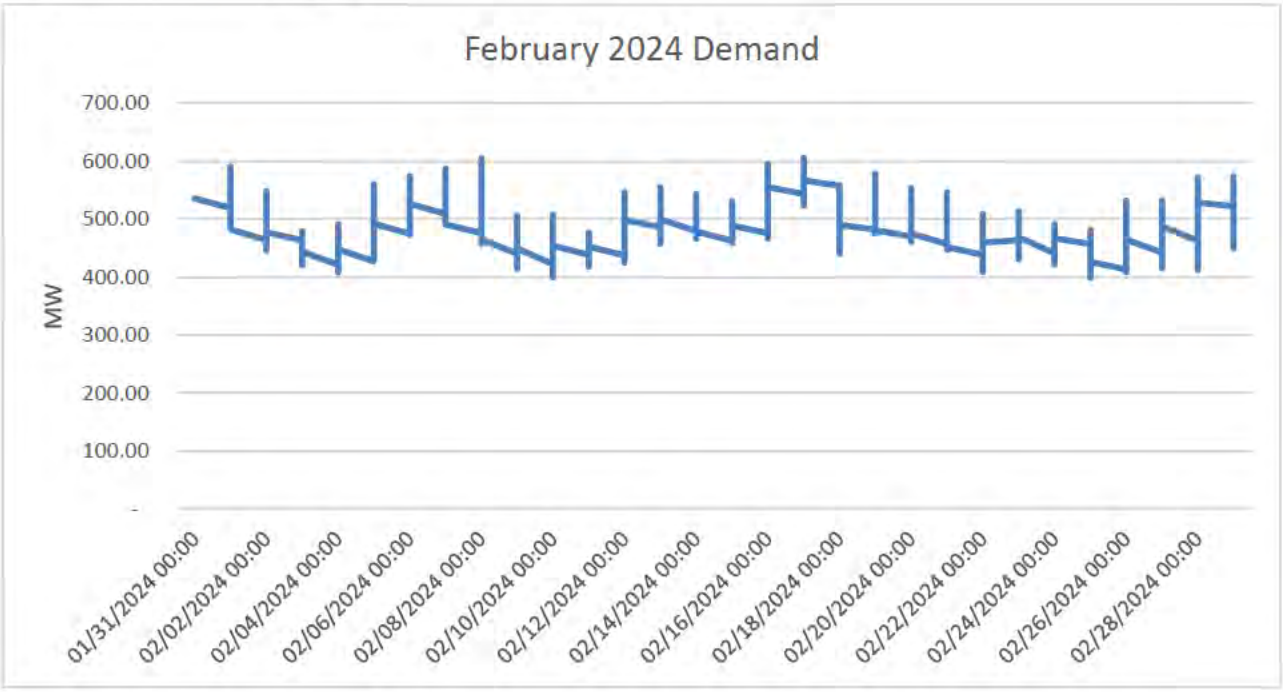


Figure 8-17- March Load

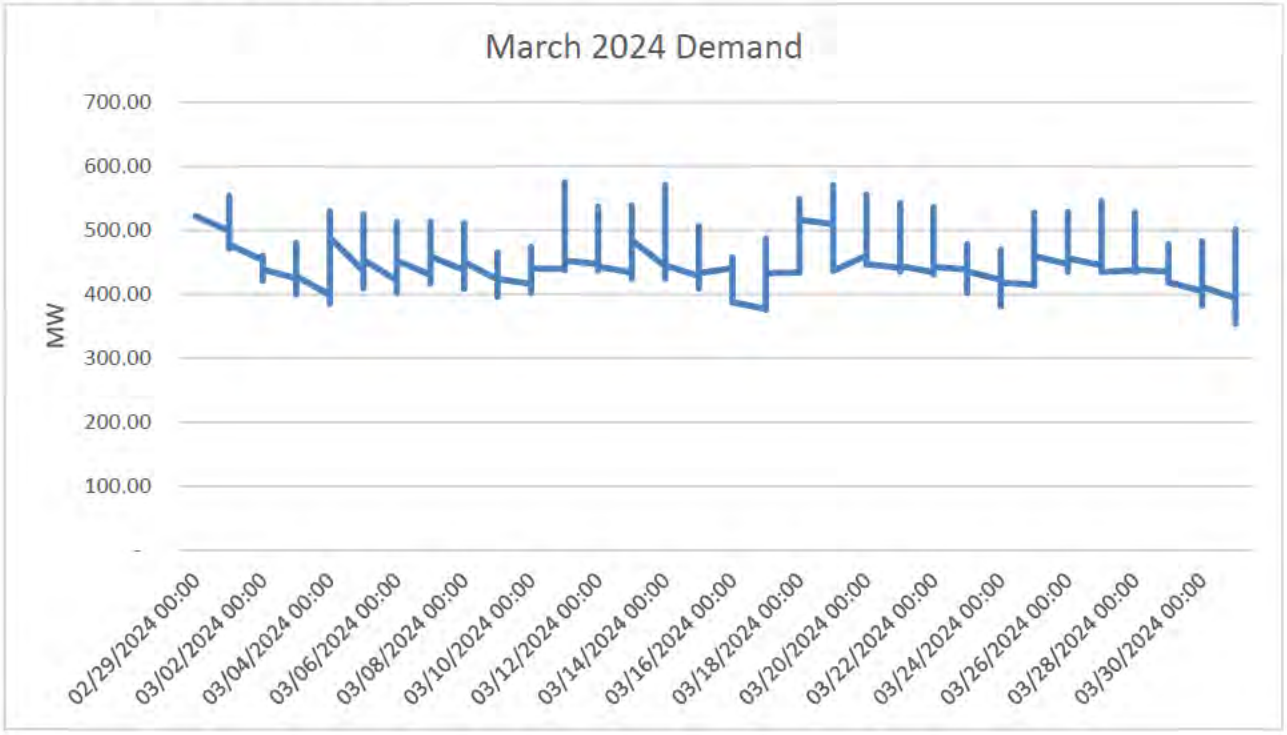


Figure 8-18- April Load

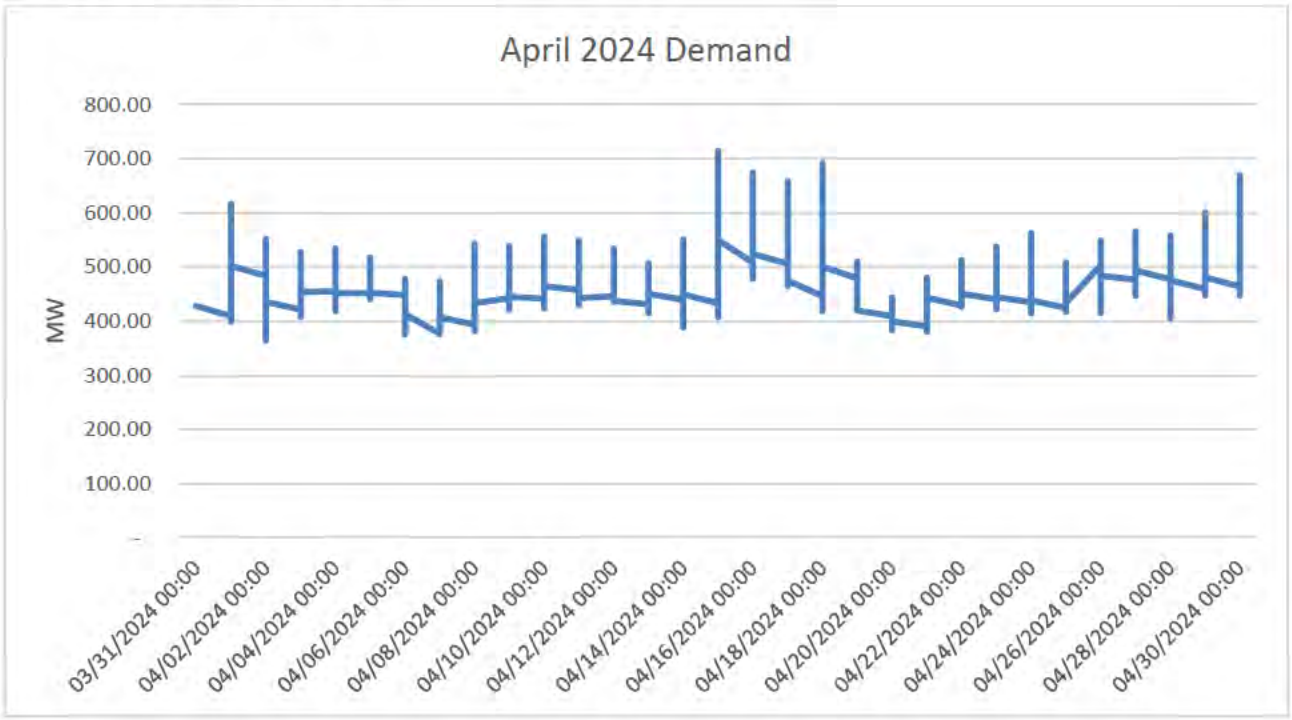


Figure 8-19- May Load

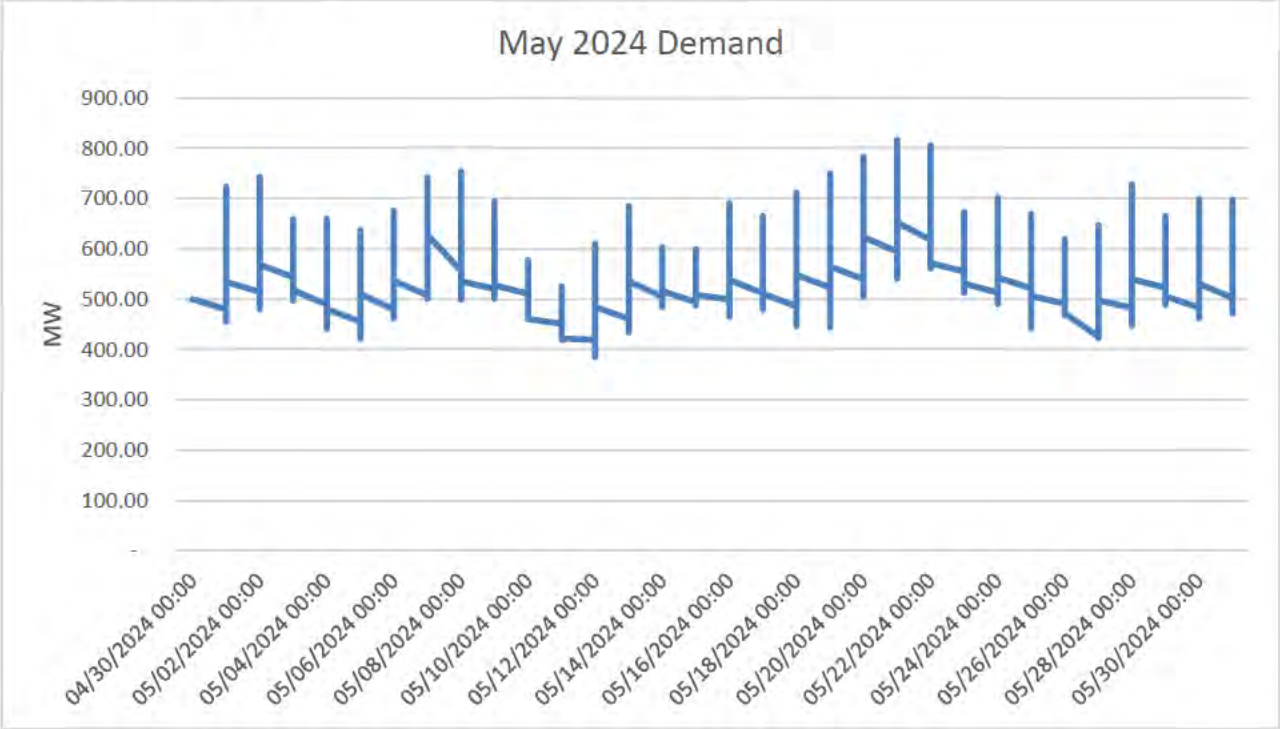


Figure 8-20- June Load

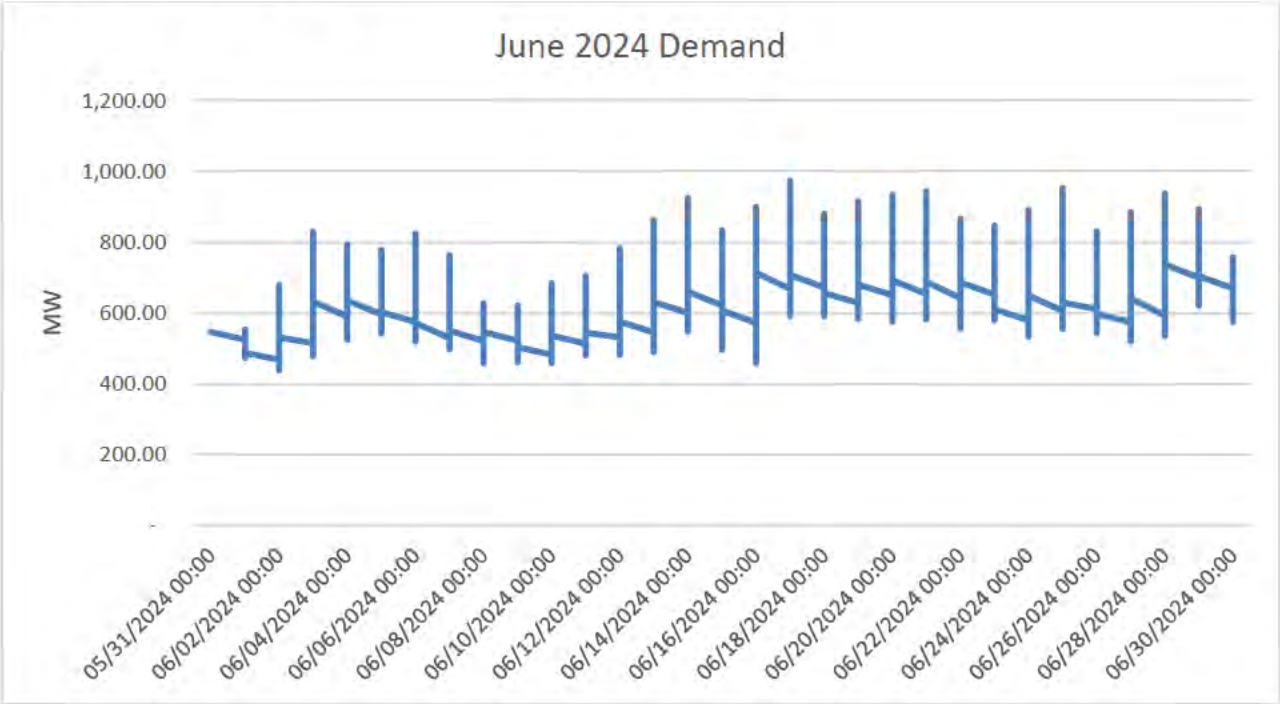


Figure 8-21- July Load

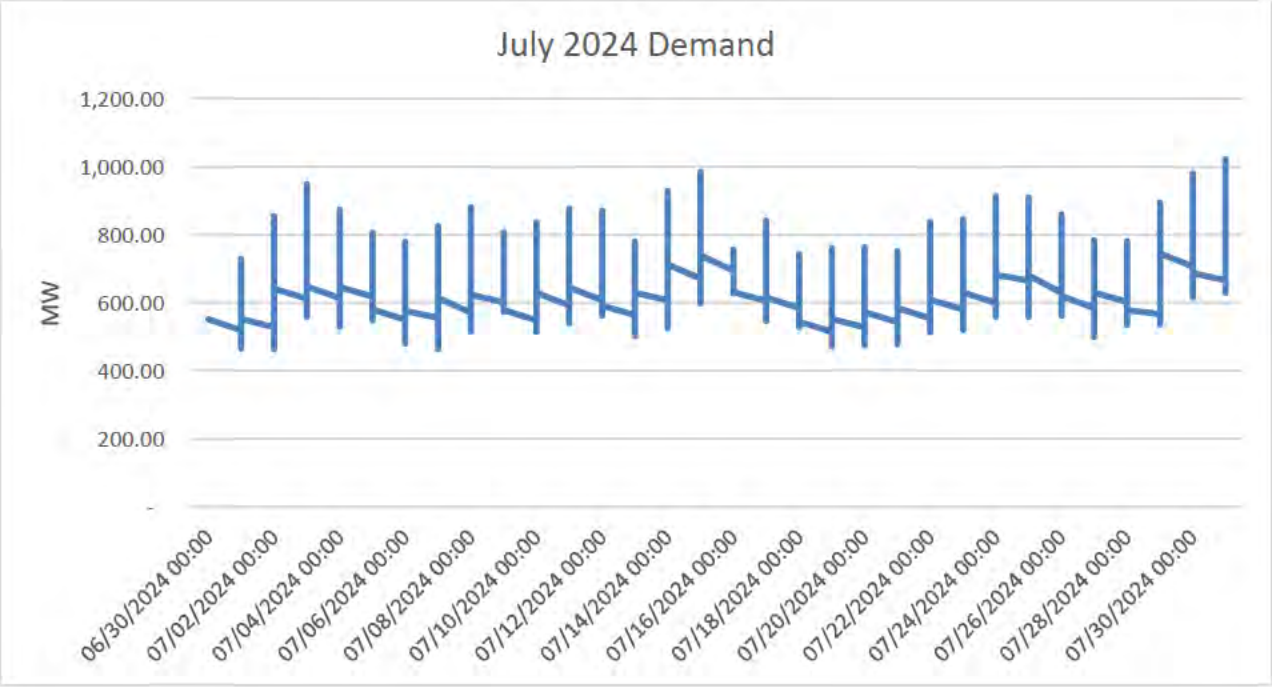


Figure 8-22- August Load

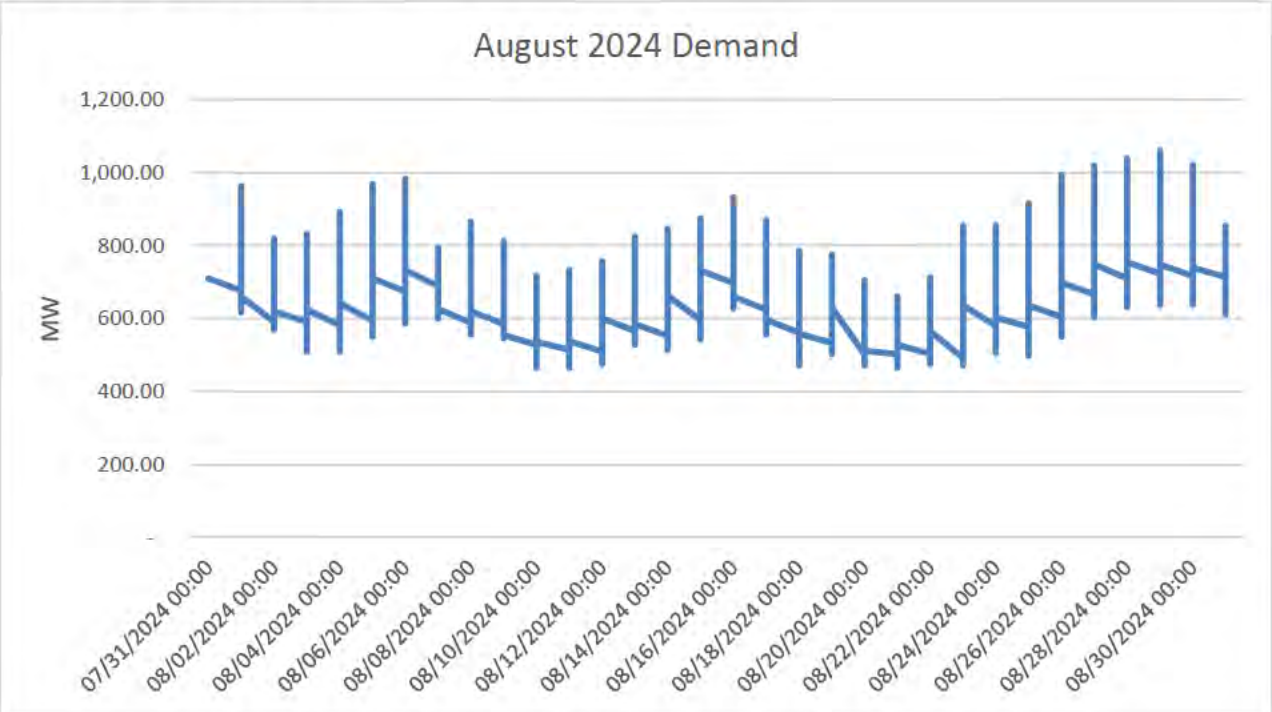


Figure 8-23- September Load

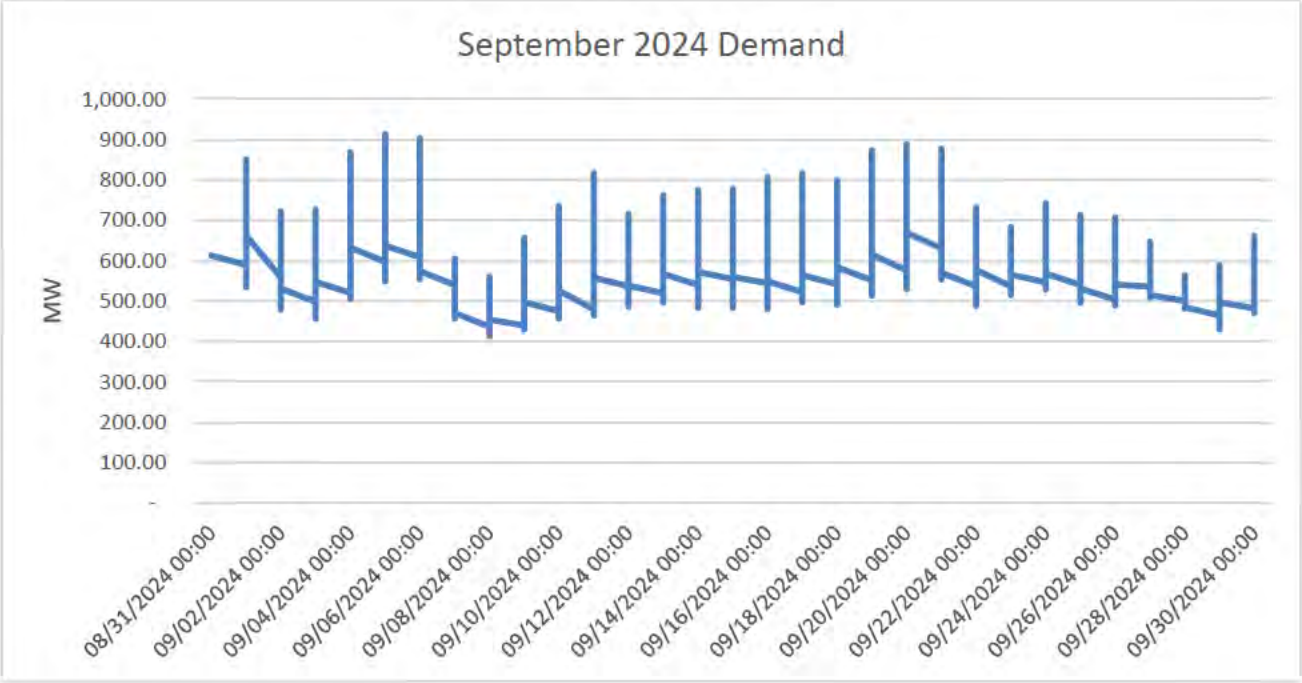


Figure 8-24- October Load

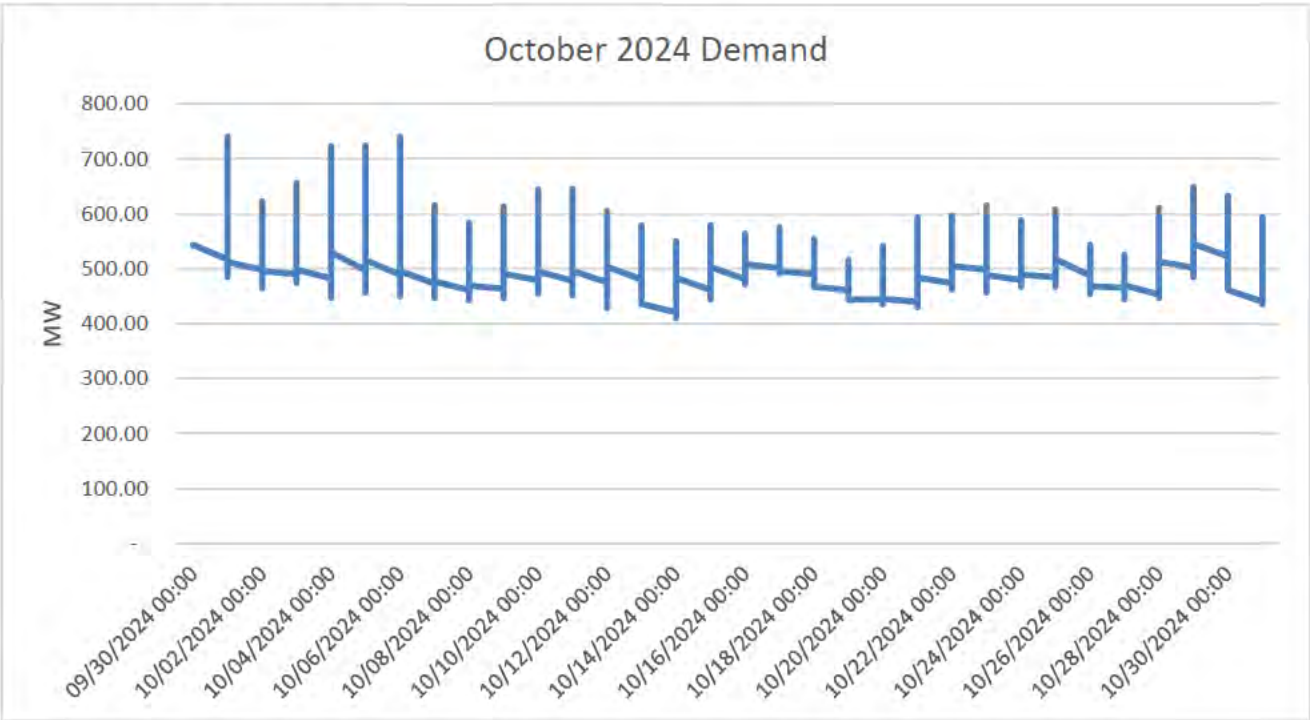


Figure 8-25- November Load

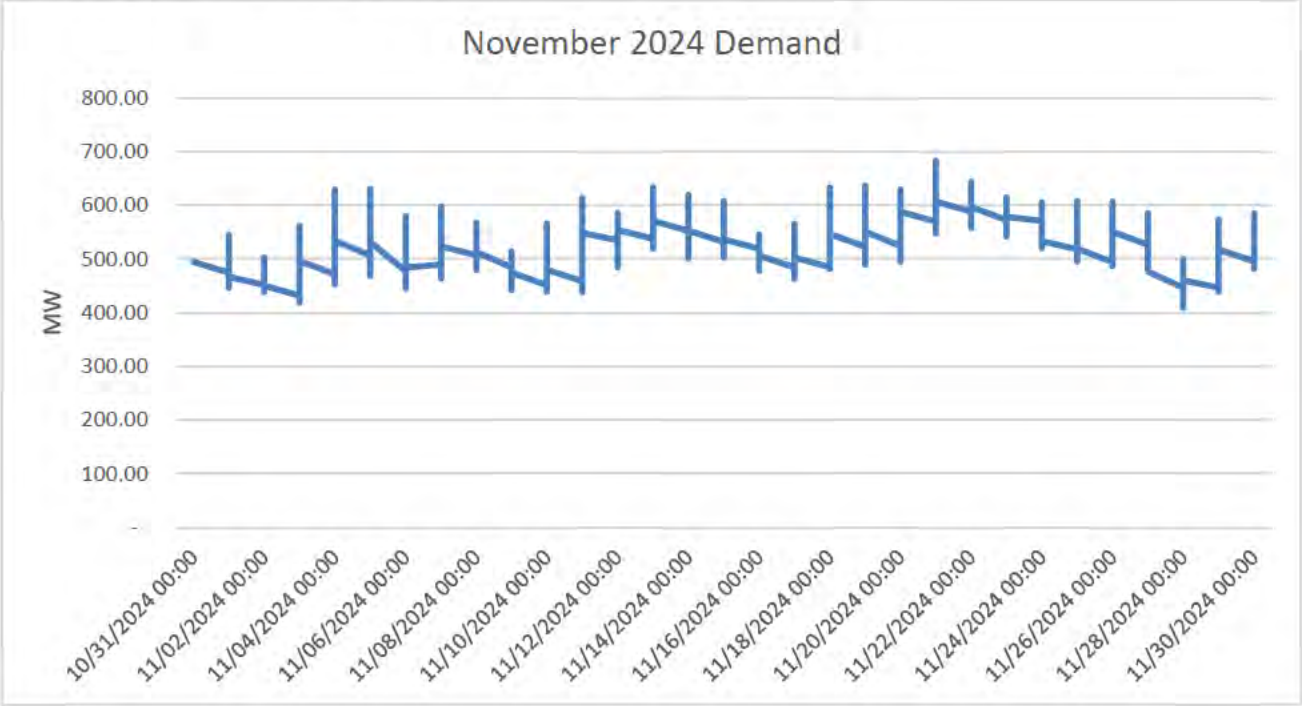


Figure 8-26- December Load



8.1.5. Advanced Metering Infrastructure and Continuous Improvement

CEI South has Advanced Metering Infrastructure (“AMI”). As described previously, the company continues to enhance the system with the use of edge computing applications that provide the company with valuable data to evaluate reliability and resiliency performance, and to find and correct items before they turn into issues that could affect customers. This information can be utilized to enhance forecasting and to perform more effective system planning and improved outage management resulting in better service and communications to customers. CEI South has been actively creating a system to help utilize AMI data for the CPP TOU rate. The pilot that is set to begin in Q2 2026, which has a time-based rate component and a demand response component, is enabled by the system that was put into place years ago. This program is intended to reduce system peak demand, mitigate capacity needs, and encourage cost efficient consumption behaviors. Incentivizing customers to lower consumption during the system’s most constrained hours reduces the need for peak generation resources and provides a mechanism to manage load during tight system conditions or during extreme weather events.

8.2. Environmental Appendix

8.2.1. Air Emissions

It was assumed that current or future generation resources would not exceed CEI South’s allocated annual SO_2 and NO_x emission allowances. CEI South’s fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NO_x emissions, while the cost of emission control equipment and NO_x is factored into any new natural gas-fired facilities, or in the case of a natural gas conversion for Culley Unit 3, that would be selected as part of a portfolio. In 2023 EPA promulgated the Good Neighbor Plan which required 23 states, including Indiana, to further lower existing caps for seasonal NO_x allowances to be allocated to emissions units in the affected states and creating a CSAPR NO_x Ozone Season Group 3 Trading Program which would become effective in the 2024 ozone season. However, on June 27, 2024, the US Supreme Court granted emergency stay petitions, staying implementation of the rule. EPA issued guidance on August 5, 2024, reestablishing the existing CSAPR NO_x Ozone Season Group 2 allowance caps. Air emissions allowance costs are accounted for within IRP modeling.

8.2.2. Solid Waste Disposal

Fly ash from the F.B. Culley facility that meets beneficial reuse specifications is transported off site for beneficial reuse in a cement application, while fly ash that does not meet beneficial reuse specifications is transported for disposal in a permitted local landfill. The F.B. Culley facility completed the conversion of the Unit 3 bottom ash system to a dry

system in December 2020 and similarly sends bottom ash to beneficial reuse or transported for disposal in a permitted local landfill. The F.B. Culley facility utilizes a GeoTube Containment Area that collects the bottom ash and drains the filtrate to a lined pond. The collected bottom ash is sent for beneficial reuse or landfilled. Additionally, the F.B. Culley facility completed the construction of a Spray Dryer Evaporator to handle the FGD Wastewater from the scrubber. The East Ash Pond (approximately 10 acres) no longer receives any waste streams and is in final stages of closure. The West Pond (32 acres) completed closure in December 2020. The closure project included the construction of a new geosynthetic lined contact storm water pond that receives the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is sent off-site for beneficial reuse via shipment by river barge from F.B. Culley to a wallboard manufacturer.

8.2.3. Hazardous Waste

CEI South's A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include outage or maintenance related wastes, paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

8.2.4. Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under NPDES wastewater discharge permits issued by the IDEM. A.B. Brown natural gas fired combustion turbines have closed-loop cooling systems, while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission ("ORSANCO") regional water quality standards mercury limit of 12 ppt monthly average.

8.3. DSM Appendix

8.3.1.1. DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level and costs of DSM to be offered in CEI South's service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for CEI South, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 3 years CEI South engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP

and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

8.3.1.2. Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. CEI South considers the results of each test and ensures that the portfolio passes the Total Resource Cost test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test (“UCT”)
- Total Resource Cost Test (“TRC”)

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company’s customer participating in the program. The test compares the participant’s bill savings over the life of the DSM program to the participant’s cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure (“RIM”) Test shows the impact of a program on all utility customers through impacts on average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The TRC Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by

program participants. In completing the tests listed above, CEI South used 6.77% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on December 5, 2023 in Cause No. 45990.

Figure 8-27 - CEI South Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

8.3.2. Gross Savings 2025-2027 Plan

Figure 8-28 - 2025-2027 Approved Plan Gross kWh Energy Savings

	2025		2026		2027	
Sector	**Gross kWh Energy Savings**	**Gross KW Demand Savings**	**Gross kWh Energy Savings**	**Gross KW Demand Savings**	**Gross kWh Energy Savings**	**Gross KW Demand Savings**
Residential	14,377,963	8,184	15,932,490	9,214	15,862,630	8,236
C&I	22,600,000	3,005	25,024,327	3,492	25,400,000	3,279
Total	**36,977,963**	**11,189**	**40,956,817**	**12,706**	**41,262,630**	**11,515**

8.3.3. DSM Programs

CEI South has offered tariff-based DSM resource options to customers for many years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all CEI South's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized CEI South to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

8.3.4. Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 8-29 - 2025 Electric DSM Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,978	74%	474,041	240	350,980	195	0 099	144
Residential Midstream	Residential	1,783	47%	1,841,874	1,033	874,256	581	0 326	276
Home Energy Assessment	Residential	478	100%	377,520	790	377,520	27	0 056	27
In Store Discount	Residential	4,575	100%	457,893	100	457,893	36	0 008	36
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0 969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0 001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0 197	19

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Income Qualified Weatherization	Residential	837	100%	779,346	931	779,346	83	0 099	83
Marketplace	Residential	7,209	100%	1,618,571	225	1,618,571	603	0 084	603
Residential Behavioral Savings	Residential	49,700	100%	6,125,117	123	6,125,117	1,850	0 037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1 100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1 100	1,430
Commercial Prescriptive	Commercial	13,047	84%	10,751,737	824	9,031,459	1,709	0 131	1,435
Commercial Midstream	Commercial	32	84%	448,263	14,008	376,541	53	1 658	45
Commercial Custom	Commercial	89	84%	5,600,000	62,921	4,704,000	754	8 468	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2 000	20
DSM Portfolio Total		**142,955**	**88%**	**36,977,963**	**259**	**32,483,256**	**11,189**	**0.078**	**10,345**

Figure 8-30 - 2026 Electric DSM Proposed Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	2,638	74%	427,293	162	314,238	166	0 063	122
Residential Midstream	Residential	2,642	48%	1,861,980	705	884,859	587	0 222	279
Home Energy Assessment	Residential	385	100%	473,865	1,231	473,865	35	0 091	35
In Store Discount	Residential	3,300	100%	532,856	161	532,856	40	0 012	40
Multi Family Energy Solutions	Residential	350	100%	369,015	1,054	369,015	25	0 072	25
Community Connections	Residential	28,040	100%	778,895	28	778,895	24	0 001	24
Residential New Construction	Residential	167	64%	78,637	471	50,609	30	0 181	19
Income Qualified Weatherization	Residential	800	100%	784,991	981	784,991	86	0 108	86
Marketplace	Residential	6,100	100%	1,694,556	278	1,694,556	632	0 104	632
Residential Behavioral Savings	Residential	62,000	100%	6,125,117	99	6,125,117	1,850	0 030	1,850
Smart Cycle (DLC Change Out)	Residential	2,500	100%	1,477,053	591	1,477,053	3,300	1 320	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,800	100%	0	0	0	1,430	0 794	1,430
Commercial Prescriptive	Commercial	13,003	84%	12,032,995	925	10,107,640	1,883	0 145	1,582
Commercial Midstream	Commercial	38	84%	567,005	14,921	476,284	82	2 150	69
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8 106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	5	100%	1,500,000	300,000	1,500,000	20	4 000	20
DSM Portfolio Total		**143,646**	**88%**	**40,956,817**	**285**	**36,158,538**	**12,706**	**0.088**	**11,836**

Figure 8-31 - 2027 Electric DSM Approved Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,724	73%	395,946	230	287,817	141	0 082	103
Residential Midstream	Residential	1,793	48%	1,896,389	1,058	902,894	597	0 333	284
Home Energy Assessment	Residential	748	100%	570,893	763	570,893	44	0 058	44
In Store Discount	Residential	7,275	100%	607,820	84	607,820	43	0 006	43
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0 969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0 001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0 197	19
Income Qualified Weatherization	Residential	907	100%	790,637	872	790,637	90	0 099	90
Marketplace	Residential	7,893	100%	1,772,227	225	1,772,227	661	0 084	661
Residential Behavioral Savings	Residential	49,700	100%	7,125,117	143	7,125,117	1,850	0 037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1 100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1 100	1,430
Commercial Prescriptive	Commercial	12,958	84%	12,824,803	990	10,767,584	1,964	0 152	1,649
Commercial Midstream	Commercial	33	84%	675,197	20,461	567,166	72	2 170	60
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8 106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2 000	20
DSM Portfolio Total		**146,351**	**88%**	**41,262,630**	**282**	**36,303,727**	**11,515**	**0.079**	**10,631**

8.3.5. Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed Operations and Maintenance ("O&M") cost. For this avoided cost analysis, a 235 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled CEI South system marginal energy cost from the Preferred Portfolio under Reference Case assumptions. This included estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below (Figure 8-32) shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 235 MW 1x F-class simple cycle gas turbine is avoided.

Figure 8-32 - Avoided Costs

Year	Avoided Capital/ O&M Cost ($/kW)	Transmission & Distribution Avoided Capital Cost ($/kW)	Total Capacity Avoided Cost ($/kW)	Natural Gas Forecast ($/MMBtu)	System Marginal Cost ($/MWh)
2026	$180.11	$13.74	**$193.85**	$3.48	$44.65
2027	$183.95	$13.58	**$197.53**	$3.76	$45.97
2028	$187.87	$13.72	**$201.59**	$4.08	$49.69
2029	$191.87	$14.16	**$206.03**	$4.39	$55.71
2030	$195.95	$14.62	**$210.57**	$4.62	$54.37
2031	$200.13	$14.30	**$214.42**	$4.82	$56.65
2032	20439%	$14.70	**$219.09**	$4.91	$57.73
2033	$208.74	$14.93	**$223.67**	$4.99	$59.41
2034	$213.19	$15.21	**$228.40**	$5.14	$48.46
2035	$217.73	$15.71	**$233.44**	$5.31	$58.75
2036	$222.37	$15.94	**$238.31**	$5.45	$60.34
2037	$227.11	$16.29	**$243.40**	$5.57	$60.95
2038	$231.94	$16.63	**$248.57**	$5.74	$62.16
2039	$236.88	$16.99	**$253.87**	$5.92	$63.85
2040	$241.93	$17.37	**$259.30**	$6.22	$66.94
2041	$247.08	$17.72	**$264.80**	$6.37	$66.63
2042	$252.34	$18.10	**$270.45**	$6.58	$66.70
2043	$257.72	$18.49	**$276.21**	$6.77	$69.91
2044	$263.21	$18.88	**$282.09**	$7.00	$70.70
2045	$268.82	$19.29	**$288.10**	$7.33	$69.87

8.3.6. Estimated Impact on Historical Forecasted Peak Demand and Energy

The load forecast developed by Itron incorporates CEI South's historical DSM in the residential and commercial models to account for historical program savings. The DSM variables help explain historical usage trends. For additional details on the impact of DSM on the forecast see *Technical Appendix Attachment 3.12025 CEIS Long-Term Electric Energy & Demand Forecast Report, Section 5.4 Historical DSM Savings*.

8.3.7. Appliance Saturation Survey

CEI South conducted a residential energy efficiency baseline survey which launched on February 17, 2025 and was closed on February 28, 2025. CEI South fielded forty-seven

(47) questions, which were developed with input from GDS (CEI South's Market Potential Study vendor), Itron, and the OSB. The survey contained a set of core questions with an option for customers to answer additional questions. CEI had 1,048 people who started the survey and 730 who completed the entire survey for a response rate of 5.4% out of the total number of people who received the survey. Survey responses informed the market potential study both qualitative, and quantitative in terms of saturation and efficiency levels of measures. The 2025 CNP Residential Energy Efficiency Baseline Survey presentation can be found in *Technical Appendix Attachment 3.7*. The results of the 2025 Survey will be incorporated into the sales and demand forecasts in future IRPs.

8.4. Risk Appendix

The probabilistic risk assessment allows for the development of portfolio results based on a range of randomly sampled input values. Specifically, it evaluates uncertainty around coal, natural gas, CO_2, and MISO energy prices, peak load, capital costs for new renewable, thermal, and storage resources, and market energy sales. With the uncertainty around the variables defined by probability distributions, the variables were modeled stochastically using Encompass's Monte Carlo sampling capability. Stochastically developed inputs allow for the testing of each portfolio's performance across a wide range of probable market conditions. The development of probability distributions around uncertainty variables, combined with running these distributions through a stochastic process to develop 200 sets of inputs, is key to the probability risk assessment approach. The probability distributions used in the assessment are described in more detail below.

8.4.1. Stochastics (Probabilistic Modeling)

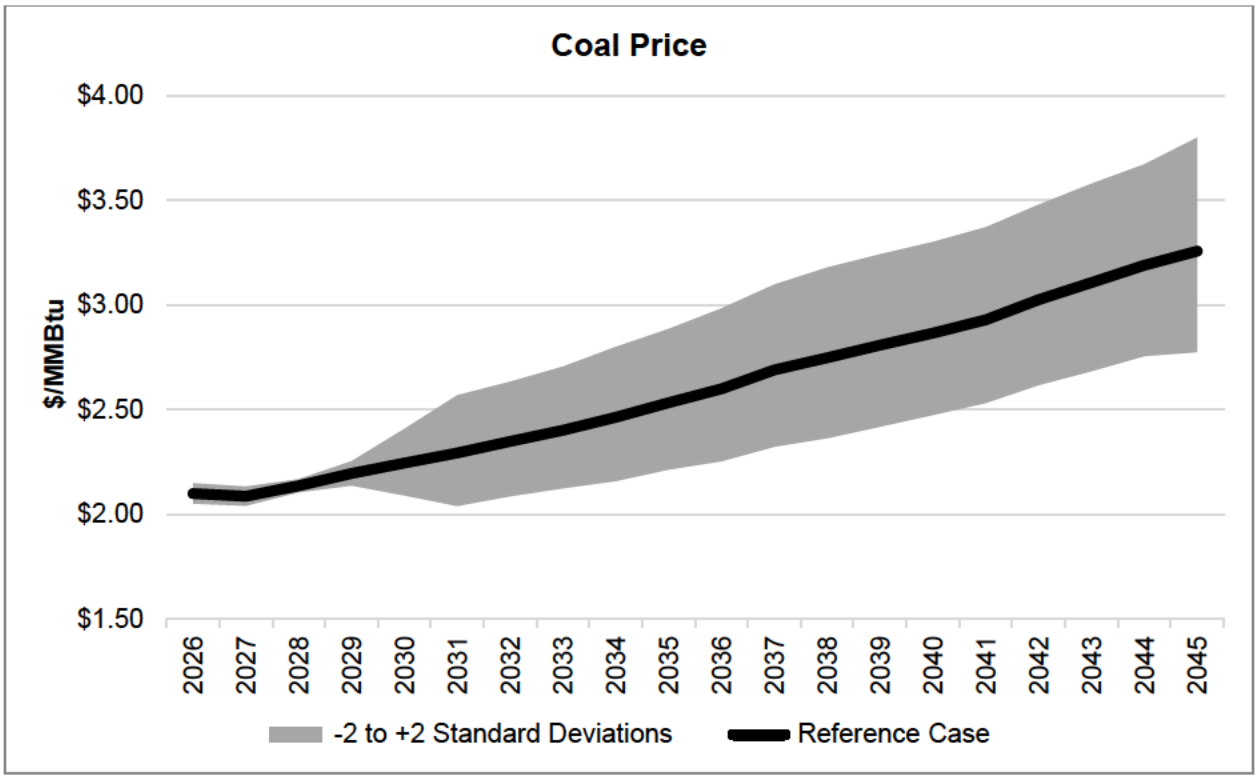
To perform the stochastics (probabilistic modeling), a set of probability distributions that characterize uncertainty was required for each of the key variables described above (coal prices, natural gas prices, MISO energy prices, peak demand, CO_2 prices, capital costs for new resources, and market sales). Monthly lognormal probability distributions were assumed for coal prices, natural gas prices, and peak demand. For the other variables, discrete distributions were developed at varying time intervals: hourly for MISO energy prices, monthly for sales limits, and annually for CO_2 prices and new resource capital costs. The lognormal probability distributions were stochastically simulated together in EnCompass with cross-variable correlation using Monte Carlo Sampling. This produced 200 sets of correlated inputs for coal prices, natural gas prices and peak demand. These stochastic runs in EnCompass assumed 100 percent mean reversion. The discrete distributions for MISO energy prices, CO_2 prices, new resource capital costs, and sales limits were then randomly assigned to each of the 200 stochastic iterations. These input sets were individually run through the dispatch model in EnCompass with each of 12

selected portfolios for a total of 2,400 simulations. The following sections describe the methodologies for developing the stochastic variables.

8.4.1.1. Coal Price Uncertainty

To define the uncertainty around coal prices to be used in the stochastic modeling, 1898 & Co. relied on a base, high and low coal price forecast from U.S. Energy Information Administration's ("EIA") 2025 Annual Energy Outlook ("AEO"). Specifically, 1898 & Co. developed annual standard deviations based on the EIA's Interior Minemouth price forecasts for the Reference Case, High Oil Price Case, and the Alternative Electricity Case. These annual standard deviations were converted to monthly standard deviations, which were then divided by EIA Interior Minemouth Reference Case pricing to arrive at percent standard deviations for coal pricing. The monthly percent standard deviations were then applied to the IRP consensus Reference Case pricing to impute a monthly lognormal probability distribution for coal pricing. These monthly distributions of coal prices were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. Figure 8-33 displays the base coal forecast as well as two standard deviations from the mean.

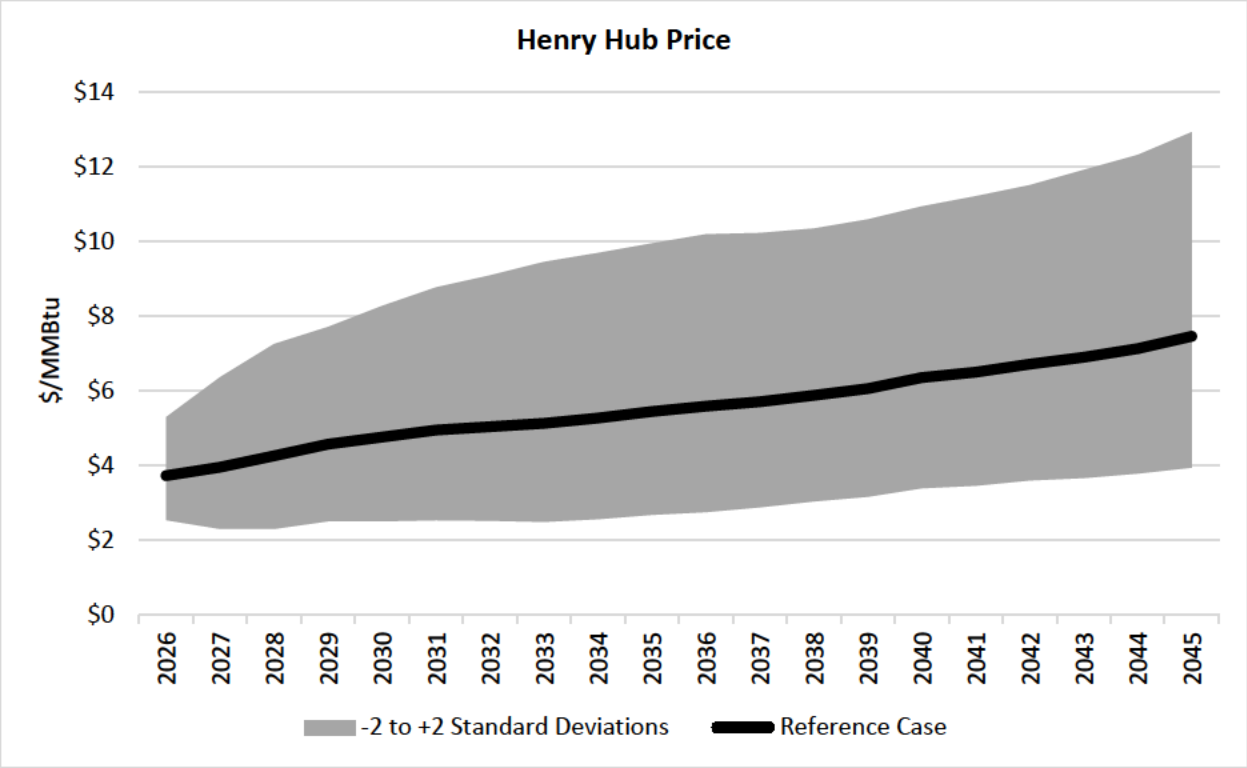
Figure 8-33 - Coal Price Distribution (Nominal$/MMBtu)



8.4.1.2. Natural Gas Price Uncertainty

To define the uncertainty around natural gas prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low Henry Hub natural gas price forecast using data from Hitachi (ABB). Specifically, 1898 & Co. developed monthly standard deviations from the base, high and low forecasts, divided the result by the base price forecast to arrive at a percent standard deviation. The monthly percent standard deviations were then applied to the consensus Reference Case pricing to impute a monthly lognormal probability distribution for natural gas pricing. These monthly natural gas price distributions were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. An illustration of the Reference Case natural gas forecast as well as its uncertainty is given in Figure 8-34.

Figure 8-34 - Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)

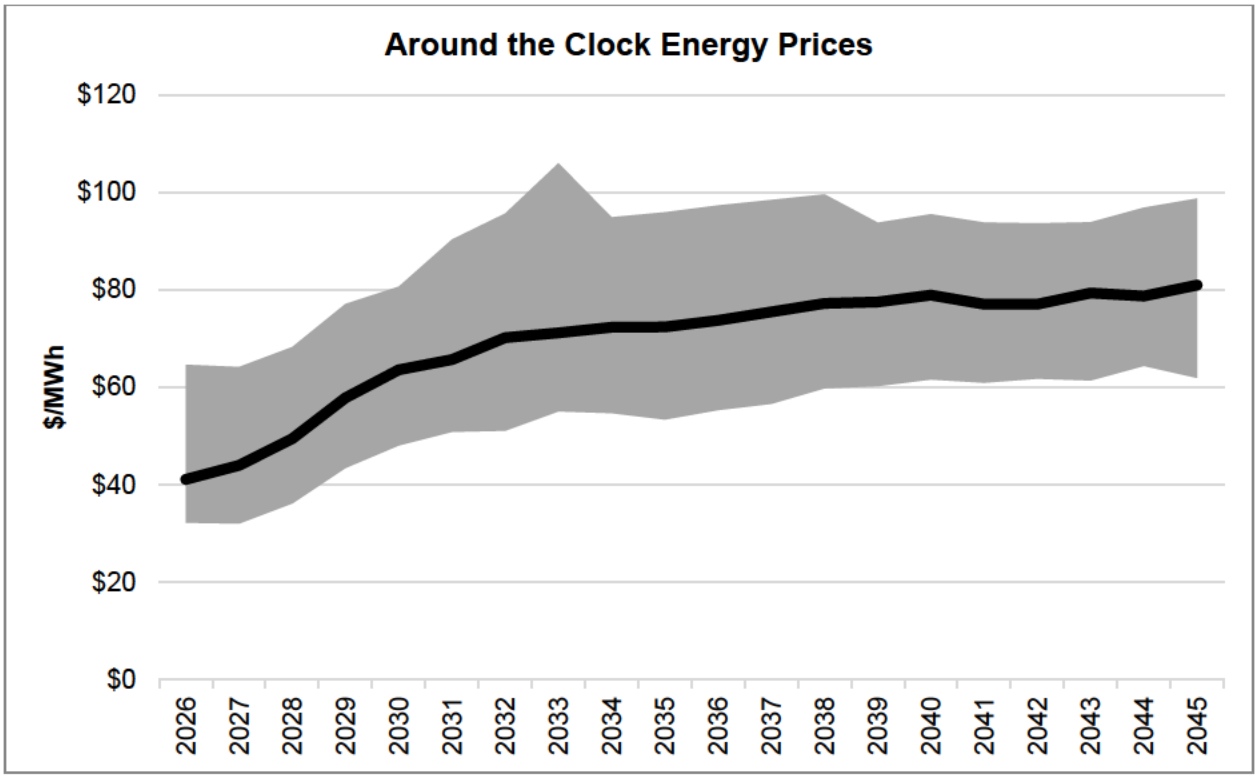


8.4.1.3. Energy Price Distribution

1898 & Co. updated energy prices that were input into EnCompass for each of the 200 draws. 1898 & Co. used the national database licensed from Horizon Energy, LLC as the starting point for creating the energy prices. Using the different IRP scenarios, unique energy price forecasts were developed. The energy prices and associated natural gas prices from the scenario model runs were used to develop monthly implied market heat

rate curves. These monthly implied market heat rates were applied to the monthly natural gas price for the 200 iterations to arrive at monthly energy prices for each iteration.

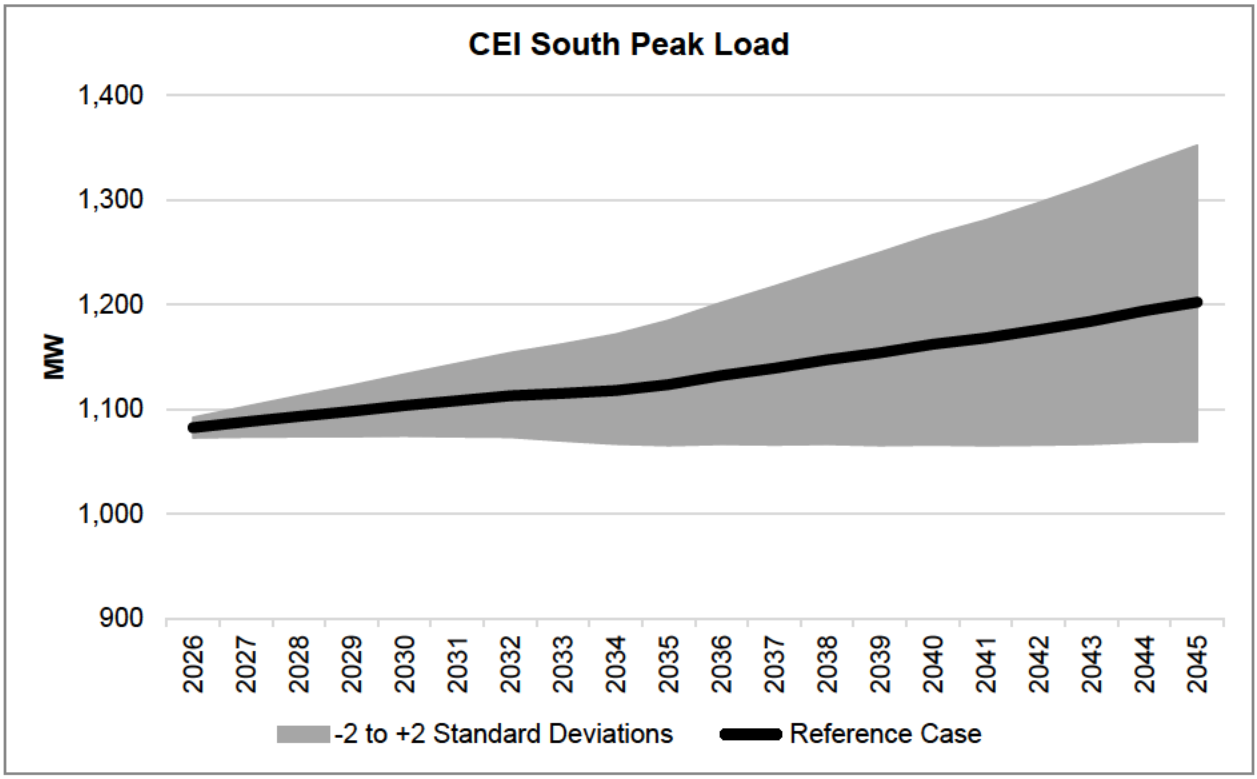
Figure 8-35 - Stochastic Inputs Energy Prices – Market Forecast



8.4.1.4. Load Uncertainty

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, 1898 & Co. relied on monthly peak load forecasts developed by CEI South's vendor, Itron. Itron developed base high and low peak demand forecasts. Using these forecasts, 1898 & Co. calculated monthly peak demand standard deviations which were applied to a lognormal distribution to represent the probability of monthly peak demand within the stochastic modeling framework. Figure 8-36 below shows uncertainty around peak loads.

Figure 8-36 - CEI South Load Distribution (Megawatts)



8.4.1.5. CO_2 Emissions Price Uncertainty

No CO_2 emissions prices are assumed for the Reference Case, rather CO_2 prices are assumed for the High Regulatory scenario. Because of these assumptions, CO_2 price uncertainty is assigned on a discrete basis. Specifically, 1898 & Co. randomly assigned a zero price for CO_2 for 150 iterations out of the 200 iterations of stochastic inputs and the CO_2 price from the High Regulatory scenario for 50 iterations.

8.4.1.6. Capital Cost Uncertainty

1898 & Co. developed base, high, and low capital cost assumptions for renewable, thermal, and storage resources used in the scenario analyses. For technologies that had a purchase option submitted to the 2024 All-Source RFP – namely storage, solar and solar plus storage – the base forecast was developed using the average purchase price for received bids. For wind resources, the technology assessment was combined with data collected for wind Power Purchase Agreements ("PPA") received during the 2024 All Source RFP to create an estimate that reflected current market conditions. The proposals reflect current near-term purchase options and were forecasted through the study period using capital cost estimates from the NREL. The low forecast follows a similar methodology; however, it uses

the lowest received purchase price as a starting point and then trends linearly to the NREL reference case cost in 2045. In contrast, the high forecast begins with the highest bid price and then escalates throughout the study period at the assumed inflation rate (2.13%).

For technologies that did not have a purchase option submitted in the recent RFP, the technology assessment provided a starting point for cost estimates. Specifically, for nuclear and thermal technologies, the technology assessment cost estimate was used for a starting price, which was then forecasted to follow the moderate NREL curve. The low forecast follows the same methodology, starting at the technology assessment data point and then following the low NREL cost curve. Finally, the high forecast begins at the same point and then escalates through the study period at the assumed escalation rate.

Since the base, high and low capital costs were developed based on fundamental assumptions and do not conform to a specific probability distribution type, the costs were treated as discrete distributions and assigned to the 200 iterations for inclusion in the stochastic inputs. Low capital costs were assigned to the first 50 stochastic iterations, base (Reference Case) capital costs to the next 100, and high capital costs to the final 50 iterations. Because it is unlikely capital costs would stay high or low for every year of the study period, the order of iterations was randomly shuffled every four years prior to the 50/100/50 iteration assignments. With this approach, any one iteration would have a combination of base, high and low capital costs in four year segments.

The following figures provide examples of capital cost curves from each resource category. Note that these diagrams are provided without the adder for Allowance for Funds Used During Construction (“AFUDC”), which was applied to the capital costs seen in the EnCompass Model.

Figure 8-37 - Lithium-Ion 100 MW/400 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,273	$1,955	$2,591	$1,805
2027	$2,273	$1,955	$2,591	$1,786
2028	$2,273	$1,955	$2,591	$1,765
2029	$2,244	$1,948	$2,646	$1,742
2030	$2,212	$1,942	$2,703	$1,718
2031	$2,227	$1,936	$2,760	$1,729
2032	$2,241	$1,930	$2,819	$1,740
2033	$2,255	$1,924	$2,879	$1,751
2034	$2,269	$1,918	$2,940	$1,762
2035	$2,282	$1,912	$3,003	$1,772
2036	$2,294	$1,905	$3,067	$1,782
2037	$2,307	$1,899	$3,132	$1,791
2038	$2,318	$1,893	$3,199	$1,800
2039	$2,329	$1,887	$3,267	$1,809
2040	$2,340	$1,881	$3,336	$1,817
2041	$2,350	$1,875	$3,407	$1,825
2042	$2,359	$1,869	$3,480	$1,832
2043	$2,367	$1,862	$3,554	$1,838
2044	$2,375	$1,856	$3,630	$1,845
2045	$2,382	$1,850	$3,707	$1,850

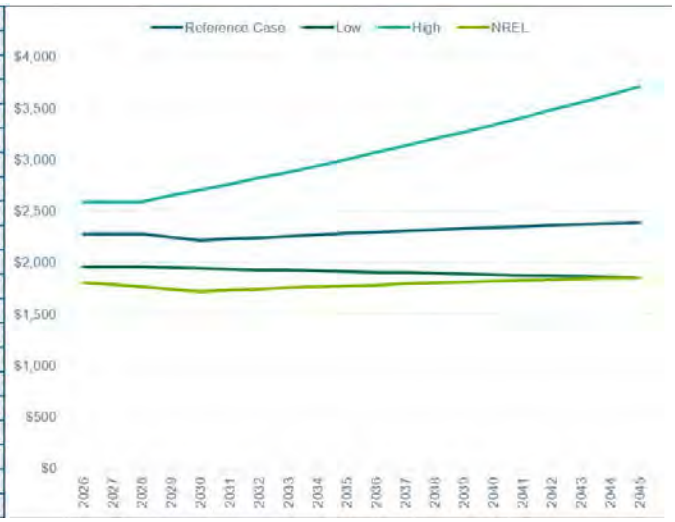


Figure 8-38 - Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,351	$1,895	$2,750	$1,558
2027	$2,351	$1,895	$2,750	$1,525
2028	$2,351	$1,895	$2,750	$1,490
2029	$2,351	$1,895	$2,750	$1,452
2030	$2,287	$1,853	$2,809	$1,413
2031	$2,219	$1,811	$2,868	$1,371
2032	$2,147	$1,769	$2,929	$1,326
2033	$2,071	$1,727	$2,992	$1,279
2034	$1,991	$1,685	$3,056	$1,230
2035	$1,906	$1,643	$3,121	$1,177
2036	$1,916	$1,601	$3,187	$1,183
2037	$1,925	$1,559	$3,255	$1,189
2038	$1,934	$1,517	$3,324	$1,195
2039	$1,943	$1,475	$3,395	$1,200
2040	$1,950	$1,433	$3,467	$1,205
2041	$1,958	$1,391	$3,541	$1,209
2042	$1,965	$1,350	$3,616	$1,213
2043	$1,971	$1,308	$3,693	$1,217
2044	$1,976	$1,266	$3,772	$1,221
2045	$1,981	$1,224	$3,852	$1,224

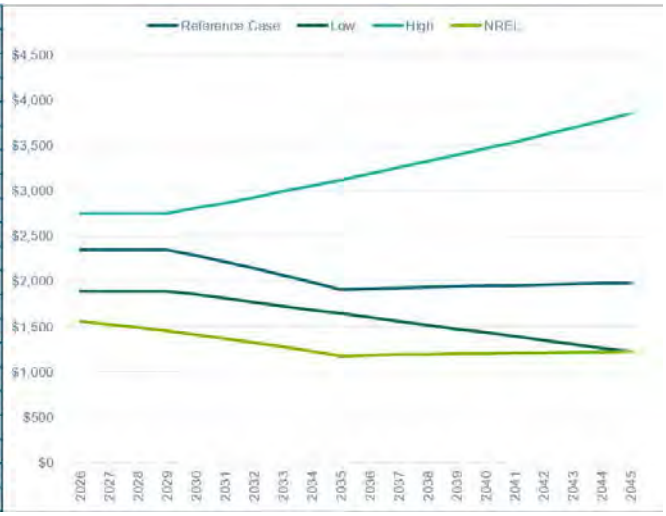


Figure 8-39 – Solar plus Storage Capital Costs Alternate Scenarios (100 + 50 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$3,492	$2,722	$4,500	$2,384
2027	$3,492	$2,722	$4,500	$2,342
2028	$3,492	$2,722	$4,500	$2,296
2029	$3,492	$2,722	$4,500	$2,248
2030	$3,412	$2,681	$4,596	$2,196
2031	$3,359	$2,641	$4,694	$2,163
2032	$3,303	$2,600	$4,794	$2,126
2033	$3,243	$2,559	$4,896	$2,088
2034	$3,178	$2,519	$5,000	$2,046
2035	$3,110	$2,478	$5,106	$2,002
2036	$3,125	$2,438	$5,215	$2,012
2037	$3,139	$2,397	$5,326	$2,021
2038	$3,152	$2,357	$5,440	$2,029
2039	$3,165	$2,316	$5,555	$2,037
2040	$3,176	$2,276	$5,674	$2,045
2041	$3,187	$2,235	$5,794	$2,052
2042	$3,197	$2,194	$5,918	$2,058
2043	$3,206	$2,154	$6,044	$2,064
2044	$3,213	$2,113	$6,173	$2,069
2045	$3,220	$2,073	$6,304	$2,073

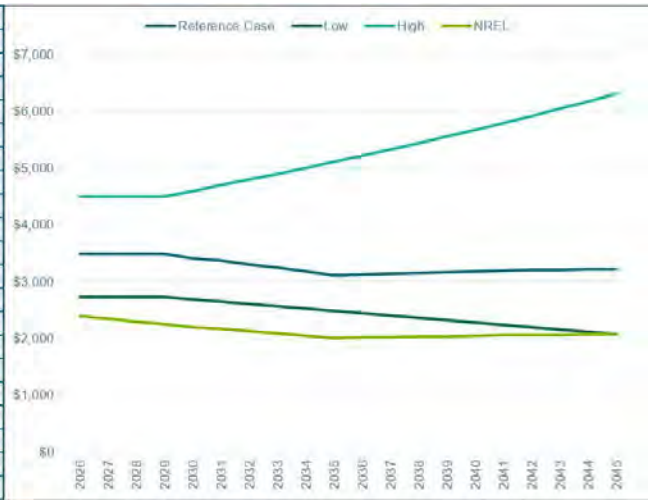


Figure 8-40 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,195	$1,625	$2,611	$1,672
2027	$2,195	$1,641	$2,667	$1,672
2028	$2,193	$1,657	$2,724	$1,671
2029	$2,191	$1,673	$2,782	$1,669
2030	$2,188	$1,689	$2,841	$1,666
2031	$2,211	$1,705	$2,902	$1,684
2032	$2,234	$1,721	$2,963	$1,702
2033	$2,258	$1,737	$3,026	$1,720
2034	$2,281	$1,753	$3,091	$1,737
2035	$2,304	$1,769	$3,157	$1,755
2036	$2,327	$1,785	$3,224	$1,773
2037	$2,351	$1,801	$3,292	$1,791
2038	$2,374	$1,817	$3,363	$1,808
2039	$2,397	$1,833	$3,434	$1,826
2040	$2,420	$1,849	$3,507	$1,843
2041	$2,442	$1,865	$3,582	$1,861
2042	$2,465	$1,881	$3,658	$1,878
2043	$2,488	$1,897	$3,736	$1,895
2044	$2,510	$1,913	$3,816	$1,912
2045	$2,532	$1,929	$3,897	$1,929

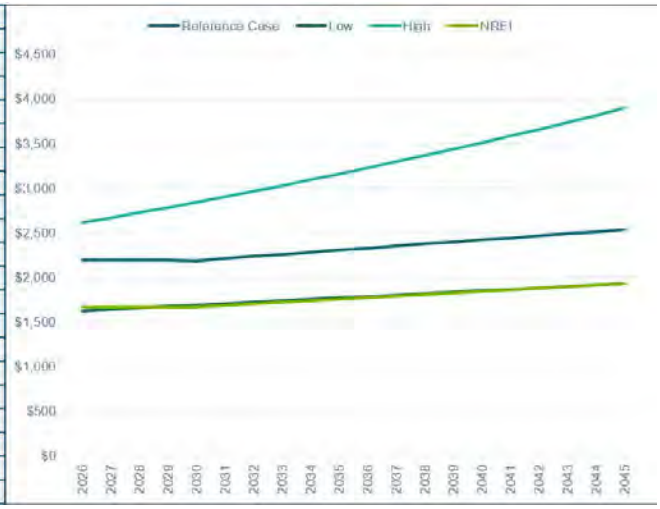


Figure 8-41 – 1x1 J Class Unfired CCGT Capital Costs Alternate Scenarios (620 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,065	$2,061	$2,082	$1,579
2027	$2,092	$2,083	$2,127	$1,599
2028	$2,119	$2,106	$2,172	$1,620
2029	$2,146	$2,128	$2,218	$1,640
2030	$2,173	$2,151	$2,266	$1,661
2031	$2,200	$2,173	$2,314	$1,682
2032	$2,228	$2,195	$2,363	$1,703
2033	$2,255	$2,217	$2,413	$1,724
2034	$2,283	$2,239	$2,465	$1,745
2035	$2,311	$2,262	$2,517	$1,767
2036	$2,342	$2,290	$2,571	$1,791
2037	$2,374	$2,319	$2,626	$1,815
2038	$2,406	$2,348	$2,681	$1,839
2039	$2,438	$2,377	$2,739	$1,864
2040	$2,471	$2,407	$2,797	$1,889
2041	$2,503	$2,436	$2,856	$1,914
2042	$2,536	$2,466	$2,917	$1,939
2043	$2,570	$2,496	$2,979	$1,964
2044	$2,603	$2,526	$3,043	$1,990
2045	$2,637	$2,556	$3,108	$2,016

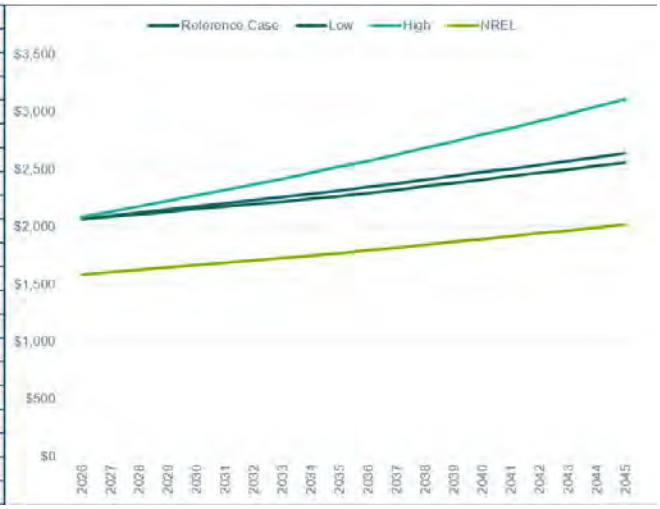


Figure 8-42 – J Class SCGT Capital Costs Alternate Scenarios (426 MW) ($/kW)[42]

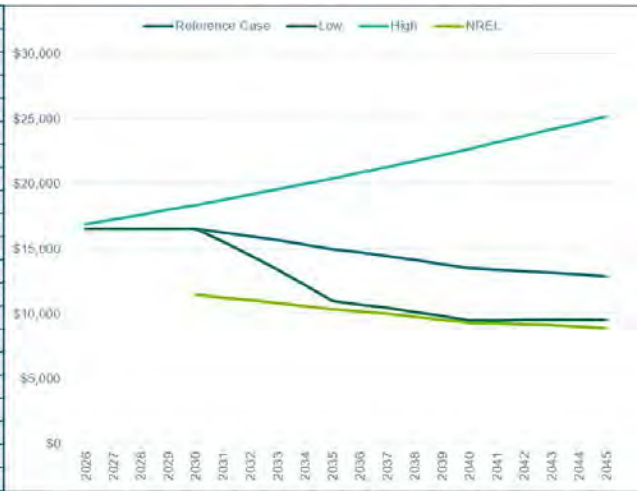
Year	Reference Case	Low	High	NREL
2026	$1,206	$1,206	$1,215	$1,425
2027	$1,223	$1,223	$1,241	$1,444
2028	$1,239	$1,239	$1,268	$1,464
2029	$1,256	$1,256	$1,295	$1,484
2030	$1,273	$1,273	$1,322	$1,504
2031	$1,290	$1,290	$1,350	$1,524
2032	$1,307	$1,307	$1,379	$1,544
2033	$1,325	$1,325	$1,408	$1,565
2034	$1,342	$1,342	$1,438	$1,585
2035	$1,360	$1,360	$1,469	$1,606
2036	$1,378	$1,378	$1,500	$1,627
2037	$1,396	$1,396	$1,532	$1,649
2038	$1,414	$1,414	$1,565	$1,670
2039	$1,432	$1,432	$1,598	$1,692
2040	$1,451	$1,451	$1,632	$1,713
2041	$1,469	$1,469	$1,667	$1,735
2042	$1,488	$1,488	$1,703	$1,757
2043	$1,506	$1,506	$1,739	$1,779
2044	$1,525	$1,525	$1,776	$1,802
2045	$1,544	$1,544	$1,814	$1,824



[42] For combustion turbines, the NREL base, low, and high curves are all identical. As such, the low and Reference Case curves are identical for this analysis. The high curve, as stated previously, is based on inflation and therefore remains unique.

Figure 8-43 – Advanced Nuclear (SMR) Capital Costs Alternate Scenarios (300 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$16,528	$16,528	$16,880	
2027	$16,528	$16,528	$17,239	
2028	$16,528	$16,528	$17,606	
2029	$16,528	$16,528	$17,981	
2030	$16,528	$16,528	$18,364	$11,422
2031	$16,255	$15,523	$18,755	$11,233
2032	$15,962	$14,469	$19,154	$11,031
2033	$15,650	$13,362	$19,562	$10,815
2034	$15,317	$12,201	$19,979	$10,585
2035	$14,963	$10,986	$20,404	$10,340
2036	$14,703	$10,717	$20,839	$10,161
2037	$14,425	$10,432	$21,282	$9,968
2038	$14,128	$10,130	$21,735	$9,763
2039	$13,812	$9,811	$22,198	$9,545
2040	$13,477	$9,473	$22,671	$9,313
2041	$13,378	$9,489	$23,153	$9,245
2042	$13,269	$9,501	$23,646	$9,169
2043	$13,149	$9,509	$24,150	$9,086
2044	$13,017	$9,513	$24,664	$8,996
2045	$12,875	$9,514	$25,189	$8,897



8.4.1.7. Market Sales Limits

In order to ensure the economic viability of portfolios independent of market sales, 1898 & Co. imposed a limit on energy market sales within the stochastic portfolios. This limit follows a discrete distribution with one third of draws randomly assigned 660 MW, one third assigned 330 MW, and one third assigned a 165 MW limit. 660 MW was chosen as the highest sales limit because that is approximately the capability of the physical transmission system today and thus a reasonable boundary for the IRP modeling. The lower limits, scaled to 50% and 25% of the maximum, account for the risk of lower market sales than projected under current model assumptions.

8.4.2. Rate Metric Ranking

Figure 8-44 provides the cost of each portfolio on a per kWh basis.

Figure 8-44 – Portfolio Cost Rate (¢/kWh)

Portfolio Number	Portfolio Description	(¢/kWh)
2	FBC3 NG 2035	6.50¢
1	Reference Case	6.52¢
8	Low Reg	6.58¢
12	Delayed Reference	6.71¢
11	FBC3 Co-Fire	6.74¢
3	FBC3 on Coal	7.05¢
10	Alt High Reg	7.37¢
9	High Reg	7.52¢
5	FBC3 to SCGT	7.53¢
6	Renewable Heavy	7.54¢
7	FBC3 NG with Renewables	7.65¢
4	FBC3 to SMR	7.79¢

8.5. Transmission Appendix

8.5.1. MISO Regional Transmission Planning

MISO performs the NERC functional role of Planning Coordinator on behalf of CEI South. In its NERC functional role of Transmission Planner, CEI South supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. CEI South is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

CEI South participates in MISO coordinated Seasonal Transmission Assessments ("CSA") for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. CEI South also participates in MISO Generator

Interconnection (“DPP”) and Transmission Service Requests (“TSR”) planning processes as required.

CEI South participates in MISO’s regional Transmission Expansion Plan (“MTEP”). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports the development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved the LRTP Tranche 2.1 portfolio during the MTEP 2024 planning cycle. 24 transmission projects (MISO LRTP ID #19-42) were approved across the MISO Midwest, including ID #35 which includes major transmission investments in the SIGE region. The project has a targeted completion date of 2032 per MISO. The various upgrades included in LRTP project #35 consist of a new 345/138kV, 400MVA transformer at A.B. Brown substation, a new 345kV line from Duff substation to the new 765/345kV Pike County substation (AEP/DEI), a new 345kV line from Duff substation to the F.B. Culley area, and a new 345kV line from the Culley area to the Ohio River Crossing. From the river crossing, the 345kV line will continue to BREC Reid substation. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line from the Ohio River crossing to BREC Reid substation. This project in Kentucky was awarded to Republic Transmission, LLC. CEI South, as the incumbent transmission owner, is responsible for all other modifications required for the project, apart from the terminal at BREC Reid substation. The overall project cost will be shared according to MISO’s Tariff. The Tranche 2.1 projects will provide regional economic benefits and enhanced grid reliability for the CEI South region looking into the future as generation and load profiles change across the Midwest.

8.5.2. Annual Transmission Assessment

CEI South’s most recent transmission assessment was completed in 2025. The study used MISO MTEP24 models for the year 2029 representing transmission system conditions in the winter season, summer season, and off-peak, light load conditions. The study used CEIS transmission system performance criteria as documented in VEC-008 Electric Transmission Planning Criteria as a measure to determine the strength of the SIGE transmission system. Siemens PTI PSS/E (version 35.6) software was used to conduct the assessment. The study also uses SIGE transmission ratings methodology as

documented in VEC-014 which was applied to all existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (“FDNS”) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled, and VAR limits applied automatically. Dynamic simulations were not completed in 2025, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with the MTEP24 annual assessment with MISO.

The scope of this 2025 study involved several key assessments as shown below.

- Overall Reliability Assessment using NERC TPL-001 “Transmission System Planning Performance Requirements” criteria
- Reactive Power Deficiency Assessment
- Assessment of MISO Tranche 2.1 approved projects
- SIGE Import and Export Capability Assessment
- Review of the 2025 Long-Range Distribution Plan

Overall, the CEI South Bulk Electrical System (100kV and above) is expected to be stable and perform well through 2034. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, CEI South plans projects to mitigate the violations.

8.5.3. DSM Impacts on Transmission and Distribution Systems

Potential future DSM interconnection requests are currently being studied, per the planning criteria outlined in VEC-008 Electric Transmission Planning Criteria (*Technical Appendix Attachment* 3.9). If VEC-008 does not address applicable planning criteria, CEI South defaults to MISO’s criteria.

At this time, no controllable loads or demand side management resources exist on CEI South’s transmission system.

8.6. Public Advisory Process Appendix

As defined by 170 IAC, the public advisory process refers to a set of procedures that provide customers and interested parties with the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility's IRP.

Highlights:

- CEI South views the public as an essential partner in developing our integrated resource plan and therefore strives to conduct an inclusive stakeholder process that encourages feedback.

- CEI executive leadership and subject matter experts attended public meetings to hear feedback and respond to questions.

- CEI South held four public (in person and virtual) meetings. An average of 70 individuals, representing local residents and over 30 organizations, registered for the public meetings.

- Three virtual technical meetings were held with interested stakeholders who signed an NDA. Leadership and subject matter experts attended the technical meetings to hear feedback and respond to questions.

- Stakeholder feedback made an impact on various aspects of the IRP, including assumptions, scenarios, sensitivities, and scorecard metrics.

8.6.1. Foundational Elements

Framework

Ensuring meaningful and sustained stakeholder engagement is crucial to the public advisory process. CEI South's Stakeholder Engagement Framework serves as a guide for fostering substantive and impactful discourse. The Framework is built on four objectives: Inform, Consult, Involve, and Collaborate. Figure 8-45 highlights the alignment among a sample of CEI's engagement activities and the Framework objectives.

Figure 8-45 - Stakeholder Engagement Framework



Stakeholders

CEI South's IRP development is a robust process involving input from many stakeholders, including, but are not limited to, CEI South residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials.

8.6.2. Engagement Resources and Strategies

Given the significant impact IRP decisions can have, conducting the IRP with transparency and full participation from interested stakeholders is essential. CEI South implemented engagement resources and strategies to encourage wide participation.

Engagement Resources

Website

Throughout the 2025 IRP process, CEI South's IRP website[43] served as an information hub for stakeholders. Meeting materials (presentations and post-meeting summaries) as well as the registration links for public meetings were published on the site. Prior IRP materials are also available on the website.

Meeting Notifications

CEI South maintains a confidential IRP stakeholder contact list. With over 300 individual contacts, the list includes CEI South customers, advocates, technical/industry experts, regulators, elected officials, etc. The list is updated throughout the IRP process to ensure new registrants or interested individuals are added. Those on the list received several meeting-related notifications: 1) invitations and reminders to register for meetings via the posted registration link, 2) meeting reminders for registrants, 3) posting of meeting presentation prior to the meeting, and 4) posting of meeting summary after the meeting.

Email Communications

CEI South continued to use a dedicated IRP email address for IRP-related communications. The simple and singular email address provided an easy method for stakeholders to stay involved and engaged outside the public meetings. Stakeholders' written requests for information and CEI South's subsequent responses were also administered through irp@centerpointenergy.com.

File Share

Technical stakeholders, with signed NDAs, were provided access to a secure file share site. The site served as a repository for modeling files and other detailed data and inputs used in the development of the 2025 IRP. The data release schedule and data type were included in the public and Tech-to-Tech meeting presentations.

Engagement Strategies

Stakeholder Meetings

CEI South again engaged 1898 & Co., a third-party consultant and facilitator, to assist in facilitation and support CEI SOUTH's focus on conducting the IRP with full participation from stakeholders. In collaboration with 1898, CEI South hosted four public stakeholder meetings and three technical meetings during the 2025 IRP process. Highlighting the

[43] CEI South, Integrated Resource Plan website available at https://www.centerpointenergy.com/irp

importance of the meetings, CEI South executive leadership actively participated as presenters and subject matter experts.

Presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling methodology, planned sensitivities and analytical results. To ensure ample opportunity for participants to ask questions, provide feedback, and share information, designated Q&A and feedback periods were included in the agendas. If feedback was received following the meetings, questions were answered via e-mail (irp@centerpointenergy.com) and/or during subsequent public or tech-to-tech meetings, as appropriate.

Public Meetings
In a continued effort to remove barriers to participation, CEI South provided both in-person and virtual attendance options. The CenterPoint Plaza in Evansville, Indiana served as the meeting location for the in-person option. Meeting presentations and meeting summaries, in question-and-answer format, were posted to CEI South's IRP website seven calendar days prior to the meeting and 15 calendar days following the meeting, respectively.

Figure 8-46 is a summary of the stakeholder meetings, see *Technical Appendix Attachment 4.2 Stakeholder Materials* for a comprehensive account of stakeholder meetings, presentations, and meeting summaries.

Figure 8-46 - 2025 Stakeholder Meeting Schedule



Meeting one laid the foundation of CEI South's IRP by providing an overview of the IRP process, metrics, inputs, and assumptions. In the spirit of continuous improvement, past stakeholder feedback and 2025 IRP enhancements were also covered.

2025 IRP Enhancements

1. *5 pillar-focused score card*
2. *Refreshed IRP layout*
3. *Expanded sensitivity analysis*
4. *Collaboration with Transmission & Distribution*
5. *Additional analysis of underserved energy*
6. *Data release schedule*

Meeting two, as with meetings three and four, opened with a review of stakeholder feedback and requests. Presenters also provided updates for ongoing work and furthered the discussion of inputs, modeling assumptions, portfolio methodology. A preview of the draft Reference Case modeling was also provided.

Meeting three began with an update on CEI South's generation transition timeline, followed by a review of stakeholder feedback and requests. Topics included the DSM Market Potential Study results, updates on scenario revisions and probabilistic modeling, as well as initial scenario optimization and deterministic portfolio results.

Meeting four also started with stakeholder feedback and requests. The last of the stakeholder meetings, meeting four covered the Preferred Portfolio, Alternative Preferred Portfolio and near-term action plan, as well as examined each portfolio's capacity, energy mix, and associated benefits and challenges. Presenters also shared the detailed risk metrics via a scorecard, reviewed an alternate reference case and optimization outcomes, presented sensitivity analyses, and concluded with a summary of key takeaways.

Tech-to-Tech

Tech-to-Tech meetings were held virtually and facilitated by 1898 & Co. While the meeting dates were made public, attendance was limited to self-identified technical stakeholders with executed NDAs. NDAs were provided to technical stakeholders upon request. Members of Indiana Office of Utility Consumer Counselor, Citizens Action Coalition, Reliable Energy, Sierra Club, State Utility Forecasting Group, and Indiana Utility Regulatory Commission staff were invited to attend these meetings.

The meetings allowed CEI South to share and consult with technical stakeholders on detailed, and often confidential, modeling assumptions and inputs. They also had the added benefit of increasing transparency in the planning process. Tech-to-Tech meeting dates and agendas are listed below (Figure 8-47):

Figure 8-47 - 2025 Tech-to-Tech Meetings



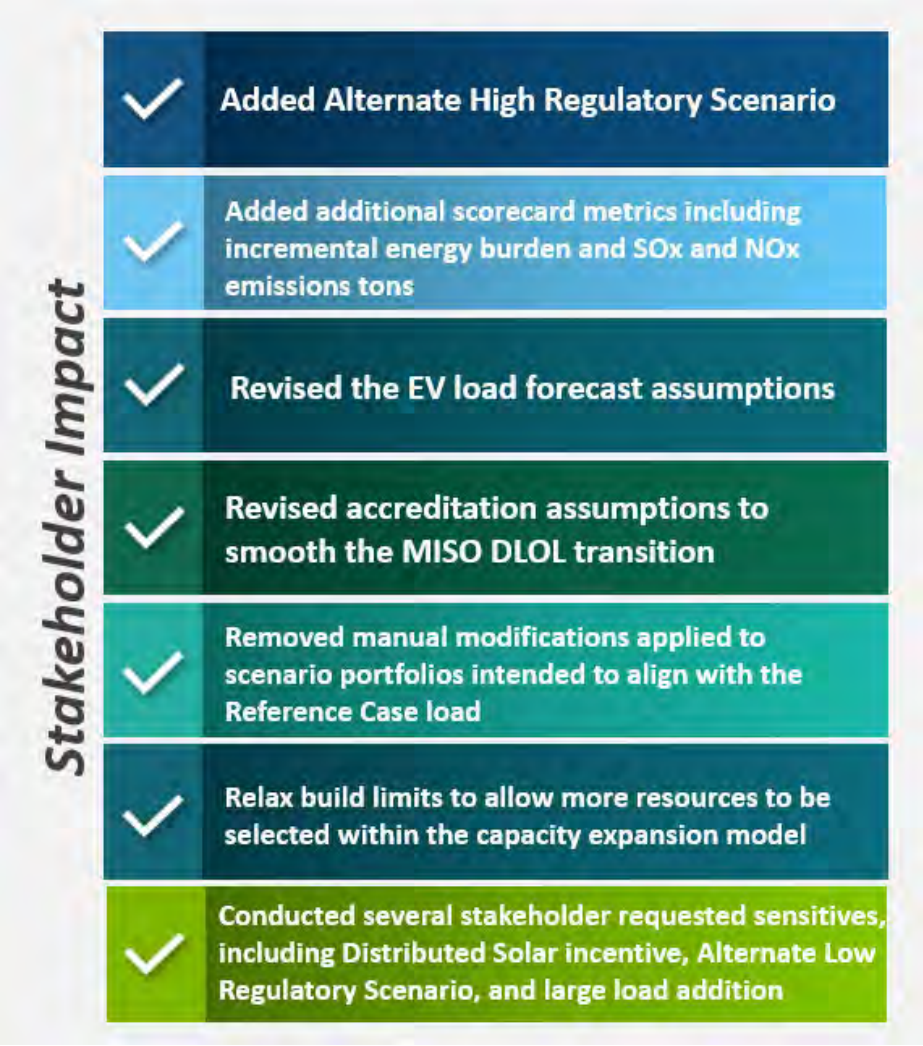
In addition to Tech-to-Tech meetings and public stakeholder meetings, CEI South met with individual stakeholders on various topics. For example, CEI South met several times with the CAC on Energy Efficiency modeling inputs.

8.6.3. Stakeholder Input

As discussed in Section 8.6.2, CEI South provided multiple avenues for engagement throughout the 2025 IRP process – dedicated Q&A and feedback time during public meetings; use of the IRP email address for written feedback/requests; Tech-to-Tech meetings between public meetings; and individual meetings upon request.
Critical to the IRP, feedback was reviewed, responded to, and incorporated as applicable.

In recognition of the importance of the received feedback, Figure 8-48 is a summary of key feedback that was ultimately included in the 2025 IRP analysis. For a full list, including suggestions not taken, see the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

Figure 8-48 - Summary of Key Stakeholder Input



8.6.4. Data Requests Summary

During the public stakeholder process CEI South received seven data requests from the Citizens Action Coalition, Clean Grid Alliance, Reliable Energy, Sierra Club, Solar United, and State Utility Forecasting Group. These data requests and CEI South's response can be found in the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

8.7.5 DSM OSB Presentations and Data Requests

CEI South collaborates with the CenterPoint Energy Oversight Board (which consists of CEI South, the OUCC, and CAC) on a monthly basis to discuss energy efficiency programs, results, and solicits feedback on program design and funding. This same collaborative group was utilized to discuss DSM in the 2025 Market Potential Study and

the development of energy efficiency and demand response inputs into the IRP. CEI South held seven meetings with the kickoff meeting occurring in-person at our Indianapolis office. The meeting dates and topics are listed in Figure 8-49 below, OSB stakeholder presentations can be found in *Technical Appendix Attachment 8.1 2025 MPS Slide Decks for Stakeholders*. This process allowed for robust discussion on topics to drive consensus, where possible, with several data requests and responses which can be found in *Technical Appendix Attachment 8.2 2025 DSM Data Requests and Responses*.

Figure 8-49 - DSM Oversight Board Meetings

Date	Discussion Topic
December 11, 2024	Integrated Gas & Electric Market Potential Study Kickoff
February 5, 2025	Data Request Response Updates/Observations; Measure Lists
March 6, 2025	Initial Demand Response Program Assumptions and Historical Performance Benchmarking
March 13, 2025	Additional Interruptible & Aggregation Discussion
April 17, 2025	Draft Demand Response Potential and EE Measure Assumptions
May 22, 2025	Draft EE Potential Results and Refined Demand Response Potential Results
June 30, 2025	Final EE Results and Initial IRP Inputs



Technical Appendix Attachments

Chapter 9

Attachment 1.1 Non-Technical Summary

Attachment 2.1 2024 All-Source Request for Proposal & Report

Attachment 2.2 2025 Technology Assessment Summary (Confidential)

Attachment 2.3 Transmission Study (Confidential)

Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report

Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential)

Attachment 3.3 CEIS 2024 System Hourly Load

Attachment 3.4 CEIS Electric 2025-2027 DSM Plan

Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)

Attachment 3.6 2025 DSM Market Potential Study

Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey

Attachment 3.8 CEIS Distribution System Long Range Planning Report

Attachment 3.9 VEC-008 Electric Transmission Planning Criteria

Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)

Attachment 4.2 Stakeholder Materials

Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)

Attachment 6.2 Large Load Study Results (Confidential)

Attachment 8.1 2025 MPS Slide Decks for Stakeholders

Attachment 8.2 2025 DSM Data Requests and Responses



IRP Rule Requirements Cross Reference Table

Chapter 10

IRP Rule Requirements Cross Reference Table

Rule	Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:	
(1) The IRP.	2025 IRP submitted on December 5, 2025
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	8 Technical Appendix; 9 Technical Appendix Attachments
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.	Executive Summary (Non-Technical Summary Document)
The utility shall make the IRP summary readily accessible on its website.	www.centerpointenergy.com/irp

Rule	Section(s)
170 IAC 4-7-2.6 Public advisory process Sec. 2.6	
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(d) The utility retains full responsibility for the content of its IRP.	n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(2) The utility may hold additional meetings.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(3) The schedule for meetings shall:	2.4 Stakeholder Engagement;

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(A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
170 IAC 4-7-4 Integrated resource plan contents Sec. 4	
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.	3.1.4 Reference Case
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	8.1.2 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	3.1.5 Alternative Scenarios
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	3.7.1 Current Resource Mix
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	3.7 Resource Options; 4 Portfolio Development and Evaluation
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	3.7 Resource Options
(7) The resource screening analysis and resource summary table required by section 7 of this rule.	3.7 Resource Options; Figure 3-40; Figure 3-41
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	4 Portfolio Development and Evaluation
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	7 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	11 List of Acronyms/Abbreviations with Definitions; 2 Resource Planning Process; 4 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If	9 Technical Appendix Attachments

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the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	3.7 Resource Options; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 8.1.1.1 Energy Data; 8.1.1.4 Equipment Efficiencies and Market Share Data
(15) A proposed schedule for industrial, commercial and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	8.1.1.4 Equipment Efficiencies and Market Share Data
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs and other aspects of planning.	8.1.5 Advanced Metering Infrastructure and Continuous Improvement
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Executive Summary Section V. Stakeholder Process
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and	3.8 Transmission Planning and Distribution Planning; 4.1.1.1.3 Distributed Generation Resource Portfolios;

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(D) load forecasting.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	2.11.2 Modeling Tools
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	5.1.8 Fuel Inventory and Procurement Planning
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	8.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	3 Forecasts and Key Modeling Assumptions; 4 Portfolio Development and Evaluation
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	2.1 Planning Scenarios; 2.6 Reference Case; 2.7 Alternative Scenarios; 3.5 Environmental Regulations
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference Case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources.	2.6 Reference Case

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(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A Reference Case scenario need not align with the utility's preferred resource portfolio.	
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.	2.7 Alternative Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.	3.8 Transmission and Distribution Planning 8.5.1 MISO Regional Transmission Planning 9 Technical Appendix Attachment 3.9 VEC-008 Electric Transmission Planning Criteria
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast;	2 Resource Planning Process; 3 Forecasts and Key Assumptions; 4 Portfolio Development and Evaluation; 8.1.1.5 Load Forecast Continuous Improvement; 8.6 Public Advisory Process Appendix;

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(ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential); 9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	8.3.5 Avoided Costs
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.	Executive Summary; 2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	3.7 Resource Options; 3.9.1 Resource Availability 3.8.4 Transmission Facilities as a Resource;
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following:	8.1.4 Load Shapes; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-

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(A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days and a typical weekday and weekend day.	Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	8.1.2 Overview of Past Forecasts; 9 Technical Appendix Attachments Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(3) Actual and weather normalized energy and demand levels.	8.1.2 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.	8.1.2 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	3.1.4 Reference Case
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.	8.1.2 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(8) Justification for the selected forecasting methodology.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools and analysis.	8.1.1.5 Load Forecast Continuous Improvement
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	n/a
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.	3.1.5 Alternate Scenarios

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(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	3.1 Load Forecast; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
170 IAC 4-7-6 Description of available resources	
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP

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	Alternate Reference Stochastics Model (Confidential)
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	8.2 Environmental Appendix
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	8.5 Transmission Appendix
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.	3.7 Resource Options; 8.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	3.7.2.14 Innovative Rate Design
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 3.7.2.11 Demand Response; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback;

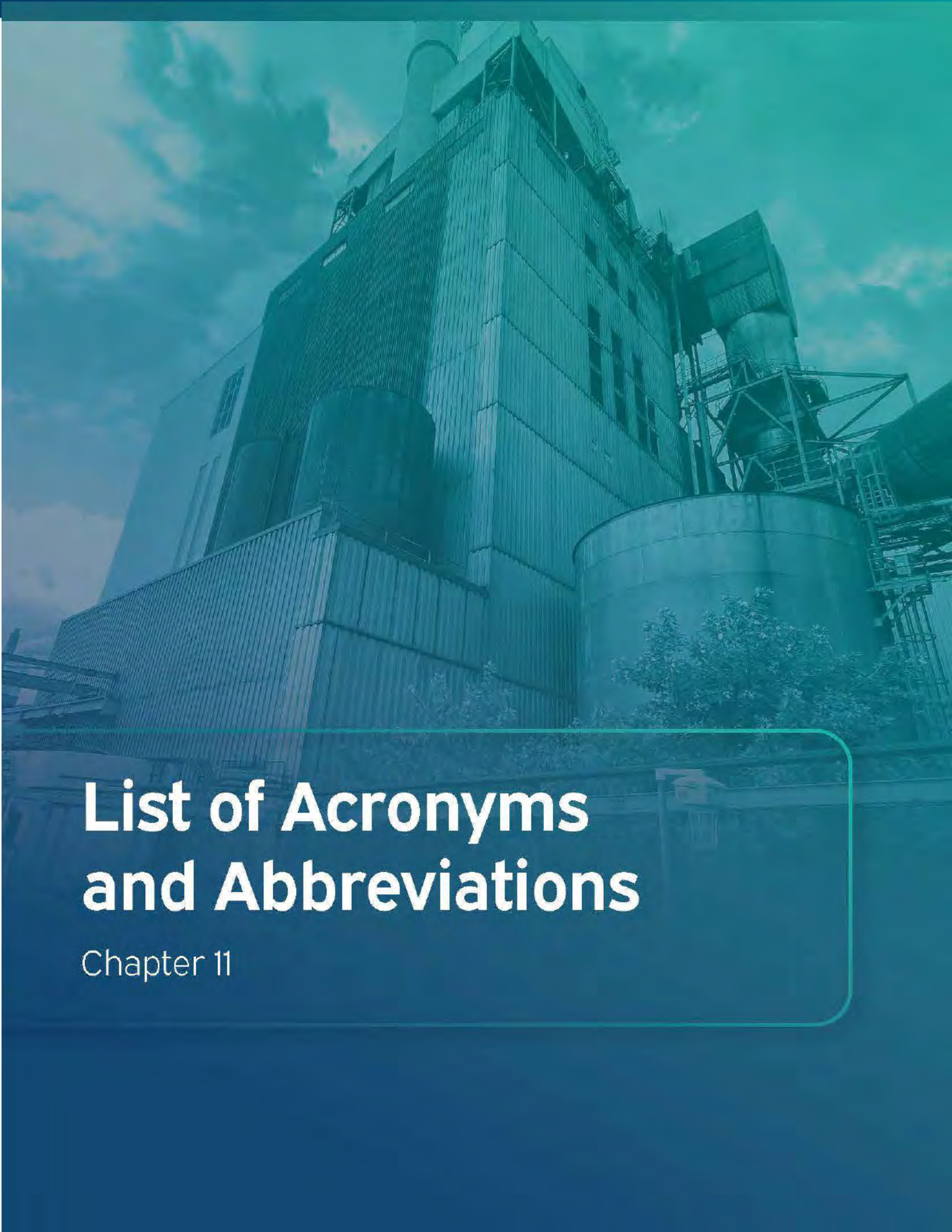
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(C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following:	
(A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of non-dispatchable resources. (iv) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction and operation of the supply-side resource with other utilities to reduce cost. (C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.	3.7 Resource Options; 3.9.1 Resource Availability; 9 Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential); 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following:	
(A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby	3.8.4 Transmission Facilities as a Resource; 8.5 Transmission Appendix

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increasing the utilization of geographically constrained cost-effective resources. (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	
170 IAC 4-7-7 Selection of resources	
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	N/A
170 IAC 4-7-8 Resource portfolios Sec. 8	
(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per	4 Portfolio Development and Evaluation; 8.4.2 Rate Metric Ranking

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kilowatt-hour delivered, with the interest rate specified.	
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently and cost-effectively meets the electric system demand taking cost, risk and uncertainty into consideration.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	8.5.3 DSM Impacts on Transmission and Distribution Systems
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio: 7.2.6 Ability to Finance the Preferred Portfolio; 8.3.5 Avoided Costs; 8.4.2 Rate Metric Ranking; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following:	Executive Summary; 1 Integrated Resource Planning; 2 Resource Planning Process;

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(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	2.11.3 Process Enhancements; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback; 3.7.2.14 Innovative Rate Design; 7.2.7 Continuous Improvement; 8.1.1.5 Load Forecast Continuous Improvement; 8.1.5 Advanced Metering Infrastructure Continuous Improvement; 8.3.7 Appliance Saturation Survey
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 7 Short Term Action Plan

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170 IAC 4-7-9 Short term action plan Sec. 9	
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	7 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.	7 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.	7 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 7.2 Discussion Of Plans For The Next 3 Years
(3) The implementation schedule for the preferred resource portfolio.	7.3 Schedule
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	7 Short Term Action Plan; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.	7.1 Differences Between the Last Short Term Action Plan from What Transpired



List of Acronyms and Abbreviations

Chapter 11

List of Acronyms/Abbreviation

1898 & Co.	1898 & Co., a part of Burns & McDonnell
AAR	Ambient Adjusted Rating
ABB	Power Consulting Company (Hitachi Predecessor)
ABB	A.B. Brown Generating Station
ACE	Affordable Clean Energy
ADR	Aggregation Demand Response
AEO	Annual Energy Outlook
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
ATB	Annual Technology Baseline
ATC	Around the Clock
AUPC	Average Use Per Customer
BAU	Business as Usual
BES	Bulk Electric System
BESS	Battery Energy Storage System
Btu	British Thermal Unit
BYOT	Bring Your Own Thermostat
CAA	Clean Air Act
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CRL	Combustion Residual Leachate
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DC	Direct Current
DCP	Distributed Capacity Procurement
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

DLOL	Direct Loss of Load
DPP	Definitive Planning Phase
DR	Demand Response DSM Demand Side Management
DSMA	Demand Side Management Adjustment
eCFR	Electronic Code of Federal Regulations
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
$EFOR_d$	Equivalent Forced Outage
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ERAS	Expedited Resource Addition Study
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GAO	General Administrative Order
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GET	Grid Enhancing Technology
GS	General Service
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator

ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LCR	Local Clearing Requirement
LDES	Long Duration Energy Storage
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
Li-ion	Lithium-ion
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LP	Large Power
LRZ	Local Resource Zone
LRTP	Long-Range Transmission Plan
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Plan
MVAR	Dynamic VAR Support
MW	Megawatt
MWh	Megawatt Hour
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NT	Near-term
NTG	Net to Gross
NYMEX	New York Mercantile Exchange
OBBBA	One Big Beautiful Bill Act
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin

PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
PY	Planning Year
RBDC	Reliability Based Demand Curve
RAN	Resource Availability and Need
RERRA	Relevant Electric Retail Rate Authority
RF	ReliabilityFirst
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RRA	Regional Resource Assessment
RS	Residential
RTO	Regional Transmission Operator
SAC	Seasonal Accredited Capacity
SAE	Statistically Adjusted End-use
SCGT	Simple Cycle Gas Turbine
SCR	Short Circuit Ratio
SGS	Small General Service
SIGE	Southern Indiana Gas and Electric
SIGECO	Southern Indiana Gas and Electric Company
SMR	Small Modular Reactor
Sox	Sulfur Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TOU	Time of Use
TRC	Total Resource Cost
TSR	Transmission Service Request
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
V	Volt
VAR	Volt-Amp Reactance
VPP	Virtual Power Plant
VER	Variable Energy Resources
WN	Weather Normalized
ZLD	Zero Liquid Discharge

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 23
Wayne Games 2021 Testimony

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

IURC CAUSE NO. 45501

REBUTTAL TESTIMONY
OF
WAYNE D. GAMES
VICE-PRESIDENT POWER GENERATION OPERATIONS

ON

RESPONSE TO THE DIRECT TESTIMONY OF INTERVENING PARTIES ON NEED FOR RESOURCES TO REPLACE EXISTING INEFFICIENT UNITS

SPONSORING PETITIONER'S EXHIBIT NO. 3-R (PUBLIC)
ATTACHMENTS WDG-R1

REBUTTAL TESTIMONY OF WAYNE D. GAMES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Wayne D. Games. My business address is 211 NW Riverside Drive, Evansville, Indiana, 47708.

Q. By whom are you employed?

A. I am employed by Vectren Corporation ("Vectren"), a wholly-owned subsidiary of CenterPoint Energy, Inc.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CenterPoint Indiana South", "Petitioner", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

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

A. I am Vice President Power Generation Operations.

Q. Are you the same Wayne D. Games who pre-filed direct testimony in this Cause?

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the direct testimony of witnesses presenting testimony on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC") and Sunrise Coal, LLC ("Sunrise Coal"). I summarize the recommendations made by both the OUCC and Sunrise Coal. I respond to Sunrise Coal Witness Emily Medine's testimony relating to the need to retire A.B. Brown and Warrick Unit #4.

I have not attempted to respond to every argument made by each OUCC or Intervenor witness. The fact that I may not have responded to any particular argument or statement

made by either the OUCC or Intervenor witnesses does not indicate my agreement with that argument or statement.

Q. Are you sponsoring any attachments to your rebuttal testimony in this proceeding?

A. Yes. I sponsor the following attachments:

- Petitioner's Exhibit No. 3-R, **Attachment WDG-R1**: Portions of Alcoa's 2020 Sustainability Plan

Q. Was this attachment prepared by you or under your supervision?

A. No, however, I reviewed it as part of my role as Vice President Power Generation Operations.

II. OVERVIEW OF OUCC AND INTERVENOR TESTIMONY

Q. Does the OUCC contest the reasonableness of adding the Posey County Solar Project and Warrick County Solar Project to CenterPoint Indiana South's generation portfolio.

A. No. Neither OUCC witness contests the need to add energy produced by the proposed Build Transfer Agreement ("BTA") or the Power Purchase Agreement ("PPA"). OUCC Witness Peter Boerger recommends "the Commission approve the projects CenterPoint [Indiana South] proposes in this proceeding." The OUCC makes certain ratemaking recommendations, which are addressed by other witnesses in this proceeding.

Q. What does Sunrise Coal recommend with respect to the Posey County Solar Project and Warrick County Solar Project?

A. Sunrise Coal suggests that the Commission should disapprove the two projects because in Witness Medine's view, it is unclear (1) how approval of the Posey County Solar Project affects other parts of the Preferred Plan and (2) whether a potential extension of the Joint Operating Agreement ("JOA") with Alcoa for Warrick Unit #4 obviates the immediate need for replacement. Sunrise Coal does not dispute the need to retire F.B. Culley Unit 2 ("F.B. Culley 2" or "Culley 2") and in Ms. Medine's Attachment 2 indicates "[t]here is no dispute

Coal states that according to the 2019/2020 Integrated Resource Plan ("IRP"), the need for urgency in approving these projects had been tied to concerns about the expiration of the income tax credit ("ITC") in 2021, which has now been extended.

Q. Is expiration of the ITC a factor in the timing of the need for urgency in approving the Posey County Solar Project and Warrick County Solar Project?

A. It was a factor, but contrary to Ms. Medine's testimony, as indicated in the 2019/2020 IRP, the need for the projects is based on the retirement of Culley 2 and the expiration of the JOA for Warrick Unit #4. The 2019/2020 IRP states:

> Vectren plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) and Vectren's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. In order to replace this generation, Vectren plans to acquire renewable generation in the next three years in order for Vectren's customers to benefit from expiring renewables tax incentives and, at a minimum, replace this portion of Vectren's coal fleet. This equates to approximately 700-1,000 MWs of capacity from solar generation towards the 2023/2024 and the 2024/2025 MISO planning years, partially dependent on expected solar penetration levels within MISO at that time and MISO resource accreditation.

(Attachment MAR-1; page 284.)[1]

Q. In your opinion, is it unclear how approval of the Posey County Solar Project affects other parts of the Preferred Plan?

A. No. In my direct testimony, I noted that the Posey County Solar Project and the Warrick County Solar Project will replace most of the capacity provided by F.B. Culley 2 and Warrick Unit #4. Specifically, I stated in my direct testimony:

> The 400 MWac of solar generation from these projects will replace the capacity currently supplied by the 150 MWs of CenterPoint [Indiana South]'s share of Warrick Unit #4, co-owned with Alcoa and currently operated and maintained by Alcoa, and a portion of the capacity produced by F.B. Culley 2 – CenterPoint [Indiana South]'s smallest and most inefficient unit. The Preferred Portfolio calls for those units to operate through 2023 only to allow time to obtain replacement capacity, which avoids further investment in the oldest units in CenterPoint [Indiana South]'s generation portfolio.

[1] Southern Indiana Gas & Electric Company, Inc. d/b/a CenterPoint Indiana South formerly conducted business as Vectren.

As I stated in my direct testimony, this filing will be followed by a request to construct two quick start and fast ramping combustion turbines ("CTs") to complement renewable resources and replace dispatchable capacity currently supplied by the A.B. Brown coal units and finally a third filing in 2021 to complete the need for the balance of renewable generation per the 2019/2020 IRP Preferred Portfolio. Nonetheless, much of Ms. Medine's testimony is devoted to discussing the A.B. Brown plant. Among other things, Ms. Medine speculates that an additional 300 MW from the Posey County Solar Project to be connected to the A.B. Brown – Gibson 345 kV transmission line could impact continued operation of the A.B. Brown plant or change the economics of placing replacement CTs at that site. Petitioner's Witnesses F. Shane Bradford and Mathew Rice describe why that concern is unfounded.

Q. Why is it necessary that CenterPoint Indiana South take this first step to enter into a BTA for the Posey County Solar Project and PPA for the Warrick County Solar Project?

A. Absent these projects, CenterPoint Indiana South would need to turn to the market to purchase capacity in the 2024 to 2025 timeframe, which would expose customers to the risk of market prices.

III. UNCONTESTED NEED TO RETIRE F. B. CULLEY 2

Q. Does Sunrise Coal object to the need to retire F.B. Culley 2?

A. No. It did not mention an objection to retiring F.B Culley 2 and, of course, neither did the OUCC witnesses. Sunrise Coal Witness Medine, in fact, does not mention F.B. Culley 2 at all. In the Joint Comments of Sunrise Coal and the Indiana Coal Council ("ICC") that are attached to Ms. Medine's testimony, the ICC and Sunrise Coal stated: "Culley 2 is a small older unit. There is no dispute over whether it should be retired and, therefore, there is no reason to include incremental costs in BAU to 2039 that would allow it to continue to run." (Sunrise Coal; Attachment 2; page 6).

Q. Why do you believe there is no dispute that F.B. Culley 2 should be retired?

A F.B. Culley 2 will be nearly 60 years old in 2023. F.B. Culley 2 is Petitioner's oldest, smallest (90MWs) and least efficient (12,500-13,000 BTU/kWh) coal unit. As a result, the unit only produces energy for customers or the MISO market when energy prices spike to a level that justifies MISO dispatching the unit for a 24-hour period. From 2015 through 2020, the average capacity factor was only 18 percent due to its high cost to produce energy.

Q. Has anything changed regarding the plan to retire F.B. Culley 2 in 2023?

A. Yes. The recent Coal Combustion Residuals ("CCR") Part A Rule has provided CenterPoint Indiana South with a path to continue operating F.B. Culley 2 through 2025 by constructing a CCR compliant pond to dispose of bottom ash. The cost to construct the pond to handle bottom ash from F.B. Culley 2 and maintain the capacity accreditation from F.B. Culley 2 to meet the MISO Planning Reserve Margin Requirement ("PRMR") is estimated at $6 million. This is a lower cost than recent bids the Company received to purchase market capacity to meet the projected shortfall as described in the direct testimony of Witness Bradford.

Q. Does continuing to operate F.B. Culley 2 through 2025 eliminate the need for the Posey County and Warrick County Solar Projects?

A. No. Continued operation of F.B. Culley 2, however, will reduce the amount of market capacity CenterPoint Indiana South has to purchase to meet the MISO PRMR in 2024 and 2025. CenterPoint Indiana South must also take into consideration that the Posey County and/or Warrick County Solar Projects will only receive 50 percent MISO capacity accreditation in the first year of operation and one or both projects could be delayed or the final output reduced due to issues and or challenges discovered during construction.

Q. What would be required to operate F.B. Culley 2 beyond 2025?

A. The proposed new CCR compliant pond, which is required by the U.S. Environmental Protection Agency ("EPA") CCR Part A rule, provides an opportunity to operate F.B. Culley 2 through 2025. I would note that these dollars must be spent even if F.B. Culley 2 were retired in October 2023 as previously planned, due to the CCR Part A Rule requirement to obtain alternative capacity in the fastest technically feasible manner. However, to

operate the unit beyond 2025 would require several million dollars of additional capital investment to comply with the Effluent Limit Guidelines ("ELG") Reconsideration Rule, which requires the bottom ash transport water to be eliminated by the end of 2025 as well as unit upgrades to ensure the unit can operate in a safe and reliable manner. In 2025, the plant will be years past due for a turbine and generator overhaul and will require major boiler work and other capital investments to maintain safe and reliable operation.

Q. In your opinion, is it prudent from a planning perspective to plan on the continued operation of F.B. Culley 2 beyond 2025?

A. No. Beyond the capital investment in a Dry Bottom Ash System, due to the age and current condition of F.B. Culley 2, it doesn't make sense for our customers to continue to invest millions of dollars in this small and inefficient unit. F.B. Culley 2 is the smallest and least efficient unit in the CenterPoint Indiana South fleet, and therefore, both of the two most recent IRPs have identified the plant for retirement. Accordingly, there has been little investment made in the unit over the past several years. The last turbine/generator overhaul was completed in 2011, and the manufacturer recommends an overhaul be completed every seven to eight years. This overhaul alone will cost in the $4 to $6 million range. In addition, the unit will require major boiler work and other capital investments to maintain reliable operation. Once the Warrick County Solar Project and Posey County Solar Project are operational and F.B. Culley 2 is no longer needed to minimize capacity purchases, it can be retired as called for in the two most recent IRPs.

Q. Are there other issues with continued operation of F.B. Culley 2?

A. The year to date equivalent forced outage rate ("EFOR") for F.B. Culley 2 is over 25 percent. If the unit were to have major issues, CenterPoint Indiana South would likely retire it rather than invest further capital. The only reason the Company is planning to delay retirement of F.B. Culley 2 until 2025 is because the U.S. EPA CCR Part A Rule requires CenterPoint Indiana South to construct a CCR compliant pond for Culley bottom ash water even if we were to commit to retire the unit prior to October of 2023 and the ELG Reconsideration Rule provides an opportunity to utilize the new CCR compliant pond for management of the F.B. Culley 2 bottom ash transport water through 2025. Our hope is that CenterPoint Indiana South will be able to continue operating the plant during this

period to mitigate the need to purchase capacity while the Posey County Solar Project and Warrick County Solar Project come on-line and ramp up.

IV. NEED TO EXIT WARRICK UNIT #4 JOA

Q. What does Sunrise Coal recommend with respect to Warrick Unit #4?

A. Sunrise Coal Witness Medine states that continued operation of Warrick Unit #4 is technically still an option subject to negotiation of acceptable terms. Ms. Medine also suggests that the obvious and likely lower cost option for CenterPoint Indiana South customers is to enter into a PPA with Alcoa for the capacity CenterPoint Indiana South currently owns at Warrick Unit #4.

Q. Is continued operation of Warrick Unit #4 "technically still an option"?

A. Technically, remaining in the JOA is still an option. However, from a financial perspective the last two IRPs have both identified that the best option for our customers is to exit the JOA. In addition, from a risk perspective, CenterPoint Indiana South has determined that the risk of further capital and Operations and Maintenance ("O&M") investments in a unit with a partner that has a short-term exit opportunity is not the best decision for our customers. In addition, customers have a strong desire for renewable generation to help meet corporate carbon reduction goals as Ms. Harris discussed in her direct testimony.

Q. Sunrise Coal Witness Medine testifies that "it is hard to believe that Kaiser Aluminum invested $670 million in a rolling mill that it did not intend to operate well into the future, so clearly, the outlook for the Alcoa smelter (to supply aluminum to the rolling mill), and therefore, the Warrick Unit #4 plant (to supply power to both the smelter and rolling mill), seems brighter than reflected in Witness Games testimony." Do you agree that Kaiser Aluminum still will need to purchase electricity to operate the rolling mill?

A. Yes, Kaiser Aluminum will need to purchase electricity. However, those needs may not be met in the manner that Ms. Medine suggests. Furthermore, Kaiser's public filing with the United States Securities and Exchange Commission outlines transition services between

Alcoa and Kaiser, and it alludes to the development of infrastructure necessary for the rolling mill to obtain electricity from a "third party supplier" (aside from Kaiser and Alcoa). This provides a signal that the operation of the rolling mill is not tied to Alcoa Warrick Unit #4 plant.[2]

Q. Ms. Medine notes that Alcoa will enter into a market-based metal supply agreement with Kaiser Aluminum. Does that mean that Alcoa will continue operating Warrick Unit #4 to power the smelter?

A. No. None of us have seen the agreement between Kaiser Aluminum and Alcoa. While I do not doubt that Alcoa has agreed to supply market-based metals to Kaiser Aluminum, it is certainly possible that those metals could be supplied through sources other than the Warrick smelter. I would note that Alcoa has closed the smelter and still operated the rolling mill in the past, and this could be done again. Most recently, Alcoa closed the Warrick smelter in 2016 due to low import alumina prices and continued to operate the rolling mill. The prices later rebounded, and Alcoa restarted a portion of the Warrick smelter operation in 2018.

Q. Ms. Medine cites an Alcoa press release indicating, "Alcoa will enter into a market-based metal supply agreement with Kaiser Aluminum at closing. Alcoa will continue to operate the smelter and the power plant, which together employ approximately 660 people." Does that give you comfort that Alcoa will continue operating the power plant beyond the expiration of the JOA?

A. No. The press release does not state how long Alcoa will continue to operate the power plant. CenterPoint Indiana South has received no indication that Alcoa is interested in continuing to operate the coal plant at Warrick Unit #4 beyond the expiration of the JOA on December 31, 2023. As indicated in my direct testimony, the JOA provides that either party may exit the agreement with [redacted], as opposed to the [redacted]

[2] Form 8-K available at https://investors.kaiseraluminum.com/node/17731/html ("In order to transition the Company's operations from being dependent on the "Support Services" to an independent facility with its own self-sufficient infrastructure, Alcoa will provide "Transition Services," including providing infrastructure and equipment for the production of steam, hot water and compressed air and conveying the filtration plant currently utilized for the supply of potable water. Moreover, the Lease Agreement requires Alcoa to pay for the development of infrastructure necessary for the Rolling Mill to obtain electricity from a third party power supplier, subject to the terms of the Lease Agreement. Alcoa will provide the Support Services through a period to extend no later than June 30, 2024, by which date Alcoa must complete its Transition Services.")

required under the prior agreement. There is a reason the parties negotiated [redacted]. I would note that if Alcoa were to provide notice of its intent to terminate the agreement, CenterPoint Indiana South could not obtain a certificate of public convenience and necessity and construct a plant to replace the energy and capacity within that notice period. Aside from that, Warrick Unit #4 would likely require substantial upgrades to operate beyond to 2023. Warrick Unit #4 has averaged an annual EFOR of over 16 percent in the past five-year period. In my experience, an EFOR Rate this high suggests that the unit requires substantial capital investment.

Q. Are there other reasons that you believe Alcoa may not have an interest in operating coal generation beyond December 31, 2023?

A. Yes. Alcoa, like many companies, has adopted environmental sustainability initiatives. Alcoa's 2020 Sustainability Report shows that approximate 78 percent of the energy used by its smelters comes from renewable resources. Alcoa has established a corporate goal to reduce greenhouse gas emission intensity by 30 percent by 2025 and 50 percent by 2030 from a 2015 baseline. Information regarding Alcoa's sustainability initiatives taken from the 2020 Sustainability Report is included as Petitioner's Exhibit No. 3-R, **Attachment WDG-R1**.[3]

Q. Do you know for certain that Alcoa will not operate its Warrick Unit #4 coal generation beyond the term of the JOA?

A. No. Until Alcoa announces its intentions, there is no way to know for certain what it will do upon the expiration of the JOA. As I said in my direct testimony, the long-term outlook for Warrick Unit #4 is uncertain.

Q. Even if Alcoa were to continue to operate Warrick Unit #4, would it be in customers' interest for CenterPoint Indiana South to enter into a new JOA for the unit.

A. No. As indicated in my direct testimony, Warrick Unit #4 has been the worst performing unit in Petitioner's fleet over the 2016-2019 period based on EFOR performance. Moreover, based on annual O&M cost per MWh of capacity, Warrick Unit #4 is the most

[3] The full report is available on-line athttps://www.alcoa.com/sustainability/en.

expensive unit to operate among the CenterPoint Indiana South coal units. Moreover, if CenterPoint Indiana South were to continue its investment in the Warrick Unit #4 beyond the expiration of the JOA, Petitioner would [redacted].

Q. On page 19 of her testimony, Ms. Medine speculates that continued operation of Warrick Unit #4 may be beneficial to ratepayers. Do you agree?

A. No. The previous two IRPs have identified that exiting the JOA with Aloca for Warrick Unit #4 is beneficial for CenterPoint Indiana South customers.

Q. Respond to Sunrise Coal's contention that the obvious and lower cost option for CenterPoint Indiana South customers is to enter into a PPA with Alcoa for the capacity CenterPoint Indiana South currently owns at Warrick Unit #4.

A. That doesn't seem to be an option [redacted].

Q. In your opinion, is it prudent from a planning perspective to plan on the continued operation of Warrick Unit #4?

A. No. Any plans that relied on CenterPoint Indiana South obtaining capacity and/or energy from Warrick Unit #4 beyond December 31, 2023, would expose ratepayers to significant risk.

V. A.B. BROWN AND OTHER ISSUES

Q. How do you respond to Ms. Medine's testimony that the testimony in this proceeding does not address the A.B. Brown plant?

A. As I mentioned above, the Posey County Solar Project and Warrick County Solar Project

do not impact the A.B. Brown plant. Mr. Bradford and Mr. Rice testify that interconnection of the Posey County Solar Project will not impact the use of the transmission at the A.B. Brown plant at all. Mr. Rice testifies that CenterPoint Indiana South studied that very issue contrary to Ms. Medine's testimony. Mr. Bradford notes that MISO requires a Generator Interconnection Request for every new generator and requires upgrades necessary to ensure that the MISO system can operate in a reliable manner with all resource producing at maximum output.

Q. How do you respond to Ms. Medine's testimony that "the economic analysis [included in the Company's 2019/2020 IRP] was biased against continued operation of A.B. Brown because CenterPoint Indiana South chose not to consider a firm 12-year offer—which it had received well prior to the issuance of the IRP—from the CSX railroad that would have materially reduced the delivered cost of coal and thus lowered both total and dispatch cost"?

A. Again, the proposal in this case does not impact the decision to retire the A.B. Brown plant. The primary drivers to retire the A.B. Brown plant is based on the capital investments and ongoing O&M to make upgrades to continue to operate the facility in a safe and reliable manner while complying with all environmental regulations. In addition, there are risk associated with investing in a facility that will likely be impacted by more strict air and water regulation in the future. Moreover, as Mr. Rice indicates this lower price contract proposal was taken into account when modeling the coal delivery price to Brown in three of the five scenarios including the High Technology scenario portfolio, which became the Preferred Portfolio. That said, the "offer" Ms. Medine is referencing is not as firm as she suggests. The "offer" that CenterPoint Indiana South received was still subject to negotiation and in fact indicated: "[t]his proposal requires Operations and Commercial senior management approval, both within CSXT and the [Evansville Western Railway] EVWR."

Q. How were lower transportation costs reflected in coal-based alternatives?

A. In three of the five scenarios including the High Technology scenario portfolio, the coal delivery price for A.B. Brown was reduced by nearly 25 percent in 2025 through 2030, as compared to the 2019 Base Case delivery price. I believe that this appropriately considers the impact of the CSX railroad offer, assuming it would have been approved by senior

management of CSX and the Evansville Western Railway and materialized.

VI. CONCLUSION

Q. What do you recommend to the Commission?

A. The Posey County and Warrick County Solar Projects are consistent with the Preferred Portfolio in Petitioner's 2019/2020 IRP and are necessary to meet our customers' needs beyond 2023. Accordingly, I recommend that the Commission approve CenterPoint Indiana South's proposed Solar Projects and requested ratemaking and accounting relief.

Q. Does this conclude your rebuttal testimony?

A. Yes, at the present time.

VERIFICATION

I, Wayne D. Games, Vice President Power Generation Operations for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, under the penalty of perjury, affirm that the answers in the foregoing Rebuttal Testimony are true to the best of my knowledge, information and belief.

Wayne D. Games

Vice President, Power Generation Operations

Alcoa Sustainability Performance 2020

1 contractor fatality

1.6% decrease in carbon dioxide equivalent emissions

2020

1.1% decrease in energy intensity

0.61 days away, restricted and transfer rate per 100 full-time workers

Approximately 78% of electricity consumed by our smelters was from renewable sources

0.92:1 ratio for new active mining disturbance to mine rehabilitation for the 2016 to 2020 period

1.7% reduction in bauxite residue land requirements per metric ton of alumina produced

95 score on the Corporate Equality Index 2020

2020

6.8% decrease in freshwater use intensity

4.2% decrease in landfilled waste

15.6% of our global employees were women

2,020 employee volunteer hours in the community

US$8.2 billion in purchased goods and services

US$5.6 million in Alcoa Foundation community investments

2020

Strategic Long-term Goals

Our sustainability approach is driven by—and measured against—our strategic long-term goals, which further integrate sustainable practices into our business to minimize environmental impacts and maximize value for our stakeholders.

We review and update these goals on a periodic basis to ensure we are focused on items relevant to our company's strategic priorities and current operations. We also seek input from stakeholders.

In 2020, we began implementing new goals for water conservation, waste management and social management. We also expanded our existing GHG goal to encompass our alumina refining segment in addition to our aluminum smelting operations.



Strategic Long-term Goals

Goal	Progress
Align our GHG (direct + indirect) emissions reduction targets with the below 2° C decarbonization path by reducing GHG emission intensity by 30 percent by 2025 and 50 percent by 2030 from a 2015 baseline. More 	**14.6 percent** reduction from 2015
From a 2015 baseline, reduce the intensity of our total water use from water-scarce locations by 5 percent by 2025 and 10 percent by 2030. More 	**3.0 percent** reduction from 2015

Goal	Progress
From a 2015 baseline, reduce landfilled waste by 15 percent by 2025 and 25 percent by 2030. More 	**14.4 percent** reduction from 2015
From a 2015 baseline, reduce bauxite residue land requirements per metric ton of alumina produced by 15 percent by 2030. More 	**12.8 percent** reduction from 2015
Maintain a corporate-wide running five-year average ratio of 1:1 or better for active mining disturbance (excluding long-term infrastructure) to mine rehabilitation. More 	**0.92:1 ratio** for the 2016 to 2020 period
Zero fatalities and serious injuries (life-threatening or life-altering injuries and illnesses). More 	**One fatality** and **zero serious injuries** in 2020
Attain an inclusive everyone culture that reflects the diversity of the communities in which we operate. More 	• Formed the Alcoa Global Inclusion & Diversity Council to support the execution of our inclusion and diversity strategy. • Deployed the Catalyst for Change program globally to our leaders to support our inclusion and diversity priorities. • Held our first Global Pride Week with events and actions in all regions that celebrated LGBT+ equality. • Launched the Alcoans Working Actively for Racial-Ethnic Equality (AWARE) inclusion group. • Conducted our second gender pay equity analysis.

Goal	Progress
By 2022, implement a social management system at all locations, including the definition of performance metrics and long-term goals to be accomplished by 2025 and 2030 More 	• Engaged external consultants with expertise in social management systems and Indigenous Peoples to help us benchmark the industry. • Conducted a gap analysis of our existing practices to the best-in-class social management systems and have defined a program to close identified gaps by the end of 2022. • Performed human rights due diligence at two additional sites in Brazil—Juruti and Poços de Caldas—and human rights risks assessments in Iceland, Norway and Spain.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 24
Schahfer 2020 NPDES Permit

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Bruno Pigott
Commissioner

September 24, 2020

VIA ELECTRONIC MAIL

Mr. Bertil C. Valenkamph
Director Station Chemistry & Environmental Compliance
Northern Indiana Public Service Company LLC
2755 Raystone Drive
Valparaiso, IN 46383

Dear Mr. Valenkamph

Re: NPDES Permit No. IN0053201
Northern Indiana Public Service Company LLC - R. M. Schahfer Generating Station
Wheatfield, IN – Jasper County

Your application for a National Pollutant Discharge Elimination System (NPDES) permit for authorization to discharge into the waters of the State of Indiana has been processed in accordance with Section 402 and 405 of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1251, et seq.), and IC 13-15, IDEM's permitting authority. All discharges from this facility shall be consistent with the terms and conditions of this permit.

One condition of your permit requires periodic reporting of several effluent parameters. You are required to submit both federal discharge monitoring reports (DMRs) and state Monthly Monitoring Reports (MMRs) on a routine basis. The MMR form can be found on IDEM's web site at http://www.in.gov/idem/cleanwater/2396.htm. Once you are on this page, select the "IDEM Forms" page and locate the "Monthly Monitoring Report (MMR) for Industrial Discharge Permits-30530" under the Wastewater Facilities heading. We recommend selecting the "XLS" version because it will complete all of the calculations when you enter the data.

IDEM no longer accepts paper DMR or MMR. All NPDES permit holders are required to submit their monitoring data to IDEM using NetDMR. Please contact Rose McDaniel at (317) 233-2653 or Helen Demmings at (317) 232-8815 for more information on NetDMR. Information is also available on our website at http://IN.gov/idem/cleanwater/2422.htm.

Another condition, which needs to be clearly understood, concerns violation of the effluent limitations in the permit. Exceeding the limitations constitutes a violation of the permit and may subject the permittee to criminal or civil penalties. (See Part II A.2.) It is therefore urged that your office and treatment operator understand this part of the permit.

The draft NPDES permit for NIPSCO R.M. Schahfer Generating Station was made available for public comment from August 5, 2020 through September 4, 2020 as part of Public Notice No. 20200805–IN0053201–D on IDEM's website at https://www.in.gov/idem/6408.htm. A response to the comments contained in the letter September 4, 2020, from Jeffrey Loewe of NIPSCO, pertaining to the draft NPDES permit is contained in the Post Public Notice Addendum. The Post Public Notice Addendum is located at the end of the Fact Sheet.

It should also be noted that any appeal must be filed under procedures outlined in IC 13-15-6, IC 4-21.5, and the enclosed Public Notice. The appeal must be initiated by filing a petition for administrative review with the Office of Environmental Adjudication (OEA) within fifteen (15) days of the emailing of an electronic copy of this letter or within eighteen (18) days of the mailing of this letter by filing at the following addresses:

Director
Office of Environmental Adjudication
Indiana Government Center North
Room N103
100 North Senate Avenue
Indianapolis, Indiana 46204

Commissioner
Indiana Department of Environmental Management
Indiana Government Center North
Room 1301
100 North Senate Avenue
Indianapolis, Indiana 46204

If you have any questions concerning the permit, please contact Trisha Williams at 317/234-8210 or twilliam@idem.in.gov. More information on the appeal review process is available at the website for the Office of Environmental Adjudication at http://www.in.gov/oea.

Sincerely,



Jerry Dittmer, Chief
Permits Branch
Office of Water Quality

Enclosures
cc: Jasper County Health Department
Nicholas Babbitt, NiSource
Jeff Loewe, NiSource
Craig Myers, NiSource
Mark Hein, Certified Operator, NiSource
Chief, Permits Section, U.S. EPA, Region 5
Aaron Deeter, IDEM inspector

STATE OF INDIANA

DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

AUTHORIZATION TO DISCHARGE UNDER THE

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Water Pollution Control Act, as amended, (33 U.S.C. 1251 et seq., the "Act"), and IDEM's authority under IC 13-15,

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
R.M. SCHAHFER GENERATING STATION

is authorized to discharge from a coal-fired and natural gas-fired electric generating facility that is located 2723 East 1500 North, Wheatfield, Indiana to receiving waters identified as Davis Ditch, Stalbaum Ditch, and the Kankakee River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I II, III, and IV hereof. This permit may be revoked for the nonpayment of applicable fees in accordance with IC 13-18-20.

Effective Date: October 1, 2020

Expiration Date: September 30, 2025

In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit such information and forms as are required by the Indiana Department of Environmental Management no later than 180 days prior to the date of expiration.

Issued on _September 24, 2020_ for the Indiana Department of Environmental Management.



_____
Jerry Dittmer, Chief
Permits Branch
Office of Water Quality

PART I

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

1. The permittee is authorized to discharge from the outfall listed below in accordance with the terms and conditions of this permit. The permittee is authorized to discharge from Outfalls 001 and 002, located at Latitude 41° 15' 2.34", Longitude -87° 1' 40.55" and Latitude 41° 13' 35.87", Longitude -87° 1' 18.43", respectively. The discharge from the Final Basin (Outfall 001) and the Final Basin Overflow (Outfall 002) is limited to FGD WWTP discharge, low volume waste, bottom ash transport water, cooling tower blowdown, coal pile runoff, treated sanitary wastewater, construction dewater water [10], and stormwater. Samples taken in compliance with the monitoring requirements below shall be taken at a point representative of the discharge but prior to entry into the Kankakee River. Such discharge shall be limited and monitored by the permittee as specified below:

DISCHARGE LIMITATIONS [1][2][3][4][20]
Outfall 001 [17] & 002

Table 1

	Quantity or Loading			Quality or Concentration			Monitoring Requirements	
Parameter	Monthly Average	Daily Maximum	Units	Monthly Average	Daily Maximum	Units	Measurement Frequency	Sample Type
Intake Flow	Report	39	MGD	----	----	----	1 X Daily	Continuous
Flow [5]	Report	Report	MGD	----	----	----	1 X Daily	Continuous
Cycles of Conc. (COC)	Report	Report	number	----	----	----	1 X Daily	Report
Temperature [16][21]	---	----	----	Report	Report	°F	1 X Weekly	Grab
TSS [19]	----	----	----	15	30	mg/l	1 X Weekly	24-Hr. Comp.
O&G [19]	----	----	----	5	15	mg/l	1 X Weekly	Grab
Chromium [6]	----	----	----	0.2	0.2	mg/l	1 X Monthly [9]	Grab
Zinc [6]	----	----	----	0.301	0.604	mg/l	1 X Monthly [9]	Grab
Mercury [6,7,8]	----	----	----	12.0	20.0	ng/l	6 X Yearly	Grab
Sulfate	----	----	----	748	1,501	mg/l	1 X Weekly	Grab
TRC [11,12]								
Continuous [13]	----	----	----	0.02	0.04	mg/l	1 X Daily	Grab
Intermittent [14]	----	----	----	----	0.2	mg/l	1 X Daily	Grab
Chlorination [14,15]								
Frequency	----	----	----	----	4	Times/Day	1 X Daily	Report
Duration	----	----	----	----	40	Minutes/Dose	1 X Daily	Report
Ammonia (as N)	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Arsenic [6][11]	----	----	----	Report	Report	ug/l	1 X Weekly	Grab
Boron [6]	----	----	----	Report	Report	ug/l	1 X Weekly	Grab
Chloride	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Manganese [6]	----	----	----	Report	Report	mg/l	1 X Weekly	Grab
Selenium [6][11]	----	----	----	Report	Report	ug/l	1 X Weekly	Grab
Nitrate/Nitrite	----	----	----	Report	Report	mg/l	1 X Weekly	Grab

Table 2

Parameter	Quality or Concentration Daily Minimum	Daily Maximum	Units	Monitoring Requirements Measurement Frequency	Sample Type
pH [18]	6.0	9.0	s.u.	1 X Weekly	Grab

[1] See Part I.B. of the permit for the Narrative Water Quality Standards.

[2] The Storm Water Monitoring and Non Numeric Effluent Limits and the Storm Water Pollution Prevention Plan (SWPPP) requirements can be found in Part I.D. and I.E. of this permit.

[3] See Permit Part III (Other Requirements) & Permit Part IV (Intake Structure Requirements) for additional requirements.

[4] In the event that a new water treatment additive is to be used that will contribute to this Outfall, or changes are to be made in the use of water treatment additives, including dosage, the permittee must apply for and receive approval from IDEM prior to such discharge. Discharges of any such additives must meet Indiana water quality standards. The permittee must apply for permission to use water treatment additives by completing and submitting State Form 50000 (Application for Approval to Use Water Treatment Additives) currently available at: http://www.in.gov/idem/5157.htm

[5] Pump hour flow meter calculations are adequate to monitor the discharge flow in lieu of an electronic continuous monitoring device at Outfall 001. Outfall 002 is an emergency overflow outfall only. In the event of an emergency overflow discharge at Outfall 002, the flow reporting may be an estimate based upon flow duration and estimated discharge rate and TSS may be monitored by grab sample.

[6] The permittee shall measure and report the identified metal as total recoverable metal.

[7] Mercury monitoring shall be conducted bi-monthly in the months of February, April, June, August, October, and December of each year for the term of the permit using EPA Test Method 1631, Revision E.

[8] The following EPA test methods and/or Standard Methods and associated LODs and LOQs are to be used in the analysis of the effluent samples. Alternative methods may be used if first approved by IDEM.

Parameter	Test Method	LOD	LOQ
Mercury	1631, Revision E	0.2 ng/l	0.5 ng/l

[9] Monitoring frequency shall increase to 1 X Weekly during periods during which construction dewatering is being discharged through outfall 001.

[10] NIPSCO shall submit to the Industrial NPDES Permit Section of IDEM a groundwater sample when construction dewatering takes place that is representative of that dewatering water and includes the following: Arsenic, Boron, Chromium, Manganese, Selenium, Zinc, Sulfate, and the BTEX parameters. Other parameters should be included if NIPSCO believes them to be present in the groundwater.

[11]

Parameter	Test Method	LOD	LOQ
Chlorine	4500-Cl-D,E or 4500-Cl-G	0.02 mg/l	0.06 mg/l
Arsenic	3113B-2004	1 ug/l	3.2 ug/l
Arsenic	200.9	0.5 ug/l	1.6 ug/l
Arsenic	200.8	0.4 ug/l	1.3 ug/l
Selenium	3113B-2004 or 3114B-2009	2 ug/l	6.4 ug/l
Selenium	200.8	2.1 ug/l	6.7 ug/l
Selenium	200.9	0.6 ug/l	1.9 ug/l

[12] The chlorine limits are applicable when chlorine may be expected to be in the effluent. Chlorine monitoring is required on days when chlorination occurs and shall be commenced on such days within an hour of initial chlorination.

[13] The water quality based effluent limit (WQBEL) for TRC is less than the limit of quantitation (LOQ) as specified below. Compliance with this permit will be demonstrated if the effluent concentrations measured are less than the LOQ.

If the measured concentration of TRC is greater than the water quality based effluent limitations and above the respective LOD specified in the table below in any three (3) consecutive analyses, or any five (5) out of nine (9) analyses, then the discharger shall:

(1) Determine the source of the parameter through an evaluation of sampling techniques, analytical/laboratory procedures, and waste streams (including internal waste streams); and re-examine the chlorination /dechlorination procedures.

(2) The sampling and analysis for TRC shall be increased to 2 X Daily and remain at this increased sampling frequency until:

(a) The increased sampling frequency for TRC has been in place for at least two weeks.

(b) At least nine (9) samples have been taken under this increased sampling frequency; and

(c) The measured concentration of TRC is less than the LOD specified in the table above in at least seven (7) out of the nine (9) most recent analyses.

Case-Specific LOD/LOQ The permittee may determine a case-specific LOD or LOQ using the analytical method specified above, or any other test method which is approved by the Commissioner prior to use. The LOD shall be derived by the procedure specified for method detection limits contained in 40 CFR Part 136, Appendix B, and the LOQ shall be set equal to 3.18 times the LOD. Other methods may be used if first approved by the Commissioner.

[14] The limit is based on 327 IAC 2-1-6 Table 6-1. “To be considered an intermittent discharge, total residual chlorine shall not be detected in the discharge for a period of more than forty (40) minutes in duration, and such periods shall be separated by at least five (5) hours”.

[15] Reporting requirements for chlorination frequency and duration apply only when the facility is chlorinating intermittently, as defined in [14].

[16] The following conditions apply to Temperature outside the mixing zone:

(1) There shall be no abnormal temperature changes that may adversely affect aquatic life unless caused by natural conditions.

(2) The normal daily and seasonal temperature fluctuations that existed before the addition of heat due to other than natural causes shall be maintained.

(3) The maximum temperature rise at any time or place above natural shall not exceed:

(i) five (5) degrees Fahrenheit (two and eight-tenths (2.8) degrees Celsius) in streams.

[17] The discharge of cooling tower blowdown is regulated by the 40 CFR 423.13(d). 40 CFR 423.13(d)(1) prohibits the discharge of the 126 priority pollutants listed in Appendix A of this regulation in detectable amounts with the exception of total zinc and total chromium which have specific numeric limits. In accordance with 423.13(d)(3), instead of the monitoring specified in 40 CFR 122.48(b), compliance with the limitations for the 126 priority pollutants in paragraph (d)(1) of 40 CFR 423.13 may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136. However, compliance with the above limitations for the 126 priority pollutants (with the exception of zinc and chromium) in paragraph (d)(1) of 40 CFR 423.13 must be reported each time there is a change in the chemicals added for cooling tower maintenance.

[18] If the permittee collects more than one grab sample on a given day for pH, the values shall not be averaged for reporting daily maximums or daily minimums. The permittee must report the individual minimum and the individual maximum pH value of any sample during the month on the Monthly Monitoring Report form.

[19] In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

In lieu of establishing new internal outfalls for low volume waste and bottom ash wastewater, should the permittee require a permit to continue operations beyond December 31, 2023, the permittee must submit an evaluation of alternate limitations for TSS and Oil & Grease developed using building the block approach and provide supporting documentation. The evaluation should be submitted with the next permit renewal.

[20] The permittee shall comply with the requirements of the effluent limitation guidelines for Steam Electric Generating Stations, 40 CFR 423.13(k)(1)(i), for bottom ash transport water by December 31, 2023.

[21] The “daily maximum” means the highest temperature value measured for any calendar day.

2. The permittee is authorized to discharge from the outfall listed below in accordance with the terms and conditions of this permit. The permittee is authorized to discharge from Internal Outfall 101, located at Latitude 41° 15' 2.34", Longitude -87° 0' 40.55". The discharge is limited to Sanitary Wastewater. Samples taken in compliance with the monitoring requirements below shall be taken at a point representative of the discharge but prior to entry into the Final Basin. Such discharge shall be limited and monitored by the permittee as specified below:

DISCHARGE LIMITATIONS [1]
Internal Outfall 101

Table 1

	Quantity or Loading			Quality or Concentration			Monitoring Requirements	
Parameter	Monthly Average	Daily Maximum	Units	Monthly Average	Daily Maximum	Units	Measurement Frequency	Sample Type
Flow [2]	Report	Report	MGD	----	----	----	2 X Monthly	24-Hr. Total
$CBOD_5$	----	----	----	25	40	mg/l	2 X Monthly	24-Hr. Comp.
TSS	----	----	----	30	45	mg/l	2 X Monthly	Grab
E. coli [3][4]	----	----	----	125	235	cfu/100 ml	2 X Monthly	Grab

[1] Discharge from Internal Outfall 101, which flows to the Final Basin, is limited solely to sanitary wastewater, free from process or other wastewater discharges.

[2] Pump hour flow meter calculations are adequate to monitor the discharge flow at Internal Outfall 101.

[3] The *E. coli* limitations and monitoring requirements apply from April 1 through October 31 annually. IDEM has specified the following methods as allowable for the detection and enumeration of *Escherichia coli* (*E. coli*):

1. Coliscan MF® Method
2. EPA Method 1603 Modified m-TEC agar
3. mColi Blue-24®.
4. Colilert® MPN Method or Colilert-18® MPN Method

If less than ten samples are taken and analyzed for *E. coli* in a calendar month, no samples may exceed two hundred thirty-five (235) cfu or mpn as a daily maximum. However, when ten (10) or more samples are taken and analyzed for *E. coli* in a calendar month, not more than ten percent (10%) of those samples may exceed two hundred thirty-five (235) cfu or mpn as a daily maximum. When calculating ten percent, the result must not be rounded up. In reporting for compliance purposes on the Discharge Monitoring Report (DMR) form, the permittee shall record the highest nonexcluded value for the daily maximum.

[4] The monthly average E. coli value shall be calculated as a geometric mean. Per 327 IAC 5-10-6, the concentration of E. coli shall not exceed one hundred twenty-five (125) cfu or mpn per 100 milliliters as a geometric mean of the effluent samples taken in a calendar month. No samples may be excluded when calculating the monthly geometric mean.

3. The permittee is authorized to discharge from the internal outfalls listed below in accordance with the terms and conditions of this permit. The permittee is authorized to discharge from Internal Outfall 201, located at Latitude 41° 13' 3", Longitude -87° 1' 14". The permittee is also authorized to discharge from proposed Internal Outfall 301. The discharge is limited to FGD WWTP discharge. The discharge from the WWTP discharge is limited to Unit 14/15 FGD wastewater, Unit 17/18 FGD wastewater, and leachate from the on-site Type I landfill. Samples taken in compliance with the monitoring requirements below shall be taken at a point prior to entry into the Final Basin. Such discharge shall be limited and monitored by the permittee as specified below:

DISCHARGE LIMITATIONS

Internal Outfall 201 and Internal Outfall 301 (Proposed)

Table 1

	Quantity or Loading			Quality or Concentration			Monitoring Requirements	
Parameter	Monthly Average	Daily Maximum	Units	Monthly Average	Daily Maximum	Units	Measurement Frequency	Sample Type
Flow	Report	Report	MGD	----	----	----	2 X Monthly	24-Hr. Total
TSS	----	----	----	30.0	100.0	mg/l	2 X Monthly	24-Hr. Comp.
O&G	----	----	----	15.0	20.0	mg/l	2 X Monthly	Grab
Arsenic [1,4]								
Interim	----	----	----	Report	Report	ug/l	2 X Monthly	Grab
Final [5]	----	----	----	8	11	ug/l	2 X Monthly	Grab
Mercury [1,2,4]								
Interim	----	----	----	Report	Report	ng/l	6 X Yearly	Grab
Final [5]	----	----	----	356	788	ng/l	6 X Yearly	Grab
Selenium [1,4]								
Interim	----	----	----	Report	Report	ug/l	2 X Monthly	Grab
Final [5]	----	----	----	12	23	ug/l	2 X Monthly	Grab
Nitrate/Nitrite (as N)								
Interim	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Final [5]	----	----	----	4.4	17.0	mg/l	2 X Monthly	Grab
Ammonia (as N)	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Boron [1]	----	----	----	Report	Report	ug/l	2 X Monthly	Grab
Chloride	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Manganese [1]	----	----	----	Report	Report	mg/l	2 X Monthly	Grab
Zinc [1]	----	----	----	Report	Report	mg/l	2 X Monthly	Grab

Table 2

	Quality or Concentration			Monitoring Requirements	
Parameter	Daily Minimum	Daily Maximum	Units	Measurement Frequency	Sample Type
pH [3]	6.0	9.0	s.u.	2 X Monthly	Grab

[1] The permittee shall measure and report these parameters as total recoverable metal.

[2] Mercury monitoring shall be conducted be-monthly (every other month) in the months of February, April, June, August, October, and December of each year for the term of the permit from the effective date of this permit using EPA Test Method 1631, Revision E.

[3] If the permittee collects more than one grab sample on a given day for pH, the values shall not be averaged for reporting daily maximums or daily minimums. The permittee must report the individual minimum and the individual maximum pH value of any sample during the month on the Monthly Monitoring Report form.

[4] The following EPA approved test methods and associated LODs and LOQs are to be used in the analysis of the effluent samples. Alternative methods may be used if first approved by IDEM and EPA, if applicable.

Parameter	Test Method	LOD	LOQ
Mercury	1631E	0.2 ng/l	0.5 ng/l
Arsenic	3113B-2004	1 ug/l	3.2 ug/l
Arsenic	200.9	0.5 ug/l	1.6 ug/l
Arsenic	200.8	0.4 ug/l	1.3 ug/l
Selenium	3113B-2004 or 3114B-2009	2 ug/l	6.4 ug/l
Selenium	200.8	2.1 ug/l	6.7 ug/l
Selenium	200.9	0.6 ug/l	1.9 ug/l

[5] The permittee must comply with the limits established under 40 CFR 423.13(g)(1)(i) no later than December 31, 2023 for both Outfalls 201 and 301.

4. The permittee is authorized to discharge storm water from the outfalls listed below in accordance with the terms and conditions of this permit. The permittee is authorized to discharge from Outfalls 003S, 004S, 005S, 006S, and 007S. The permittee shall also sample Stream Monitoring Sites 010S, 011S (both from Davis Ditch), 012S, and 013S (both from Stalbaum Ditch). The location of each of these outfalls is listed below:

003S: Latitude 41° 13' 8.55", Longitude -87° 0' 20"
004S: Latitude 41° 12' 22", Longitude -87° 1' 38"
005S: Latitude 41° 12' 31", Longitude -87° 1' 38"
006S: Latitude 41° 13' 31", Longitude -87° 1' 36"
007S: Latitude 41° 12' 17.46", Longitude -87° 1' 47.3"
010S: Latitude 41° 12' 5.22", Longitude -87° 0' 56.4"
011S: Latitude 41° 13' 19.21", Longitude -87° 1' 47.3"
012S: Latitude 41° 12' 29.88", Longitude -87° 0' 3.9"
013S: Latitude 41° 13' 24.52", Longitude -87° 1' 21.3"

Such discharge shall be limited and monitored by the permittee as specified below:

DISCHARGE LIMITATIONS [1, 3, 4]
Stormwater Outfalls 003S, 004S [5], 007S
Stream Monitoring Sites 010S, 011S, 012S, 013S

			Monitoring Requirements	
Parameter	Daily Maximum	Units	Measurement Frequency	Sample Type
Flow	Report	MGD	Annually	Estimate Total
TSS	Report	mg/l	Annually	Grab
pH	Report	s.u.	Annually	Grab
Oil & Grease	Report	mg/l	Annually	Grab
Arsenic [2]	Report	mg/l	Annually	Grab
Cadmium [2]	Report	mg/l	Annually	Grab
Chromium [2]	Report	mg/l	Annually	Grab
Copper [2]	Report	mg/l	Annually	Grab
Lead [2]	Report	mg/l	Annually	Grab
Nickel [2]	Report	mg/l	Annually	Grab
Selenium [2]	Report	mg/l	Annually	Grab
Zinc [2]	Report	mg/l	Annually	Grab
Sulfate	Report	mg/l	Annually	Grab

[1] The Storm Water Monitoring and Non Numeric Effluent Limits and the Storm Water Pollution Prevention Plan (SWPPP) requirements can be found in Part I.D. and I.E. of this permit.

[2] The permittee shall measure and report the identified metal as total recoverable metal.

[3] See Part I.B. of the permit for the Narrative Water Quality Standards.

[4] All samples shall be collected from the discharge resulting from a storm event that is greater than 0.1 inches and at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event. There shall be a minimum of three (3) months between reported sampling events.

For each sample taken, the permittee shall record the duration and total rainfall of the storm event, the number of hours between beginning of the storm measured and the end of the previous measurable rain event, and the outside temperature at the time of sampling.

A grab sample shall be taken during the first thirty (30) minutes of the discharge (or as soon thereafter as practicable).

The permittee shall conduct a visual inspection at the outfall(s) on an annual basis. During visual inspections the permittee shall report the presence of turbidity, color, foam, solids, floatables, and oil sheen. The results of the visual inspections shall be recorded and maintained as part of the SWPPP plan. Visual inspections should allow for timely adjustments to be made to the SWPPP. If BMPs are performing ineffectively, corrective action must be implemented. A set of tracking or follow-up procedures must be used to ensure that appropriate actions are taken in response to the examinations.

[5] Outfall 004S discharge shall be representative of discharge from Outfalls 005S and 006S.

B. NARRATIVE WATER QUALITY STANDARDS

1. At all times and at all places, including waters within the mixing zone, the discharge shall meet the minimum conditions of being free from substances, materials, floating debris, oil, or scum attributable to municipal, industrial, agricultural, and other land use practices, or other discharges that do any of the following:

   a. will settle to form putrescent, or otherwise objectionable deposits;

   b. are in amounts sufficient to be unsightly or deleterious;

   c. produce color, visible oil sheen, odor, or other conditions in such degree as to create a nuisance;

   d. are in amounts sufficient to be acutely toxic to, or to otherwise severely injure or kill aquatic life, other animals, plants, or humans;

   e. are in concentrations or combinations that will cause or contribute to the growth of aquatic plants or algae to such a degree as to create a nuisance, be unsightly, or otherwise impair the designated uses.

2. At all times, outside the mixing zone, the discharge shall be free of substances in concentrations that on the basis of available scientific data are believed to be sufficient to injure, be chronically toxic to, or be carcinogenic, mutagenic, or teratogenic to humans, animals, aquatic life, or plants.

C. MONITORING AND REPORTING

1. Representative Sampling

   Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge flow and shall be taken at times which reflect the full range and concentration of effluent parameters normally expected to be present. Samples shall not be taken at times to avoid showing elevated levels of any parameters.

2. Monthly Reporting

   The permittee shall submit monitoring reports to the Indiana Department of Environmental Management (IDEM) containing results obtained during the previous month and shall be submitted no later than the 28th day of the month following each completed monitoring period. The first report shall be submitted by the 28th day of the month following the month in which the permit becomes effective.

These reports shall include, but not necessarily be limited to, the Discharge Monitoring Report (DMR) and the Monthly Monitoring Report (MMR). All reports shall be submitted electronically by using the NetDMR application, upon registration, receipt of the NetDMR Subscriber Agreement, and IDEM approval of the proposed NetDMR Signatory. Access the NetDMR website (for initial registration and DMR/MMR submittal) via CDX at: https://cdx.epa.gov/. The Regional Administrator may request the permittee to submit monitoring reports to the Environmental Protection Agency if it is deemed necessary to assure compliance with the permit. See Part II.C.10 of this permit for Future Electronic Reporting Requirements.

a. Calculations that require averaging of measurements of daily values (both concentrations and mass) shall use an arithmetic mean, except the monthly average for *E. coli* shall be calculated as a geometric mean.

b. Daily effluent values (both mass and concentration) that are less than the LOQ that are used to determine the monthly average effluent level shall be accommodated in calculation of the average using statistical methods that have been approved by the Commissioner.

c. Effluent concentrations less than the LOD shall be reported on the Discharge Monitoring Report (DMR) forms as < (less than) the value of the LOD. For example, if a substance is not detected at a concentration of 0.1 µg/l, report the value as <0.1 µg/l.

d. Effluent concentrations greater than or equal to the LOD and less than the LOQ that are reported on a DMR shall be reported as the actual value and annotated on the DMR to indicate that the value is not quantifiable.

e. Mass discharge values which are calculated from concentrations reported as less than the value of the limit of detection shall be reported as less than the corresponding mass discharge value.

f. Mass discharge values that are calculated from effluent concentrations greater than the limit of detection shall be reported as the calculated value.

3. Definitions

a. “Monthly Average” means the total mass or flow-weighted concentration of all daily discharges during a calendar month on which daily discharges are sampled or measured, divided by the number of daily discharges sampled and/or measured during such calendar month.

The monthly average discharge limitation is the highest allowable average monthly discharge for any calendar month.

b. "Daily Discharge" means the total mass of a pollutant discharged during the calendar day or, in the case of a pollutant limited in terms other than mass pursuant to 327 IAC 5-2-11(e), the average concentration or other measurement of the pollutant specified over the calendar day or any twenty-four hour period that reasonably represents the calendar day for the purposes of sampling.

c. "Daily Maximum" means the maximum allowable daily discharge for any calendar day.

d. A "24-hour composite sample" means a sample consisting of at least 3 individual flow-proportioned samples of wastewater, taken by the grab sample method or by an automatic sampler, which are taken at approximately equally spaced time intervals for the duration of the discharge within a 24-hour period and which are combined prior to analysis. A flow-proportioned composite sample may be obtained by:

(1) recording the discharge flow rate at the time each individual sample is taken,

(2) adding together the discharge flow rates recorded from each individuals sampling time to formulate the "total flow" value,

(3) the discharge flow rate of each individual sampling time is divided by the total flow value to determine its percentage of the total flow value,

(4) then multiply the volume of the total composite sample by each individual sample's percentage to determine the volume of that individual sample which will be included in the total composite sample.

e. "Concentration" means the weight of any given material present in a unit volume of liquid. Unless otherwise indicated in this permit, concentration values shall be expressed in milligrams per liter (mg/l).

f. The "Regional Administrator" is defined as the Region 5 Administrator, U.S. EPA, located at 77 West Jackson Boulevard, Chicago, Illinois 60604.

g. The “Commissioner” is defined as the Commissioner of the Indiana Department of Environmental Management, which is located at the following address: 100 North Senate Avenue, Indianapolis, Indiana 46204.

h. “Limit of Detection” or “LOD” means the minimum concentration of a substance that can be measured and reported with ninety-nine percent (99%) confidence that the analyte concentration is greater than zero (0) for a particular analytical method and sample matrix.

i. “Limit of Quantitation” or “LOQ” means a measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calibrated at a specified concentration above the method detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant. This term is also sometimes called limit of quantification or quantification level.

j. “Method Detection Level” or “MDL” means the minimum concentration of an analyte (substance) that can be measured and reported with a ninety-nine percent (99%) confidence that the analyte concentration is greater than zero (0) as determined by procedure set forth in 40 CFR 136, Appendix B. The method detection level or MDL is equivalent to the LOD.

k. “Grab Sample” means a sample which is taken from a wastestream on a one-time basis without consideration of the flow rate of the wastestream and without considerations of time.

4. Test Procedures

The analytical and sampling methods used shall conform to the version of 40 CFR 136 incorporated by reference in 327 IAC 5. Different but equivalent methods are allowable if they receive the prior written approval of the Commissioner and the U.S. Environmental Protection Agency. When more than one test procedure is approved for the purposes of the NPDES program under 40 CFR 136 for the analysis of a pollutant or pollutant parameter, the test procedure must be sufficiently sensitive as defined at 40 CFR 122.21(e)(3) and 122.44(i)(1)(iv).

5. Recording of Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall maintain records of all monitoring information and monitoring activities, including:

a. The date, exact place and time of sampling or measurement;

b. The person(s) who performed the sampling or measurements;

c. The date(s) analyses were performed;

d. The person(s) who performed the analyses;

e. The analytical techniques or methods used; and

f. The results of such measurements and analyses.

6. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of this monitoring shall be included in the calculation and reporting of the values required in the monthly Discharge Monitoring Report (DMR) and Monthly Monitoring Report (MMR). Such increased frequency shall also be indicated. Other monitoring data not specifically required in this permit (such as internal process or internal waste stream data) which is collected by or for the permittee need not be submitted unless requested by the Commissioner.

7. Records Retention

All records and information resulting from the monitoring activities required by this permit, including all records of analyses performed and calibration and maintenance of instrumentation and recording from continuous monitoring instrumentation, shall be retained for a minimum of three (3) years. In cases where the original records are kept at another location, a copy of all such records shall be kept at the permitted facility. The three years shall be extended:

a. automatically during the course of any unresolved litigation regarding the discharge of pollutants by the permittee or regarding promulgated effluent guidelines applicable to the permittee; or

b. as requested by the Regional Administrator or the Indiana Department of Environmental Management.

D. STORM WATER MONITORING AND NON-NUMERIC EFFLUENT LIMITS

Within twelve (12) months of the effective date of this permit, the permittee shall implement the non-numeric permit conditions in this Section of the permit for the entire site as it relates to storm water associated with industrial activity regardless which outfall the storm water is discharged from.

1. Control Measures and Effluent Limits

In the technology-based limits included in Part D.2-4., the term “minimize” means reduce and/or eliminate to the extent achievable using control measures (including best management practices) that are technologically available and economically practicable and achievable in light of best industry practice.

2. Control Measures

Select, design, install, and implement control measures (including best management practices) to address the selection and design considerations in Part D.3 to meet the non-numeric effluent limits in Part D.4. The selection, design, installation, and implementation of these control measures must be in accordance with good engineering practices and manufacturer’s specifications. Any deviation from the manufacturer’s specifications shall be documented. If the control measures are not achieving their intended effect in minimizing pollutant discharges, the control measures must be modified as expeditiously as practicable. Regulated storm water discharges from the facility include storm water run-on that commingles with storm water discharges associated with industrial activity at the facility.

3. Control Measure Selection and Design Considerations

When selecting and designing control measures consider the following:

a. preventing storm water from coming into contact with polluting materials is generally more effective, and cost-effective, than trying to remove pollutants from storm water;

b. use of control measures in combination is more effective than use of control measures in isolation for minimizing pollutants in storm water discharge;

c. assessing the type and quantity of pollutants, including their potential to impact receiving water quality, is critical to designing effective control measures that will achieve the limits in this permit;

d. minimizing impervious areas at your facility and infiltrating runoff onsite (including bioretention cells, green roofs, and pervious pavement, among other approaches), can reduce runoff and improve groundwater recharge and stream base flows in local streams, although care must be taken to avoid ground water contamination;

e. flow can be attenuated by use of open vegetated swales and natural depressions;

f. conservation and/or restoration of riparian buffers will help protect streams from storm water runoff and improve water quality; and

g. use of treatment interceptors (e.g. swirl separators and sand filters) may be appropriate in some instances to minimize the discharge of pollutants.

4. Technology-Based Effluent Limits (BPT/BAT/BCT): Non-Numeric Effluent Limits:

a. Minimize Exposure

Minimize the exposure of raw, final, or waste materials to rain, snow, snowmelt, and runoff. To the extent technologically available and economically practicable and achievable, either locate industrial materials and activities inside or protect them with storm resistant coverings in order to minimize exposure to rain, snow, snowmelt, and runoff (although significant enlargement of impervious surface area is not recommended). In minimizing exposure, pay particular attention to the following areas:

Loading and unloading areas: locate in roofed or covered areas where feasible; use grading, berming, or curbing around the loading area to divert run-on; locate the loading and unloading equipment and vehicles so that leaks are contained in existing containment and flow diversion systems.

Material storage areas: locate indoors, or in roofed or covered areas where feasible; install berms/dikes around these areas; use dry cleanup methods.

Note: Industrial materials do not need to be enclosed or covered if storm water runoff from affected areas will not be discharged to receiving waters.

b. Good Housekeeping

Keep clean all exposed areas that are potential sources of pollutants, using such measures as sweeping at regular intervals, keeping materials orderly and labeled, and stowing materials in appropriate containers.

As part of the developed good housekeeping program, include a cleaning and maintenance program for all impervious areas of the facility where particulate matter, dust, or debris may accumulate, especially areas where material loading and unloading, storage, handling, and processing occur; and where practicable, the paving of areas where vehicle traffic or material storage occur but where vegetative or other stabilization methods are not practicable (institute a sweeping program in these areas too). For unstabilized areas where sweeping is not practicable, consider using storm water management devices such as sediment traps, vegetative buffer strips, filter fabric fence, sediment filtering boom, gravel outlet protection, or other equivalent measures that effectively trap or remove sediment.

c. Maintenance

Maintain all control measures which are used to achieve the effluent limits required by this permit in effective operating condition. Nonstructural control measures must also be diligently maintained (e.g., spill response supplies available, personnel appropriately trained). If control measures need to be replaced or repaired, make the necessary repairs or modifications as expeditiously as practicable.

d. Spill Prevention and Response Procedures

You must minimize the potential for leaks, spills and other releases that may be exposed to storm water and develop plans for effective response to such spills if or when they occur. At a minimum, you must implement:

(1) Procedures for plainly labeling containers (e.g., "Used Oil", "Spent Solvents", "Fertilizers and Pesticides", etc.) that could be susceptible to spillage or leakage to encourage proper handling and facilitate rapid response if spills or leaks occur;

(2) Preventive measures such as barriers between material storage and traffic areas, secondary containment provisions, and procedures for material storage and handling;

(3) Procedures for expeditiously stopping, containing, and cleaning up leaks, spills, and other releases. Employees who may cause, detect or respond to a spill or leak must be trained in these procedures and have necessary spill response equipment available. If possible, one of these individuals should be a member of your storm water pollution prevention team;

(4) Procedures for notification of appropriate facility personnel, emergency response agencies, and regulatory agencies. State or local requirements may necessitate reporting spills or discharges to local emergency response, public health, or drinking water supply agencies. Contact information must be in locations that are readily accessible and available;

(5) Procedures for documenting where potential spills and leaks could occur that could contribute pollutants to storm water discharges, and the corresponding outfalls that would be affected by such spills and leaks; and

(6) A procedure for documenting all significant spills and leaks of oil or toxic or hazardous pollutants that actually occurred at exposed areas, or that drained to a storm water conveyance.

e. Erosion and Sediment Controls

Through the use of structural and/or non-structural control measures stabilize, and contain runoff from, exposed areas to minimize onsite erosion and sedimentation, and the resulting discharge of pollutants. Among other actions to meet this limit, place flow velocity dissipation devices at discharge locations and within outfall channels where necessary to reduce erosion and/or settle out pollutants. In selecting, designing, installing, and implementing appropriate control measures, you are encouraged to check out information from both the State and EPA websites. The following two websites are given as information sources:

http://www.in.gov/idem/stormwater/2363.htm
and
https://www.epa.gov/npdes/stormwater-discharges-industrial-activities

f. Management of Runoff

Divert, infiltrate, reuse, contain or otherwise reduce storm water runoff, to minimize pollutants in the discharge.

g. Salt Storage Piles or Piles Containing Salt

Enclose or cover storage piles of salt, or piles containing salt, used for deicing or other commercial or industrial purposes, including maintenance of paved surfaces. You must implement appropriate measures (e.g., good housekeeping, diversions, containment) to minimize exposure resulting from adding to or removing materials from the pile. Piles do not need to be enclosed or covered if storm water runoff from the piles is not discharged.

h. Waste, Garbage, and Floatable Debris

Ensure that waste, garbage, and floatable debris are not discharged to receiving waters by keeping exposed areas free of such materials or by intercepting them before they are discharged.

i. Employee Training

Train all employees who work in areas where industrial material or activities are exposed to storm water, or who are responsible for implementing activities necessary to meet the conditions of this permit (e.g., inspectors, maintenance personnel), including all members of your Pollution Prevention Team. Training must cover the specific control measures used to achieve the effluent limits in this part, and monitoring, inspection, planning, reporting, and documentation requirements in other parts of this permit.

j. Non-Storm water Discharges

You must determine if any non-storm water discharges not authorized by an NPDES permit exist. Any non-storm water discharges discovered must either be eliminated or modified into this permit. The following non-storm water discharges are authorized and must be documented in the Storm Water Pollution Prevention Plan:

Discharges from fire-fighting activities;
Fire Hydrant flushings;
Potable water, including water line flushings;
Uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;
Irrigation drainage;
Landscape watering provided all pesticides, herbicides, and fertilizer have been applied in accordance with the approved labeling;

Pavement wash water where no detergents are used and no spills or leaks of toxic or hazardous material have occurred (unless all spilled material has been removed);
Routine external building washdown that does not use detergents;
Uncontaminated ground water or spring water;
Foundation or footing drains where flows are not contaminated with process materials;
Incidental windblown mist from cooling towers that collects on rooftops or adjacent portions of the facility, but not intentional discharges from cooling towers (e.g., “piped cooling tower blowdown or drains);
Vehicle wash- waters where uncontaminated water without detergents or solvents is utilized; and
Runoff from the use of dust suppressants approved for use by IDEM.

k. Dust Generation and Vehicle Tracking of Industrial Materials

You must minimize generation of dust and off-site tracking of raw, final, or waste materials.

l. Fugitive Dust Emission.

Minimize fugitive dust emissions from coal handling areas. To minimize the tracking of coal dust offsite, consider procedures such as installing specially designed tires or washing vehicles in a designated area before they leave the site and controlling the wash water.

m. Delivery Vehicles

Minimize contamination of storm water runoff from delivery vehicles arriving at the plant site. Consider procedures to inspect delivery vehicles arriving at the plant site and ensure overall integrity of the body or container and procedures to deal with leakage or spillage from vehicles or containers.

n. Fuel Oil Unloading Areas

Minimize contamination of precipitation or surface runoff from fuel oil unloading areas. Consider using containment curbs in unloading areas, having personnel familiar with spill prevention and response procedures present during deliveries to ensure that any leaks or spills are immediately contained and cleaned up, and using spill and overflow protection devices (e.g., drip pans, drip diapers, or other containment devices placed beneath fuel oil connectors to contain potential spillage during deliveries or from leaks at the connectors).

o. Chemical Loading and Unloading

Minimize contamination of precipitation or surface runoff from chemical loading and unloading areas. Consider using containment curbs at chemical loading and unloading areas to contain spills, having personnel familiar with spill prevention and response procedures present during deliveries to ensure that any leaks or spills are immediately contained and cleaned up, and loading and unloading in covered areas and storing chemicals indoors.

p. Miscellaneous Loading and Unloading Areas

Minimize contamination of precipitation or surface runoff from loading and unloading areas. Consider covering the loading area; grading, berming, or curbing around the loading area to divert run-on; locating the loading and unloading equipment and vehicles so that leaks are contained in existing containment and flow diversion systems; or equivalent procedures.

q. Liquid Storage Tanks

Minimize contamination of surface runoff from above-ground liquid storage tanks. Consider protective guards around tanks, containment curbs, spill and overflow protection, dry cleanup methods, or equivalent measures.

r. Large Bulk Fuel Storage Tanks

Minimize contamination of surface runoff from large bulk fuel storage tanks. Consider containment berms (or their equivalent). You must also comply with applicable State and Federal laws, including Spill Prevention, Control and Countermeasure (SPCC) Plan requirements.

s. Spill Reduction Measures

Minimize the potential for an oil or chemical spill, or reference the appropriate part of your SPCC plan. Visually inspect as part of your routine facility inspection the structural integrity of all above-ground tanks, pipelines, pumps, and related equipment that may be exposed to storm water, and make any necessary repairs immediately.

t. Oil-Bearing Equipment in Switchyards

Minimize contamination of surface runoff from oil-bearing equipment in switchyard areas. Consider using level grades and gravel surfaces to retard flows and limit the spread of spills, or collecting runoff in perimeter ditches.

u. Residue-Hauling Vehicles

Inspect all residue-hauling vehicles for proper covering over the load, adequate gate sealing, and overall integrity of the container body. Repair vehicles without load covering or adequate gate sealing, or with leaking containers or beds.

v. Ash Loading Areas

Reduce or control the tracking of ash and residue from ash loading areas. Clear the ash building floor and immediately adjacent roadways of spillage, debris, and excess water before departure of each loaded vehicle.

w. Areas Adjacent to Disposal Ponds or Landfills

Minimize contamination of surface runoff from areas adjacent to disposal ponds or landfills. Reduce ash residue that may be tracked on to access roads traveled by residue handling vehicles, and reduce ash residue on exit roads leading into and out of residue handling areas.

x. Landfills, Scrap yards, Surface Impoundments, Open Dumps, General Refuse Sites

Minimize the potential for contamination of runoff from these areas.

5. Annual Review

At least once every twelve (12) months, you must review the selection, design, installation, and implementation of your control measures to determine if modifications are necessary to meet the effluent limitations in this permit. You must document the results of your review in a report that shall be retained within the SWPPP. You must also submit the report to the Industrial NPDES Permit Section, as well as the Compliance Branch, on an annual basis. The report may be submitted by email to the Industrial NPDES Permit Section at OWQWWPER@idem.in.gov and to the Compliance Branch at wwReports@idem.in.gov. The email subject line should include the NPDES Permit # and the type of report being submitted (Annual Storm Water Report). The permittee's first annual review report will be due twelve (12) months from the effective date of the permit.

6. Corrective Actions – Conditions Requiring Review

a. If any of the following conditions occur, you must review and revise the selection, design, installation, and implementation of your control measures to ensure that the condition is eliminated and will not be repeated:

(1) an unauthorized release or discharge (e.g., spill, leak, or discharge of non-storm water not authorized by this NPDES permit) occurs at this facility;

(2) it is determined that your control measures are not stringent enough for the discharge to meet applicable water quality standards;

(3) it is determined in your routine facility inspection, an inspection by EPA or IDEM, comprehensive site evaluation, or the Annual Review required in Part D.5 that modifications to the control measures are necessary to meet the effluent limits in this permit or that your control measures are not being properly operated and maintained; or

(4) Upon written notice by the Commissioner that the control measures prove to be ineffective in controlling pollutants in storm water discharges exposed to industrial activity.

b. If construction or a change in design, operation, or maintenance at your facility significantly changes the nature of pollutants discharged in storm water from your facility, or significantly increases the quantity of pollutants discharged, you must review and revise the selection, design, installation, and implementation of your control measures to determine if modifications are necessary to meet the effluent limits in this permit.

7. Corrective Action Deadlines

You must document your discovery of any of the conditions listed in Part I.D.6 within thirty (30) days of making such discovery. Subsequently, within one-hundred and twenty (120) days of such discovery, you must document any corrective action(s) to be taken to eliminate or further investigate the deficiency or if no corrective action is needed, the basis for that determination. Specific documentation required within 30 and 120 days is detailed below. If you determine that changes to your control measures are necessary following your review, any modifications to your control measures must be made before the next storm event if possible, or as soon as practicable following that storm event. These time intervals are not grace periods, but schedules considered reasonable for the documenting of your findings and for making repairs and improvements. They are included in this permit to ensure that the conditions prompting the need for these repairs and improvements are not allowed to persist indefinitely.

8. Corrective Action Report

a. Within 30 days of a discovery of any condition listed in Part I.D.6, you must document the following information:

(1) Brief description of the condition triggering corrective action;

(2) Date condition identified; and

(3) How deficiency identified.

b. Within 120 days of discovery of any condition listed in Part I.D.6, you must document the following information:

(1) Summary of corrective action taken or to be taken (or, for triggering events identified in Part I.D.6.b.(1), where you determine that corrective action is not necessary, the basis for this determination)

(2) Notice of whether SWPPP modifications are required as a result of this discovery or corrective action;

(3) Date corrective action initiated; and

(4) Date corrective action completed or expected to be completed.

9. Inspections

The inspections in this Part must be conducted at this facility when the facility is operating. Any corrective action required as a result of an inspection or evaluation conducted under Part I.D.9. must be performed consistent with Part I.D.6 of this permit.

a. Monthly Site Compliance Inspection

The following areas shall be inspected monthly: coal handling areas, loading or unloading areas, switchyards, fueling areas, bulk storage areas, ash handling areas, areas adjacent to disposal ponds and landfills, maintenance areas, liquid storage tanks, and long term and short term material storage areas.

Areas contributing to a storm water discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of the permit or whether additional control measures are needed. Structural storm water management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the plan shall be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the plan, such as spill response equipment, shall be made.

b. Quarterly Routine Facility Inspections

At least once during the calendar year, a routine facility inspection must be conducted while a discharge is occurring.

1. Routine Facility Inspection - At a minimum, quarterly routine inspections of the storm water management measures and storm water run-off conveyances. The routine inspections must be performed by qualified personnel with at least one member of your storm water pollution prevention team.

2. Routine Facility Inspection Documentation – You must document the findings of each routine facility inspection performed and maintain this documentation within your SWPPP or have the on-site record keeping location referenced in the SWPPP. At a minimum, your documentation must include:

   i. The inspection date and time;

   ii. The name(s) and signature(s) of the inspectors;

   iii. Weather information and a description of any discharges occurring at the time of the inspection;

   iv. Any previously unidentified discharges of pollutants from the site;

   v. Any control measures needing maintenance or repairs;

   vi. Any failed control measures that need replacement;

   vii. Any incidents of noncompliance observed; and

   viii. Any additional control measures needed to comply with the permit requirements.

c. Annual Comprehensive Site Inspections

Comprehensive Site Inspection - Qualified personnel and at least one member of your Pollution Prevention Team shall conduct a comprehensive site inspection, at least once per calendar year, to confirm the accuracy of the description of potential pollution sources contained in the plan, determine the effectiveness of the plan, and assess compliance with the permit. Each Comprehensive Site Inspection shall include:

1. Each Comprehensive Site Inspection shall address all potential sources of pollutants, including (if applicable) air pollution control equipment (e.g., baghouses, electrostatic precipitator, scrubbers, and cyclones), for any signs of degradation (e.g., leaks, corrosion, or improper operation) that could limit their efficiency and lead to excessive emissions. Considering monitoring air flow at inlets and outlets (or use equivalent measures) to check for leaks (e.g., particulate deposition) or blockage in ducts.

Also inspect all process and material handling equipment (e.g., conveyors, cranes, and vehicles) for leaks, drips, or the potential loss of material; and material storage areas (e.g., piles, bins, or hoppers for storing coke, coal, scrap, or slag, as well as chemicals stored in tanks and drums) for signs of material loss due to wind or storm water runoff.

2. Based on the results of the inspection, the description of potential pollutant sources identified in the SWPPP in accordance with Part I.E.2.b of this permit and pollution prevention measures and controls identified in the SWPPP in accordance with Part I.D.4. of this permit shall be revised as appropriate within the timeframes contained in Part I.D.7 of this permit.

3. A report summarizing the scope of the inspection, personnel conducting the inspection, the date(s) of the inspection, major observations relating to the implementation of the storm water pollution prevention plan, and actions taken in accordance with the above paragraph must be documented and either contained in, or have on-site record keeping location referenced in, the SWPPP at least 3 years after the date of the inspection. The report shall identify any incidents of noncompliance. Where a report does not identify any incidents of noncompliance, the report shall contain a certification that the facility is in compliance with the storm water pollution prevention plan and this permit. The report shall be signed in accordance with the signatory requirements of Part II.C.6 of this permit.

4. Where the inspection schedules overlap under this section, the Comprehensive Site Inspection may be conducted in place of one such inspection.

E. STORM WATER POLLUTION PREVENTION PLAN

1. Development of Plan

Within 12 months from the effective date of this permit, the permittee is required to revise and update the current Storm Water Pollution Prevention Plan (SWPPP) for the permitted facility. The plan shall at a minimum include the following:

a. Identify potential sources of pollution, which may reasonably be expected to affect the quality of storm water discharges associated with industrial activity from the facility. Storm water associated with industrial activity (defined in 40 CFR 122.26(b)(14)) includes, but is not limited to, the discharge from any conveyance which is used for collecting and conveying storm water and which is directly related to manufacturing, processing or materials storage areas at an industrial plant;

b. Describe practices and measure to be used in reducing the potential for pollutants to be exposed to storm water; and

c. Assure compliance with the terms and conditions of this permit.

2. Contents

The plan shall include, at a minimum, the following items:

a. Pollution Prevention Team -The plan shall list, by position title, the member or members of the facility organization as members of a Storm Water Pollution Prevention Team who are responsible for developing the storm water pollution prevention plan (SWPPP) and assisting the facility or plant manager in its implementation, maintenance, and revision. The plan shall clearly identify the responsibilities of each storm water pollution prevention team member. Each member of the storm water pollution prevention team must have ready access to either an electronic or paper copy of applicable portions of this permit and your SWPPP.

b. Description of Potential Pollutant Sources – The plan shall provide a description of areas at the site exposed to industrial activity and have a reasonable potential for storm water to be exposed to pollutants. The plan shall identify all activities and significant materials (defined in 40 CFR 122.26(b)), which may potentially be significant pollutant sources. As a minimum, the plan shall contain the following:

(1) A soils map indicating the types of soils found on the facility property and showing the boundaries of the facility property.

(2) A graphical representation, such as an aerial photograph or site layout maps, drawn to an appropriate scale, which contains a legend and compass coordinates, indicating, at a minimum, the following:

(A) All on-site storm water drainage and discharge conveyances, which may include pipes, ditches, swales, and erosion channels, related to a storm water discharge.

(B) Known adjacent property drainage and discharge conveyances, if directly associated with run-off from the facility.

(C) All on-site and known adjacent property water bodies, including wetlands and springs.

(D) An outline of the drainage area for each outfall.

(E) An outline of the facility property, indicating directional flows, via arrows, of surface drainage patterns.

(F) An outline of impervious surfaces, which includes pavement and buildings, and an estimate of the impervious and pervious surface square footage for each drainage area placed in a map legend.

(G) On-site injection wells, as applicable.

(H) On-site wells used as potable water sources, as applicable.

(I) All existing major structural control measures to reduce pollutants in storm water run-off.

(J) All existing and historical underground or aboveground storage tank locations, as applicable.

(K) All permanently designated plowed or dumped snow storage locations.

(L) All loading and unloading areas for solid and liquid bulk materials.

(M) All existing and historical outdoor storage areas for raw materials, intermediary products, final products, and waste materials. Include materials handled at the site that potentially may be exposed to precipitation or runoff, areas where deposition of particulate matter from process air emissions or losses during material-handling activities.

(N) All existing or historical outdoor storage areas for fuels, processing equipment, and other containerized materials, for example, in drums and totes.

(O) Outdoor processing areas.

(P) Dust or particulate generating process areas.

(Q) Outdoor assigned waste storage or disposal areas.

(R) Pesticide or herbicide application areas.

(S) Vehicular access roads.

(T) Identify any storage or disposal of wastes such as spent solvents and baths, sand, slag and dross; liquid storage tanks and drums; processing areas including pollution control equipment (e.g., baghouses); and storage areas of raw material such as coal, coke, scrap, sand, fluxes, refractories, or metal in any form. In addition, indicate where an accumulation of significant amounts of particulate matter could occur from such sources as furnace or oven emissions, losses from coal and coke handling operation, etc., and could result in a discharge of pollutants.

(U) The mapping of historical locations is only required if the historical locations have a reasonable potential for storm water exposure to historical pollutants.

(3) An area site map that indicates:

(A) The topographic relief or similar elevations to determine surface drainage patterns;

(B) The facility boundaries;

(C) All receiving waters;

(D) All known drinking water wells; and

Includes at a minimum, the features in clauses (A), (C), and (D) within a one-fourth (1/4) mile radius beyond the property boundaries of the facility. This map must be to scale and include a legend and compass coordinates.

(4) A narrative description of areas that generate storm water discharges exposed to industrial activity including descriptions for any existing or historical areas listed in subdivision 2.b.(2)(J) through (T) of this Part, and any other areas thought to generate storm water discharges exposed to industrial activity. The narrative descriptions for each identified area must include the following:

(A) Type and typical quantity of materials present in the area.

(B) Methods of storage, including presence of any secondary containment measures.

(C) Any remedial actions undertaken in the area to eliminate pollutant sources or exposure of storm water to those sources. If a corrective action plan was developed, the type of remedial action and plan date shall be referenced.

(D) Any significant release or spill history dating back a period of three (3) years from the effective date of this permit, in the identified area, for materials spilled outside of secondary containment structures and impervious surfaces in excess of their reportable quantity, including the following:

i. The date and type of material released or spilled.

ii. The estimated volume released or spilled.

iii. A description of the remedial actions undertaken, including disposal or treatment.

Depending on the adequacy or completeness of the remedial actions, the spill history shall be used to determine additional pollutant sources that may be exposed to storm water. In subsequent permit terms, the history shall date back for a period of five (5) years from the date of the permit renewal application.

(E) Where the chemicals or materials have the potential to be exposed to storm water discharges, the descriptions for each identified area must include a risk identification analysis of chemicals or materials stored or used within the area. The analysis must include the following:

i. Toxicity data of chemicals or materials used within the area, referencing appropriate material safety data sheet information locations.

ii. The frequency and typical quantity of listed chemicals or materials to be stored within the area.

iii. Potential ways in which storm water discharges may be exposed to listed chemicals and materials.

iv. The likelihood of the listed chemicals and materials to come into contact with water.

(5) A narrative description of existing and planned management practices and measures to improve the quality of storm water run-off entering a water of the state. Descriptions must be created for existing or historical areas listed in subdivision 2.b.(2)(J) through (T) and any other areas thought to generate storm water discharges exposed to industrial activity. The description must include the following:

(A) Any existing or planned structural and nonstructural control practices and measures.

(B) Any treatment the storm water receives prior to leaving the facility property or entering a water of the state.

(C) The ultimate disposal of any solid or fluid wastes collected in structural control measures other than by discharge.

(D) Describe areas that due to topography, activities, or other factors have a high potential for significant soil erosion.

(E) Document the location of any storage piles containing salt used for deicing.

(F) Information or other documentation required under Part I.E.2(d) of this permit.

(6) The results of storm water monitoring. The monitoring data must include completed field data sheets, chain-of-custody forms, and laboratory results. If the monitoring data are not placed into the facility's SWPPP, the on-site location for storage of the information must be reference in the SWPPP.

(7) Drainage Area Site Map. Document in your SWPPP the locations of any of the following activities or sources that may be exposed to precipitation or surface runoff: storage tanks, scrap yards, and general refuse areas; short- and long-term storage of general materials (including but not limited to supplies, construction materials, paint equipment, oils, fuels, used and unused solvents, cleaning materials, paint, water treatment chemicals, fertilizer, and pesticides); landfills and construction sites; and stock pile areas (e.g., coal or limestone piles).

(8) Documentation of Good Housekeeping Measures. You must document in your SWPPP the good housekeeping measures implemented to meet the effluent limits in Part I.D.4 of this NPDES permit.

c. Non-Storm water Discharges – You must document that you have evaluated for the presence of non-storm water discharges not authorized by an NPDES permit. Any non-storm water discharges have either been eliminated or incorporated into this permit. Documentation of non-storm water discharges shall include:

(1) A written non-storm water assessment, including the following:

(A) A certification letter stating that storm water discharges entering a water of the state have been evaluated for the presence of illicit discharges and non-storm water contributions.

(B) Detergent or solvent-based washing of equipment or vehicles that would allow washwater additives to enter any storm water only drainage system shall not be allowed at this facility unless appropriately permitted under this NPDES permit.

(C) All interior maintenance area floor drains with the potential for maintenance fluids or other materials to enter storm water only storm sewers must be either sealed, connected to a sanitary sewer with prior authorization, or appropriately permitted under this NPDES permit. The sealing, sanitary sewer connecting, or permitting of drains under this item must be documented in the written non-storm water assessment program.

(D) The certification shall include a description of the method used, the date of any testing, and the on-site drainage points that were directly observed during the test.

d. General Requirements – The SWPPP must meet the following general requirements:

(1) The plan shall be certified by a qualified professional. The term qualified professional means an individual who is trained and experienced in water treatment techniques and related fields as may be demonstrated by state registration, professional certification, or completion of course work that enable the individual to make sound, professional judgments regarding storm water control/treatment and monitoring, pollutant fate and transport, and drainage planning.

(2) The plan shall be retained at the facility and be available for review by a representative of the Commissioner upon request. IDEM may provide access to portions of your SWPPP to the public.

(3) The plan must be revised and updated as required. Revised and updated versions of the plan must be implemented on or before three hundred sixty-five (365) days from the effective date of this permit. The Commissioner may grant an extension of this time frame based on a request by the person showing reasonable cause.

(4) If the permittee has other written plans, required under applicable federal or state law, such as operation and maintenance, spill prevention control and countermeasures (SPCC), or risk contingency plans, which fulfill certain requirements of an SWPPP, these plans may be referenced, at the permittee's discretion, in the appropriate sections of the SWPPP to meet those section requirements.

(5) The permittee may combine the requirements of the SWPPP with another written plan if:

(A) The plan is retained at the facility and available for review;

(B) All the requirements of the SWPPP are contained within the plan; and

(C) A separate, labeled section is utilized in the plan for the SWPPP requirements.

F. REOPENING CLAUSES

This permit may be modified, or alternately, revoked and reissued, after public notice and opportunity for hearing:

1. to comply with any applicable effluent limitation or standard issued or approved under 301(b)(2)(C),(D) and (E), 304 (b)(2), and 307(a)(2) of the Clean Water Act, if the effluent limitation or standard so issued or approved:

   a. contains different conditions or is otherwise more stringent than any effluent limitation in the permit; or

   b. controls any pollutant not limited in the permit.

2. to incorporate any of the reopening clause provisions cited at 327 IAC 5-2-16.

3. to include a case-specific Limit of Detection (LOD) and/or Limit of Quantitation (LOQ). The permittee must demonstrate that such action is warranted in accordance with the procedures specified under Appendix B, 40 CFR Part 136, using the most sensitive analytical methods approved by EPA under 40 CFR Part 136, or approved by the Commissioner.

4. to include effluent limitations and requirements for a revised Storm Water Pollution Prevention Plan.

5. to comply with any applicable standards, regulations and requirements issued or approved under section 316(b) of the Clean Water Act.

6. to incorporate applicable limits and/or requirements based on newly promulgated and effective Federal Effluent Limitation Guidelines for Steam Electric Generating Stations under 40 CFR 423.

PART II

STANDARD CONDITIONS FOR NPDES PERMITS

A. GENERAL CONDITIONS

1. Duty to Comply

The permittee shall comply with all terms and conditions of this permit in accordance with 327 IAC 5-2-8(1) and all other requirements of 327 IAC 5-2-8. Any permit noncompliance constitutes a violation of the Clean Water Act and IC 13 and is grounds for enforcement action or permit termination, revocation and reissuance, modification, or denial of a permit renewal application.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

2. Duty to Mitigate

In accordance with 327 IAC 5-2-8(3), the permittee shall take all reasonable steps to minimize or correct any adverse impact to the environment resulting from noncompliance with this permit. During periods of noncompliance, the permittee shall conduct such accelerated or additional monitoring for the affected parameters, as appropriate or as requested by IDEM, to determine the nature and impact of the noncompliance.

3. Duty to Reapply

If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must obtain and submit an application for renewal of this permit in accordance with 327 IAC 5-2-8(2). It is the permittee's responsibility to obtain and submit the application. In accordance with 327 IAC 5-2-3(c), the owner of the facility or operation from which a discharge of pollutants occurs is responsible for applying for and obtaining the NPDES permit, except where the facility or operation is operated by a person other than an employee of the owner in which case it is the operator's responsibility to apply for and obtain the permit. Pursuant to 327 IAC 5-3-2(a)(2), the application must be submitted at least 180 days before the expiration date of this permit. This deadline may be extended if all of the following occur:

a. permission is requested in writing before such deadline;

b. IDEM grants permission to submit the application after the deadline; and

c. the application is received no later than the permit expiration date.

4. Permit Transfers

In accordance with 327 IAC 5-2-8(4)(D), this permit is nontransferable to any person except in accordance with 327 IAC 5-2-6(c). This permit may be transferred to another person by the permittee, without modification or revocation and reissuance being required under 327 IAC 5-2-16(c)(1) or 16(e)(4), if the following occurs:

a. the current permittee notified the Commissioner at least thirty (30) days in advance of the proposed transfer date;

b. a written agreement containing a specific date of transfer of permit responsibility and coverage between the current permittee and the transferee (including acknowledgment that the existing permittee is liable for violations up to that date, and the transferee is liable for violations from that date on) is submitted to the Commissioner;

c. the transferee certifies in writing to the Commissioner their intent to operate the facility without making such material and substantial alterations or additions to the facility as would significantly change the nature or quantities of pollutants discharged and thus constitute cause for permit modification under 327 IAC 5-2-16(d). However, the Commissioner may allow a temporary transfer of the permit without permit modification for good cause, e.g., to enable the transferee to purge and empty the facility's treatment system prior to making alterations, despite the transferee's intent to make such material and substantial alterations or additions to the facility; and

d. the Commissioner, within thirty (30) days, does not notify the current permittee and the transferee of the intent to modify, revoke and reissue, or terminate the permit and to require that a new application be filed rather than agreeing to the transfer of the permit.

The Commissioner may require modification or revocation and reissuance of the permit to identify the new permittee and incorporate such other requirements as may be necessary under the Clean Water Act or state law.

5. Permit Actions

a. In accordance with 327 IAC 5-2-16(b) and 327 IAC 5-2-8(4), this permit may be modified, revoked and reissued, or terminated for cause, including, but not limited to, the following:

1. Violation of any terms or conditions of this permit;

2. Failure of the permittee to disclose fully all relevant facts or misrepresentation of any relevant facts in the application, or during the permit issuance process; or

3. A change in any condition that requires either a temporary or a permanent reduction or elimination of any discharge controlled by the permit, e.g., plant closure, termination of discharge by connection to a POTW, a change in state law that requires the reduction or elimination of the discharge, or information indicating that the permitted discharge poses a substantial threat to human health or welfare.

b. Filing of either of the following items does not stay or suspend any permit condition: (1) a request by the permittee for a permit modification, revocation and reissuance, or termination, or (2) submittal of information specified in Part II.A.3 of the permit including planned changes or anticipated noncompliance.

The permittee shall submit any information that the permittee knows or has reason to believe would constitute cause for modification or revocation and reissuance of the permit at the earliest time such information becomes available, such as plans for physical alterations or additions to the permitted facility that:

1. could significantly change the nature of, or increase the quantity of pollutants discharged; or
2. the commissioner may request to evaluate whether such cause exists.

c. In accordance with 327 IAC 5-1-3(a)(5), the permittee must also provide any information reasonably requested by the Commissioner.

6. Property Rights

Pursuant to 327 IAC 5-2-8(6) and 327 IAC 5-2-5(b), the issuance of this permit does not convey any property rights of any sort or any exclusive privileges, nor does it authorize any injury to persons or private property or invasion of other private rights, any infringement of federal, state, or local laws or regulations. The issuance of the permit also does not preempt any duty to obtain any other state, or local assent required by law for the discharge or for the construction or operation of the facility from which a discharge is made.

7. Severability

In accordance with 327 IAC 1-1-3, the provisions of this permit are severable and, if any provision of this permit or the application of any provision of this permit to any person or circumstance is held invalid, the invalidity shall not affect any other provisions or applications of the permit which can be given effect without the invalid provision or application.

8. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject to under Section 311 of the Clean Water Act.

9. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Clean Water Act or state law.

10. Penalties for Violation of Permit Conditions

Pursuant to IC 13-30-4, a person who violates any provision of this permit, the water pollution control laws; environmental management laws; or a rule or standard adopted by the Environmental Rules Board is liable for a civil penalty not to exceed twenty-five thousand dollars ($25,000) per day of any violation.

Pursuant to IC 13-30-5, a person who obstructs, delays, resists, prevents, or interferes with (1) the department; or (2) the department's personnel or designated agent in the performance of an inspection or investigation performed under IC 13-14-2-2 commits a class C infraction.

Pursuant to IC 13-30-10-1.5(e), a person who willfully or negligently violates any NPDES permit condition or filing requirement, or any applicable standards or limitations of IC 13-18-3-2.4, IC 13-18-4-5, IC 13-18-12, IC 13-18-14, IC 13-18-15, or IC 13-18-16, commits a Class A misdemeanor.

Pursuant to IC 13-30-10-1.5(i), an offense under IC 13-30-10-1.5(e) is a Level 4 felony if the person knowingly commits the offense and knows that the commission of the offense places another person in imminent danger of death or serious bodily injury. The offense becomes a Level 3 felony if it results in serious bodily injury to any person, and a Level 2 felony if it results in death to any person.

Pursuant to IC 13-30-10-1.5(g), a person who willfully or recklessly violates any applicable standards or limitations of IC 13-18-8 commits a Class B misdemeanor.

Pursuant to IC 13-30-10-1.5(h), a person who willfully or recklessly violates any applicable standards or limitations of IC 13-18-9, IC 13-18-10, or IC 13-18-10.5 commits a Class C misdemeanor.

Pursuant to IC 13-30-10-1, a person who knowingly or intentionally makes any false material statement, representation, or certification in any NPDES form, notice, or report commits a Class B misdemeanor.

11. Penalties for Tampering or Falsification

In accordance with 327 IAC 5-2-8(10), the permittee shall comply with monitoring, recording, and reporting requirements of this permit. The Clean Water Act, as well as IC 13-30-10-1, provides that any person who knowingly or intentionally (a) destroys, alters, conceals, or falsely certifies a record, (b) tampers with, falsifies, or renders inaccurate or inoperative a recording or monitoring device or method, including the data gathered from the device or method, or (c) makes a false material statement or representation in any label, manifest, record, report, or other document; all required to be maintained under the terms of a permit issued by the department commits a Class B misdemeanor.

12. Toxic Pollutants

If any applicable effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is established under Section 307(a) of the Clean Water Act for a toxic pollutant injurious to human health, and that standard or prohibition is more stringent than any limitation for such pollutant in this permit, this permit shall be modified or revoked and reissued to conform to the toxic effluent standard or prohibition in accordance with 327 IAC 5-2-8(5). Effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants injurious to human health are effective and must be complied with, if applicable to the permittee, within the time provided in the implementing regulations, even absent permit modification.

13. Wastewater treatment plant and certified operators

The permittee shall have the wastewater treatment facilities under the responsible charge of an operator certified by the Commissioner in a classification corresponding to the classification of the wastewater treatment plant as required by IC 13-18-11-11 and 327 IAC 5-22. In order to operate a wastewater treatment plant the operator shall have qualifications as established in 327 IAC 5-22-7.

327 IAC 5-22-10.5(a) provides that a certified operator may be designated as being in responsible charge of more than one (1) wastewater treatment plant, if it can be shown that he will give adequate supervision to all units involved. Adequate supervision means that sufficient time is spent at the plant on a regular basis to assure that the certified operator is knowledgeable of the actual operations and that test reports and results are representative of the actual operations conditions. In accordance with 327 IAC 5-22-3(11), “responsible charge operator” means the person responsible for the overall daily operation, supervision, or management of a wastewater facility.

Pursuant to 327 IAC 5-22-10(4), the permittee shall notify IDEM when there is a change of the person serving as the certified operator in responsible charge of the wastewater treatment facility. The notification shall be made no later than thirty (30) days after a change in the operator.

14. Construction Permit

In accordance with IC 13-14-8-11.6, a discharger is not required to obtain a state permit for the modification or construction of a water pollution treatment or control facility if the discharger has an effective NPDES permit.

If the discharger modifies their existing water pollution treatment or control facility or constructs a new water pollution treatment or control facility for the treatment or control of any new influent pollutant or increased levels of any existing pollutant, then, within thirty (30) days after commencement of operation, the discharger shall file with the Department of Environment Management a notice of installation for the additional pollutant control equipment and a design summary of any modifications.

The notice and design summary shall be sent to the Office of Water Quality, Industrial NPDES Permits Section, 100 North Senate Avenue, Indianapolis, IN 46204-2251.

15. Inspection and Entry

In accordance with 327 IAC 5-2-8(8), the permittee shall allow the Commissioner, or an authorized representative, (including an authorized contractor acting as a representative of the Commissioner) upon the presentation of credentials and other documents as may be required by law, to:

a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept pursuant to the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of this permit;

c. Inspect at reasonable times any facilities, equipment or methods (including monitoring and control equipment), practices, or operations regulated or required pursuant to this permit; and

d. Sample or monitor at reasonable times, any discharge of pollutants or internal wastestreams for the purposes of evaluating compliance with the permit or as otherwise authorized.

16. New or Increased Discharge of Pollutants

This permit prohibits the permittee from undertaking any action that would result in a new or increased discharge of a bioaccumulative chemical of concern (BCC) or a new or increased permit limit for a regulated pollutant that is not a BCC unless one of the following is completed prior to the commencement of the action:

a. Information is submitted to the Commissioner demonstrating that the proposed new or increased discharges will not cause a significant lowering of water quality as defined under 327 IAC 2-1.3-2(50). Upon review of this information, the Commissioner may request additional information or may determine that the proposed increase is a significant lowering of water quality and require the submittal of an antidegradation demonstration.

b. An antidegradation demonstration is submitted to and approved by the Commissioner in accordance with 327 IAC 2-1.3-5 and 327 IAC 2-1.3-6.

B. MANAGEMENT REQUIREMENTS

1. Proper Operation and Maintenance

The permittee shall at all times maintain in good working order and efficiently operate all facilities and systems (and related appurtenances) for the collection and treatment which are installed or used by the permittee and which are necessary for achieving compliance with the terms and conditions of this permit in accordance with 327 IAC 5-2-8(9).

Neither 327 IAC 5-2-8(9), nor this provision, shall be construed to require the operation of installed treatment facilities that are unnecessary for achieving compliance with the terms and conditions of the permit.

2. Bypass of Treatment Facilities

Pursuant to 327 IAC 5-2-8(12), the following are requirements for bypass:

a. The following definitions:

(1) “Bypass” means the intentional diversion of a waste stream from any portion of a treatment facility.

(2) “Severe property damage” means substantial physical damage to property, damage to the treatment facilities which would cause them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

b. The permittee may allow a bypass to occur that does not cause a violation of the effluent limitations contained in this permit, but only if it is also for essential maintenance to assure efficient operation. These bypasses are not subject to Part II.B.2.c. and d.

c. The permittee must provide the Commissioner with the following notice:

(1) If the permittee knows or should have known in advance of the need for a bypass (anticipated bypass), it shall submit prior written notice. If possible, such notice shall be provided at least ten (10) days before the date of the bypass for approval by the Commissioner.

(2) As required by 327 IAC 5-2-8(11)(C), the permittee shall orally report an unanticipated bypass that exceeds any effluent limitations in the permit within twenty-four (24) hours from the time the permittee becomes aware of such noncompliance. A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; and if the cause of noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance. If a complete report is submitted by e-mail within 24 hours of the noncompliance, then that e-mail report will satisfy both the oral and written reporting requirement. E-mails should be sent to wwreports@idem.in.gov.

d. The following provisions are applicable to bypasses:

(1) Except as provided by Part II.B.2.b., bypass is prohibited, and the Commissioner may take enforcement action against a permittee for bypass, unless the following occur:

(A) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage.

(B) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment down time. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass that occurred during normal periods of equipment downtime or preventive maintenance.

(C) The permittee submitted notices as required under Part II.B.2.c.

(2) The Commissioner may approve an anticipated bypass, after considering its adverse effects, if the Commissioner determines that it will meet the conditions listed above in Part II.B.2.d.(1). The Commissioner may impose any conditions determined to be necessary to minimize any adverse effects.

e. Bypasses that result in death or acute injury or illness to animals or humans must be reported in accordance with the "Spill Response and Reporting Requirements" in 327 IAC 2-6.1, including calling 888/233-7745 as soon as possible, but within two (2) hours of discovery. However, under 327 IAC 2-6.1-3(1), when the constituents of the bypass are regulated by this permit, and death or acute injury or illness to animals or humans does not occur, the reporting requirements of 327 IAC 2-6.1 do not apply.

3. Upset Conditions

Pursuant to 327 IAC 5-2-8(13):

a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

b. An upset shall constitute an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of Paragraph c of this section, are met.

c. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs or other relevant evidence, that:

(1) An upset occurred and the permittee has identified the specific cause(s) of the upset;

(2) The permitted facility was at the time being properly operated;

(3) The permittee complied with any remedial measures required under Part II.A.2; and

(4) The permittee submitted notice of the upset as required in the "Twenty-Four Hour Reporting Requirements," Part II.C.3, or 327 IAC 2-6.1, whichever is applicable. However, under 327 IAC 2-6.1-3(1), when the constituents of the discharge are regulated by this permit, and death or acute injury or illness to animals or humans does not occur, the reporting requirements of 327 IAC 2-6.1 do not apply.

d. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof pursuant to 40 CFR 122.41(n)(4).

4. Removed Substances

Solids, sludges, filter backwash, or other pollutants removed from or resulting from treatment or control of wastewaters shall be disposed of in a manner such as to prevent any pollutant from such materials from entering waters of the State and to be in compliance with all Indiana statutes and regulations relative to liquid and/or solid waste disposal. The discharge of pollutants in treated wastewater is allowed in compliance with the applicable effluent limitations in Part I. of this permit.

C. REPORTING REQUIREMENTS

1. Planned Changes in Facility or Discharge

Pursuant to 327 IAC 5-2-8(11)(F), the permittee shall give notice to the Commissioner as soon as possible of any planned physical alterations or additions to the permitted facility. In this context, permitted facility refers to a point source discharge, not a wastewater treatment facility. Notice is required only when either of the following applies:

a. The alteration or addition may meet one of the criteria for determining whether the facility is a new source as defined in 327 IAC 5-1.5.

b. The alteration or addition could significantly change the nature of, or increase the quantity of, pollutants discharged. This notification applies to pollutants that are subject neither to effluent limitations in Part I.A. nor to notification requirements in Part II.C.9. of this permit.

Following such notice, the permit may be modified to revise existing pollutant limitations and/or to specify and limit any pollutants not previously limited.

2. Monitoring Reports

Pursuant to 327 IAC 5-2-8(10) and 327 IAC 5-2-13 through 15, monitoring results shall be reported at the intervals and in the form specified in "Monthly Reporting", Part I.C.2.

3. Twenty-Four Hour Reporting Requirements

Pursuant to 327 IAC 5-2-8(11)(C), the permittee shall orally report to the Commissioner information on the following types of noncompliance within 24 hours from the time permittee becomes aware of such noncompliance. If the noncompliance meets the requirements of item b (Part II.C.3.b) or 327 IAC 2-6.1, then the report shall be made within those prescribed time frames. However, under 327 IAC 2-6.1-3(1), when the constituents of the discharge that is in noncompliance are regulated by this permit, and death or acute injury or illness to animals or humans does not occur, the reporting requirements of 327 IAC 2-6.1 do not apply.

a. Any unanticipated bypass which exceeds any effluent limitation in the permit;

b. Any noncompliance which may pose a significant danger to human health or the environment. Reports under this item shall be made as soon as the permittee becomes aware of the noncomplying circumstances;

c. Any upset (as defined in Part II.B.3 above) that causes an exceedance of any effluent limitation in the permit; or

d. Violation of a maximum daily discharge limitation for any of the following toxic pollutants or hazardous substances: Chromium, Zinc, Mercury.

The permittee can make the oral reports by calling (317)232-8670 during regular business hours and asking for the Compliance Data Section or by calling (317) 233-7745 ((888)233-7745 toll free in Indiana) during non-business hours. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce and eliminate the noncompliance and prevent its recurrence. The Commissioner may waive the written report on a case-by-case basis if the oral report has been received within 24 hours.

Alternatively the permittee may submit a "Bypass/Overflow Report" (State Form 48373) or a "Noncompliance 24-Hour Notification Report" (State Form 52415), whichever is appropriate, to IDEM at (317) 232-8637 or wwreports@idem.in.gov. If a complete e-mail submittal is sent within 24 hours of the time that the permittee became aware of the occurrence, then the email report will satisfy both the oral and written reporting requirements.

4. Other Compliance/Noncompliance Reporting

Pursuant to 327 IAC 5-2-8(11)(D), the permittee shall report any instance of noncompliance not reported under the "Twenty-Four Hour Reporting Requirements" in Part II.C.3, or any compliance schedules at the time the pertinent Discharge Monitoring Report is submitted. The report shall contain the information specified in Part II.C.3;

The permittee shall also give advance notice to the Commissioner of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements; and

All reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.

5. Other Information

Pursuant to 327 IAC 5-2-8(11)(E), where the permittee becomes aware of a failure to submit any relevant facts or submitted incorrect information in a permit application or in any report, the permittee shall promptly submit such facts or corrected information to the Commissioner.

6. Signatory Requirements

Pursuant to 327 IAC 5-2-22 and 327 IAC 5-2-8(15):

a. All reports required by the permit and other information requested by the Commissioner shall be signed and certified by a person described below or by a duly authorized representative of that person:

(1) For a corporation: by a responsible corporate officer. A "responsible corporate officer" means either of the following:

a. A president, secretary, treasurer, any vice president of the corporation in charge of a principal business function, or any other person who performs similar policymaking or decision making functions for the corporation; or

b. The manager of one (1) or more manufacturing, production, or operating facilities provided the manager is authorized to make management decisions that govern the operation of the regulated facility including having the explicit or implicit duty to make major capital investment recommendations, and initiating and directing other comprehensive measures to assure long-term environmental compliance with environmental laws and regulations; the manager can ensure that the necessary systems are established or actions taken to gather complete and accurate information for permit application requirements; and where authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

(3) For a Federal, State, or local governmental body or any agency or political subdivision thereof: by either a principal executive officer or ranking elected official.

b. A person is a duly authorized representative only if:

(1) The authorization is made in writing by a person described above.

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. (A duly authorized representative may thus be either a named individual or any individual occupying a named position.); and

(3) The authorization is submitted to the Commissioner.

c. Electronic Signatures. If documents described in this section are submitted electronically by or on behalf of the NPDES-regulated facility, any person providing the electronic signature for such documents shall meet all relevant requirements of this section, and shall ensure that all of the relevant requirements of 40 CFR part 3 (including, in all cases, subpart D to part 3) (Cross-Media Electronic Reporting) and 40 CFR part 127 (NPDES Electronic Reporting Requirements) are met for that submission.

d. Certification. Any person signing a document identified under Part II.C.6., shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

7. Availability of Reports

Except for data determined to be confidential under 327 IAC 12.1, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Indiana Department of Environmental Management and the Regional Administrator. As required by the Clean Water Act, permit applications, permits, and effluent data shall not be considered confidential.

8. Penalties for Falsification of Reports

IC 13-30 and 327 IAC 5-2-8(15) provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance, shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 180 days per violation, or by both.

9. Changes in Discharge of Toxic Substances

Pursuant to 327 IAC 5-2-9, the permittee shall notify the Commissioner as soon as it knows or has reason to know:

a. That any activity has occurred or will occur which would result in the discharge of any toxic pollutant that is not limited in the permit if that discharge will exceed the highest of the following notification levels.

(1) One hundred micrograms per liter (100 µg/l);

(2) Two hundred micrograms per liter (200 µg/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 µg/l) for 2,4-dinitrophenol and 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/l) for antimony;

(3) Five (5) times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR 122.21(g)(7); or

(4) A notification level established by the Commissioner on a case-by-case basis, either at the Commissioner's own initiative or upon a petition by the permittee. This notification level may exceed the level specified in subdivisions (1), (2), or (3) but may not exceed the level which can be achieved by the technology-based treatment requirements applicable to the permittee under the CWA (see 327 IAC 5-5-2).

b. That it has begun or expects to begin to use or manufacture, as an intermediate or final product or byproduct, any toxic pollutant that was not reported in the permit application under 40 CFR 122.21(g)(9). However, this subsection b. does not apply to the permittee's use or manufacture of a toxic pollutant solely under research or laboratory conditions.

10. Future Electronic Reporting Requirements

IDEM is currently developing the technology and infrastructure necessary to allow compliance with the EPA Phase 2 e-reporting requirements per 40 CFR 127.16 and to allow electronic reporting of applications, notices, plans, reports, and other information not covered by the federal e-reporting regulations.

IDEM will notify the permittee when IDEM's e-reporting system is ready for use for one or more applications, notices, plans, reports, or other information. This IDEM notice will identify the specific applications, notices, plans, reports, or other information that are to be submitted electronically and the permittee will be required to use the IDEM electronic reporting system to submit the identified application(s), notice(s), plan(s), report(s), or other information.

See Part I.C.2. of this permit for the current electronic reporting requirements for the submittal of monthly monitoring reports such as the Discharge Monitoring Report (DMR) and the Monthly Monitoring Report (MMR).

PART III
Other Requirements

A. Polychlorinated Biphenyl

There shall be no discharge of polychlorinated biphenyl (PCBs) compounds such as those commonly used for transformer fluid.

Many electrical transformers manufactured prior to 1978 contained PCBs. Therefore, in order to determine compliance with the PCB prohibition, the permittee shall provide the following PCB* data for Outfall 001 within twelve (12) months of the effective date of the permit. The permittee shall submit the data to the Industrial NPDES Permit Section at OWQWWPER@idem.in.gov and the Compliance Branch at wwReports@idem.in.gov.

Parameter	Test Method	LOD	LOQ
*Total PCBs	608	0.1 ug/l	0.3 ug/l

*Total PCBs is the sum of the following aroclors: PCB-1016, PCB-1221, PCB-1232, PCB-1242, PCB-1248, PCB-1254, and PCB-1260.

Part IV
Cooling Water Intake Structures

A. Best Technology Available (BTA) Determination

In accordance with 40 CFR 401.14, the location, design, construction and capacity of cooling water intake structures of any point source for which a standard is established pursuant to section 301 or 306 of the Clean Water Act (CWA) shall reflect the best technology available for minimizing adverse environmental impact.

The EPA promulgated a CWA section 316(b) regulation on August 15, 2014, which became effective on October 14, 2014. 79 Fed. Reg. 48300-439 (August 15, 2014). This regulation established application requirements and standards for cooling water intake structures. The regulation is applicable to point sources with a cumulative design intake flow (DIF) greater than 2 MGD where 25% or more of the water withdrawn (using the actual intake flow (AIF)) is used exclusively for cooling purposes. The regulation establishes best technology available (BTA) standards to reduce impingement and entrainment of aquatic organisms at existing power generation and manufacturing facilities.

Impingement is the process by which fish and other aquatic organisms are trapped and often killed or injured when they are pulled against the cooling water intake structures (CWIS's) outer structure or screens as water is withdrawn from a water body. Entrainment is the process by which fish larvae and eggs and other aquatic organisms in the intake flow enter and pass through a CWIS and into a cooling water system, including the condenser or heat exchanger, which often results in the injury or the death of the organisms (see definitions at 40 CFR § 125.92(h) and (n)).

The R.M. Schahfer facility's design intake flow (DIF) rate is 57.7 MGD, almost all of which is used for non-contact cooling water. Therefore, since the facility has a DIF greater than 2 MGD, and because the percentage of flow used at the facility exclusively for cooling is greater than 25%, the facility is required to meet the BTA standards for impingement mortality and entrainment, including any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under 40 CFR 125.94(g).

Based on available information, IDEM has determined that the impingement BTA option for the operation of a cooling water intake structure (CWIS) with a maximum actual through screen intake velocity of 0.5 fps will result in compliance with the BTA to minimize adverse environmental impact from impingement. Further, IDEM has determined that the existing facility meets BTA for entrainment. Primary in this entrainment BTA determination is that the facility will cease operations no later than December 31, 2023 and the permittee does have closed-cycle cooling via a single multi-cell mechanical draft cooling tower on each unit which has allowed the permittee to achieve substantial reductions in water usage.

B. Permit Requirements

The permittee must comply with requirements below:

1. In accordance with 40 CFR 125.98(b)(1), nothing in this permit authorizes take for the purposes of a facility's compliance with the Endangered Species Act.

2. The permittee must at all times properly operate and maintain the cooling water intake structure and associated intake equipment.

3. The permittee must inform IDEM of any proposed changes to the CWIS or proposed changes to operations at the facility that affect the information taken into account in the current BTA evaluation.

4. There shall be no discharge of intake screen backwash.

5. In accordance with 40 CFR 125.97(c), by January 31 of each year, the permittee must submit to Industrial NPDES Permit Section IDEM-OWQ an annual certification statement for the preceding calendar year signed by the responsible corporate officer as defined in §122.22 (see 327 IAC 5-2-22) subject to the following:

    a. If the information contained in the previous year's annual certification is still pertinent, you may simply state as such in a letter to IDEM and the letter, along with any applicable data submission requirements specified in this section shall constitute the annual certification.

    b. If you have substantially modified operation of any unit at your facility that impacts cooling water withdrawals or operation of your cooling water intake structures, you must provide a summary of those changes in the report. In addition, you must submit revisions to the information required at §122.21(r) of this chapter in your next permit application.

6. Best technology available (BTA) determinations for entrainment mortality and impingement mortality at cooling water intake structures will be made in each permit reissuance, in accordance with 40 CFR 125.90-98. The permittee shall submit all the information required by the applicable provisions of 40 CFR 122.21(r)(2) through (r)(8) with the next renewal application. Since the permittee has submitted the studies required by 40 CFR 122.21(r), the permittee may, in subsequent renewal applications pursuant to 40 CFR 125.95(c), request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Any habitat designated as critical or species listed as threatened or endangered after issuance of the current permit whose range of habitat or designated critical habitat includes waters where a facility intake is located constitutes potential for a substantial change that

must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take. The permittee must submit a request for reduced cooling water intake structure and waterbody application information at least **two years and six months** prior to the expiration of its NPDES permit. The request must identify each element in 40 CFR 122.21(r) that it determines has not substantially changed since the previous permit application and the basis for the determination. IDEM has the discretion to accept or reject any part of the request.

7. The permittee must maintain an intake daily flow rate of 39 MGD or less. Further, the permittee shall submit an annual summary of the actual intake flows measured at a minimum frequency of daily.

8. The permittee must monitor the velocity at the screen at a minimum frequency of daily. In lieu of velocity monitoring at the screen face, the permittee may calculate the through-screen velocity using water flow, water depth, and the screen open areas.

9. The permittee must monitor and report its cycles of concentration at a minimum frequency of daily.

10. The permittee shall either conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation as required by 40 CFR 125.96(e). The permittee shall conduct such inspections at least weekly to ensure that any technologies operated to comply with 40 CFR 125.94 are maintained and operated to function as designed including those installed to protect Federally-listed threatened or endangered species or designated critical habitat. Alternative procedures can be approved if this requirement is not feasible (e.g., an offshore intake, velocity cap, or during periods of inclement weather).

11. The permittee shall submit and maintain all the information required by the applicable provisions of 40 CFR 125.97.

12. All required reports shall be submitted to the IDEM, Office of Water Quality, NPDES Permits Branch, Industrial NPDES Permit Section at OWQWWPER@idem.in.gov and the Compliance Branch at wwReports@idem.in.gov

National Pollutant Discharge Elimination System
Fact Sheet for
Northern Indiana Public Service Company LLC (NIPSCO)
R.M. Schahfer Generating Station
Draft: July 2020
Final: September 2020

Indiana Department of Environmental Management
100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

Permittee:	Northern Indiana Public Service Company LLC (NIPSCO) R.M. Schahfer Generating Station 2723 E. 1500 N. Wheatfield, IN 46392
Existing Permit Information:	Permit Number: IN0053201 Expiration Date: September 30, 2020
Facility Contact:	Nicholas Babbitt 219-956-5385 nbabbitt@nisource.com
Facility Location:	2723 East 1500 North Wheatfield, IN 46392 Jasper County
Receiving Stream(s):	Kankakee River (Outfall 001 and 002), Davis Ditch and Stalbaum Ditch (storm water Outfalls)
GLI/Non-GLI:	Non-GLI
Proposed Permit Action:	Renew
Date Application Received:	April 3, 2020
Source Category	NPDES Major– Industrial
Permit Writer:	Trisha Williams (317)234-8210, twilliam@idem.in.gov

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1.0 INTRODUCTION

The Indiana Department of Environmental Management (IDEM) received a National Pollutant Discharge Elimination System (NPDES) Permit application from the Northern Indiana Public Service Company LLC (NIPSCO) R.M. Schahfer Generating Station on April 3, 2020.

In accordance with 327 IAC 5-2-6(a), the current five-year permit was issued with an effective date of October 1, 2015. A five-year permit is proposed in accordance with 327 IAC 5-2-6(a).

The Federal Water Pollution Control Act (more commonly known as the Clean Water Act), as amended, (Title 33 of the United States Code (U.S.C.) Section 1251 *et seq.*), requires an NPDES permit for the discharge of pollutants into surface waters. Furthermore, Indiana law requires a permit to control or limit the discharge of any contaminants into state waters or into a publicly owned treatment works. This proposed permit action by IDEM complies with and implements these federal and state requirements.

In accordance with Title 40 of the Code of Federal Regulations (CFR) Sections 124.8 and 124.56, as well as Title 327 of the Indiana Administrative Code (IAC) Article 5-3-8, a Fact Sheet is required for certain NPDES permits. This document fulfills the requirements established in these regulations. This Fact Sheet was prepared in order to document the factors considered in the development of NPDES Permit effluent limitations. The technical basis for the Fact Sheet may consist of evaluations of promulgated effluent guidelines, existing effluent quality, receiving water conditions, Indiana water quality standards-based wasteload allocations, and other information available to IDEM. Decisions to award variances to Water Quality Standards or promulgated effluent guidelines are justified in the Fact Sheet where necessary.

2.0 FACILITY DESCRIPTION

2.1 General

Effective February 16, 2018, the Northern Indiana Public Service Company, a domestic corporation, converted to a limited liability company, with the new name Northern Indiana Public Service Company LLC.

Northern Indiana Public Service Company LLC (NIPSCO) R.M. Schahfer Generating Station is classified under Standard Industrial Classification (SIC) Code 4911- Electric Power Services.

NIPSCO - R.M. Schahfer Generating Station is natural gas and coal fired power steam electric generation facility, in Wheatfield, Indiana, Jasper County. The coal-fired boilers convert water into high pressure steam which drives turbines that are connected to electrical generators. There are four (4) coal-fired steam generating units (14, 15, 17, and 18) and two natural gas-fired combustion turbine peaking units (16A & B) located at the facility. The total coal fired production capacity of the station is 1,625 megawatts (MW). Units 16A & B can produce approximately 155 megawatts (MW) total.

Intake water is withdrawn from the Kankakee River at a location approximately one (1) mile north of the facility and is then discharged into the Intake Basin (IB). The IB has supply and bypass lines to various unit service water systems. The largest portion of water used at the plant is condenser cooling water, which is recirculated through cooling towers and discharged to the Final Basin (FB). A number of waste streams discharge internally to the FB and can be reused/recycled to the cooling towers or other systems. The FB discharges to the Kankakee River via Outfall 001. The FB also has an emergency overflow, Outfall 002, which may discharge to the Kankakee River via Davis Ditch.

A map showing the location of the facility has been included as Figure 1.

Figure 1: Facility Location



NIPSCO NIPSCO R.M. Schahfer Generating Station
FIGURE 1. SITE LOCATION MAP - Outfall, Stormwater and Stream Monitoring Site Locations

2723 East 1500 N
Wheatfield, IN 46392
Jasper County

2.2 Outfall Locations

Table 1. Inventory of Process and Stormwater Outfalls

Location Identification	Description	Location Latitude/ Longitude	Receiving Water
Outfall 001	Cooling tower blowdown, treated sanitary wastewater (Outfall 101), treated FGD wastewater (Outfall 201), low volume wastes, bottom ash transport water, coal pipe run-off, construction dewatering water, and stormwater	N 41° 15' 2.34" W 87° 1' 40.55"	Kankakee River
Outfall 002	Outfall 001 Emergency Overflow	N 41° 13' 35.87" W 87° 1' 18.43"	Kankakee River
Outfall 101	Treated Sanitary Wastewater	N 41° 15' 2.34" W 87° 0' 40.55"	Kankakee River via Outfall 001
Outfall 201	Treated Landfill Leachate and FGD Wastewater from Units 14/15	N 41° 13' 3" W 87° 1' 14"	Kankakee River via Outfall 001
Outfall 003S	Stormwater associated with industrial activity; surface water runoff from a perimeter storm water network from the onsite restricted waste landfill	N 41° 13' 8.55" W 87° 0' 20"	Stalbaum Ditch
Outfall 004S	Stormwater associated with industrial activity; drainage from coal car tracks exiting the plant and the perimeter security road (representative of Outfalls 005S and 006S)	N 41° 12' 22" W 87° 1' 38"	Davis Ditch
Outfall 005S	Stormwater associated with industrial activity; drainage from coal car tracks exiting the plant and the perimeter security road	N 41° 12' 31" W 87° 1' 38"	Davis Ditch
Outfall 006S	Stormwater associated with industrial activity; drainage for the perimeter security road and emergency overflow from the Intake Basin	N 41° 13' 31" W 87° 1' 36"	Davis Ditch
Outfall 007S	Stormwater associated with industrial activity; roof drain runoff and storm water collected from the area surrounding the main buildings of the generating facility	N 41° 12' 17.46" W 87° 1' 47.3"	Davis Ditch

Internal Outfall 301 is proposed in this permit; therefore, the coordinates are not known at this time.

2.3 Wastewater Treatment

Outfall 001 (primary) and 002 (emergency overflow):

The sources of wastewater contributing to these outfalls are cooling tower blowdown, treated sanitary wastewater from internal Outfall 101, treated flue gas desulfurization (FGD) wastewater from internal Outfall 201, FGD blowdown wastewaters from proposed internal Outfall 301, low volume wastes, bottom ash transport water, coal pile runoff, construction dewatering water, and storm water. Treatment includes sedimentation and dechlorination.

The wastewater treatment system has an average discharge of approximately 20.3 MGD and a maximum monthly discharge of 21.6 MGD, based on the recent 2-year period from April 2018 to April 2020 data from DMR/MMR Reports.

Internal Outfall 101:

The discharge from internal Outfall 101 consists of treated sanitary wastewater only. Treatment includes pre-aeration, activated sludge, sedimentation and UV disinfection. No chemical treatment is currently provided for sanitary wastewaters. The average long-term effluent flow from internal Outfall 101 has been 0.009 MGD per Form 2C.

Internal Outfalls 201 (Existing) and 301 (Proposed):

Internal Outfall 201 discharges effluent from a refurbished and upgraded former wastewater treatment plant (WWTP) which is designed to treat the blowdown from the FGD scrubbers for Units 14 and 15 prior to discharge to the Final Basin via internal Outfall 201. The wastewater treatment process at this treatment plant consists of neutralization, chemical precipitation, coagulation, flocculation, sedimentation, and filtration. The treatment plant includes an equalization tank, reaction tank, clarifier, effluent sand filter, and an additional mercury polishing step. Sludge thickening and dewatering technologies are also utilized. Currently, the discharge from internal Outfall 201 consists of treated Unit 14 FGD blowdown only.

The maximum daily effluent value from internal Outfall 201 has been 0.4275 MGD and the long-term average value has been reported to be 0.05 MGD. The FGD WWTP treats the blowdown from Units 14 and 15, as well as FGD Landfill Leachate. A Flow Diagram for FGD WWTP is provided in Figure 3.

Electric Generating Units 17 and 18 FGD systems operate as limestone forced oxidation systems producing synthetic gypsum, a byproduct with beneficial re-use. Boiler slag from Unit 14 and bottom ash from Units 15, 17, and 18 is quenched and is sent to the Waste Disposal Area. Boiler slag is commercially marketed for re-use and bottom ash from Units 15, 17, and 18 is used as construction material in the on-site coal ash landfill. Bottom ash and conditioned (wetted) fly ash from Units 14, 17, and 18 are landfilled on-site, while the fly ash from Unit 15 is marketed for beneficial re-use. The FGD system blowdown from Units 17 and 18 is currently discharged to the Material Storage Runoff Basin (MSRB) and settled before discharging to the FB. As currently designed, the Unit 17/18 FGD system discharges may comingle with non-FGD

related wastewaters in the MSRB as shown in the flow diagram provided by the facility. A requirement for a new internal monitoring (internal Outfall 301) is proposed in this permit to be located prior to the FGD blowdown wastewaters from Units 17 and 18 commingling with non-FGD wastewater in the MSRB.

A Water Flow Diagram has been included as Figure 2. An FGD Treatment System Water Flow Diagram has been included as Figure 3.

Figure 2: Water Flow Diagram

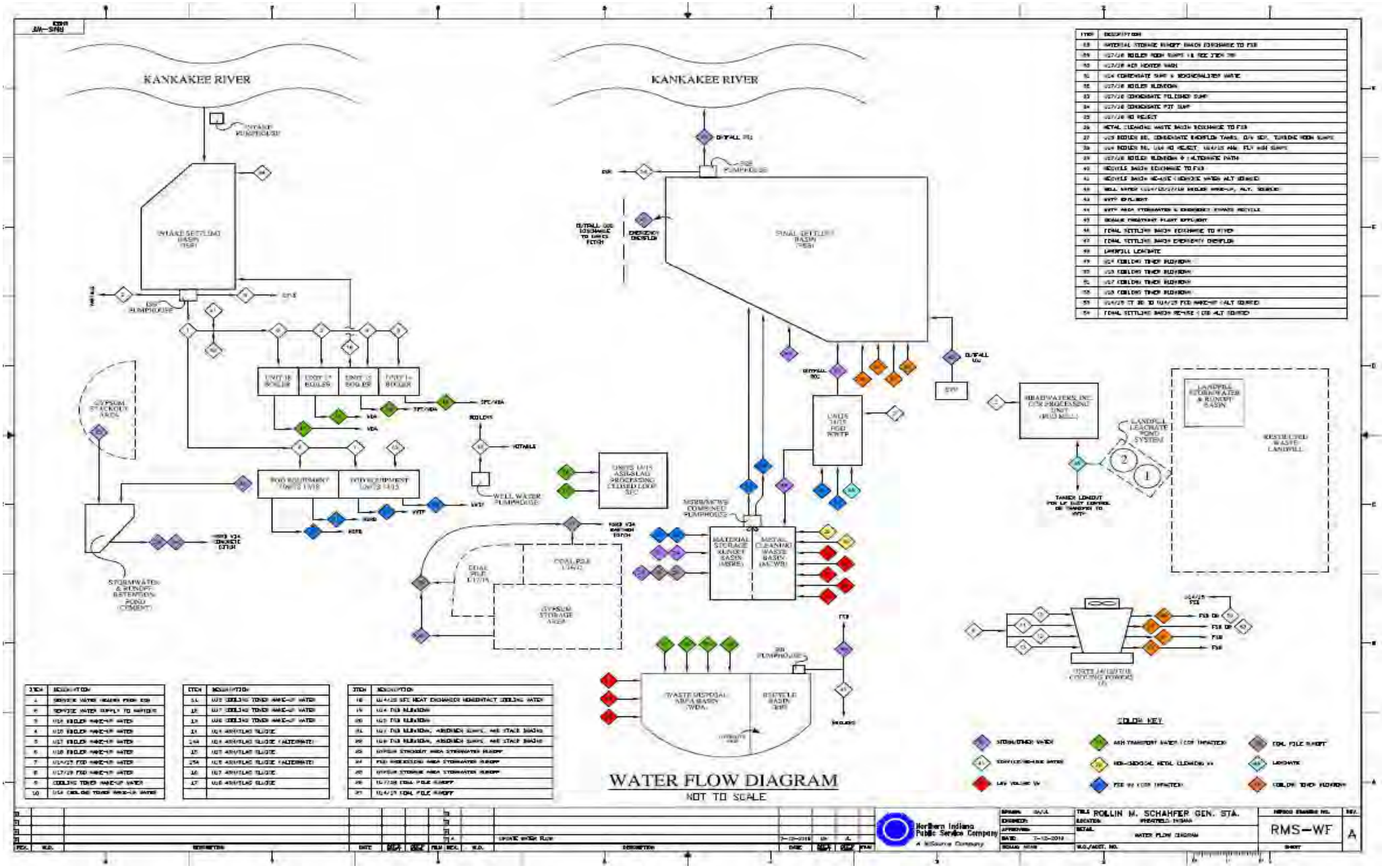
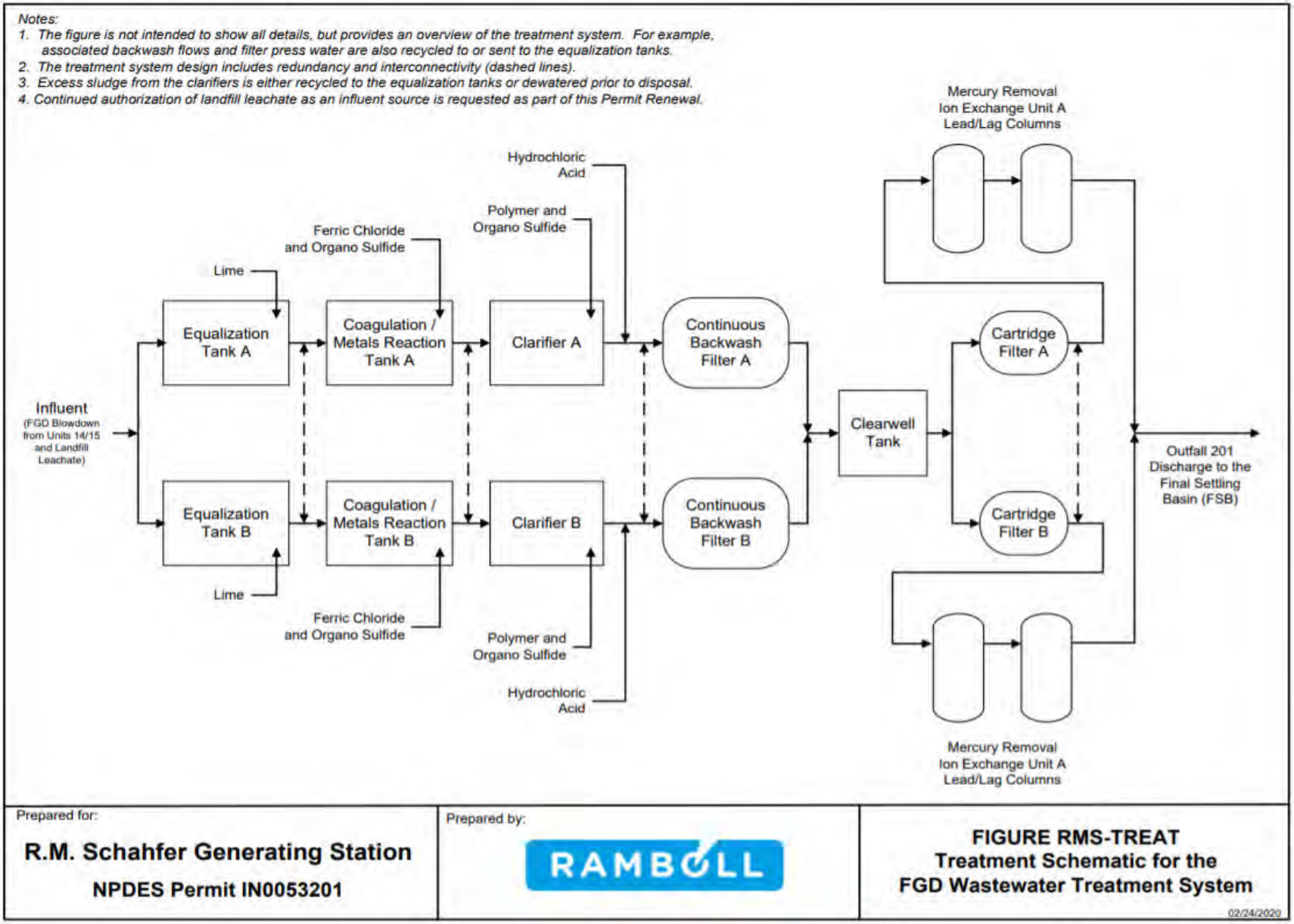


Figure 3. FGD Wastewater Treatment System Flow Diagram



The permittee shall have the wastewater treatment facilities under the responsible charge of an operator certified by the Commissioner in a classification corresponding to the classification of the wastewater treatment plant as required by IC 13-18-11-11 and 327 IAC 5-22-5. In order to operate a wastewater treatment plant, the operator shall have qualifications as established in 327 IAC 5-22-7. IDEM has given the permittee a Class D industrial wastewater treatment plant classification.

2.4 Changes in Operation

Announced through NIPSCO's 2018 Integrated Resource Plan released October 31, 2018, the Northern Indiana Public Service Company LLC has publicly announced the planned retirement of all coal-fired generation at the R.M. Schahfer Generating Station (RMSGS). Actions supporting this goal have already been initiated. The short-term action plan includes the initiation of activities in preparation for the retirement of RMSGS Units 14, 15, 17, and 18 by 2023, thereby aligning with NIPSCO's long term action plan to fully retire the RMSGS Units 14, 15, 17, and 18 by the end of 2023.

To implement the Coal Combustion Residual (CCR) rule compliance plan for NIPSCO-RMSGS, piping will be rerouted from the Metal Cleaning Waste Basin (MCWB) and MSRB, collectively referred to as the Multicell Unit (MCU), to the larger Waste Disposal Area (WDA) or Recycle Basin (RB). Engineering design is currently being finalized. The following information is PROPOSED / DRAFT and subject to change pursuant to final engineering specifications. CCR waste streams (FGD blowdown from Units 17 and 18 [i.e. U17/18 FGD WW]) currently going to the MCU will be routed to the WDA. Non-CCR waste streams currently going to the MCU will be routed to the RB. Pipe redirects will employ a combination of new and existing collection sumps, as well as new and existing pipelines. Work also includes the installation of an additional crosstie between the RB discharge lines and the MSRB/MCWB discharge line to the Final Settling Basin (FSB) to allow for greater blowdown capacity to the FSB. The following table presents the disposition of the waste streams to be redirected and the peak flow rates from their respective sources. The peak flows rates can occur simultaneously; although most are intermittent, except for the FGD Filter Building Sump Pumps which always have some level of flow in order to minimize solids deposition.

Table 3. Draft Waste Stream Pipe Redirect Summary

Contributing Streams	Re-Piped from WDA to Recycle Basin	Re-Piped To Recycle Basin via Coal Pile Runoff (CPR) Sump	Re-Piped To WDA via Existing Ash Piping[1]
	(gpm)	(gpm)	(gpm)
Non-CCR Streams to (WDA)			
Yard Drains	1,200		
U14 Boiler Room Sump	4,000		
U14 Boiler Room Sump	3,000		
Material Storage Runoff Basin (MSRB) Streams			
U17 & 18 FGD Filter Building North Sump			1,500
U17 & 18 FGD Filter Building South Sump			1,500
Coal Pile Run Off		6,000	
Unit 14/15 Chimney Drain[2]		0	
Run Off Retention Pond		500	
Metal Cleaning Waste Basin (MCWB) Streams			
U17 Fly Ash Truck Scale Sump		200	
U18 Fly Ash Truck Scale Sump		200	
U14 Fly Ash Silo Sump		200	
U17/18 Chimney Drain		125	
U14 Waste Neutralization		450	
U17 Make Up Demineralizer Sump		400	
U17/18 Metal Cleaning Waste Sumps		3,400	
U14/15 WWT Emergency Bypass			0
U14/15 Storm Water Run Off[3]		820	
Totals	8,200	12,295	3,000

[1] Deleted
[2] NIPSCO confirmed U14/15 Chimney Drain had no flow. This pipe will be capped.
[3] The U14/15 WWT Emergency Bypass and Storm Water Runoff currently discharge to the MCWB through a common line. The storm Water flow will be redirected to the Recycle Pond and the WWT Emergency Bypass will be disconnected.

2.5 Facility Storm Water

The facility is located within a mile of the Kankakee River with shallow groundwater and a potential for periodic flooding. It has been identified that the groundwater in the area of the Restricted Waste Site Type I Landfill (RWS I), that accepts FGD Sludge and Coal Ash, has been impacted by a showing of elevated levels of sodium, sulfate, and specific conductance.

The shallow groundwater has the potential to discharge to surface water by way of the two (2) primary drainage ditches (Stalbaum Ditch and Davis Ditch) that flow through the property. Therefore, Outfalls 004S and 007S, and Stream Monitoring Sites (SMS) 010S and 011S shall monitor for storm water in Davis Ditch. Outfall 004S discharge shall be representative of discharge from Outfalls 005S and 006S.

Outfalls 004S and 005S provide drainage from coal car tracks exiting the plant and the perimeter security road. Outfall 006S provides drainage for a different section of the perimeter security road and emergency overflow from the IB. Outfall 007S consists of roof drain runoff and storm water collected from the area surrounding the main buildings of the generating facility. Outfalls 003S and SMS 012S and 013S shall monitor for storm water in Stalbaum Ditch. Outfall 003S is surface water runoff from a perimeter storm

water network from the onsite restricted waste landfill. To date, no discharge from Outfall 003S has been reported.

Table 2. Stream Monitoring Sites

Location Identification	Description	Location Latitude/ Longitude
SMS 010S	Stormwater in Davis Ditch	N 41° 12' 5.22" W 87° 0' 56.4"
SMS 011S	Stormwater in Davis Ditch	N 41° 13' 19.21" W 87° 1' 47.3"
SMS 012S	Stormwater in Stalbaum Ditch	N 41° 12' 29.88" W 87° 0' 3.9"
SMS 013S	Stormwater in Stalbaum Ditch	N 41° 13' 24.52" W 87° 1' 21.3"

-+

3.0 PERMIT HISTORY

3.1 Compliance History

The purpose of this section is to summarize any violations and enforcement actions associated with the permit.

A review of this facility's discharge monitoring data was conducted for compliance verification and shows the following permit limitation violations at Outfall 001 and 101 between April 2015 and April 2020. There are no pending or current enforcement actions regarding this NPDES permit.

Outfall 001: Exceedances in TSS
Outfall 101: Exceedances in TSS, *E. coli*, and $CBOD_5$

4.0 LOCATION OF DISCHARGE/RECEIVING WATER USE DESIGNATION

The receiving stream for Outfalls 001 and 002 is the Kankakee River. The $Q_{7, 10}$ low flow value of the Kankakee River is 294 cfs and shall be capable of supporting a well-balanced warm water aquatic community and full body contact recreation in accordance with 327 IAC 2-1-3.

Shallow groundwater has the potential to discharge to surface water by way of the two (2) primary drainage ditches (Stalbaum Ditch and Davis Ditch) that flow through the property. The $Q_{7, 10}$ low flow values of the Stalbaum Ditch and Davis Ditch are 0.0 cfs.

The permittee discharges to a waterbody that has been identified as a water of the state that is not within the Great Lakes system. Therefore, it is subject to water-quality standards and the procedures to calculate and incorporate water quality-based effluent limitations specific to dischargers not discharging to waters within the Great Lakes system under 327 IAC 2-1 and 327 IAC 5-2-11.1.

4.1 Total Maximum Daily Loads (TMDLs)

Section 303(d) of the Clean Water Act requires states to identify waters, through their Section 305(b) water quality assessments, that do not or are not expected to meet applicable water quality standards with federal technology based standards alone. States are also required to develop a priority ranking for these waters taking into account the severity of the pollution and the designated uses of the waters. Once this listing and ranking of impaired waters is completed, the states are required to develop Total Maximum Daily Loads (TMDLs) for these waters in order to achieve compliance with the water quality standards. Indiana's 2018 303(d) List of Impaired Waters was developed in accordance with Indiana's Water Quality Assessment and 303(d) Listing Methodology for Waterbody Impairments and Total Maximum Daily Load Development for the 2018 Cycle.

A TMDL for the Kankakee/Iroquois River Watershed was completed by IDEM in 2009. The primary cause of impairment is *Escherichia coli* bacteria (*E. coli*), therefore, the Kankakee River (in the Kankakee/Iroquois River Watershed), (Assessment-Unit INK0189_M1008), 12 Digit HUC 71200010800) is on the 2018 303(d) list for *E. coli*, impaired biotic communities, and PCBs in fish tissue.

The receiving streams Stalbaum Ditch and Davis Ditch are not on the 2018 303(d) list for impairments. TMDLs for Stalbaum Ditch and Davis Ditch are not currently planned.

5.0 PERMIT LIMITATIONS

Under 327 IAC 5-2-10 (see also 40 CFR 122.44), NPDES permit limits are based on either TBELs (including TBELs developed on a case-by-case basis using BPJ, where applicable) or WQBELs, whichever is most stringent. The decision to limit or monitor the parameters contained in this permit is based on information contained in the permittee's NPDES application, and other available information relating to the facility and the receiving waterbody. In addition, when renewing a permit, the existing permit limits and the antibacksliding requirements under 327 IAC 5-2-10(a)(11) must be considered.

5.1 Technology-Based Effluent Limits (TBEL)

TBELs require every individual member of a discharge class or category to operate their water pollution control technologies according to industry-wide standards and accepted engineering practices. TBELs are developed by applying the National Effluent Limitation Guidelines (ELGs) established by EPA for specific industrial categories. Technology-based treatment requirements established pursuant to sections 301(b) and 306 of the Clean Water Act (CWA) represent the minimum level of control that must be imposed in an NPDES permit (327 IAC 5-5-2(a)).

In the absence of ELGs, TBELs can also be established on a case-by-case basis using best professional judgment (BPJ) in accordance with 327 IAC 5-2-10 and 327 IAC 5-5 (which implement 40 CFR 122.44, 125.3, and Section 402(a)(1) of the CWA).

The applicable technology-based standards for the facility are contained in 40 CFR 423 – Steam Electric Point Source Category. Since this facility is classified as an "existing point source", all discharges are subject to effluent guidelines identified in 40 CFR 423.12, Best Practicable Control Technology (BPT) and 40 CFR 423.13; Best Available Control Technology (BAT). The applicable effluent guidelines are as follows:
Applicable ELG Subparts:

Requirements applicable to all wastewater streams:

1. pH Control - 40 CFR 423.12(b)(1), the pH of all discharges, except once through cooling water, shall be within the range of 6.0-9.0 s.u. (BPT)

2. Polychlorinated biphenyl (PCB) - 40 CFR 423.12(b)(2), there shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. (BPT)

Regulated wastewater streams and their applicable requirements

There are eight (8) separate wastewater streams that are regulated by 40 CFR Part 423. Not every wastewater stream may not be present at every facility. The wastewater streams are:

1. Once through non-contact cooling water for a plant with a total rated electric generating capacity of 25 or more megawatts – The BPT guidelines are contained in 40 CFR 423.12(b)(6) and (8), and the BAT guidelines are contained in 40 CFR 423.13(b).

2. Cooling tower blowdown - The BPT guidelines are contained in 40 CFR 423.12(b)(7) and (8), and the BAT guidelines are contained in 40 CFR 423.13(d).

3. Low volume wastewater - The BPT guidelines are contained in 40 CFR 423.12(b)(3), and there are no BAT guidelines.

4. Ash handling wastewater - The BPT guidelines are contained in 40 CFR 423.12(b)(4). The BAT guidelines are contained in 40 CFR 423.13(k)(1)(i) - Bottom Ash and 40 CFR 423.13(h)(1)(i) – Fly Ash

5. Metal cleaning wastewater - The BPT guidelines are contained in 40 CFR 423.12(b)(5) [non-chemical] and the BAT guidelines are contained in 40 CFR 423.13(e) [chemical].

6. Coal Pile Runoff - The BPT guidelines are contained in 40 CFR 423.12(b)(9) and (10), and there are no BAT guidelines.

7. FGD wastewater - The BPT guidelines are contained in 40 CFR 423.12(b)(11), and the BAT guidelines are contained in 40 CFR 423.13(g)(1)(i).

8. Combustion residual leachate - The BPT guidelines are contained in 40 CFR 423.12(b)(11), and the BAT guidelines are contained in 40 CFR 423.13(l).

For the cooling water discharges (cooling tower blowdown and once through noncontact cooling water) identified above, the BAT guidelines are more stringent and/or more comprehensive than the BPT guidelines. However, the BPT guidelines are more stringent and/or more comprehensive than the BAT guidelines for the metal cleaning wastewater discharges. The tables below identifies the most stringent guidelines for each wastewater sources.

Table 1a
Effluent Guidelines from 40 CFR 423

Wastewater Stream***	pH	Res. Chlorine	TSS		O & G		T. Copper		T. Iron	
			Daily Max	Mo. Avg.	Daily Max	Mo. Avg.	Daily Max	Mo. Avg.	Daily Max	Mo. Avg.
Once through non-contact	n/a	0.2 mg/l*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Cooling tower blowdown	≥ 6.0 s.u. and ≤ 9.0 s.u	0.2 mg/l*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Low volume wastewater	≥ 6.0 s.u. and ≤ 9.0 s.u	n/a	100 mg/l	30 mg/l	20 mg/l	15 mg/l	n/a	n/a	n/a	n/a
+Ash handling wastewater	≥ 6.0 s.u. and ≤ 9.0 s.u	n/a	100 mg/l	30 mg/l	20 mg/l	15 mg/l	n/a	n/a	n/a	n/a
Metal cleaning wastewater	≥ 6.0 s.u. and ≤ 9.0 s.u	n/a	100 mg/l	30 mg/l	20 mg/l	15 mg/l	1 mg/l	1 mg/l	1 mg/l	1 mg/l
Coal Pile Runoff	≥ 6.0 s.u. and ≤ 9.0 s.u	n/a	50 mg/l**	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Combustion residual leachate	n/a	n/a	100.0 mg/l	30.0 mg/l	20.0 mg/l	15.0 mg/l	n/a	n/a	n/a	n/a

* The discharge of chlorine is limited to a maximum two hours per day for each electrical generating unit.

** This value is an instantaneous limitation (at any time), not a daily maximum.

*** When wastewater streams are combined for discharge and/or treatment 40 CFR 423 requires that the quantity of each pollutant or pollutant property controlled attributable to each controlled waste source shall not exceed the specified limitations for that waste source.

Table 1b
FGD Effluent Guidelines from 40 CFR 423

Wastewater Stream*	TSS		O & G		T. Arsenic		T. Mercury		T. Selenium		Nitrate/nitrite (as N)	
	Daily Max	Mo. Avg.	Daily Max	Mo. Avg.	Daily Max	Daily Max	Daily Max	Mo. Avg.	Daily Max	Mo. Avg.	Daily Max	Mo. Avg.
FGD wastewater	100.0 mg/l	30.0 mg/l	20.0 mg/l	15.0 mg/l	11 ug/l	8 ug/l	788 ng/l	356 ng/l	23 ug/l	12 ug/l	17.0 mg/l	4.4 mg/l

* When wastewater streams are combined for discharge and/or treatment 40 CFR 423 requires that the quantity of each pollutant or pollutant property controlled attributable to each controlled waste source shall not exceed the specified limitations for that waste source.

5.2 Water Quality-Based Effluent Limits (WQBELs)

WQBELs are designed to be protective of the beneficial uses of the receiving water and are independent of the available treatment technology. The WQBELs for this facility are based on water quality criteria in 327 IAC 2-1-6 or developed under the procedures described in 327 IAC 2-1-8.2 through 8.7 and 327 IAC 2-1-8.9, and implementation procedures in 327 IAC 5. Limitations are required for any parameter which has the reasonable potential to exceed a water quality criterion as determined using the procedures under 327 IAC 5-2-11.1(h).

5.3 Effluent Limitations and Monitoring Requirements by Outfall

Under 327 IAC 5-2-10(a) (see also 40 CFR 122.44), NPDES permit requirements are technology-based effluent limitations and standards (including TBELs based on federal effluent limitations guidelines or developed on a case-by-case basis using best professional judgment (BPJ), where applicable), water quality standards-based, or based on other more stringent requirements. The decision to limit or monitor the parameters contained in this permit is based on information contained in the permittee's NPDES application and other available information relating to the facility and the receiving waterbody as well as the applicable federal effluent limitations guidelines. In addition, when renewing a permit, the existing permit limits, the antibacksliding requirements under 327 IAC 5-2-10(a)(11), and the antidegradation requirements under 327 IAC 2-1.3 must be considered.

5.3.1 All External Outfalls

Narrative Water Quality Based Limits

The narrative water quality criteria contained under 327 IAC 2-1-6(a)(1) and (2) have been included in this permit to ensure that these minimum water quality conditions are met.

Flow
The effluent flow is to be monitored in accordance with 327 IAC 5-2-13(a)(2).

pH

Discharges to waters of the state are limited to the range of 6.0-9.0 s.u., in accordance with 327 IAC 2-1-6(b)(2) and 40 CFR 423.12(b)(1).

5.3.2 Outfalls 001 and 002

Intake Flow

The actual intake flows must be measured at a minimum frequency of daily in accordance with 40 CFR 125.94. The permittee must maintain an intake daily flow rate of 39 MGD or less.

Cycles of Concentration

The cycles of concentration must be measured at a minimum frequency of daily. The definition at 40 CFR 125.92 requires makeup flows be minimized. COC serve as an indicator of minimized makeup flows, and thus may be used by IDEM when assessing performance of a particular closed-cycle recirculating cooling system (CCRS) CCRS.

Temperature

Effluent limitations for temperature are based on the criteria established in 327 IAC 2-1-6(b).

Total Suspended Solids (TSS)

TSS limitations are based upon 327 IAC 5-5-2(h)(2) and are 30 mg/l daily maximum and 15 mg/l monthly average. These limits have been retained from the previous permit, and are considered sufficient to ensure compliance with narrative water quality criteria in 327 IAC 2-1-6(a)(1)(C) which prohibits oil or other substances in amounts sufficient to produce color, visible sheen, odor, or other conditions in such a degree to create a nuisance.

Oil and Grease (O & G)

The proposed O & G limitations are more stringent than the limitations based upon 327 IAC 5-5-2(h)(2) and are 15 mg/l daily maximum and 5 mg/l monthly average. These limits have been retained from the previous permit which are considered sufficient to ensure compliance with narrative water quality criteria in 327 IAC 2-1-6(a)(1)(C) which prohibits oil or other substances in amounts sufficient to produce color, visible sheen, odor, or other conditions in such a degree to create a nuisance.

Sulfate

In 2004, a reasonable potential to exceed (RPE) analysis showed that Sulfate was discharged at levels having an RPE water quality criteria (see Attachment A). These effluent limitations are included in the permit because sulfate is a significant component of the landfill waste material. The effluent limitations have been retained from the previous permit in accordance with antibacksliding regulations and are 1,501 mg/l Daily Maximum and 748 mg/l Monthly Average.

Total Residual Chlorine (TRC) - Continuous

The limits for continuous total residual chlorine are retained from the previous permit and are based on the water quality standards in 327 IAC 2-1-6. The limits are 0.02 mg/l monthly average and 0.04 mg/l daily maximum. The WQBELs for chlorine are less than the limit of quantitation (LOQ) of 0.06 mg/l. The permittee will be considered in compliance with the permit limits if the effluent concentrations measured are less than the LOQ of 0.06 mg/l.

Total Residual Chlorine (TRC) - Intermittent

The intermittent TRC limit of 0.2 mg/l daily maximum has been retained from the previous permit and is based on 327 IAC 2-1-6. To be considered an intermittent discharge, total residual chlorine shall not be detected in the discharge from any single generating unit for a period of more than forty (40) minutes in duration, and such periods shall be separated by at least five (5) hours. The permittee is limited to no more than four (4) chlorination cycles per day. The intermittent TRC limitations were developed for the control of zebra mussels.

Chlorination - Frequency

The monitoring of chlorination frequency applies only when the facility is chlorinating intermittently. The permit requires the permittee to provide a monthly report on the “times per day” the permittee is intermittently chlorinating. The permittee is limited to no more than four (4) chlorination cycles per day.

Chlorination - Duration

The monitoring for duration of chlorination dose applies only when the facility is chlorinating intermittently. The permit requires the permittee to provide a monthly report on the number of minutes per chlorination cycle the permittee is chlorinating intermittently. The permittee is limited to no more than forty (40) minutes per chlorination cycle.

Mercury

Flue gas desulfurization (FGD) wastestreams are common wastestreams at coal fired steam electric power generating facilities. It is generated when a wet scrubbing system is used to scrub pollutants, such as mercury, from power plant air emissions. FGD wastewater is often treated in a dedicated wastewater facility rather than through a plants existing wastewater treatment system.

In 2010, an RPE analysis showed that Mercury was discharged at levels having an RPE water quality criteria (see Attachment B). The effluent limitations have been retained from the previous permit in accordance with antibacksliding regulations. The limits are 12.0 ng/l monthly average and 20.0 ng/l daily maximum. The previous permit required that Mercury sampling be conducted 6 X annually in the months of February, April, June, August, October, and December of each year for the term of the permit.

Total Chromium

Monitoring requirements and effluent limitations have been retained from the previous permit for Total Chromium. These limits are technology-based from 40 CFR 423.13(d)(1) for discharges from cooling tower blowdown. The effluent limitations have been retained from the previous permit in accordance with antibacksliding regulations. The permittee is required to meet a daily maximum limit of 0.2 mg/l for Total Chromium.

Total Zinc

The 2004 RPE analysis showed that Zinc was discharged at levels having an RPE water quality criteria (see Attachment A). The WQBELs are more stringent that the TBELs from 40 CFR 423.13(d)(1) for discharges from cooling tower blowdown. The effluent limitations are 0.604 mg/l Daily Maximum and 0.301 mg/l Monthly Average.

Ammonia (as N), Arsenic, Boron, Chloride, Manganese, Selenium, Nitrate/Nitrite

IDEM identified the following as pollutants of concern for the facility's FGD wastewater: Ammonia, Arsenic, Boron, Chloride, Manganese, Selenium, and Nitrate/Nitrite. The monitoring requirements for these parameters have been retained in this permit in accordance with 40 CFR Part 423.

126 Priority Pollutants

To ensure that the 126 priority pollutants listed in 40 CFR 423, Appendix A, are not present in the discharge at Outfall 001 with the exception of chromium and zinc, the permittee shall provide engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR 136. The permittee is required to submit engineering calculations to the IDEM, Office of Water Quality, Industrial NPDES Permit Section as part of the next permit renewal.

The discharge of cooling tower blowdown is regulated by the 40 CFR 423.13(d). 40 CFR 423.13(d)(1) prohibits the discharge of the 126 priority pollutants listed in Appendix A of this regulation in detectable amounts with the exception of total chromium and total zinc which have specific numeric limits. In accordance with 423.13(d)(3), instead of the monitoring specified in 40 CFR 122.48(b), compliance with the limitations for the 126 priority pollutants in paragraph (d)(1) of 40 CFR 423.13 may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136. However, compliance with the above limitations for the 126 priority pollutants (with the exception of chromium and zinc) in paragraph (d)(1) of 40 CFR 423.13 must be reported each time there is a change in the chemicals added for cooling tower maintenance.

5.3.3 Outfall 101

E.coli

The *E. coli* limitations are set in accordance with regulations specified in 327 IAC 5-10-6.

$CBOD_5$ and TSS

Effluent limitations for $CBOD_5$ and TSS were established using BPJ and are based on 40 CFR 133 and 327 IAC 5-10-5; Small Sanitary Discharge.

5.3.4 Outfalls 201 (existing) and 301 (proposed)

Oil and Grease (O & G)

The proposed O & G limitations based upon 40 CFR 423.12(b)(11) and are 20.0 mg/l daily maximum and 15.0 mg/l monthly average.

Total Suspended Solids (TSS)

TSS limitations are based upon 40 CFR 423.12(b)(11) and are 100.0 mg/l daily maximum and 30.0 mg/l monthly average.

Arsenic

Arsenic limitations are based upon 40 CFR 423.13(g)(1)(i) and are 11 ug/l daily maximum and 8 ug/l monthly average. As allowed by the ELG, and based on the planned shutdown of the facility, the permittee must comply with the limits no later than December 31, 2023.

Mercury

Mercury limitations are based upon 40 CFR 423.13(g)(1)(i) and are 788 ng/l daily maximum and 356 ng/l monthly average. As allowed by the ELG, and based on the planned shutdown of the facility, the permittee must comply with the limits no later than December 31, 2023.

Selenium

Selenium limitations are based upon 40 CFR 423.13(g)(1)(i) and are 23 ug/l daily maximum and 12 ug/l monthly average. As allowed by the ELG, and based on the planned shutdown of the facility, the permittee must comply with the limits no later than December 31, 2023.

Nitrate/Nitrite, as N

Nitrate/Nitrite, as N, limitations are based upon 40 CFR 423.13(g)(1)(i) and are 17.0 mg/l daily maximum and 4.4 mg/l monthly average. As allowed by the ELG, and based on the planned shutdown of the facility, the permittee must comply with the limits no later than December 31, 2023.

Ammonia, Boron, Chloride, Manganese, and Zinc

These parameters are included because IDEM identified them as pollutants of concern for the facility's FGD wastewater. Monitoring for these parameters will be retained from the previous permit.

5.3.5 Storm Water Outfalls 003S, 004S, and 007S; Stream Monitoring Sites 010S, 011S, 012S, and 013S

TSS, Oil & Grease (O & G), Arsenic, Cadmium, Chromium, Copper, Lead, Nickel, Selenium, Zinc, Sulphate, and pH

The above identified parameters are associated with storm water discharges at this facility. The monitoring requirements for TSS, O & G, Arsenic, Cadmium, Chromium, Copper, Lead, Nickel, Selenium, Zinc, Sulphate, and pH have been retained from the previous permit.

5.4 Whole Effluent Toxicity (WET) TESTING

The permit does not contain a requirement to conduct whole effluent toxicity (WET) tests.

5.5 Antibacksliding

Pursuant to 327 IAC 5-2-10(a)(11), unless an exception applies, a permit may not be renewed, reissued or modified to contain effluent limitations that are less stringent than the comparable effluent limitations in the previous permit. None of the limits included in this permit are less stringent than the comparable effluent limitations in the previous permit, therefore, backsliding is not an issue in accordance with 327 IAC 5-2-10(a)(11).

5.6 Antidegradation

Indiana's Antidegradation Standards and Implementation procedures are outlined in 327 IAC 2-1.3. The antidegradation standards established by 327 IAC 2-1.3-3 apply to all surface waters of the state. The permittee is prohibited from undertaking any deliberate action that would result in a new or increased discharge of a bioaccumulative chemical of concern (BCC) or a new or increased permit limit for a regulated pollutant that is not a BCC unless information is submitted to the commissioner demonstrating that the proposed new or increased discharge will not cause a significant lowering of water quality, or an antidegradation demonstration submitted and approved in accordance 327 IAC 2-1.3-5 and 2-1.3-6.

The NPDES permit does not propose to establish a new or increased loading of a regulated pollutant; therefore, the Antidegradation Implementation Procedures in 327 IAC 2-1.3-5 and 2-1.3-6 do not apply to the permitted discharge.

5.7 Storm Water

Under 327 IAC 5-4-6(d), if an individual permit is required under 327 IAC 5-4-6(a) for discharges consisting entirely of storm water, or if an individual permit is required under 327 IAC 5-2-2 that includes discharge of commingled storm water associated with industrial activity, IDEM may consider the following in determining the requirements to be contained in the permit:

(1) The provisions in the following: (A) 327 IAC 15-5, 327 IAC 15-6, and 327 IAC 15-13, as appropriate to the type of storm water discharge, (B) NPDES Pesticide General Permit for Point Source Discharges to Waters of the State from the Application of Pesticides, Permit Number ING870000, effective October 31, 2011, available at:

http://www.in.gov/idem/cleanwater/2480.htm#pesticide or from the IDEM Office of Water Quality, Permits Branch, 100 North Senate Avenue, Indianapolis, IN 46204-2251, and (C) 327 IAC 5-2 [Basic NPDES Requirements], 327 IAC 5-5 [NPDES Criteria and Standards for Technology-based Treatment Requirements], and 327 IAC 5-9 [Best Management Practices; Establishment].

(2) "Interim Permitting Approach for Water Quality-Based Effluent Limitations in Storm Water Permits", EPA 833-D-96-001, September 1, 1996, available from U.S. EPA, National Service Center for Environmental Publications at https://www.epa.gov/nscep or from IDEM.

(3) The nature of the discharges and activities occurring at the site or facility.

(4) Other information relevant to the potential impact on water quality.

In accordance with 327 IAC 15-2-2(a), the commissioner may regulate storm water discharges associated with industrial activity, as defined in 40 CFR 122.26(b)(14), consistent with the EPA 2008 NPDES Multi-Sector General Permit for Storm water Discharges Associated with Industrial Activity, as modified, effective May 27, 2009, under an NPDES general permit. Therefore, using Best Professional Judgment to develop case-by-case technology-based limits as authorized by 327 IAC 5-2-10, 327 IAC 5-5, and 327 IAC 5-9 (see also 40 CFR 122.44, 125.3, and Section 402(a)(1) of the Clean Water Act (CWA)), IDEM has developed storm water requirements for individual permits that are consistent with the EPA 2008 NPDES Multi-Sector General Permit for Storm water Discharges Associated with Industrial Activity. The 2008 Multi-Sector General Permit and Fact Sheet is available from: https://www.epa.gov/npdes/previous-versions-epas-msgp-documents.

According to 40 CFR 122.26(b)(14) and 327 IAC 15-6-2 facilities classified under Standard Industrial Classification (SIC) Code 4911 – Electric Power Service, are considered to be engaging in “industrial activity” for purposes of 40 CFR 122.26(b). Therefore, the permittee is required to have all storm water discharges associated with industrial activity permitted. Treatment for storm water discharges associated with industrial activities is required to meet, at a minimum, best available technology economically achievable/best conventional pollutant control technology (BAT/BCT) requirements. EPA has determined that non-numeric technology-based effluent limits have been determined to be equal to the best practicable technology (BPT) or BAT/BCT for storm water associated with industrial activity.

Storm water associated with industrial activity must also be assessed to ensure compliance with all water quality standards. Effective implementation of the non-numeric technology-based requirements should, in most cases, control discharges as necessary to meet applicable water quality standards. Violation of any of these effluent limitations constitutes a violation of the permit.

Additionally, IDEM has determined that with the appropriate implementation of the required control measures and Best Management Practices (BMPs) found in Part I.D. of the permit, the discharge of storm water associated with industrial activity from this facility will meet applicable water quality standards and will not cause a significant lowering of water quality. Therefore, the storm water discharge is in compliance with the antidegradation standards found in 327 IAC 2-1.3-3, and pursuant to 327 IAC 2-1.3-4(a)(5), an antidegradation demonstration is not required.

The technology-based effluent limits (TBELs) require the permittee to minimize exposure of raw, final, or waste materials to rain, snow, snowmelt, and runoff. In doing so, the permittee is required, to the extent technologically available and economically achievable, to either locate industrial materials and activities inside or to protect them with storm resistant coverings. In addition, the permittee is required to: (1) use good housekeeping practices to keep exposed areas clean, (2) regularly inspect, test, maintain and repair all industrial equipment and systems to avoid situations that may result in leaks, spills, and other releases of pollutants in storm water discharges, (3) minimize the potential for leaks, spills and other releases that may be exposed to storm water and develop plans for effective response to such spills if or when they occur, (4) stabilize exposed area and contain runoff using structural and/or non-structural control measures to minimize onsite erosion and sedimentation, and the resulting discharge of pollutants, (5) divert, infiltrate, reuse, contain or otherwise reduce storm water runoff, to minimize pollutants in the permitted facility discharges, (6) enclose or cover storage piles of salt or piles containing salt used for deicing or other commercial or industrial purposes, including maintenance of paved surfaces, (7) train all employees who work in areas where industrial materials or activities are exposed to storm water, or who are responsible for implementing activities necessary to meet the conditions of this permit (e.g., inspectors, maintenance personnel), including all members of your Pollution Prevention Team, (8) ensure that waste, garbage and floatable debris are not discharged to receiving waters by keeping exposed areas free of such materials or by intercepting them before they are discharged, and (9) minimize generation of dust and off-site tracking of raw, final or waste materials.

To meet the non-numeric effluent limitations in Part I.D.4, the permit requires the facility to select control measures (including BMPs) to address the selection and design considerations in Part I.D.3.

The permittee must control its discharge as necessary to meet applicable water quality standards. It is expected that compliance with the non-numeric technology-based requirements should ensure compliance with applicable water quality standards. However, if at any time the permittee, or IDEM, determines that the discharge causes or contributes to an exceedance of applicable water quality standards, the permittee must take corrective actions, and conduct follow-up monitoring and IDEM may impose additional water quality-based limitations.

"Terms and Conditions" to Provide Information in a Storm Water Pollution Prevention Plan (SWPPP)

Distinct from the effluent limitation provisions in the permit, the permit requires the discharger to prepare a SWPPP for the permitted facility. The SWPPP is intended to document the selection, design, installation, and implementation (including inspection, maintenance, monitoring, and corrective action) of control measures being used to comply with the effluent limits set forth in Part I.D. of the permit. In general, the SWPPP must be kept up-to-date, and modified when necessary, to reflect any changes in control measures that were found to be necessary to meet the effluent limitations in the permit.

The requirement to prepare a SWPPP is not an effluent limitation. Rather, it documents what practices the discharger is implementing to meet the effluent limitations in Part I.D. of the permit. The SWPPP is not an effluent limitation because it does not restrict quantities, rates, and concentrations of constituents which are discharged. Instead, the requirement to develop a SWPPP is a permit "term or condition" authorized under sections 402(a)(2) and 308 of the Act. Section 402(a)(2) states, "[t]he Administrator shall prescribe conditions for [NPDES] permits to assure compliance with the requirements of paragraph (1) of this subsection, including conditions on data and information collection, reporting, and such other requirements as he deems appropriate." The SWPPP requirements set forth in this permit are terms or conditions under the CWA because the discharger is documenting information on how it intends to comply with the effluent limitations (and inspection and evaluation requirements) contained elsewhere in the permit. Thus, the requirement to develop a SWPPP and keep it up-to-date is no different than other information collection conditions, as authorized by 327 IAC 5-1-3 (see also CWA section 402(a)(2)).

It should be noted that EPA has developed a guidance document, "Developing your Storm Water Pollution Prevention Plan – A guide for Industrial Operators (EPA 833-B09-002), February 2009, to assist facilities in developing a SWPPP. The guidance contains worksheets, checklists, and model forms that should assist a facility in developing a SWPPP.

Public availability of documents

Part I.E.2.d(2) of the permit requires that the permittee retain a copy of the current SWPPP at the facility and make it immediately available, at the time of an onsite inspection or upon request, to IDEM. When submitting the SWPPP to IDEM, if any information in the SWPPP is considered to be confidential, that information shall be submitted in accordance with 327 IAC 12.1. Interested persons can request a copy of the SWPPP through IDEM. Any information that is confidential pursuant to Indiana law will not be released to the public.

5.8 Water Treatment Additives

In the event that changes are to be made in the use of water treatment additives that could significantly change the nature of or increase the discharge concentration of any of the additives contributing to an outfall governed under the permit, the permittee must apply for and obtain approval from IDEM prior to such discharge. Discharges of any such additives must meet Indiana water quality standards. The permittee must apply for permission to use water treatment additives by completing and submitting State Form 50000 (Application for Approval to Use Water Treatment Additives) available at: http://www.in.gov/idem/5157.htm and submitting any needed supplemental information. In the review and approval process, IDEM determines, based on the information submitted with the application, whether the use of any new or changed water treatment additives/chemicals or dosage rates could potentially cause the discharge from any permitted outfall to cause chronic or acute toxicity in the receiving water.

The authority for this requirement can be found under one or more of the following: 327 IAC 5-2-8(11)(B), which generally requires advance notice of any planned changes in the permitted facility, any activity, or other circumstances that the permittee has reason to believe may result in noncompliance with permit requirements; 327 IAC 5-2-8(11)(F)(ii), which generally requires notice as soon as possible of any planned physical alterations or additions to the permitted facility if the alteration or addition could significantly change the nature of, or increase the quantity of, pollutants discharged; and 327 IAC 5-2-9(2) which generally requires notice as soon as the discharger knows or has reason to know that the discharger has begun or expects to begin to use or manufacture, as an intermediate or final product or byproduct, any toxic pollutant that was not reported in the permit application.

The following is a list of water treatment additives currently approved for use at the facility:

Additive Name	Supplier	Injection Points	Purpose
Sodium Hypochlorite	Rowe	U17, U18 Cooling Tower Basin	Algaecide and biocide
Nalco 90005	Nalco	U14, U15, U17, U18 Cooling Tower	Algaecide and biocide
Sulfuric Acid	Wilson	U14, U15, U17, U18 Cooling Tower	pH control
3D Trasar 3DT198	Nalco	U14, U17, U18 Condenser	Cooling Tower treatment
Nalco 7385	Nalco	U14, U15, U17, U18 Cooling Tower	Scale inhibitor
AGS Plus DBA	Solutia	FGD specific	FGD process additive
Nalco 7408	Nalco	RO units, Feedw ater Ion Exchange Unit, Wastewater	Boiler chlorine scavenger
Perma Treat PC-191T	Nalco	Reverse Osmosis system	Boiler antiscalant
Nalco 8735	Nalco	RO systems	RO system pH stabilizer
Trasar Trac 109	Nalco	FGD, Boiler, RO, and cooling towers	Cooling Tower corrosion inhibitor
Nalco PermaClean PC-11	Nalco	RO systems	RO system biocide
Nalco 7468	Nalco	Cooling towers	Cooling tower Antifoam (used in conjunction with Nalco 73550)
Ammonium Hydroxide	Wilson	North of Unit 14, 17	Boiler pH control
Citric Acid (anhydrous)	Wilson	Unit 14, 15 basement	RO system maintenance
Sodium Hydroxide	Rowe	Unit 14 basement	pH control
Ferric Chloride	PVS Chemical	14 / 15 FGD WWTP	Wastewater treatment chemical
Hydrated Lime	Mississippi Lime	14 / 15 FGD WWTP	Wastewater treatment chemical
Hydrochloric Acid	PVS Chemical	14 / 15 FGD WWTP	Wastewater treatment pH control
Nalmet 1689	Nalco	14 / 15 FGD WWTP	Wastewater treatment chemical
Nalclear 7763	Nalco	14 / 15 FGD WWTP	Wastewater treatment chemical
CL5828	ChemTreat	Circ Water System	Cooling Water Treatment Dispersant
CL206	ChemTreat	Circ Water System	Cooling Water and Reserve Osmosis
CL4125	ChemTreat	Circ Water System	Cooling Water Treatment
CL4704	ChemTreat	Circ Water System	Cooling Water Treatment
CL1370	ChemTreat	Circ Water System	Cooling Water Treatment
RL9005	ChemTreat	U14/15/17/18 RO Systems	Reverse Osmosis Treatment
P8200L	ChemTreat	Circ Water System	Metal Precipitant
FCT42	ChemTreat	U14/15/17/18 Coal Feeders	Fuel Additive
CL2840	ChemTreat	Circ Water System	Closed System Treatment
PE2505	Suez	Circ Water System	Corrosion/scale inhibitor
3DT138	NALCO	Circ Water System	Water Chemistry control
CL5450	ChemTreat	Circ Water System	Cooling Water Treatment
2877	NALCO	Recycle Basin	Algaecide
3DT337	NALCO	U14/17/18 Condensers	Corrosion control
RL124	ChemTreat	U14/15/17/18 RO Systems	Dechlorination
AZ8100	Suez	U14/17/18 Condensers	Corrosion control
CT1300	Suez	U14/15/17/18 CTs	Algaecide
RL9007	ChemTreat	U14/15/17/18 CTs	Corrosion/scale inhibitor
BL1304	ChemTreat	U14/17 RO Systems	pH control

6.0 PERMIT DRAFT DISCUSSION

6.1 Discharge Limitations, Monitoring Conditions and Rationale

The proposed final effluent limitations are based on the more stringent of the Indiana water quality-based effluent limitations (WQBELs), technology-based effluent limitations (TBELs), or approved total maximum daily loads (TMDLs) and NPDES regulations as appropriate for each regulated outfall. Section 5.3 of this document explains the rationale for the effluent limitations at each Outfall.

Analytical and sampling methods used shall conform to the version of 40 CFR 136 as referenced in 327 IAC 5-2-13(d)(1) and 327 IAC 5-2-1.5.

Nothing has changed to warrant modifying the monitoring conditions.

Outfalls 001 and 002:

Parameter	Monthly Average	Daily Maximum	Units	Minimum Frequency	Sample Type
Intake Flow	Report	39	MGD	1 X Daily	Continuous
Flow	Report	Report	MGD	1 X Daily	Continuous
COC	Report	Report	number	1 X Daily	Report
Temperature	Report	Report	°F	1 X Weekly	Grab
TSS	15	30	mg/l	1 X Weekly	24-Hr. Comp.
Oil & Grease	5	15	mg/l	1 X Weekly	Grab
Chromium	----	0.2	mg/l	1 X Monthly	Grab
Zinc	0.301	0.604	mg/l	1 X Monthly	Grab
Mercury	12.0	20.0	ng/l	6 X Yearly	Grab
Sulfate	748	1,501	mg/l	1 X Weekly	Grab
TRC Continuous Intermittent	 0.02 ----	 0.04 0.2	 mg/l mg/l	 1 X Daily 1 X Daily	 Grab Grab
Chlorination Frequency Duration	 ---- ----	 4 40	 Times/Day Minutes/Dose	 1 X Daily 1 X Daily	 Report Report
Ammonia (as N)	Report	Report	mg/l	2 X Monthly	Grab
Arsenic	Report	Report	ug/l	1 X Weekly	Grab
Boron	Report	Report	ug/l	1 X Weekly	Grab
Chloride	Report	Report	mg/l	2 X Monthly	Grab
Manganese	Report	Report	mg/l	1 X Weekly	Grab
Selenium	Report	Report	ug/l	1 X Weekly	Grab
Nitrate/Nitrite	Report	Report	mg/l	1 X Weekly	Grab

Parameter	Daily Minimum	Daily Maximum	Units	Minimum Frequency	Sample Type
pH	6.0	9.0	Std Units	1 X Weekly	Grab

Internal Outfall 101:

Parameter	Monthly Average	Daily Maximum	Units	Minimum Frequency	Sample Type
Flow	Report	Report	MGD	2 X Monthly	24-Hr. Total
$CBOD_5$	25	40	mg/l	2 X Monthly	24-Hr. Comp.
TSS	30	45	mg/l	2 X Monthly	Grab
E. coli	125	235	cfu/100 ml	2 X Monthly	Grab

Internal Outfalls 201 (Existing) and 301 (Proposed):

Parameter	Monthly Average	Daily Maximum	Units	Minimum Frequency	Sample Type
Flow	Report	Report	MGD	2 X Monthly	24-Hr. Total
TSS	30.0	100.0	mg/l	2 X Monthly	24-Hr. Comp.
Oil & Grease	15.0	20.0	mg/l	2 X Monthly	Grab
Arsenic Interim Final	 Report 8	 Report 11	 ug/l ug/l	 2 X Monthly 2 X Monthly	 Grab Grab
Mercury Interim Final	 Report 356	 Report 788	 ng/l ng/l	 6 X Yearly 6 X Yearly	 Grab Grab
Selenium Interim Final	 Report 12	 Report 23	 ug/l ug/l	 2 X Monthly 2 X Monthly	 Grab Grab
Nitrate/Nitrite (as N) Interim Final	 Report 4.4	 Report 17.0	 mg/l mg/l	 2 X Monthly 2 X Monthly	 Grab Grab
Ammonia (as N)	Report	Report	mg/l	2 X Monthly	Grab
Boron	Report	Report	ug/l	2 X Monthly	Grab
Chloride	Report	Report	mg/l	2 X Monthly	Grab
Manganese	Report	Report	mg/l	2 X Monthly	Grab
Zinc	Report	Report	mg/l	2 X Monthly	Grab

Parameter	Daily Minimum	Daily Maximum	Units	Minimum Frequency	Sample Type
pH	6.0	9.0	Std Units	2 X Monthly	Grab

Storm Water Outfalls: 003S, 004S, 007S
Stream Monitoring Sites: 010S, 011S, 012S, 013S

Parameter	Daily Maximum	Units	Minimum Frequency	Sample Type
Flow	Report	MGD	Annually	Grab
TSS	Report	mg/l	Annually	Grab
O&G	Report	mg/l	Annually	Grab
Arsenic	Report	mg/l	Annually	Grab
Cadmium	Report	mg/l	Annually	Grab
Chromium	Report	mg/l	Annually	Grab
Copper	Report	mg/l	Annually	Grab
Lead	Report	mg/l	Annually	Grab
Nickel	Report	mg/l	Annually	Grab
Selenium	Report	mg/l	Annually	Grab
Zinc	Report	mg/l	Annually	Grab
Sulfate	Report	mg/l	Annually	Grab
pH	Report	s.u.	Annually	Grab

6.2 Schedule of Compliance

The circumstances in this NPDES permit do not qualify for a schedule of compliance.

6.3 Polychlorinated Biphenyl

There shall be no discharge of polychlorinated biphenyl (PCBs) compounds such as those commonly used for transformer fluid.

Many electrical transformers manufactured prior to 1978 contained PCBs. Therefore, in order to determine compliance with the PCB prohibition, the permittee shall provide the following PCB* data for Outfall 001 within twelve (12) months of the effective date of the permit. The permittee shall submit the data to the Industrial NPDES Permit Section at OWQWWPER@idem.in.gov and the Compliance Branch at wwReports@idem.in.gov.

Parameter	Test Method	LOD	LOQ
*Total PCBs	608	0.1 ug/l	0.3 ug/l

*Total PCBs is the sum of the following aroclors: PCB-1016, PCB-1221, PCB-1232, PCB-1242, PCB-1248, PCB-1254, and PCB-1260.

6.4 Clean Water Act Section 316(b) Cooling Water Intake Structure(s) (CWIS)

A. Introduction

In accordance with 40 CFR 401.14, the location, design, construction and capacity of cooling water intake structures of any point source for which a standard is established pursuant to section 301 or 306 of the Clean Water Act (CWA) shall reflect the best technology available for minimizing adverse environmental impact.

The EPA promulgated a CWA section 316(b) regulation on August 15, 2014, which became effective on October 14, 2014. 79 Fed. Reg. 48300-439 (August 15, 2014). This regulation established application requirements and standards for cooling water intake structures. The regulation is applicable to point sources with a cumulative design intake flow (DIF) greater than 2 MGD where 25% or more of the water withdrawn (using the actual intake flow (AIF)) is used exclusively for cooling purposes. The regulation establishes best technology available standards to reduce impingement and entrainment of aquatic organisms at existing power generation and manufacturing facilities.

Impingement is the process by which fish and other aquatic organisms are trapped and often killed or injured when they are pulled against the CWISs outer structure or screens as water is withdrawn from a water body. Entrainment is the process by which fish larvae and eggs and other aquatic organisms in the intake flow enter and pass through a CWIS and into a cooling water system, including the condenser or heat exchanger, which often results in the injury or the death of the organisms (see definitions at 40 CFR § 125.92(h) and (n)).

The R.M. Schahfer facility's DIF rate is 57.7 MGD, almost all of which is used for non-contact cooling water. The AIF, as defined under 40 CFR 125.92(a), is the average volume of water withdrawn on an annual basis by the cooling water intake structures over the previous five years. The annual actual intake flows from January 2015 through December 2019 are shown in the below table and the average actual intake flow over this entire five year period is 21.7 MGD.

Year	Actual Intake Flow (MGD)
2015	22.03
2016	18.79
2017	20.26
2018	24.56
2019	22.93

Therefore, since the facility has a DIF greater than 2 MGD, and because the percentage of flow used at the facility exclusively for cooling is greater than 25%, the facility is required to meet the BTA standards for impingement and entrainment mortality,

including any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under 40 CFR 125.94(g).

Also, since the design intake flow at this facility is greater than 2 MGD and since the AIF is not greater than 125 MGD, the permittee was required to submit the application information required by 40 CFR § 122.21(r)(2) through (r)(8). This information was originally submitted to IDEM in April 2015 in the report titled "Schahfer Generating Station NPDES Permit Application Submittal Requirements §122.21(r)(2) – (r)(8)" authored by Golder Associates, Inc. (referred to herein as the April 2015 CWIS Report). The April 2015 CWIS Report is available in IDEM's Virtual File Cabinet (VFC) at:

https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=80458487&dDocName=80457843&Rendition=web&allowInterrupt=1&noSaveAs=1

As part of the April 2020 NPDES permit renewal application for the facility, the permittee included as Attachment 2 of that application, an update of the 316(b) Cooling Water Intake Structure requirements in §122.21(R)(2) – (R)(8). This update, herein referred to as the 2020 CWIS Requirements Update, stated that the required 316(b) application information was submitted to IDEM in the April 2015 CWIS Report and that the main elements of that report continue to be substantially unchanged. A copy of this 2020 CWIS Requirements Update is included as Attachment C of this Fact Sheet.

The 316(b) regulation also established requirements that build on existing Clean Water Act requirements to coordinate with the U.S. Fish and Wildlife Service prior to issuing NPDES permits. Pursuant to 40 CFR 125.98(h), upon receipt of an NPDES 316(b) application for an existing facility subject to the rule, the Director (IDEM) must forward a copy of the 316(b) application to the appropriate Field Office of the U.S. Fish and Wildlife Service for a 60-day review prior to public notice of the permit. A copy of this application was sent to the Bloomington Field Office of the U.S. Fish and Wildlife Service (USFWS) on April 3, 2020. Comments were received from Mr. Daniel W. Sparks of the U.S. Fish and Wildlife Service on April 15, 2020 that were also based on an earlier June 5, 2015 response from Mr. Sparks and which are discussed in the sections below.

Much of the factual information presented below was taken, sometimes directly, from the April 2015 CWIS Report (available from VFC) and the 2020 CWIS Requirements Update (Attachment C).

A. Facility and Cooling Water Intake Structure (CWIS) Description

The NIPSCO R.M. Schahfer Generating Station ("R.M. Schahfer") has four coal-fired boilers (Units 14, 15, 17, and 18) which began operating in 1976 when Unit 14 came online followed by Unit 15 (1979), Unit 17 (1983) and Unit 18 (1986). The R.M. Schahfer generating station is a base-load facility with all four units operating under normal conditions based on information in the April 2015 CWIS Report (available in VFC). The 2020 CWIS Requirements Update (see Attachment C) did not include any new information on unit operating rates.

All four units feature close-cycle cooling via a single multi-cell mechanical draft cooling tower per unit. Makeup water for the recirculating water system comes from the cooling water intake system (CWIS) located on Davis Ditch approximately two miles north of the plant. See Attachment D for an aerial view of the CWIS and Attachment E for a topographical map of the CWIS and R.M. Schahfer. The intake structure sits on the east bank of Davis Ditch, approximately 550 feet south of the confluence with the Kankakee River. Due to the close proximity of this intake structure to the Kankakee River, water from the Kankakee River is drawn upstream to the intake via Davis Ditch. Water depths in Davis Ditch immediately in front of the intake pump house are approximately eight feet.

Makeup water is drawn through the CWIS by a set of three circulating water pumps, each with a capacity of 20,000 gallons per minute (gpm); however, only two of the pumps can be operated together at any one time, thus the maximum DIF is approximately 40,100 gpm (57.7 MGD). Makeup water is pulled into the service water pump house through a pair of steel bar trash racks then into two separate bays, each containing one traveling screen with stainless steel mesh panels.

From the CWIS, makeup water travels via underground pipe to the Intake Basin. Water from the Intake Basin is pumped into the facility to be used as cooling tower makeup water, as well as makeup water to the recycle line, and to provide water to the boilers and the flue-gas desulfurization equipment.

After passing through the plant processes, all water is routed to the Final Setting Basin (FSB) located on the north side of the plant. The FSB contains a primary outfall (Outfall 001) to the Kankakee River and an emergency outfall (Outfall 002) to the Kankakee River via Davis Ditch.

The CWIS operates as needed to provide makeup water for the R.M. Schahfer water system. The CWIS service pumps are run to maintain a normal operational water depth of 2.0 to 5.5 ft. in the Intake Basin; makeup water also may bypass the Intake Basin and be drawn directly into the cooling recirculation systems, if needed. CWIS operations may be altered to address abnormal conditions in the Kankakee River or in the permittee’s operations.

Coarse environmental debris is removed from the intake flow at the CWIS prior to entry into the permittee’s water system. Debris is removed from the trash rack, as needed, by a mechanical rake system and emptied into a dumpster for disposal. Typically, the traveling screens do not operate continuously but rotate when sufficient head differential occurs across the screens from flow blockage by debris buildup. While rotating, debris is cleared from the traveling screens by spray wash nozzles, cleared debris is washed into a collection trough and flows out of the intake building to a receptacle for disposal.

Intake Flows, Through-Screen Velocity and Area of Influence

The maximum DIF at the facility is 57.7 MGD. For the period 2015 through 2019, the AIF was 21.7 MGD. The permittee in their 2020 CWIS Requirements Update (see Attachment C) reported a maximum observed daily intake flow of 39 MGD.

At the maximum DIF of 57.7 MGD, the through-screen velocity is 0.58 feet per second (fps), at maximum observed daily intake flow of 39 MGD, the through-screen velocity is 0.39 fps and at the AIF of 21.7 MGD, the through–screen velocity is 0.22 fps.

The hydraulic zone of influence (HZI) sometimes called the area of influence, is that portion of the source waterbody hydraulically affected by the CWIS withdrawal of water. In the context of Section 316(b), the HZI defines the source area or the near field capture zone for small, weakly motile or planktonic organisms that are easily entrained. A detailed discussion of the calculations and methodology to determine the HZI is included in the April 2015 CWIS Report (available in VFC).

The input values and the calculated dimensions of the HZI for the shoreline CWIS located on the Davis Ditch are shown in Table 1 of the April 2015 CWIS Report (available in VFC). This table provides results for two river flow conditions based on data from U.S. Geological Survey (USGS) Gaging Station No. 05517500, Kankakee River at Dunns Bridge, Indiana, for the period of record 2007 through 2015, and the maximum design intake flow condition. The flow conditions evaluated are:

1. Mean annual flow in the Kankakee River = 1,605 cubic feet per second (cfs)
2. Lowest mean annual flow in the Kankakee River = 943 cfs
3. The maximum design intake flow condition is the DIF (57.7 MGD or 89.28 cfs)

Under all river and intake flow conditions, it is assumed that the entire area of the Davis Ditch is within the HZI. The location of the HZI-line with the Kankakee River will change with stream flow and intake flow, and therefore with time. The location of the HZI-line at any time will depend on the ratio of the intake flow to the river flow. Under extreme low-flow hydrologic conditions (e.g., lowest mean annual flow conditions at the Dunns Bridge gaging station), the HZI-line will move away from the shoreline and downstream. The maximum values for this scenario are approximately 12.6 ft and 3.6 ft, respectively (Table 1 of the April 2015 CWIS Report (available in VFC). Consequently, outside a line defined by these dimensions, the probability of hydraulically influencing nonmotile organisms remains low most of the time. Under normal hydrologic conditions (e.g., mean annual flow conditions), the HZI-line will move toward the shoreline and toward the intake. The values for this scenario are approximately 7.9 ft and 2.1 ft, respectively (Table 1 of the April 2015 CWIS Report (available in VFC). Consequently, inside a line defined by these dimensions, the probability is high most of the time. Between these extremes, the probability of hydraulically influencing non-motile organisms is moderate and variable.

The DIF of 57.7 MGD (89 cfs) is less than 10% of the lowest mean annual flow of the Kankakee River for the period studied of 2007 through 2015 and less than 6% of the mean annual flow of 1605 cfs for the period of study. Although flow values were not provided for Davis Ditch, since it is such a small stream, it is expected that the DIF of 57.7 MGD would be 100% of the lowest mean annual flow and mean annual flow of Davis Ditch.

Cooling Towers Detailed Information

The following information about the cooling towers was obtained from supplemental information provided by the permittee in a June 17, 2020 e-mail.

1. Cycles of Concentration (COC)

The four cooling towers at R.M. Schahfer average 1.7 cycles of concentration (COC). The actual COC has varied at times throughout the history of the R.M. Schahfer but our current chemistry plan has been optimized around the design and operating parameters of this facility. The primary goal of the chemistry program is to prevent scaling within the condensers. The current chemistry plan is designed to target 2.0 - 2.2 COC while the average (as mentioned) is currently 1.7. Previous attempts to cycle as high as 3 have failed. This was largely due to the scaling issue experienced under such operating conditions. Water from the Kankakee River is brought into the Intake Settling Basin (ISB) as the source of service water used throughout the facility. The Kankakee has a fairly high concentration of calcium, which left untreated results in our scaling issue. There is no chemical pretreatment performed on the water in the ISB. Accordingly, controlling the FGD blowdown rate moderates the COC. The plant engineers routinely monitor the chloride levels within the scrubber to best maximize the system (i.e. to blowdown the scrubbers at little as possible; less blowdown results in increased COC). As an ancillary note to the chemistry control, a purposeful factor in the design of our program is to not increase the sulfate (and other ions) levels in the Final Settling Basin (FSB). All internal ponds and process water combine in the FSB prior to discharge at final outfall 001. The FSB has an engineered capability of providing water directly (if and as needed) into the ISB under low flow conditions in the Kankakee River. Adding unwanted salts into the ISB would only exacerbate the scaling potential and prove problematic in limiting blowdown (which results in lower cycles of concentration).

2. Percent Reduction

Using real world data and recent operating conditions (such as run times of the various Units), the permittee estimated a once-through system would require 1.044 billion gallons of water per day. The permittee calculated an estimated water use of 48.5 million gallons per day at 1.7 COC, and 40 million gpd at 2.0 COC. The 1.7 COC results in a 95.4% reduction when compared to a once-through system (and 96.2% at 2.0 COC).

The permittee is aware of the EPA 316(b) guidance document reference to reducing AIF by 97.5 percent with a closed cycle cooling tower system being operated at a minimum 3.0 cycles of concentration. As affected by the circumstances mentioned above, despite minimizing blow down (thus minimizing make up flow), employing an appropriate chemistry control program, and operating a closed cycle system the permittee is unable to replicate these COC levels or percent flow reductions.

3. Chemistry Control Program Guidance

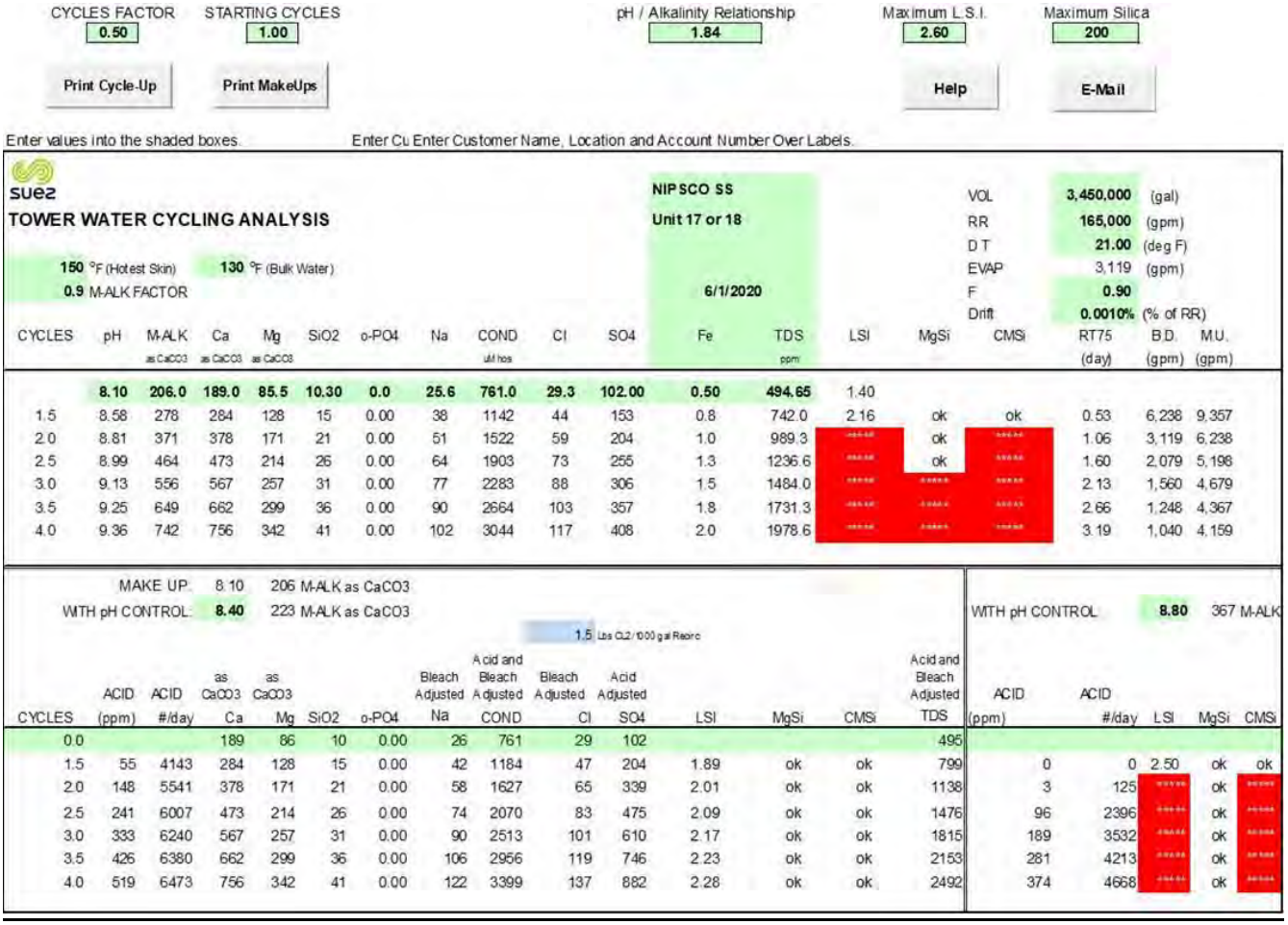
The following is feedback from the permittee's chemical provider (Suez) after discussing the design of our program with respect to potentially increasing cycles of concentration.

The current target cycles at R.M. Schahfer is 2 cycles with pH control to pH 8.4 (via acid feed). A gauge for the "treatability" of the water from a calcium carbonate scaling perspective is the Langelier Saturation index (LSI), with typical treatable LSIs < 2.6. It is critical to keep the condensers clean of deposit, with calcium carbonate being the main potential culprit at these conditions. Under the abovementioned operating parameters and typical water compositions, LSIs are generally < 2.6, and treatable.

With an increase in cycles and the strict maintenance at the appropriate pH, elevated cycles can be achieved. However, with an upset such as a loss of acid feed or pH measurement issue, calcium carbonate scale and silicate scales can be issues; please refer to Figure 1, below. Note that a modest deviation from the target pH would lead to elevated LSIs and exceedances of limits of select mineral salts. In addition, effluent turbidities will increase, which may pose a challenge with regard to TSS permit limit requirements.

In brief, operating at higher cycles poses more risk and potential negative consequences to the operation.

Figure 1. Water chemistry composition and the associated limits for NIPSCO Schahfer Station as a function of cycles; indicates “over limit”.



CYCLES FACTOR 0.50 | STARTING CYCLES 1.00 | pH / Alkalinity Relationship 1.84 | Maximum L.S.I. 2.60 | Maximum Silica 200

Print Cycle-Up | Print MakeUps | Help | E-Mail

Enter values into the shaded boxes. Enter Cu Enter Customer Name, Location and Account Number Over Labels.

SUEZ

TOWER WATER CYCLING ANALYSIS

NIPSCO SS
Unit 17 or 18
6/1/2020

150 °F (Hotest Skin) 130 °F (Bulk Water)
0.9 M-ALK FACTOR

VOL 3,450,000 (gal)
RR 165,000 (gpm)
D T 21.00 (deg F)
EVAP 3,119 (gpm)
F 0.90
Drift 0.0010% (% of RR)

CYCLES	pH	M-ALK as CaCO3	Ca as CaCO3	Mg as CaCO3	SiO2	o-PO4	Na	COND uM hos	Cl	SO4	Fe	TDS ppm	LSI	MgSi	CMSi	RT75 (day)	B.D. (gpm)	M.U. (gpm)
	8.10	206.0	189.0	85.5	10.30	0.0	25.6	761.0	29.3	102.00	0.50	494.65	1.40					
1.5	8.58	278	284	128	15	0.00	38	1142	44	153	0.8	742.0	2.16	ok	ok	0.53	6,238	9,357
2.0	8.81	371	378	171	21	0.00	51	1522	59	204	1.0	989.3	*****	ok	*****	1.06	3,119	6,238
2.5	8.99	464	473	214	26	0.00	64	1903	73	255	1.3	1236.6	*****	ok	*****	1.60	2,079	5,198
3.0	9.13	556	567	257	31	0.00	77	2283	88	306	1.5	1484.0	*****	*****	*****	2.13	1,560	4,679
3.5	9.25	649	662	299	36	0.00	90	2664	103	357	1.8	1731.3	*****	*****	*****	2.66	1,248	4,367
4.0	9.36	742	756	342	41	0.00	102	3044	117	408	2.0	1978.6	*****	*****	*****	3.19	1,040	4,159

MAKE UP 8.10 206 M-ALK as CaCO3
WITH pH CONTROL 8.40 223 M-ALK as CaCO3
1.5 Lbs Cl2/1000 gal Reqrd

WITH pH CONTROL 8.80 367 M-ALK

CYCLES	ACID (ppm)	ACID #/day	as CaCO3 Ca	as CaCO3 Mg	SiO2	o-PO4	Bleach Adjusted Na	Acid and Bleach Adjusted COND	Bleach Adjusted Cl	Acid Adjusted SO4	LSI	MgSi	CMSi	Acid and Bleach Adjusted TDS	ACID (ppm)	ACID #/day	LSI	MgSi	CMSi
0.0			189	86	10	0.00	26	761	29	102				495					
1.5	55	4143	284	128	15	0.00	42	1184	47	204	1.89	ok	ok	799	0	0	2.50	ok	ok
2.0	148	5541	378	171	21	0.00	58	1627	65	339	2.01	ok	ok	1138	3	125	*****	ok	*****
2.5	241	6007	473	214	26	0.00	74	2070	83	475	2.09	ok	ok	1476	96	2396	*****	ok	*****
3.0	333	6240	567	257	31	0.00	90	2513	101	610	2.17	ok	ok	1815	189	3532	*****	ok	*****
3.5	426	6380	662	299	36	0.00	106	2956	119	746	2.23	ok	ok	2153	281	4213	*****	ok	*****
4.0	519	6473	756	342	41	0.00	122	3399	137	882	2.28	ok	ok	2492	374	4668	*****	ok	*****

Operational Status and Upcoming Unit Retirements

The 2018 Integrated Resource Plan (IRP) which NIPSCO submitted to the Indiana Utility Regulatory Commission (IURC) identified the preferred retirement path, which included the retirements of R.M. Schahfer Units 14, 15, 17, and 18. NIPSCO’s short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the R.M. Schahfer 14, 15, 17, and 18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to Midcontinent Independent System Operator (MISO), North American Reliability Corporation (NERC) and other relevant organizations of its intention to retire the R.M. Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.

B. Biological Condition of the Kankakee River

The Kankakee River is 140 miles long and is located in northwestern Indiana and northeastern Illinois (IDNR 1990 https://www.in.gov/dnr/water/4108.htm). The Kankakee River Basin (part of the Illinois River Basin) is 2,989 square miles (mi^2) and drains portions of Michigan, Indiana, and Illinois. The Kankakee River originates just southwest of South Bend, Indiana in St. Joseph County. It then travels 104 miles to the west and southwest to Illinois. The mainstem of the Kankakee River forms the southern boundaries of Lake, Porter, and LaPorte Counties and the northern borders of Newton, Jasper, and Starke Counties (IDNR 1990). The Kankakee River was channelized during the late 1800's and early 1900's during the draining of the Grand Kankakee Marsh, resulting in a river system prone to flooding.

According to the IDEM Integrated Report on the status of impairment of Indiana waters, the upper Illinois River Basin, including the upper Kankakee, Iroquois, and Yellow River basins, 42% of the stream miles are attaining their designated uses, while 58% are not (IDEM 2018). A complete listing of Kankakee River Section 303(d) impaired waters of the Kankakee River can be found at https://www.in.gov/idem/nps/2647.htm. Indiana's Integrated Monitoring and Assessment Report can be found at https://www.in.gov/idem/nps/2639.htm.

At the confluence with Davis Ditch, the Kankakee River flows from southeast to northwest. The river generally proceeds west where it joins with the Des Plaines River southwest of Joliet, Illinois, becoming the Illinois River, which flows southwest before emptying into the Mississippi River near Grafton, Illinois. The Illinois River is also connected to the Chicago River and, ultimately, Lake Michigan via the Illinois Waterway, which was constructed in 1933 to replace the Illinois and Michigan Canal (Lamb 1983).

The Kankakee River is a productive system, with a predominance of its drainage area in agricultural use. It is home to a warmwater fish community with species including Small and Largemouth Bass, Walleye, Northern Pike, and various panfish.

In a June 5, 2015 email to IDEM, US F&WS Dan Sparks raised concerns about high selenium levels (but not likely at acute levels) in barn swallows sampled on the Kankakee River approximately 25 miles downstream of the R.M. Schahfer facility. His exact comment is below:

> *One general biological comment I would like for you to consider. The level of selenium discharged to the Kankakee is significant from a wildlife standpoint. Source of this emanates from outfall 201 to outfall 001 which based on what I have learned in recent years from a similar facility, I assume comes from their fly ash management. First a related observation. During my bird studies of the Grand Calumet River in the mid-1990s, I sampled barn swallows on the Kankakee River approximately 25 miles downstream of this outfall to be my reference samples. Using sediment data collected by IDEM's biomonitoring program, estimated selenium bioconcentration factors (BCF) from sediment to barn swallow bird eggs and chicks of 6.9 and 9.7, respectively. These selenium*

BCFs are high, none of my other sites were this high even the Grand Calumet River so this is significant. Overall barn swallow egg and chick concentrations were high at the Hwy 41 bridge, but not likely to be at acute levels. Since sediment selenium concentrations were low, what this says to me is that there is a lot of bioavailable selenium in the water column of the Kankakee River persisting many miles downstream from this facility. Given this observation, I would hope that NIPSCO tries to minimize bird use in its final settling basin as it could be a significant attractive nuisance to birds.

A total of 99 fish species and 35 freshwater Unionid mussel species have been identified in the Kankakee River basin based on historical accounts and published reports between 1971 and 1991 (Kwak 1993). Several of these species are now considered extirpated from the basin, and others are state threatened or endangered (see below), while the Kankakee River has seen the introduction of approximately seven non-native fish species (Kwak 1993). Simon (1991) listed 82 fish species in the Kankakee River drainage of the Illinois River Basin.

A long-term study conducted between 1977 and 1990 at the Braidwood Station Aquatic Monitoring Area in Will County, Illinois identified 79 fish species (Kwak 1993, Larimore *et al.* 1988). Many of these studies look at downstream areas or the Kankakee River watershed as a whole and identify species that may not be expected in the main channel of the Kankakee in the vicinity of the plant.

In 2001, Price and Robertson (2005) performed extensive electrofishing surveys within Indiana portions of the main branch of the Kankakee, including a station at Dunns Bridge, approximately 3.5 miles upstream of the plant intake. During this study, a total of 46 fish species were identified; these species are considered to be the most likely species found in the vicinity of the CWIS due to their presence in the main stem of the Kankakee River. Relative abundance of each species in the Price and Robertson (2005) study is presented in Table 3, below (see April 2015 CWIS Report, available in VFC) to provide estimated relative abundances within the main channel of the Kankakee River in the vicinity of the R.M. Schahfer intake. Creel surveys were also conducted during the study to identify recreational catch. Species identified during the creel survey are noted in Table 3 (see April 2015 CWIS Report, available in VFC)

To assess substantially changed conditions from the information submitted in the April 2015 CWIS Report (available in VFC) Ramboll consultants conducted a review for the permittee of publicly-available information from published and online sources. Rule guidance documents, including the U.S. Fish and Wildlife Service (USFWS)/National Marine Fisheries Service (NMFS) Biological Opinion, as well as USEPA and USFWS online resources/databases, were utilized to guide this data search.

Based on the Ramboll review, the extensive electrofishing surveys within Indiana portions of the main branch of the Kankakee performed by Price and Robertson in 2001 were identified by the permittee as the most recent, representative reference of species and relative abundance in the vicinity of the cooling water intake structure. See Attachment C, 2020 CWIS Requirements Update.

The Ramboll review noted above did not, however, include an evaluation of any studies or data collected by IDEM.

Fish community studies in the Kankakee River Basin have been conducted by the IDEM Office of Water Quality in 1999 (5 sites on the mainstem Kankakee River), 2004 (6 sites on the mainstem), 2009 (4 sites on the mainstem) and 2017 (8 sites on the mainstem) as part of its Probabilistic Monitoring Program. This program entails a basin-wide sampling approach of sites selected by a stratified probabilistic design in order to provide a statistically valid assessment of the overall water quality of the basin based on fish community status and/or other metrics. Regular revisits to the basin with a new set of randomly chosen sites also gives an assessment of water quality trends in the basin. These basin assessments include the potential selection of sites from all stream reaches in the basin including headwaters, Strahler (Strahler 1957) first order, second order, third order, and fourth and greater, selected with equal weight probability. Sites close to R.M. Schahfer included at Dunn's Bridge (upstream) and downstream of R.M. Schahfer's Outfall 001. Sampling included sites in LaPorte, Porter, Jasper, Newton, and Lake counties. From these studies, 66 fish species were documented in the mainstem Kankakee River (Table 1, below).

Table 1. Fish Species documented by IDEM OWQ in the mainstem Kankakee River between 1999 and 2017.

Species Documented from OWQ Probabilistic Site Studies		
American Brook Lamprey	Golden Redhorse	River Redhorse
Banded Darter	Golden Shiner	Rock Bass
Banded Killifish	Goldeye	Rosyface Shiner
Bigmouth Buffalo	Greater Redhorse	Sand Shiner
Black Buffalo	Green Sunfish	Shorthead Redhorse
Black Crappie	Highfin Carpsucker	Silver Redhorse
Black Redhorse	Johnny Darter	Slenderhead Darter
Blackside Darter	Largemouth Bass	Smallmouth Bass
Bluegill	Logperch	Smallmouth Buffalo
Bluntnose Darter	Longear Sunfish	Spotfin Shiner
Bluntnose Minnow	Mottled Sculpin	Spotted Bass
Bowfin	Northern Hog Sucker	Spotted Sucker
Brook Silverside	Northern Pike	Steelcolor Shiner
Brook Stickleback	Northern Sunfish	Stonecat
Brown Bullhead	Orangespotted Sunfish	Striped Shiner
Bullhead Minnow	Pirate Perch	Walleye
Channel Catfish	Pumpkinseed	Weed Shiner
Common Carp	Quillback	White Crappie
Dusky Darter	Redear Sunfish	White Sucker
Emerald Shiner	Redfin Pickerel	Yellow Bullhead
Flathead Catfish	Redfin Shiner	Yellow Perch
Gizzard Shad	River Carpsucker	

The top 10 most abundant species in order of numbers of individuals from these studies, included Spotfin Shiner, Bluegill, Common Carp, Redhorse spp. Bluntnose Minnow, Green Sunfish, Rock Bass, Largemouth Bass, Buffalo spp. and Smallmouth Bass. Of note was all three buffalo species (Bigmouth, Black, and Smallmouth) and five redhorse species were documented from these studies. Other important sport fish documented included Largemouth Bass, Northern Pike, Smallmouth Bass, Walleye, and Yellow Perch. Data from these studies are managed in the Office of Water Quality Watershed Assessment and Planning Branch's Assessment Information Management System (AIMS) and can be provided upon request.

Index of Biotic Integrity (IBI) scores were tallied for these sites to assess aquatic life use attainment status. An IBI score is a multi-metric scoring based on aspect of the fish community structure. There are 12 metrics that make up the IBI score including compositional, functional, and health indicators about the fish community. The IBI

scoring ranges from 12 to 60 when fish are present. Calibration of the IBI scoring for a region is based on sampling of sites across a wide range of conditions and determining a gradient of expectation for each of the metrics chosen to make up that IBI. The calibration applicable for the Kankakee River Basin is based on Simon's (1991) IBI calibration for the Central Corn Belt Plains Ecoregion in Indiana. The IDEM OWQ has determined that an IBI total score of 36 or greater meets the definition for aquatic life use support for purposes of Section 303d listing of Impaired water in the State. Sites are sampled for a distance of 15 times the ambient wetted width of the stream. Sampling occurs along both the right and left descending banks.

The average total IBI score for the Kankakee River from these 24 samples was 38 with a median of 41. IBI scores ranged from 17 to 56. Nine of the 24 sites (37.5%) had IBI scores below the 36 threshold and would be considered not meeting their aquatic life use. The average species richness for these sites was 18 species with a median of 19. The species richness ranged from 3 to 27 species. The Dunn's Bridge site, upstream of R.M. Schahfer, had a total IBI score of 22 and species richness of 13. Much further downstream in the Kankakee River, the next three sites had IBI scores ranging from 40 to 46.

In 2017, a Travelling Zone (Emery and Thomas 2002) approach to fish community sampling was employed in the immediate reach downstream of the R.M. Schahfer thermal outfall. The purpose of this approach was to understand near and far-field community structure changes that might occur with distance from the thermal discharge outfall as thermal influence dissipates. For this, the reach immediately downstream of the R.M. Schahfer was divided into 60-meter segments starting near the Outfall 001 (10 segments including both left and right descending banks, and middle of river) for a total distance of 600 meters downstream of Outfall 001. Fish accounts were maintained separately for each 60-meter segments of the river reach (Table 2). For the analysis, data from each segment were combined into succeeding 300 meter zones (segments 1-5, 2-6,3-7,4-8, 5-9, and 6-10) (Table 3). Three hundred meters was based on 15X the average wetted width of the River to give the standard unit of effort used for IDEM fish community studies. Thirty-three fish species were documented in the 600 meters immediately downstream of the R.M. Schahfer Outfall 001. Included in this list were four species of Redhorse, Bigmouth Buffalo, and Northern Hog Sucker. Sport fish included Largemouth Bass, Northern Pike, Rock Bass, and Smallmouth Bass.

Twelve metric attributes about the community structure were assessed for determining if a gradient of community response was apparent with increasing distance from the R.M. Schahfer including species richness, number of darter species, number of sunfish species, number of round bodied suckers, number of sensitive species, percent round bodied suckers, percent tolerant species, percent omnivores, percent insectivores, percent carnivores, catch per unit of effort, and percent simple lithophilic spawners (Table 4).

Most of these metrics indicated fair to good conditions with only catch per unit effort lacking for the first 300 meter zone. Species richness in this case would be somewhat below an ideal expectation, mostly due to the loss of intolerant forms. Trophic levels show signs of stress having an under-representation of insectivores and a possible over-abundance of carnivores to the overall community.

There were no overtly obvious trends for any of the metrics other than a pattern of decreasing round bodied sucker (which includes the redhorse species) contribution in numbers to the community structure proceeding downstream even though the proportion of insectivores increased slightly going downstream (redhorse species are Considered insectivores). However, this, on the surface, did not appear to be significant. There was also a decrease in %omnivores proceeding downstream. Both the increase in %insectivores, and decrease in %omnivores could be indicative of an improvement in conditions proceeding downstream. The higher proportion of simple lithophilic spawners in the first zone was influenced by the higher number of simple lithophilic round bodied suckers. A simple lithophilic spawners are species which broadcast their eggs over the stream bottom where they can develop in the interstices of sand, gravel, and cobble substrates without parental care. This metric provides an assessment of the suitability of a site for reproduction.

Bigmouth Buffalo were consistently found throughout the reach (Table 2), while numbers of Bluegill were quite low in the first 300 meter zone and were completely absent in the first two segments (Table 2), but increased quickly in subsequent segments. Green Sunfish, Largemouth Bass, and Spotfin Shiner numbers displayed the same pattern at the zone level. However, Smallmouth Bass numbers were consistent throughout all zones.

In conclusion, this IDEM monitoring study did not show any significant community structure change patterns proceeding downstream from the R.M. Schahfer Outfall 001. The fish community structure in this portion of the Kankakee River would be considered fair to good and probably meeting its aquatic life use designation.

Table 2. Fish species observed in the reach just downstream of the R.M. Schahfer Outfall 001 in the Kankakee River for each succeeding 60-meter segment.

Species Observed in the immediate reach downstream of th R.M. Schahfer EGS Outfall 001	0-60 meters d/s	60-120 meters d/s	120-180 meters d/s	180-240 meters d/s	240-300 meters d/s	300-360 meters d/s	360-420 meters d/s	420-480 meters d/s	480-540 meters d/s	540-600 meters d/s	Total Ind. Of each sp.
American Brook Lamprey	1								1		2
Banded Killifish						1					1
Bigmouth Buffalo	1		2	1	10	9	1	5	3	6	38
Black Crappie			1	1	4	3	1	1			11
Blackside Darter		1		1						1	3
Bluegill			1	2	5	8	1	3	6	1	27
Bluntnose Minnow	1	2	1		1	1	1				7
Bowfin							1			1	2
Bullhead Minnow				1							1
Channel Catfish								1			1
Common Carp	1		2				1			3	7
Gizzard Shad					20	16	3	1		3	43
Golden Redhorse			3	1	1						5
Golden Shiner										1	1
Green Sunfish	1	4	9	8		28	2	2		6	60
Highfin Carpsucker									1		1
Johnny Darter							1		1	1	3
Largemouth Bass	1				3	4	5	2		2	17
Logperch				1							1
Longear Sunfish					1	2	2				5
Northern Hog Sucker	1										1
Northern Pike			1		1	1				1	4
Northern Sunfish						2		1	3	3	9
Pirate Perch		1				2					3
Redfin Pickerel	1		2		1	2	1	1		5	13
River Carpsucker										1	1
River Redhorse	1	1		1	1					1	5
Rock Bass	3	1	3	1		3	3		1	5	20
Shorthead Redhorse	1							1			2
Silver Redhorse	1	1	1	1					1		5
Smallmouth Bass	2	2	3	2	2	6	1	2	1	3	24
Spotfin Shiner	5	9	2	3	11	52	11	22	1	8	124
White Sucker										1	1
Total number of Species	14	9	13	13	13	16	15	12	10	19	33

Table 3. Fish Species observed in the reach just downstream of the R.M. Schahfer Outfall 001 In the Kankakee River. Each zone represents the compilation of succeeding 60 meter segments into a 300 meter long zone moving downstream of Outfall 001.

Species Observed in the immediate reach downstream of th R.M. Schahfer EGS Outfall 001	Zone 1 0 to 300 meters	Zone 2 60 to 360 meters	Zone 3 120 to 420 meters	Zone 4 180 to 480 meters	Zone 5 240 to 540 meters	Zone 6 540 to 600 meters
American Brook Lamprey	1				1	1
Banded Killifish		1	1	1	1	1
Bigmouth Buffalo	14	22	23	26	28	24
Black Crappie	6	9	10	10	9	5
Blackside Darter	2	2	1	1		1
Bluegill	8	16	17	19	23	19
Bluntnose Minnow	5	5	4	3	3	2
Bowfin			1	1	1	2
Bullhead Minnow	1	1	1	1		
Channel Catfish				1	1	1
Common Carp	3	2	3	1	1	4
Gizzard Shad	20	36	39	40	40	23
Golden Redhorse	5	5	5	2	1	
Golden Shiner						1
Green Sunfish	22	49	47	40	32	38
Highfin Carpsucker					1	1
Johnny Darter			1	1	2	3
Largemouth Bass	4	7	12	14	14	13
Logperch	1	1	1	1		
Longear Sunfish	1	3	5	5	5	4
Northern Hog Sucker	1					
Northern Pike	2	3	3	2	2	2
Northern Sunfish		2	2	3	6	9
Pirate Perch	1	3	2	2	2	2
Redfin Pickerel	4	5	6	5	5	9
River Carpsucker						1
River Redhorse	4	3	2	2	1	1
Rock Bass	8	8	10	7	7	12
Shorthead Redhorse	1			1	1	1
Silver Redhorse	4	3	2	1	1	1
Smallmouth Bass	11	15	14	13	12	13
Spotfin Shiner	30	77	79	99	97	94
White Sucker						1
Total number of Species	24	23	25	27	26	29
Total number of Individuals	159	278	291	302	297	289

Table 4. Fish community structure metric values.

Community Structure Metrics						
Species richness	24	23	25	27	26	29
Number Darter Species	2	2	3	3	1	2
Number Sunfish Species	3	4	4	4	4	4
Number Round Bodied Suckers	4	2	2	3	3	2
Number Sensitive Species	8	4	4	5	6	4
% Round Bodied Suckers	9.4	4.0	3.1	2.0	1.3	1.0
% Tolerant Species	1.9	1.1	1.4	0.7	0.7	2.4
% Omnivores	18.2	15.8	16.2	14.9	15.2	10.7
%Insectivores	33.7	38.8	37.8	43.0	43.4	41.9
% Carnivores	18.2	13.7	15.5	13.9	13.8	17.3
Catch Per Unit Effort	159.0	278.0	291.0	302.0	297.0	289.0

D. Impingement and Entrainment

No previous impingement or entrainment studies have been performed at the facility; therefore, historic plant impingement and entrainment data were not used by the permittee to assess species and life stages or numbers of organisms susceptible to impingement and entrainment.

The April 2015 CWIS Report (available in VFC), evaluated the primary gamefish species identified in the Price and Robertson (2005) study, as well as the most prevalent forage and rough fish species, to determine their susceptibility to impingement and entrainment at R.M. Schahfer during various life stages.

The following species were considered during this evaluation: Northern Pike (*Esox lucius*), Largemouth Bass (*Micropterus salmoides*), Smallmouth Bass (*Micropterus dolomieu*), Channel Catfish (*Ictalurus punctatus*), Walleye (*Sander vitreus*), Bluegill (*Lepomis macrochirus*), Gizzard Shad (*Dorosoma cepedianum*), Spotfin Shiner (*Cyprinella spiloptera*), Carp (*Cyprinus carpio*) and Silver Redhorse (*Moxostoma anisurum*).

All species were considered to be most susceptible during the egg and larval stages of development, as they may be unable to swim away from the induced current of the R.M. Schahfer intake.

Evaluating susceptibility of these early life stages requires knowledge of species life history characteristics including egg diameter, larval head capsule width, spawning habitats and substrates, and egg adhesiveness. R.M. Schahfer traveling screens currently have 5/16-inch openings, which would not restrict egg or larval individuals of the above-listed species from becoming entrained based upon size. However, several of these species may have limited susceptibility based upon other life history factors. A discussion of each species is found in the April 2015 CWIS Report (available in VFC).

Egg and larval abundance within the Kankakee River is expected to peak during the period of late April through July. Some species, such as northern pike, begin spawning in early March whereas others, such as bluegill, spawn from May into late August. However, most species' spawning periods overlap during the late spring and early summer months of May, June, and early July. Though some fish species, such as trout and salmon, spawn in the fall and hatch in the spring, species identified in the Kankakee River primarily hatch shortly after egg fertilization; spawning periods and periods of larval emergence completely or partially overlap. Hatching typically occurs between 3 days and 3-4 weeks following fertilization, depending upon the species, at the water temperatures expected within the Kankakee River in the late spring and early summer months (Becker 1983). By late August or early September, most young-of-the-year (YOY) fishes have grown and progressed through their larval stages and are sufficiently strong swimmers to be able to avoid being drawn into the CWIS.

Summary Discussion – Impingement and Entrainment

As discussed above, no previous impingement or entrainment studies have been performed at the facility. The permittee, in-lieu of such studies, has presented data based on surveys of aquatic life in the nearby waters of the CWIS as well the design/operation of the CWIS to assess species, life stages and relative numbers of organisms susceptible to impingement and entrainment at the CWIS.

The April 2015 CWIS Report (available in VFC), indicated susceptibility to egg entrainment is expected to be highest among walleye, while larval entrainment is expected to be highest amongst silver redhorse, walleye, spotfin shiner, and gizzard shad.

These results are consistent with results found in Boehler & Baker (2013), where larval drift samples in Honey Creek, Seneca County, Ohio were dominated by sucker species (80 percent), perch species (10 percent), and minnow species (8 percent). Silver redhorse is a sucker species, walleye is a perch species, and spotfin shiner is a minnow species.

Regarding susceptibility to impingement, for juvenile and adult fish, the USEPA has indicated that a water velocity of 1.0 fps is sufficient to protect 96 percent of fish species (FR 2001). In the Rule, the USEPA has provided a level of additional safety, indicating that a design intake flow or maximum actual through-screen velocity of 0.50 fps may be considered BTA for impingement.

Although, the through-screen velocity is 0.58 fps at the maximum DIF of 57.7 MGD, the maximum actual through screen velocity is 0.39 fps at the maximum observed daily intake flow of 39 MGD.

The use of closed cycle cooling means that the DIF of the R.M. Schahfer of 57.7 MGD (89 cfs) is significantly less than a similar sized facility that does not employ closed cycle cooling. The DIF of 57.7 MGD is less than 10% of the lowest mean annual flow of the Kankakee River for the period studied of 2007 through 2015 and less than 6% of the mean annual flow of 1605 cfs for that same period. As a result, the HZI is relatively limited in the Kankakee River reducing potential numbers of organisms impacted for entrainment and impingement. As noted above, the entire area of the Davis Ditch is expected to be within the HZI and the DIF is expected to be 100% of the flow of Davis Ditch.

As noted previously, the Kankakee supports a warmwater fish community with species including small and largemouth bass, walleye, northern pike, and various panfish.

Regarding federally listed species, USFWS concurs that the one federally listed species - Sheepnose mussel - has been extirpated from the Kankakee River in the area of the CWIS and did not raise any issues related to federally listed species. See discussion below.

E. Threatened, Endangered, and Other Protected Species Susceptible to Impingement and Entrainment

Federal- and state-listed species identified for Jasper and Porter Counties of Indiana that may be located in the Kankakee River or the Davis Ditch in the vicinity of the R.M. Schahfer intake are presented in Table 5 of the April 2015 CWIS Report (available in VFC).

This list includes species that are endangered, threatened, or of special concern to the applicable managing agencies. Additionally, the species listed in Table 5 of the April 2015 CWIS Report (available in VFC), have a current or historical range that includes the area of influence of R.M. Schahfer, utilize the source waterbody (up to ordinary high water marks) for any portion of their life cycle or rely on species for their survival that meet these criteria.

Table 5 of the April 2015 CWIS Report (available in VFC) includes one federally-listed species (Sheepnose, *Plethobasus cyphyus* – a freshwater mussel) included on the Indiana Department of Natural Resources (IDNR) Indiana County Endangered, Threatened, and Rare Species lists Jasper and Porter counties (IDNR 2013a,b); however, Sheepnose is not included on USFWS County Distribution of Federally-Listed Threatened, Endangered, and Candidate Species for Jasper or Porter counties (USFWS 2015). Correspondence with Elizabeth McCloskey (USFWS Northern Indiana Suboffice) revealed that Sheepnose were extirpated from the Kankakee River in Jasper and Porter counties when the river was dredged and ditched in the late 1800s to early 1900s. Ms. McCloskey clarified that the IDNR maintains historical occurrences in their database, but that USFWS does not have any extant records of Sheepnose in the Kankakee River in Indiana. The 2002 USFWS Sheepnose status assessment report confirms that Sheepnose was extirpated from the channelized portions of the Kankakee River in Indiana (USFWS 2002).

In addition to the one federally-listed species, Table 5 of the April 2015 CWIS Report (available in VFC), includes 16 state endangered (one being the Sheepnose), four state threatened, three state rare, five state special concern, and one watchlist species that could be directly impacted. It also includes five state endangered and two state special concern species that could be indirectly impacted. Table 3 of the April 2015 CWIS Report (available in VFC) indicates threatened and endangered status for the 46 fish species identified in the main channel of the Kankakee River by Price and Robertson (2005). None of these 46 species were listed as threatened or endangered.

In addition to the federal and state listed Sheepnose, the Ellipse ((*Venustaconcha ellipsiformis*)) is the only other listed freshwater mussel species identified from USFWS and IDNR county lists. The Ellipse is state species of concern listed by IDNR in Porter County but not in Jasper County. The exclusion of the Ellipse from the Jasper County IDNR Indiana County Endangered, Threatened, and Rare Species List may indicate that the Ellipse is not found in the portion of the Kankakee River that forms the border of Jasper and Porter counties in the vicinity of R.M. Schahfer. No other federal or state listed mussel species are identified in Jasper or Porter counties on USFWS or IDNR species lists.

Like all unionid mussels, the Ellipse develops from a parasitic glochidial larval stage that requires a fish host to complete its life cycle. Although possibly not listed as threatened, endangered, or species of special concern; some common fish species within the Kankakee River are important to these threatened and endangered mussels as host species.

Sauger (*Stizostedion canadense*) and sunfish (*Lepomis* species) are the only known naturally occurring host fish species for the Ellipse (Allen et al. 2007). Sauger is not one of the 46 species listed by Price and Robertson (2005) for the Kankakee River; however, four species of *Lepomis* are present in the Kankakee River: green sunfish (*Lepomis cyanellus*), Pumpkinseed (*Lepomis gibbosus*), Warmouth (*Lepomis gulosus*), and Orangespotted sunfish (*Lepomis humilis*).

Since the April 2015 CWIS Report (available in VFC), the IDNR has updated the available Endangered, Threatened and Rare Species list. This list has been expanded to include Jasper and neighboring counties, La Porte and Porter. See Table 1 of the 2020 CWIS Requirements Update included as Attachment C of this Fact Sheet.

Consultation with Federal and State Agencies [40 CFR § 122.21(r)(4)(vii)]

Publicly available data sources were used by the permittee to identify federal and state listed species with the potential to be impacted by activities at R.M. Schahfer. Publicly available information from USFWS and IDNR was inconsistent regarding the potential presence of federal and state listed Sheepnose mussel in the Kankakee River in Indiana. The permittee indicated that correspondence with Elizabeth McCloskey (USFWS Northern Indiana Suboffice) clarified that USFWS does not have any extant records of Sheepnose in the Kankakee River in Indiana and IDNR records in the county database are historical.

In the June 5, 2015 email to IDEM regarding impacts from the CWIS, Mr. Dan Sparks, USFWS, wrote that he ….“essentially concur with their (the permittee) CWIS information and approach.” He also writes that the permittee should correct the heading of their Tables 3 and 4 in their April 2015 CWIS Report (available in VFC), “It's not Lake Michigan, its [sic] the Kankakee River they are presenting data on.” He also stated that “Their approach regarding the endangered sheepnose mussel is accurate. Someday it would be great to get some mussel surveys done in the Kankakee watershed but everything we currently know about mussels would suggest that they were extirpated when the river was straightened.”

In his April 15, 2020 email to IDEM with respect to the permittee’s updated 316(b) application (2020 CWIS Requirements Update included as Attachment C of this Fact Sheet), Mr. Sparks of USFWS indicated that his 2015 comments were still germane.

F. Best Technology Available (BTA) Determinations

Impingement BTA:

Under 40 CFR 125.94(c) existing facilities subject to the rule must comply with one of the following seven BTA Standards for Impingement Mortality:

1. Operate a closed-cycle recirculating system as defined at 40 CFR §125.92;
2. Operate a CWIS that has a maximum design through-screen design intake velocity of 0.5 fps;
3. Operate a CWIS that has a maximum actual through-screen intake velocity of 0.5 fps;
4. Operate an offshore velocity cap that is a minimum of 800 feet offshore;
5. Operate a modified traveling screen that the Director (IDEM) determines meets the definition of the rule (at §125.92(s)) and that the Director (IDEM) determines is BTA for impingement reduction;
6. Operate any other combination of technologies, management practices, and operational measures that the Director (IDEM) determines is BTA for impingement reduction; or
7. Achieve the specified impingement mortality performance standard of less than 24 percent.

The permittee has chosen Option 3, operate a CWIS that has a maximum through screen intake velocity of 0.5 fps, as their impingement mortality compliance option. Under this option, the permittee must submit information that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on best professional judgment using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure. IDEM may authorize the owner or operator of the facility to exceed the 0.5 fps velocity at an intake for brief periods for the purpose of maintaining the cooling water intake system, such as backwashing the screen face. In addition, the permittee must monitor the velocity at the screen at a minimum frequency of daily. In lieu of velocity monitoring at the screen face, the permittee may calculate the through-screen velocity using water flow, water depth, and the screen open areas.

As discussed previously, at the maximum observed daily intake flow of 39 MGD, the through-screen velocity is 0.39 fps (maximum actual through screen velocity).

In order to ensure that the facility will comply with impingement Option 3 above, a permit condition and limit has been added that requires the facility to operate at a daily intake flow rate of 39 MGD or less.

In addition, the permittee has indicated it intends to close the facility no later than December 31, 2023.

With these conditions, IDEM concurs with the permittee that Option 3, operate a CWIS that has a maximum actual through screen intake velocity of 0.5 fps, is the best technology available (BTA) for impingement mortality.

Entrainment BTA:

For existing facilities, EPA did not identify any single technology or group of technology controls as available and feasible for establishing national performance standards for entrainment. Instead, EPA's regulations require the permitting agency to make a site-specific determination of the best technology available standard for entrainment for each individual facility. See 40 CFR § 125.94(d).

EPA's regulations put in place a framework for establishing entrainment requirements on a site-specific basis, including the factors that must be considered in the determination of the appropriate entrainment controls. These factors include the number or organisms entrained, emissions changes, land availability, and remaining useful plant life as well as social benefits and costs of available technologies when such information is of sufficient rigor to make a decision. These required factors are listed under 40 CFR § 125.98(f)(2).

EPA's regulations also establish factors that may be considered when establishing site-specific entrainment BTA requirements, including: entrainment impacts on the waterbody, thermal discharge impacts, credit for flow reductions associated with unit retirements, impacts on reliability of energy delivery, impacts on water consumption, and availability of alternative sources of water. (Id. § 125.98(f)(3))

In these regulations EPA identified closed-cycle recirculating cooling systems (CCRS) as the best performing technology for entrainment (See EPA Technical Development Document for the Final Section 316(b) Existing Facilities Rule, May 2014 at page 7-6). However, despite numerous retrofits of existing units to closed cycle cooling, EPA rejected this technology as the basis for a uniform national entrainment standard because, among other things, it is not nationally available. Also, in some instances, it has unacceptable non-water quality impacts.

All four units at this facility feature closed-cycle cooling via a single multi-cell mechanical draft cooling tower per unit.

Under the 316(b) rules, a closed-cycle recirculating system (CCRS) means a system designed and properly operated using minimized make-up and blowdown flows withdrawn from a water of the United States to support contact or non-contact cooling uses within a facility. A closed-cycle recirculating system passes cooling water through the condenser and other components of the cooling system and reuses the water for cooling multiple times. properly operated and maintained closed-cycle recirculating system withdraws new source water (make-up water) only to replenish losses that have occurred due to blowdown, drift, and evaporation.
If waters of the United States are withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system, the Director (IDEM) may determine a cooling system is a closed-cycle recirculating system if the facility demonstrates to the satisfaction of the Director that make-up water withdrawals attributed specifically to the cooling portion of the cooling system have been minimized.

The EPA Technical Development Document (TDD) and Essay 17A: Closed-Cycle Recirculating Cooling (EPA Response to Public Comment: National Pollutant Discharge Elimination System Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing

Facilities and Amend Requirements at Phase I Facilities (40 CFR Parts 122 and 125) Docket # EPA-HQ-OW-2008-0667) provide additional discussion on what constitutes a closed cycle recirculating system (CCRS) under the rule. The TDD developed by USEPA provides record support for the rule and describes the methods used by EPA to analyze various options in the rule. Essay 17A was developed by USEPA to address public comments about the definition of a CCRS under the rule.

Generally, two operating parameters are used to evaluate proper operation of a closed cycle cooling system, Cycles of Concentration (COC) and Reduction in Flow (RIF). The RIF is the percent reduction in water use versus water use at a facility with once through cooling. COCs can be measured as the ratio of chloride levels in the recirculated water or blowdown relative to the chloride levels in the source water, or makeup water. Cycles of concentration represents the accumulation of dissolved minerals in the recirculated cooling water.

While EPA has determined that a COC of 3.0 for freshwater facilities and a RIF approximately equivalent to a percent reduction in flow of 97.5 is indicative of a well-operated cooling system (i.e., one that truly minimizes makeup withdrawals), EPA decided not to include a minimum COC (or RIF) requirement as part of the definition for closed-cycle systems. Instead, the definition at 40 CFR 125.92 requires makeup flows be minimized. These flow reductions and COC serve as indicators of minimized makeup flows, and thus may be used by IDEM when assessing performance of a particular CCRS.

Regardless of whether facilities achieve either these levels of COC or reductions in flow, IDEM is responsible for determining whether such facilities in fact are operating as a close-cycle recirculating cooling system. IDEM would review the information provided by the facility and determine if the facility's configuration and operation are otherwise consistent with the definition of a closed-cycle cooling system in the final rule.

The permittee, via emails of May 20 and June 17, 2020 (see the detailed information provided in the June 17, 2020 e-mail under Section 6.4.B., above), has indicated to IDEM that all four units combined typically operate at a COC of 1.7. Previous attempts by the facility to cycle at a COC of 3.0 failed due to issues with scaling. The permittee has indicated to IDEM that operating at higher cycles (above 1.7) poses more risk and potential negative consequences to the operation of the facility.

Using recent operating conditions (such as run times of the various units), the permittee estimates that a once-through system would require 1.044 billion gallons of water per day. The permittee calculates an estimated water use of 48.5 MGD day at 1.7 COC, and 40 MGD at 2.0 COC. The 1.7 COC results in a 95.4% reduction when compared to a once-through system (and 96.2% at 2.0 COC).

IDEM has not determined whether the design and operation of the closed cycle cooling system at R.M. Schahfer meets the federal rule definition of a CCRS. However, after considering all the factors that must and may be considered by the federal rules (see discussion below), IDEM finds that the existing facility meets BTA for entrainment. This is primarily based on the following factors:

1. The permittee will cease operations at this facility by no later than December 31, 2023.
2. The permittee does have closed-cycle cooling via a single multi-cell mechanical draft cooling tower on each unit which has allowed the permittee to achieve substantial reductions in water usage.

Must and May Factor Discussion (40 CFR 125.98(f)(2) and (3))

In regard to the factors that must be considered (40 CFR § 125.98(f)(2)), IDEM evaluated the following:

Number and type of organisms affected, including the numbers of federally-listed species and designated critical habitat to the lowest taxonomic classification possible:

The permittee operates a closed cycle cooling system. While IDEM has not determined that the facility meets the federal definition of a CCRS, the facility has reduced the AIF to 21.7 MGD which significantly reduces the need for intake water and therefore the number of organisms entrained by the facility compared to a facility of similar size without closed cycle cooling.

Regarding federally-listed species, there are no known federal listed species expected to be impacted by the CWIS. See above Section E. Threatened, Endangered, and Other Protected Species Susceptible to Impingement and Entrainment

In addition to the current use of closed cycle cooling, the permittee has chosen to close the facility no later than December 31, 2023.

Changes in air emissions:

Air emissions will be significantly reduced due to the proposed closure of the facility in 2023.

Land availability:

The operating units at the Schahfer Generating Station will be shut down on or before December 31, 2023. Therefore, land availability is not an issue.

Remaining useful plant life:

The operating units will be shut down on or before December 31, 2023.

Social benefits and costs:

The permittee is not required to provide Cost Evaluation Study (40 CFR 122.21(r)(10)) or Benefits Evaluation (40 CFR 122.21(r)(11)) because the AIF is less than 125 MGD. Also, the R.M. Schahfer Generating Station will be shut down on or before December 31, 2023.

Water consumption:

The facility will be shut down on or before December 31, 2023. Therefore, water consumption is not an issue.

In regard to the factors that may be considered (40 CFR § 125.98(f)(3)), IDEM evaluated the following:

- Entrainment impacts on the waterbody are not expected to impact the existing warmwater fish community. All four units use close-cycle cooling via a single multi-cell mechanical draft cooling tower per unit which significantly reduces the volume of water that would otherwise be used by the facility. Also, the facility will be closing prior to 2023.

- Water consumption will be reduced in that the facility will shut down during the permit cycle.

- Credit for flow reductions associated with unit retirements, impacts on reliability of energy delivery and impacts on water consumption are either not applicable or were not considered due to lack of information.

G. Conclusion

For the NIPSCO R.M. Schahfer Generating Station, IDEM has determined that the selection of impingement BTA option for the operation of a CWIS with a maximum actual through screen intake velocity of 0.5 fps will result in compliance with the BTA to minimize adverse environmental impact from impingement. Further, IDEM has determined that the existing facility meets BTA for entrainment. Primary in this entrainment BTA determination is that the facility will cease operations no later than December 31, 2022 and the permittee does have closed-cycle cooling via a single multi-cell mechanical draft cooling tower on each unit which has allowed the permittee to achieve substantial reductions in water usage.

H. Permit Conditions

The permittee must comply with requirements below:

1. In accordance with 40 CFR 125.98(b)(1), nothing in this permit authorizes take for the purposes of a facility's compliance with the Endangered Species Act.

2. The permittee must at all times properly operate and maintain the cooling water intake structure and associated intake equipment.

3. The permittee must inform IDEM of any proposed changes to the CWIS or proposed changes to operations at the facility that affect the information taken into account in the current BTA evaluation.

4. There shall be no discharge of intake screen backwash.

5. In accordance with 40 CFR 125.97(c), by January 31 of each year, the permittee must submit to Industrial NPDES Permit Section IDEM-OWQ an annual certification statement for the preceding calendar year signed by the responsible corporate officer as defined in §122.22 (see 327 IAC 5-2-22) subject to the following:

    a. If the information contained in the previous year's annual certification is still pertinent, you may simply state as such in a letter to IDEM and the letter, along with any applicable data submission requirements specified in this section shall constitute the annual certification.

    b. If you have substantially modified operation of any unit at your facility that impacts cooling water withdrawals or operation of your cooling water intake structures, you must provide a summary of those changes in the report. In addition, you must submit revisions to the information required at §122.21(r) of this chapter in your next permit application.

6. Best technology available (BTA) determinations for entrainment mortality and impingement mortality at cooling water intake structures will be made in each permit reissuance, in accordance with 40 CFR 125.90-98. The permittee shall submit all the information required by the applicable provisions of 40 CFR 122.21(r)(2) through (r)(8) with the next renewal application. Since the permittee has submitted the studies required by 40 CFR 122.21(r), the permittee may, in subsequent renewal applications pursuant to 40 CFR 125.95(c), request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Any habitat designated as critical or species listed as threatened or endangered after issuance of the current permit whose range of habitat or designated critical habitat includes waters where a facility intake is located constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take. The permittee must submit a request for reduced cooling water intake structure and waterbody application information at least **two years and six months** prior to the expiration of its NPDES permit. The request must identify each element in 40 CFR 122.21(r) that it determines has not substantially changed since the previous permit application and the basis for the determination. IDEM has the discretion to accept or reject any part of the request.

7. The permittee must maintain an intake daily flow rate of 39 MGD or less. Further, the permittee shall submit an annual summary of the actual intake flows measured at a minimum frequency of daily.

8. The permittee must monitor the velocity at the screen at a minimum frequency of daily. In lieu of velocity monitoring at the screen face, the permittee may calculate the through-screen velocity using water flow, water depth, and the screen open areas.

9. The permittee must monitor and report its cycles of concentration at a minimum frequency of daily.

10. The permittee shall either conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation as required by 40 CFR 125.96(e). The permittee shall conduct such inspections at least weekly to ensure that any technologies operated to comply with 40 CFR 125.94 are maintained and operated to function as designed including those installed to protect Federally-listed threatened or endangered species or designated critical habitat. Alternative procedures can be approved if this requirement is not feasible (e.g., an offshore intake, velocity cap, or during periods of inclement weather).

11. The permittee shall submit and maintain all the information required by the applicable provisions of 40 CFR 125.97.

12. All required reports shall be submitted to the IDEM, Office of Water Quality, NPDES Permits Branch, Industrial NPDES Permit Section at OWQWWPER@idem.in.gov and the Compliance Branch at wwReports@idem.in.gov

6.5 Spill Response and Reporting Requirement

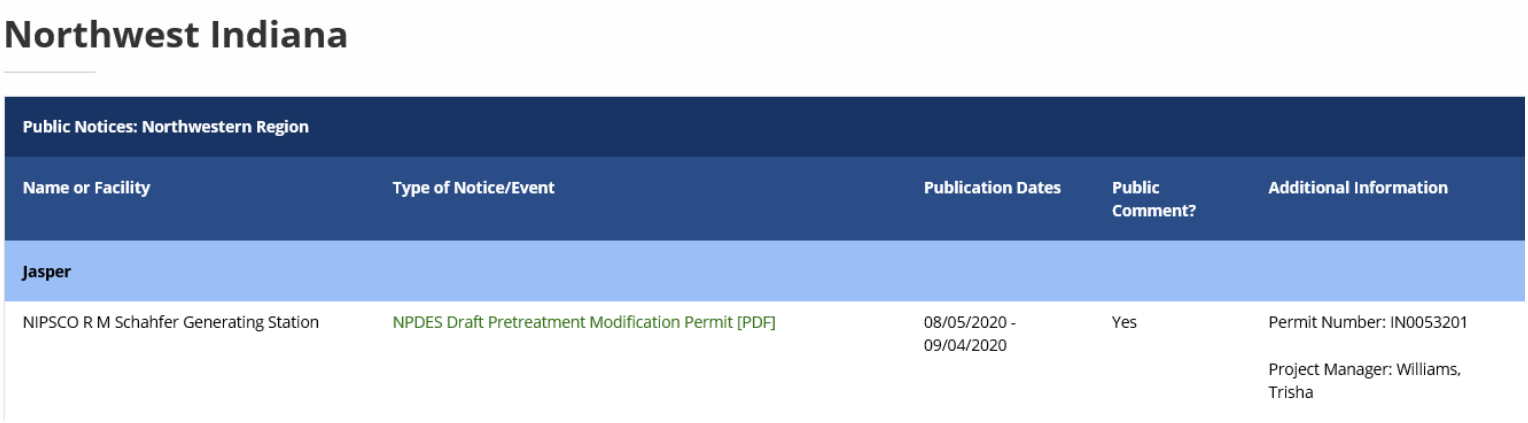
Reporting requirements associated with the Spill Reporting, Containment, and Response requirements of 327 IAC 2-6.1 are included in Part II.B.2.(d), Part II.B.3.(c), and Part II.C.3. of the NPDES permit. Spills from the permitted facility meeting the definition of a spill under 327 IAC 2-6.1-4(15), the applicability requirements of 327 IAC 2-6.1-1, and the Reportable Spills requirements of 327 IAC 2-6.1-5 (other than those meeting an exclusion under 327 IAC 2-6.1-3 or the criteria outlined below) are subject to the Reporting Responsibilities of 327 IAC 2-6.1-7.

It should be noted that the reporting requirements of 327 IAC 2-6.1 do not apply to those discharges or exceedances that are under the jurisdiction of an applicable permit when the substance in question is covered by the permit and death or acute injury or illness to animals or humans does not occur. In order for a discharge or exceedance to be under the jurisdiction of this NPDES permit, the substance in question (a) must have been discharged in the normal course of operation from an outfall listed in this permit, and (b) must have been discharged from an outfall for which the permittee has authorization to discharge that substance.

6.6 Permit Processing/Public Comment

Pursuant to IC 13-15-5-1, IDEM will publish the draft permit document online at https://www.in.gov/idem/6408.htm; additional information on options to receive notification of permit actions occurring can be found at https://www.in.gov/idem/6777.htm. A 30-day comment period is available in order to solicit input from interested parties, including the general public.

6.7 Post Public Notice Addendum



Northwest Indiana

Public Notices: Northwestern Region				
Name or Facility	**Type of Notice/Event**	**Publication Dates**	**Public Comment?**	**Additional Information**
Jasper				
NIPSCO R M Schahfer Generating Station	NPDES Draft Pretreatment Modification Permit [PDF]	08/05/2020 - 09/04/2020	Yes	Permit Number: IN0053201 Project Manager: Williams, Trisha

The draft NPDES permit for NIPSCO R.M. Schahfer Generating Station was made available for public comment from August 5, 2020 through September 4, 2020 as part of Public Notice No. 20200805–IN0053201–D on IDEM's website at https://www.in.gov/idem/6408.htm. During this comment period, a comment letter dated September 4, 2020, from Jeffrey Loewe of NIPSCO, was received. The comments submitted by Jeffrey Loewe, and this Office's corresponding responses are summarized below. Any changes to the permit and/or Fact Sheet are also noted below.

Comment 1: **Part I.A.1, Table 1, Intake Flow** – NIPSCO requests removal of the daily maximum limit of 39 MGD for Intake Flow. While our 2015 316(b) report as well as our current NPDES permit renewal application identify 39 MGD as the maximum observed intake flow, NIPSCO believes it is inappropriate to limit the intake flow to a daily volume which corresponds to a calculated through screen velocity (TSV) of less than the maximum allowable (i.e. 0.39 fps versus <0.5 fps). Intake values up to 50 MGD correlate to a TSV less than 0.5 fps (i.e. 0.4988 fps) and remain compliant with the impingement BTA standard. As an alternative to a numerical limit, the daily maximum Intake Flow can be designated as "Report". In addition to this requested change for Part I.A.1 Table 1, the same request applies to Part IV.B.7 as well and should also be revised to allow a maximum of 50 MGD intake volume.

Response 1: No changes were made. In the 2020 316(b) supplement, it states that the maximum intake flow registered by RMS is 39 MGD. The report later states that this is the maximum observed intake flow. Additional data is necessary to show that the maximum intake flow may be higher than 39 MGD.

Comment 2: **Parts I.A.1 and I.A.3** – In light of the August 31, 2020 pre-publication notice of the final Steam Electric Reconsideration Rule ("final Rule") applicable to the Federal Effluent Limits Guidelines (ELGs) at 40 CFR 423 for flue gas desulfurization (FGD) and bottom ash (BA) transport discharges, NIPSCO acknowledges that IDEM may choose to revise certain sections of the draft permit. Under the final Rule, the facility meets the definition of a facility that will cease combustion of coal no later than December 31, 2028 (40 CFR 423.11(w)). As such, once the rule is published and officially effective, the only applicable best available technology economically

achievable (BAT) ELGs for both FGD wastewater and bottom ash transport wastewater (40 CFR 432.13(g)(2)(i)) and 40 CFR 432.13(g)(2)(i)), respectively) are those for Total Suspended Solids (TSS) and Oil & Grease (O&G).

Note: the applicable best practicable control technology currently available (BPT) ELGs under 40 CFR 423.12 for TSS and Oil & Grease and these wastewaters remain unchanged.

Provided the timing of the final Rule aligns with IDEM's schedule of permit reissuance, NIPSCO requests the following three draft permit revisions be considered:

1. Part I.A.1., Footnote 19 – should be modified to also address bottom ash transport wastewater. NIPSCO offers the following suggested revised verbiage:

   In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

   In lieu of establishing new internal outfalls for low volume waste and bottom ash wastewater, should the permittee require a permit to continue operations beyond December 31, 2023, the permittee must submit an evaluation of alternate limitations for TSS and Oil & Grease developed using the combine wastestream formula (CWF), modified CWF, or building block approach and provide supporting documentation.

2. Part I.A.1., Footnote 20 – "The permittee shall comply with the requirements of the effluent limitation guidelines for Steam Electric Generating Stations, 40 CFR 423.13(k)(1)(i), for bottom ash transport water by December 31, 2023." should be removed, as it is no longer valid in the final Rule.

3. Part I.A.3. – The interim and final requirements/limits for arsenic, mercury, selenium, and nitrate/nitrite (as well as Footnotes [2], [4], and [5]) should be removed for both current Outfall 201 and proposed new Outfall 301.

Response 2: Footnote [19] has been updated.

No changes to Footnote [20] for Outfall 001 were made. The current regulations require compliance by this deadline, December 31, 2023. Once the regulatory revisions are effective, the permit can be modified.

No changes were made to the interim and final requirements/limits for arsenic, mercury, selenium, and nitrate/nitrite (as well as Footnotes [2], [4], and [5]) for both Outfall 201 and proposed new Outfall 301. The current regulations require compliance by this deadline. Once the regulatory revisions are effective, the permit can be modified.

Comment 3: **Part I.A.3, Outfall 301** – If IDEM decides not to address the final Rule at this time (as requested above) then NIPSCO requests the following permit revisions for Part I.A.3 be implemented into the renewed permit. Moreover, to provide clarity NIPSCO requests the suggested verbiage provided below in comment to Part 1.F.6, IDEM decides not to address the final Rule at this time.

> The limits and monitoring requirements in this table apply to both Outfall 201 and Outfall 301. However, Outfall 301 is a new outfall and there is currently no flow metering or sample collection infrastructure in place to assess parameter concentrations or effluent discharge flowrate. Additionally, the Unit 17/18 FGD wastewater currently comingles with other wastewaters and, therefore, an isolated, representative sampling port for Outfall 301 compliance assessment is necessary and may require significant re-piping to isolate this discharge. As such, NIPSCO requests a 3-year compliance schedule to design, procure, install, and debug the necessary power supply and equipment to properly monitor the required parameters at Outfall 301 as well as to properly segregate Unit 17/18 FGD wastewater from other sources at the new outfall location. Further, for the new Outfall 301 (only), monitoring for all parameters should not be required during the three year compliance schedule. After the compliance schedule expires, the numerical limitations for TSS and O&G would become effective when the Outfall 301 sampling equipment is properly configured and operational. Monitoring for all other parameters (i.e., “Report”) would also resume at this time. Ultimately, the limits for arsenic, mercury, selenium, and NO2+NO3 established under 40 CFR 423.13(g)(1)(i) shall apply no later than December 31, 2023 for both Outfalls 201 and 301.

Response 3: No changes were made. All applicable technology-based requirements (i.e., ELGs and BPJ) must be applied in NPDES permits without the benefit of a compliance schedule. The limits and monitoring requirements applied to Outfall 301 are not effective until that outfall starts discharging. The permit states that this outfall is proposed.

Comment 4: **Part I.A.3, Mercury** – NIPSCO requests that the monitoring frequency for Mercury be reduced from 2 X Monthly to 6 X Yearly. The 6 X Yearly frequency is consistent with the existing permit for Outfall 201, as well as this draft permit for Outfall 001. IDEM has presented no specific rationale in the Fact Sheet for increasing the monitoring frequency of Mercury. NIPSCO respectfully requests the rationale should the frequency remain as proposed.

Response 4: The changes have been made.

Comment 5: **Part I.A.4** – In the Draft Permit, NIPSCO believes IDEM has erroneously removed the reference to stormwater Outfall 005S and Outfall 006S in the introductory description as well as removed Footnote [5] in its entirety. Both references to outfalls 005S and 006S were in the July 6, 2020 Pre-public notice draft permit as well as the existing permit. These two outfalls still exist and continue to discharge. Accordingly, NIPSCO requests they be reinserted into this section with the acknowledgment that they are representatively sampled at Outfall 004. This request does not change any of the compliance requirements of the existing permit.

Response 5: References to Outfalls 005S and 006S were removed from Part 1.A.4. of the Permit because these outfalls are not sampled. However, the references to the outfalls have been returned to the Permit, along with GPS coordinates. Also, Footnote [5] has been added to the final Permit to clarify that the discharge of Outfall 004S shall be representative of discharge from Outfalls 005S and 006S.

Comment 6: **Part I.B.1** – NIPSCO requests the renewed permit retain the verbiage in the current permit. While the proposed verbiage is largely a simple restructuring from the current permit, the rewording for this section does change the meaning. The current permit verbiage addresses “the discharge not causing receiving waters to contain.” whereas the proposed verbiage focuses on the discharge itself as being free from substances, materials, floating debris, etc.

Response 6: No changes have been made. The narrative water quality standards language of the permit template was updated prior to this renewal. The narrative water quality standards are a discharge requirement. The Permit is regulating the discharge to ensure compliance with the water quality standards.

Comment 7: **Part I.C.2** – Page 15 of 58 (beginning of page through section f) is redundant with the verbiage on page 14 of 58 and should be deleted. NIPSCO believes to be an editorial oversight and removing the verbiage will result in zero effect to the requirements within the permit.

Response 7: The changes have been made.

Comment 8: **Part I.C.2.b** – NIPSCO requests this section be revised to state that an “approved statistical method” includes replacing values reported as <LOQ with 0 (zero) when calculating monthly averages for concentration. This technique is consistent with the provisions given in the current permit.

Response 8: No changes were made. The Permit issued in 2015 used the incorrect template for dischargers within the Great Lakes system. The portion of the rule that is applicable to dischargers not within the Great Lakes system is properly included in the Permit and does not include the language requested above.

Comment 9: **Part I.C.4** – NIPSCO requests “or the most recently approved version of 40 CFR 136.” Be added to the end of the first sentence in this section. The 327 IAC 5 reference (327 IAC 5-2-1.5 Incorporation by reference) does not specify a version of 40 CFR 136. However, 327 IAC 1 (specifically 1-1-2 References to the CFR) indicates that the CFR is the July 1, 2016 edition. NIPSCO believes not including the requested revision could potentially be problematic if there is a situation to use more recently approved methods.

Response 9: No changes were made. The Permit must comply with the current rules that reference the 2016 version of 40 CFR 136. Please note, Part I.C.4 of the Permit also states, “Different but equivalent methods are allowable if they receive the prior written approval of the Commissioner and the U.S. Environmental Protection Agency.” You may get prior approval if there is a situation that would require the use of more recently approved methods.

Comment 10: **Part I.F.6** – NIPSCO requests this section be revised to include the following or similar verbiage “This provision also allows the permittee to request appropriate permit modifications applicable from any newly promulgated Federal Effluent Limitation Guidelines for Steam Electric Generating Stations under 40 CFR 423.”

Response 10: Reopening Clause 6 now states, “to incorporate applicable limits and/or requirements based on newly promulgated and effective Federal Effluent Limitation Guidelines for Steam Electric Generating Stations under 40 CFR 423.”

Attachment A:

7State Form 4336

DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
INDIANAPOLIS

OFFICE MEMORANDUM **Attachment V**

To: George Oliver
Industrial Permits Section

Date: May 26, 2004

From: Gurdeo Sondhe
Modeling Section

Subject: Reply to NIPSCO Schahfer Generating Station Public Notice No. 2004-3H-RD

Staff has reviewed a memo dated April 20, 2004, submitted by Mr. Arthur Smith, Environmental Counsel of NiSource Inc, regarding NIPSCO Schahfer Generating Station NPDES Permit Public Notice No. 2004-3H-RD. Following is the response to the questions raised by the counsel:

Receiving Water Flow:

A. Schematic Flow Diagram - NPDES water balance diagram suggests that the facility withdraw approximately 45 mgd flow from the receiving stream: Kankakee River, 42.5 mgd passes through cooling tower, including cooling tower makeup flow (2.5 mgd). Approximately 50 % of the total flow is evaporated in the cooling towers; rest passes through final settling basin via Outfall 001. Staff has conducted RPE analyses of MRO data (covers period from January 1998 through December 2003) including flow adjusted for outliers. The OWQ Tech Release requires 2-year maximum monthly average flow as a design flow. The design flow used in the analysis is based on BPJ of MRO Data. Adjusted PEQ flow from Outfall 001 is 22.4 mgd, by back tracking, facility would withdraw approximately 47.3 mgd, including flow required for screen backwash and cooling towers makeup flow.

B. The receiving stream of the facility discharge is Kankakee River, which has a Q7, 10 flow of 372 cfs upstream of the intake structure. The facility withdraws approximately 47.3 mgd, and discharges approximately 22.4-mgd flow from Outfall 001 back to the receiving water. Therefore, Q7, 10 flow upstream of the Outfall 001 is 301 cfs, which provides effluent limitations wrt water-balance flow diagram. Kankakee River (non-GLI Basin) is covered under Rule 320 IAC 2-1 and designated for warmwater species, and classified for general use, including protection of fish and aquatic life.

The background concentration profile of metal/toxic pollutants of concern used in the WLA analyses, were derived from the Kankakee River WQ Monitoring Stations at KR-68 and KR-118, respectively. Background concentrations reported by the facility were also incorporated in the background profile, and appropriate/modified profile was used in the analysis.

C. The Consultant has identified and collected samples of various pollutants of concern, both at Outfall 001 and intake structure, for determining LOD and respective background concentrations. These pollutants of concern are shown in the attached documents. The following methods were used to modify LOD values for RPE analysis and PEQ value determination.

1. In mixed data set (LOD and detectable data), a value less than the LOD (non detect) shall be assigned the value (V) as determined by the formula given below.

$$V = (LOD)*(1-(\text{Number of nondetects/Total number of values})$$

Above approach was used in mixed data set

2. Higher LOD values were replaced by the lowest value in a given data set,

C. **Effluent Concentration:** Method described above is used in determination of PEQ values (Table 4), and respective values used in the analysis. PEQ values are comparable with the NIPSCO findings.

E. **Water Quality Criteria**: In the Spreadsheet, the Antinomy acute value enters as FAV = 2* Acute Criteria (non-exponential relationship)

GSS/gss
Attachments:

Table 1	**Parameters - Selected by the Permit Writer**
Table 1a	**Parameters - Monitoring or Not required**
Table 1aa	**Parameters - Monitoring with WQBELs**
Table 1aaa	**Parameters – Report Only Grab Samples [Attached with NPDES Permit]**
Table 1A	Parameters – Selected by the Permit [PEQ]
Tables 1B	Detailed Calculation of Projected Effluent Quality [PEQ]
Table 1C	Parameters - Monitoring with WQBELs [PEQ]
Table 1D	Parameters - Monitoring or Parameters not required
Tables 2&2A	Master PROG Printout
Table 3	Compact Master PROG Printout
Tables 4&4A	RPE Analysis – Data Submitted by the Facility
Tables 5	RPE Analysis – MRO Data reported by the Facility

File Name : PPNG_adrpe3_FINAL_SCHAFFER POWER PLANT_HOGE COMMENTS.xls

EFFLUENT LIMITATIONS OBTAINED FROM MASTER PROGRAM FOR RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER STATION , JASPER County

POLLUTANTS OF CONCERN As MENTIONED in WLA-CDA REQUEST/TRACKING SHEET By The PERMITS SECTION (RPE ANALYSIS)

TABLE 1

May 26, 2004

1:25:05 PM

	PARAMETERS Selected by the PERMIT WRITER				Data Collected by the Consultant is used					
OWQ Tech Release Criteria Flow (mgd) is used	22.38									OWQ Tech Release Criteria Flow (mgd) is used
Parameters	WQBELs		PEQ Plant Performance Actual MRO/MMR Data		PEQ Analyses - Samples Collected by Consultant		1995 NPDES Permit Effluent Limitations		Recommended Permit Effluent Limitations		Data Collected by the Consultant is used
	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	RESULTS
Antimony, Acid Soluble	0.088	0.176			0.012		Report	Report	0.012	0.176	Monitoring or Parameter Not Required
Beryllium, Acid Soluble	0.004	0.008			0.001		Report	Report	0.001	0.008	Monitoring or Parameter Not Required
Cadmium, Acid Soluble	0.006	0.013	0.009		0.002		Report	Report	0.002	0.013	Monitoring or Parameter Not Required
Lead, Acid Soluble	0.052	0.105	0.037		0.005		Report	Report	0.005	0.105	Monitoring or Parameter Not Required
Mercury, Acid Soluble	0.00005	0.00011			0.00002		Report	Report	0.00002	0.00011	Report ONLY Grab Samples
Selenium, Acid Soluble	0.130	0.260			0.072		Report	Report	0.072	0.260	Monitoring or Parameter Not Required
Silver, Acid Soluble	0.014	0.028			0.049	0.049	Report	Report	0.014	0.028	Monitoring With WQBELs Recommendations
Zinc, Acid Soluble	0.301	0.604	0.340		0.347				0.301	0.604	Monitoring With WQBELs Recommendations
Cyanide, Total	0.022	0.044			0.039				0.022	0.044	Monitoring With WQBELs Recommendations
Sulfate as SO4	748.26	1501.15			1610.879		Report	Report	748.2570	1501.1451	Report ONLY Grab Samples

File Name : PPNG_adrpe3_FINAL_SCHAFFER POWER PLANT_HOGE COMMENTS.xls

EFFLUENT LIMITATIONS OBTAINED FROM MASTER PROGRAM FOR RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER STATION , JASPER County

POLLUTANTS OF CONCERN As MENTIONED in WLA-CDA REQUEST/TRACKING SHEET By The PERMITS SECTION (RPE ANALYSIS)

TABLE 1_aaa

May 26, 2004

1:25:05 PM

	PARAMETERS Selected by the PERMIT WRITER				Data Collected by the Consultant is used					
OWQ Tech Release Criteria Flow (mgd) is used	22.38									OWQ Tech Release Criteria Flow (mgd) is used
Parameters	WQBELs		PEQ Plant Performance Actual MRO/MMR Data		PEQ Analyses - Samples Collected by Consultant		1995 NPDES Permit Effluent Limitations		Recommended Permit Effluent Limitations		Data Collected by the Consultant is used
	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	Monthly AVE mg/l	Daily MAX mg/l	RESULTS
Mercury, Acid Soluble	0.00005	0.00011			0.00002		Report	Report	0.00002	0.00011	Report ONLY Grab Samples
Sulfate as SO4	748.26	1501.15			1610.879		Report	Report	748.2570	1501.1451	Report ONLY Grab Samples

TABLE 2A RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER STATION, JASPER County

Upstream Source I	Upstream Source II	Upstream Source III	Upstream Conc. ug/l	Pollutants of concern N	C V	Instream Concentration D/S mg/l	Instream Concentration D/S ug/l	CAS Number	Parameters	I Human Health Organisms ug/l	II Human Health Water ug/l	III AQUATIC CHRONIC ug/l	III TOXICITY ACUTE (FAV) ug/l	Water Quality-based Effluent Limits Average ug/l	Water Quality-based Effluent Limits Maximum ug/l		LIMITS OF DETECTION ug/l	Limit of Quantitation ug/l	Limits of COMPLIANCE Average ug/l	Limits of COMPLIANCE Maximum ug/l
									VOLATILE COMPOUNDS											
		5		4	0.6			67641	Acetone											
1	1			4	0.6			107028	Acrolein			9585	127796	41900.44	84060.22	IIa	10 S	32.00		
1	1			4	0.6			107131	Acrylonitrile	780 T	320 T			3409.74	6840.58	I	0.7 C	2.24		
1	3	2		4	0.6			71432	Benzene	6.5 C	0.58 C			22.64	45.42	I	0.5 C	1.60		
1	1			4	0.6			542881	Bis (Chloromethyl) Ether	400 C	5 DC	1064	2204	1098.60	2204.00	IIb	0.2 B	0.64		
				4	0.6			74964	Bromoethane	0.018 C	0.000038 C			0.06	0.13	I				
				4	0.6			78933	2-Butanone (Methyl Ethyl Ketone)											
				4	0.6			75150	Carbon Disulfide								4.2 Y	13.44		
1	1	2		4	0.6			56235	Carbon Tetrachloride											
	1	2		4	0.6			108907	Chlorobenzene	69.4 C	4 C	278	3520	241.74	484.98	I	0.12 A	0.38		
				4	0.6			75003	Chloroethane		488 T	250	11277	1092.86	2192.49	IIa	0.2 B	0.64		
				4	0.6			110758	2-Chloroethyl vinyl ether								0.52 A	1.66		
1	3	2		4	0.6			75343	1,1-Dichloroethane								0.13 A	0.42		
1	3			4	0.6			107062	1,2-Dichloroethane	2430 C	5 DC	2000	11800	5881.80	11800.00	IIb	0.07 A	0.22		
				4	0.6			75354	1,1-Dichloroethene	18.5 C	7 DT			64.44	129.28	I	0.03 A	0.10		
				4	0.6			540590	1,2-Dichloroethene								0.13 A	0.42		
		2		4	0.6			156605	1,2-Dichloroethene, Trans											
1	1			4	0.6			78875	1,2-Dichloropropane								0.1 A	0.32		
				4	0.6			542756	Dichloropropenes			840	5250	2616.90	5250.00	IIb	0.04 A	0.13		
				4	0.6			10061015	1,3-Dichloropropene, Cis	14100 T	87 T			61637.59	123656.65	I				
1	1	2		4	0.6			10061026	1,3-Dichloropropene, Trans								0.34 A	1.09		
				4	0.6			100414	Ethylbenzene	3280 T	1400 T	622.2	28000	2719.92	5456.65	IIa	0.2 A	0.64		
				4	0.6			591786	2-Hexanone (Methyl Butyl Ketone)								0.2 B	0.64		
				4	0.6			108101	4-Methyl-2-Pentanone (Methyl Isobutyl Ketone)											
				4	0.6			100425	Styrene								3.00 Y	9.60		
1	1	2		4	0.6			79345	1,1,2,2-Tetrachloroethane								10.00 T	32.00		
1	1	2		4	0.6			127184	Tetrachloroethene	107 C	1.7 C	109.7	932	372.71	747.73	I	0.03 A	0.10		
1	1	2		4	0.6			108883	Toluene	88.5 C	5 C	124	1990	305.27	618.45	I	0.03 A	0.10		
1	3	2		4	0.6			71556	1,1,1-Trichloroethane	424000 T	14300 T	291	13109	1272.09	2552.06	IIa	0.2 B	0.64		
1	1	2		4	0.6			79005	1,1,2-Trichloroethane	1030000 T	200 DT	155	6970	677.58	1359.35	IIa	0.03 A	0.10		
1	3	2		4	0.6			79016	Trichloroethene	418 C	5 C	415	3610	1456.02	2921.05	I	0.02 A	0.06		
1	3			4	0.6			75014	Vinyl Chloride	807 C	5 DC	99.3	4470	434.09	870.86	IIa	0.12 A	0.38		
		5		4	0.6			1330207	Total Xylenes	5246 C	20 DC			18273.37	36659.83	I	0.18 A	0.58		
				4	0.6							675	9000	2950.74	5919.73	IIa	3 Y	9.60		
1	1			4	0.6				Halomethanes					1.00	1.00	IIa				
				4	0.6			75274	Bromodichloromethane	157 C	1.9 C			546.88	1097.14	I				
				4	0.6			75252	Bromoform								0.1 A	0.32		
				4	0.6			124481	Chlorodibromomethane								0.2 A	0.64		
				4	0.6			74873	Chloromethane (Methyl Chloride)								0.09 A	0.29		
				4	0.6			75718	Dichlorodifluoromethane								0.08 A	0.26		
		2		4	0.6			74839	Methyl Bromide								1.81 A	5.79		
				4	0.6			75092	Methylene Chloride								1.18 A	3.78		
				4	0.6			75694	Trichlorofluoromethane								0.25 A	0.80		
1	1	2		4	0.6			67663	Chloroform	157 C	[illegible] C	133	5780	546.88	1097.14	I	1.00 Y	3.20		
												495	22400	2176.99	4367.45	IIa	0.05 A	0.16		

TABLE 2A — RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER STATION, JASPER County

Upstream Source I	Upstream Source II	Upstream Source III	Upstream Conc. ug/l	Pollutants of concern N	C V	Instream Concentration D/S mg/l	Instream Concentration D/S ug/l	CAS Number	Parameters	I Human Health Organisms ug/l	II Human Health Water ug/l	III AQUATIC CHRONIC ug/l	III TOXICITY ACUTE (FAV) ug/l	Water Quality-based Effluent Limits Average ug/l	Water Quality-based Effluent Limits Maximum ug/l	LIMITS OF DETECTION	ug/l	Limit of Quantification ug/l	Limits of COMPLIANCE Average ug/l	Limits of COMPLIANCE Maximum ug/l
				4	0.6			65850	Benzoic Acid											
1	1			4	0.6				Dichlorobenzenes	2600 T	400 T			11365.80	22801.94	I				
				4	0.6			95501	1,2-Dichlorobenzene								0.15 A	0.48		
				4	0.6			541731	1,3-Dichlorobenzene								0.32 A	1.02		
				4	0.6			106467	1,4-Dichlorobenzene								0.24 A	0.77		
1	1	9		4	0.6			118741	Hexachlorobenzene	0.0074 C	0.0072 C	3.68	12	0.03	0.05	I	0.05 M	0.16	0.0128882	0.16
	1	2		4	0.6			98953	Nitrobenzene		19600 T	60	2700	262.29	526.20	IIa	1.9 Q	6.05		
1	1			4	0.6			608935	Pentachlorobenzene	85 T	74 T			371.57	745.45	I	50 Y	160.00		
1	1			4	0.6			95943	1,2,4,5-Tetrachlorobenzene	48 T	38 T			209.83	420.96	I	10 Y	32.00		
7	7	7		4	0.6			120821	1,2,4-Trichlorobenzene	22 T	12 T	281	675	96.17	192.94	I	0.05 M	0.16		
	1			4	0.6									1.00	1.00	IIIa				
		2		4	0.6			120832	2,4-Dichlorophenol		3090 T									
1	1			4	0.6			105679	2,4-Dimethylphenol			31.3	212	105.67	212.00	IIb	0.39 D	1.25		
		2		4	0.6				Dinitrophenol	14300 T	70 T			62511.88	125410.65	I	0.32 D	1.02		
		7		4	0.6			51285	2,4-Dinitrophenol			1.38	62	6.03	12.10	IIIa	13 Q	41.60		13
		5		4	0.6			80057	4,4'-(1-methylethylidene) Bisphenol (Bisphenol A)			10.4	466.2	45.46	91.21	IIIa				
		8		4	0.6			95487	2-Methylphenol (o-cresol)			420	5600	1836.01	3683.39	IIIa	3.6 Y	11.52		
1	1			4	0.6			106445	4-Methylphenol (p-cresol)			395	5266	1726.73	3464.14	IIIa	2.4 Y	7.68		
		2		4	0.6			534521	2-Methyl-4,6-Dinitrophenol(46DinitroCres)	765 T	13.4 T			3344.17	6709.03	I	16 D	51.20		
	1	1		4	0.6			88755	2-Nitrophenol								0.45 D	1.44		
	1	2		4	0.6			100027	4-Nitrophenol			18.4	828	80.43	161.37	IIa	0.7 E	2.24		
	1	9		4	0.6			87865	Pentachlorophenol		1000 T	1.0000	2.0000	1.00	2.00	IIb	0.59 E	1.89	0.295	
1	1			4	0.6			108952	Phenol		3500 T	669	9361	2924.51	5867.11	IIa	0.14 D	0.45		
1	1			4	0.6			95954	2,4,5-Trichlorophenol		2600 T	63	200	99.69	200.00	IIb	10 T	32.00		
				4	0.6			88062	2,4,6-Trichlorophenol	36 C	12 C			126.40	251.57	I	0.58 E	1.86		
				4	0.6				Polynuclear Aromatic Hydrocarbons	0.31 C	0.028 C			1.08	2.17	I				
		2		4	0.6				*BASE / NEUTRAL COMPOUNDS*					1.00	1.00	IIIa				
				4	0.6			83329	Acenaphthene			2.76	170	16.52	33.15	IIIa	1.8 K	5.76		
				4	0.6			208968	Acenaphthylene								2.3 K	7.36		
				4	0.6			120127	Anthracene								0.66 K	2.11		
6	6			4	0.6			56553	Benzo(a)Anthracene								0.013 K	0.04		
				4	0.6			50328	Benzo(a)Pyrene	0.31 C	0.028 C			1.08	2.17	I	0.023 K	0.07		
				4	0.6			205992	Benzo(b)Fluoranthene								0.018 K	0.06		
				4	0.6			191242	Benzo(g,h,i)Perylene								0.076 K	0.24		
				4	0.6			207089	Benzo(k)Fluoranthene								0.017 K	0.05		
				4	0.6			91587	2-Chloronaphthalene								0.94 M	3.01		
				4	0.6			218019	Chrysene								0.15 K	0.48		
				4	0.6			53703	Dibenzo(a,h)Anthracene								0.03 K	0.10		
				4	0.6			86737	Fluorene								0.21 K	0.67		
				4	0.6			193395	Indeno(1,2,3-cd)Pyrene								0.043 K	0.14		
				4	0.6			91576	2-Methylnaphthalene								2.2 Y	7.04		
		2		4	0.6			91203	Naphthalene								1.6 Q	5.12		
		9		4	0.6			85018	Phenanthrene			42	460	183.60	368.34	IIa	0.64 K	2.05		
				4	0.6			129000	Pyrene			6.3	60	27.54	55.25	IIIa	0.27 K	0.86		
1	1			4	0.6			206440	Fluoranthene	54 T	42 T			236.06	473.68	I	0.21 K	0.67		

TABLE 2A — RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER ...TION, JASPER County

Upstream Source I	Upstream Source II	Upstream Source III	Upstream Conc ug/l	Pollutants of concern N	C V	Instream Concentrasion D/S mg/l	D/S ug/l	CAS Number	Parameters	I Human Health Organisms ug/l	II Human Health Water ug/l	III AQUATIC TOXICITY CHRONIC ug/l	AQUATIC TOXICITY ACUTE (FAV.) ug/l	Water Quality-based Effluent Limits Average ug/l	Maximum ug/l		LIMITS OF DETECTION ug/l	Limit of Quantification ug/l	Limits of COMPLIANCE Average ug/l	Maximum ug/l
1	1			4	0.6			92875	Benzidine	0.0053 C	0.0012 C			0.02	0.04	I	0.1 F	0.32		0.1
				4	0.6			111911	Bis (2-Chloroethoxy) Methane								0.5 L	1.60		
1	1			4	0.6			111444	Bis (2-Chloroethyl) Ether	13.6 C	0.3 C			47.37	95.04	I	0.3 L	0.95		
1	1			4	0.6			108601	Bis (2-Chloroisopropyl) Ether	4360 T	34.7 T			19059.57	38237.09	I	0.8 L	2.56		
				4	0.6			101553	4-Bromophenyl phenyl ether								1.9 Q	6.08		
				4	0.6			7005723	4-Chlorophenyl phenyl ether								3.9 L	12.48		
				4	0.6			132649	Dibenzofuran								2.8 Y	8.96		
1	1			4	0.6			91941	3,3'-Dichlorobenzidine(Dichlorobenzidine)	0.2 C	0.1 C			0.70	1.40	I	0.13 F	0.42		
1	1			4	0.6			121142	2,4-Dinitrotoluene	91 C	1.1 C			316.98	635.92	I	0.02 J	0.06		
				4	0.6			606202	2,6-Dinitrotoluene								0.01 J	0.03		
1	1			4	0.6			122667	1,2-Diphenylhydrazine	5.6 C	0.422 C			19.51	39.13	I	2.6 Y	8.32		
		7		4	0.6			50000	Formaldehyde											
1	1			4	0.6			87683	Hexachlorobutadiene	500 C	4.47 C	11837	19399	9669.58	19399.00	IIIb				
	1			4	0.6			77474	Hexachlorocyclopentadiene		206 T			1741.85	3494.07	I	0.34 M	1.09		
1	1	2		4	0.6			67721	Hexachloroethane	87.4 C	19 C	350	980				0.4 M	1.28		
1	1	2		4	0.6			78591	Isophorone	520000 T	5200 T	4333	11700	304.44	610.76	I	0.03 M	0.10		
1	1	9		4	0.6			117817	Bis (2-Ethylhexyl) Phthalate	50000 T	15000 T	360	800	5831.95	11700.00	IIb	2.2 Q	7.04		
		2		4	0.6			85687	Butyl Benzyl Phthalate			26	660	396.77	800.00	IIb	2 G	6.40		
1	1			4	0.6			84662	Diethyl Phthalate	1600000 T	350000 T			113.66	228.02	IIIa	0.34 G	1.09		
1	1			4	0.6			131113	Dimethyl Phthalate	2900000 T	313000 T			7866828	15785958	I	0.49 G	1.57		
1	1	2		4	0.6			84742	Di-N-Butyl Phthalate	154000 T	34000 T	12.7	573	12677234	25432929	I	0.29 G	0.93		
				4	0.6			117840	Di-N-Octyl Phthalate					55.52	111.38	IIIa	0.36 G	1.15		
1	1			4	0.6			924163	N-Nitrosodibutylamine	6.9 C	0.064 C						2.5 Q	8.00		
1	1			4	0.6			55185	N-Nitrosodiethylamine	12.4 C	0.008 C			20.55	41.23	I	10 Y	32.00	5	
1	1			4	0.6			62759	N-Nitrosodimethylamine	160 C	0.014 C			43.19	86.65	I	1 Y	3.20		
				4	0.6			86306	N-Nitrosodiphenylamine	161 C	49 C			557.33	1118.10	I	0.15 H	0.48		
				4	0.6			621647	N-Nitrosodi-N-Propylamine					560.81	1125.09	I	0.81 H	2.59		
1	1			4	0.6			930552	N-Nitrosopyrrolidine								0.46 H	1.47		
1	1			4	0.6			1746016	Dioxin (2,3,7,8-TCDD)	919 C	0.16 C			3201.15	6422.11	I	1 Y	3.20		
				4	0.6					0.0000001 C	0.0000001 C			0.00	0.00	I	0.00001 R	0.00		
				4	0.6				*PESTICIDES and PCBs*											
1	1	1		4	0.6			309002	Aldrin					1.00	1.00					0.00001
1	1			4	0.6			319846	Alpha-BHC (Alpha-HCH)	0.00079 C	0.00074 C		3	0.00	0.01	I	0.004 I	0.01	0.0013759	0.0126
1	1			4	0.6			319857	Beta-BHC (Beta-HCH)	0.31 C	0.09 C			1.08	2.17	I	0.003 I	0.01		
				4	0.6			319868	Delta-BHC (Delta-HCH)	0.55 C	0.16 C			1.92	3.84	I	0.006 I	0.02		
1	1	1		4	0.6			58899	Gamma-BHC (Gamma-HCH,Lindane)								0.009 I	0.03		
1	1	1		4	0.6			57749	Chlordane	0.63 C	0.19 C	0.08	2	0.35	0.70	IIIa	0.004 I	0.01		
		1		4	0.6			2921882	Chlorpyrifos	0.0046 C	0.0046 C	0.0043	2.4	0.02	0.03	I	0.014 I	0.04	0.007	0.0448
				4	0.6			72548	4,4-DDD			0.041	0.166	0.08	0.17	IIb	0.3 O	0.96		0.3
				4	0.6			72559	4,4-DDE								0.011 I	0.04		
1	1	1		4	0.6			50293	4,4-DDT								0.004 I	0.01		
1	1	1		4	0.6			60571	Dieldrin	0.00024 C	0.00024 C	0.001	1.1	0.00	0.00	I	0.012 I	0.04		0.012
1	1	1		4	0.6			115297	Endosulfan	0.00076 C	0.00071 C	0.0019	2.6	0.00	0.01	I	0.002 I	0.01	0.001	0.0064
				4	0.6			959988	Alpha-Endosulfan	159 T	74 T	0.056	0.22	0.11	0.22	IIIb				
				4	0.6			33213659	Beta-Endosulfan								0.014 I	0.04		
				4	0.6			1031078	Endosulfan Sulfate								0.004 I	0.01		
	1	1		4	0.6			72208	Endrin		1 DT	0.0023	0.18	0.01	0.02	IIIa	0.066 I	0.21		
				4	0.6			7421934	Endrin Aldehyde								0.006 I	0.02	0.003	
																	0.023 I	0.07		

TABLE 2A — RPE Analysis (Metals) for the NIPSCO, ROLLIN M. SCHAHFER ...ATION, JASPER County

Upstream Source I	Upstream Source II	Upstream Source III	Upstream Conc. ug/l	Pollutants of concern N	C V	Instream Concentration DIS mg/l	DIS ug/l	CAS Number	Parameters	I Human Health Organisms ug/l	II Human Health Water ug/l	III AQUATIC TOXICITY CHRONIC ug/l	ACUTE (FAV) ug/l	Water Quality-based Effluent Limits Average ug/l	Maximum ug/l		LIMITS OF DETECTION ug/l	Limit of Quantification ug/l	Max. Limits of COMPLIANCE Average ug/l	Maximum ug/l
1	1	1		4	0.6			76448	Heptachlor	0.0026 C	0.0026 C	0.0038	0.52	0.01	0.02	I	0.003 I	0.27		
				4	0.6			1024573	Heptachlor Epoxide								0.063 I			
		1		4	0.6				Parathion			0.013	0.13	0.06	0.11	IIa				
1	1	1		4	0.6			8001352	Toxaphene	0.0073 C	0.0071 C	0.0002	1.46	0.0009	0.0018	IIa	0.24 I	0.77		0.24
1	1	1							PCB's	0.00079 C	0.00079 C	0.014	2	0.0028	0.0055	I				
				4	0.6			12674112	PCB-1016								0.1 I	0.32		
				4	0.6			11104282	PCB-1221								0.1 I	0.32		
				4	0.6			11141165	PCB-1232								0.1 I	0.32		
				4	0.6			53469219	PCB-1242								0.1 I	0.32		
				4	0.6			12672296	PCB-1248								0.1 I	0.32		
				4	0.6			1109769	PCB-1254								0.1 I	0.32		
				4	0.6			11096825	PCB-1260					1.00	1.00	IIa	0.1 I	0.32		

T = derived from threshold toxicity
C = derived from non-threshold cancer risk
DC = derived from drinking water standards, based on carcinogenic effects
DT = derived from drinking water standards, based on toxic effects

1) Indiana Water Quality Standards
2) IWQS Equations (327 IAC 2-1-6.2 & 6.3) with testing data from EPA
3) National Drinking Water Regulations
4) EPA Gold Book
5) Aquatic acute/chronic criteria from CH2M Hill report for Fort Wayne Reduction
6) EPA Criteria
7) IWQS Equations (327 IAC 2-1-6.2 & 6.3) with testing data from literature
8) Site-specific calculation using procedures from 327 IAC 2-1-6.2 & 6.3
9) Draft EPA Criteria

A) EPA Method 601-GC/Hal
B) EPA Method 602-GC/PID
C) EPA Method 603-GC/FID
D) EPA Method 604-GC/FID (Table 1)
E) EPA Method 604-GC/ECD (Table 2)
F) EPA Method 605-HPLC
G) EPA Method 606-GC/ECD
H) EPA Method 607-GC/N-PD
I) EPA Method 608-GC/ECD
J) EPA Method 609-GC/FID
K) EPA Method 610-HPLC
L) EPA Method 611-GC/Hal
M) EPA Method 612-GC/ECD
N) EPA Method 613-GC/MS
O) EPA Method 622-GC/Flame Photometric
P) EPA Method 624-GC/MS
Q) EPA Method 625-GC/MS
R) EPA Method 1613-HRGC/HRMS
S) EPA Method 1624-GC/MS (Isotope)
T) EPA Method 1625-GC/MS (Isotope)
U) EPA Method 200.7 (ICP)
V) EPA Methods Manual - Atomic Absorption, Furnace Technique
W) EPA Methods (- Atomic Absorption, Direct Aspiration
X) EPA Methods Manual
Y) IDEM Detection Limit

8.47 in

Attachment B:

DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

INDIANAPOLIS

OFFICE MEMORANDUM

Date: June 18, 2009
Thru: John Elliott
Permits Branch

To: George Oliver
Industrial Permits Section

From: Gurdeo Sondhe
Permits Branch

Subject: Wasteload Allocation Report for the NIPSCO Rollin M. Schahfer Generating Station in Jasper County (IN0053201, WLA001668)

A reasonable potential analysis for parameters included in the current permit (chromium, total cyanide, mercury, silver, zinc and sulfate) was done for the renewal of the NPDES permit for the NIPSCO Rollin M. Schahfer Generating Station (Wheatfield Plant). A reasonable potential analysis was also done for parameters mentioned as part of the permit renewal application. NIPSCO - RMSGS (Wheatfield Plant) is a Class D industrial wastewater treatment plant, classified in accordance with 327 IAC 5-22-5, Classification Wastewater Treatment Plants. The receiving stream of the facility is the Kankakee River, which has a Q7, 10 flow of 294 cfs. The Kankakee River is covered under Rule 327 IAC 2-1, and designated for full-body contact recreation and shall be capable of supporting a well-balanced warm water aquatic community. The Kankakee River (Assessment Unit INK0189_M1103) is on the 2008 303(d) list for *E. Coli*, and PCBs in Fish Tissue. TMDL for the Kankakee River in 14 Digit HUC {(07120001080090) [Kankakee River]} is not done and no other TMDL is currently in progress. The design flow used in the WLA analysis is 21.6 mgd.

The reasonable potential analysis for the listed pollutants of concern is included in Tables 1 and 2. The results of the analysis show that the discharge does have the reasonable potential to exceed a water quality criterion for mercury, but not for any of the other pollutants. Water quality-based effluent limitations for mercury and many of the other pollutants of concern are included in Table 3.

Based on present available information/data, the RPE/WLA analysis results are shown in the attached tables. The documentation of the wasteload allocation analysis is included as an attachment.

GSS/gss
Attachments

TABLE 1

Calculation of Projected Effluent Quality
For NIPSCO Rollin M. Schahfer Generating Station in Jasper County
Outfall 001 to Kankakee River
(IN0053201, WLA001668)

Parameter	Monthly Average PEQ					Daily Maximum PEQ				
	Maximum Monthly Average (mg/l)	Number of Monthly Averages	CV	Multiplying Factor	Monthly Average PEQ (mg/l)	Maximum Daily Sample (mg/l)	Number of Daily Samples	CV	Multiplying Factor	Daily Maximum PEQ (mg/l)
Aluminum					0.15	0.074	7	0.6	2.0	0.15
Antimony					0.012	0.0079	10	0.4	1.5	0.012
Arsenic III					0.015	0.01	15	0.6	1.5	0.015
Barium					0.18	0.16	10	0.1	1.1	0.18
Beryllium					0.00018	0.00014	10	0.3	1.3	0.00018
Cadmium					0.007	0.0026	10	1.3	2.7	0.007
Total Chromium	0.0039	45	0.2	1.0	0.0039	0.0056	77	0.3	1.0	0.0056
Cobalt					0.0029	0.0018	10	0.5	1.6	0.0029
Copper					0.036	0.028	14	0.3	1.3	0.036
Iron					0.86	0.57	15	0.6	1.5	0.86
Lead					0.048	0.02	10	1.1	2.4	0.048
Manganese					1.4	1.1	10	0.3	1.3	1.4
Mercury					0.000025	0.0000165	19	0.7	1.5	0.000025
Molybdenum					0.05	0.031	10	0.5	1.6	0.05
Nickel					0.035	0.027	10	0.3	1.3	0.035
Selenium					0.027	0.019	15	0.5	1.4	0.027
Silver	0.01	46	0.3	1.0	0.01	0.01	130	0.4	0.9	0.009
Thallium					0.033	0.015	10	0.9	2.2	0.033
Tin					0.0072	0.0045	10	0.5	1.6	0.0072
Titanium					0.0074	0.0057	10	0.3	1.3	0.0074
Zinc	0.3	46	1.0	1.1	0.33	0.3	130	1.1	0.8	0.24
Boron					17	14	15	0.2	1.2	17
Cyanide, Free	0.014	43	0.3	1.0	0.014	0.019	116	0.4	0.9	0.017
Cyanide, Total	0.014	43	0.3	1.0	0.014	0.019	116	0.4	0.9	0.017
Sulfate	872	44	0.3	1.0	872	872	118	0.3	0.9	785

6/18/2009

TABLE 2
Results of Reasonable Potential Statistical Procedure
For NIPSCO Rollin M. Schahfer Generating Station in Jasper County
Outfall 001 to Kankakee River
(IN0053201, WLA001668)

Parameter	Monthly Average Comparison			Daily Maximum Comparison			Reasonable Potential to Exceed?
	Monthly Average PEQ (mg/l)	Monthly Average PEL* (mg/l)	PEQ > PEL?	Daily Maximum PEQ (mg/l)	Daily Maximum PEL* (mg/l)	PEQ > PEL?	
Aluminum	0.15	0.17	No	0.15	0.29	No	No
Antimony	0.012	0.43	No	0.012	0.71	No	No
Arsenic III	0.015	0.49	No	0.015	0.72	No	No
Barium	0.18	6.2	No	0.18	9.1	No	No
Beryllium	0.00018	0.011	No	0.00018	0.026	No	No
Cadmium	0.007	0.014	No	0.007	0.022	No	No
Total Chromium	0.0039	3.0	No	0.0056	5.0	No	No
Cobalt	0.0029	0.1	No	0.0029	0.16	No	No
Copper	0.036	0.076	No	0.036	0.11	No	No
Iron	0.86	3.8	No	0.86	5.5	No	No
Lead	0.048	0.078	No	0.048	0.13	No	No
Manganese	1.4	4.5	No	1.4	6.6	No	No
Mercury	0.000025	0.000012	Yes	0.000025	0.00002	Yes	Yes
Molybdenum	0.05	20	No	0.05	34	No	No
Nickel	0.035	0.53	No	0.035	1.3	No	No
Selenium	0.027	0.18	No	0.027	0.26	No	No
Silver	0.01	0.016	No	0.009	0.033	No	No
Thallium	0.033	0.12	No	0.033	0.17	No	No
Tin	0.0072	0.94	No	0.0072	1.5	No	No
Titanium	0.0074	13	No	0.0074	22	No	No
Zinc	0.33	0.33	No	0.24	0.65	No	No
Boron	17	41	No	17	60	No	No
Cyanide, Free	0.014	0.022	No	0.017	0.044	No	No
Cyanide, Total	0.014	259	No	0.017	630	No	No
Sulfate	872	8600	No	785	17000	No	No

* Based on an effluent flow of 21.6 mgd.

6/18/2009

TABLE 3
Water Quality-based Effluent Limitations
For NIPSCO Rollin M. Schahfer Generating Station in Jasper County
Outfall 001 to Kankakee River
(IN0053201, WLA001668)

Parameter	Quality or Concentration* Monthly Average	Daily Maximum	Units	Quantity or Loading* Monthly Average	Daily Maximum	Units	Monthly Sampling Frequency
Aluminum	0.17	0.29	mg/l	31	52	lbs/day	1
Arsenic III	0.49	0.72	mg/l	88	130	lbs/day	1
Beryllium	0.011	0.026	mg/l	2.0	4.7	lbs/day	1
Cadmium	0.014	0.022	mg/l	2.5	4.0	lbs/day	1
Total Chromium	3.0	5.0	mg/l	541	901	lbs/day	1
Copper	0.076	0.11	mg/l	14	20	lbs/day	1
Iron	3.8	5.5	mg/l	685	991	lbs/day	1
Lead	0.078	0.13	mg/l	14	23	lbs/day	1
Mercury	0.000012	0.00002	mg/l	0.0022	0.0036	lbs/day	1
Molybdenum	20	34	mg/l	3605	6129	lbs/day	1
Nickel	0.53	1.3	mg/l	96	234	lbs/day	1
Selenium	0.18	0.26	mg/l	32	47	lbs/day	1
Silver	0.016	0.033	mg/l	2.9	5.9	lbs/day	4
Thallium	0.12	0.17	mg/l	22	31	lbs/day	1
Zinc	0.33	0.65	mg/l	59	117	lbs/day	4
Boron	41	60	mg/l	7390	10815	lbs/day	1
Cyanide, Free	0.022	0.044	mg/l	4.0	7.9	lbs/day	4
Sulfate	8600	17000	mg/l	1550167	3064284	lbs/day	4

* Based on an effluent flow of 21.6 mgd.

6/18/2009

Documentation of Wasteload Allocation Analysis
For Discharges in the Non-Great Lakes System

Analysis By:	Gurdeo Sondhe
Date:	June 18, 2009
Reviewed By:	John Elliott
Permit Writer:	George Oliver
WLA Number:	WLA001668
Previous WLA Reports:	May 2004 WLA Report

Facility Information

Name: NIPSCO Rolfin M. Schahfer Generating Station (Wheatfield Plant) (Attachment 1)

The NIPSCO operates a coal fired, steam electric generation facility in Jasper County. Coal-fired boilers convert water into high pressure steam which drives turbines that are connected to electric generators. There are four (4) steam generated units (14, 15, 17 and 18) and two natural gas-fired peaking units (16A and B). The total coal fired production capacity of station is about 1440 MW, whereas, units 16A and B produce around 104 MW.

- **NPDES Permit Number:** IN0053201
- **Permit Expiration Date:** June 30, 2009
- **County:** Jasper
- **Purpose of Analysis:** RPE/WLA Analysis for pollutants of concern
- **Type of Treatment:** NIPSCO - RMSGS (Wheatfield Plant) is a Class D industrial wastewater treatment plant, classified in accordance with 327 IAC 5-22-5, Classification Wastewater Treatment Plant.
- **Outfall Number:**
  - 001 Effluent flow is limited to low volume waste, bottom ash transport water, cooling tower blowdown, coal pile runoff, treated sanitary wastewater and stormwater. Chemical metal cleaning wastewater is excluded from the discharge.
  - 002 Emergency overflow from Final Settling Basin.
- **Effluent Flow For WLA Analysis:** 21.6 mgd
  The 2-year maximum monthly average flow was used.

Current Effluent Limits: Listed Effluent limitations for toxic/conventional parameters are based on the reported effluent limitations in the NPDES Permit.

Parameter	Pollutants of Concern - Effluent Limitations	
	Monthly Average (mg/l)	Daily Maximum (mg/l)
Chromium (1 sample/month)		0.2
Cyanide (1 sample/week)	0.022	0.044
Silver (1 sample/week)	0.014	0.028
Mercury (bi-monthly) (ng/l)	Report	Report
Zinc (1 sample/week)	0.301	0.604
Sulfate (1 sample/week)	748	1501
TRC (daily)	0. 2	

Pollutants of Concern

Pollutants of Concern Outfall 001	
Parameters	**Reason for Inclusion on Pollutants of Concern List**
Chromium	Included in current permit
Cyanide	Included in current permit
Silver	Included in current permit
Mercury	Included in current permit
Zinc	Included in current permit
Sulfate	Included in current permit

Aluminum	Data available from permit application
Antimony	Data available from permit application
Arsenic	Data available from permit application
Boron	Data available from permit application
Barium	Data available from permit application
Beryllium	Data available from permit application
Cadmium	Data available from permit application
Cobalt	Data available from permit application

Copper	Data available from permit application
Iron	Data available from permit application
Lead	Data available from permit application
Manganese	Data available from permit application
Molybdenum	Data available from permit application
Nickel	Data available from permit application
Selenium	Data available from permit application
Thallium	Data available from permit application
Tin	Data available from permit application
Titanium	Data available from permit application

Receiving Stream Information

- **Receiving Stream:** Kankakee River
- **Public Water System Intakes Downstream:** None
- **Designated Stream Use:** The Kankakee River is covered under Rule 327 IAC 2-1 and is designated for full-body contact recreation and shall be capable of supporting a well-balanced, warm water aquatic community.
- **14 Digit HUC:** (07120001080090) (Kankakee River)
- **2008 Assessment Unit:** INK0189_M1103
- **2008 303(d) List:** The Kankakee River (Assessment unit INK0189_M1103) is on the 2008 303(d) list for *E. coli and* PCBs in Fish Tissue.
- **TMDL Status:** TMDL for the Kankakee River in 14 Digit HUC (07120001080090) is not done and no other TMDL is currently in progress.
- **Q7,10 (Outfall):** 294 cfs
  1375 sq.miles (Drainage Area u/s of Outfall)

  USGS Gaging Station 05517500 Kankakee River (Q7,10 = 348 cfs, Q30,10 = 385 cfs, Q50 = 1140 cfs and Drainage Area = 1352 sq.miles) near Dunn Bridge, 3.6 mi upstream of Davis Ditch in Jasper County) is used for the Q7,10 flow calculation.

  NIPSCO-RMSGS Plant withdraws water (39 mgd – maximum 7-day consecutive pumping operating days) from the Kankakee River upstream of outfall 001 for plant operation. This flow value is based on the intake flow data (covering period from November 2006 through October 2008) submitted by the facility.

The information for the gaging station for calculating Q7, 10 of the receiving stream was obtained from the book entitled Low-Flow Characteristics of Indiana Streams by Kathleen Fowler and John T. Wilson published in 1996 by the USGS.

The drainage area upstream of the outfall was obtained from the book entitled Drainage Areas of Indiana Streams by Richard E. Hoggatt, published in 1975 by the USGS in cooperation with the IDNR.

The Q7,10, Q30,10 and Q50 were calculated from the USGS gaging station values using the ratio of drainage areas and then subtracting the intake flow.

- **Q30,10 (Outfall):** 331 cfs
- **Q50 (Outfall):** 1100 cfs

- **Nearby Discharges:** None

Calculation of Preliminary Effluent Limitations

Upstream water quality data were obtained from fixed monitoring station KR-91, Kankakee River, Dunns Bridge, Porter County. For some pollutants water quality data were obtained from trace metals sampling downstream of the outfall at fixed station KR-68. The ambient upstream concentration of a given pollutant was determined by calculating the geometric mean of the instream data for the pollutant. The survey data include values reported as less than the limit of quantitation (LOQ). If less than one-half the values in the data set were below the LOQ, the values below the LOQ were assigned the value (V) and then the geometric mean of the data set was calculated. The value (V) was determined as follows

$$V = (LOQ) \times [1 - (\text{Number below LOQ})/(\text{Total number of values})]$$

If one-half or more of the values in the data set were below the LOQ, the values below the LOQ were set equal to one-half the LOQ. The determination of ambient upstream concentrations of pollutants of concern is included in Attachments 2 and 3. Mercury is a BCC and mixing zones for all discharges of BCCs to waters in the non-Great Lakes system are prohibited after January 1, 2004. Therefore, the criteria for mercury were applied to the undiluted discharge in accordance with 327 IAC 5-2-11.1(b)(6). The time periods chosen for the different data sets are based on the availability of data, improvement in the limit of detection for some pollutants and the desire to have data for whole years.

The data sets for fixed station KR-91 were limited to total last five years (November 2002 through December 2007 including missing data) of available data. The trace metals water quality data were limited to the available data covering period from April 2002 thru March 2006. For cobalt, molybdenum, tin, titanium and boron IDEM water quality data were not available so the long term average intake concentration from the permit application was used as the ambient upstream concentration.

The 50th percentile hardness and chloride values were obtained from downstream fixed monitoring station : KR-68, Kankakee River, SR 55 Bridge 1 Mile South of Shelby, Newton County. A hardness value of 336 mg/l (actual d/s value) was obtained to determine the criteria for those metals whose criteria are dependent on hardness (Attachment 4). Considering the downstream hardness (336 mg/l) and chloride (29 mg/l) at Fixed Station : KR-68 Kankakee River, the Indiana Sulfate criterion is 2005 mg/l.

The coefficient of variation used to calculate monthly average and daily maximum PELs was set equal to the default value of 0.6. The number of samples per month used to calculate monthly average PELs of the requested parameters was set equal to the expected monitoring frequency mentioned in the permit. The number of samples per month for mercury was set equal to 1. The spreadsheet used to calculate PELs is included in Attachment 5.

Reasonable Potential Analysis for Toxics

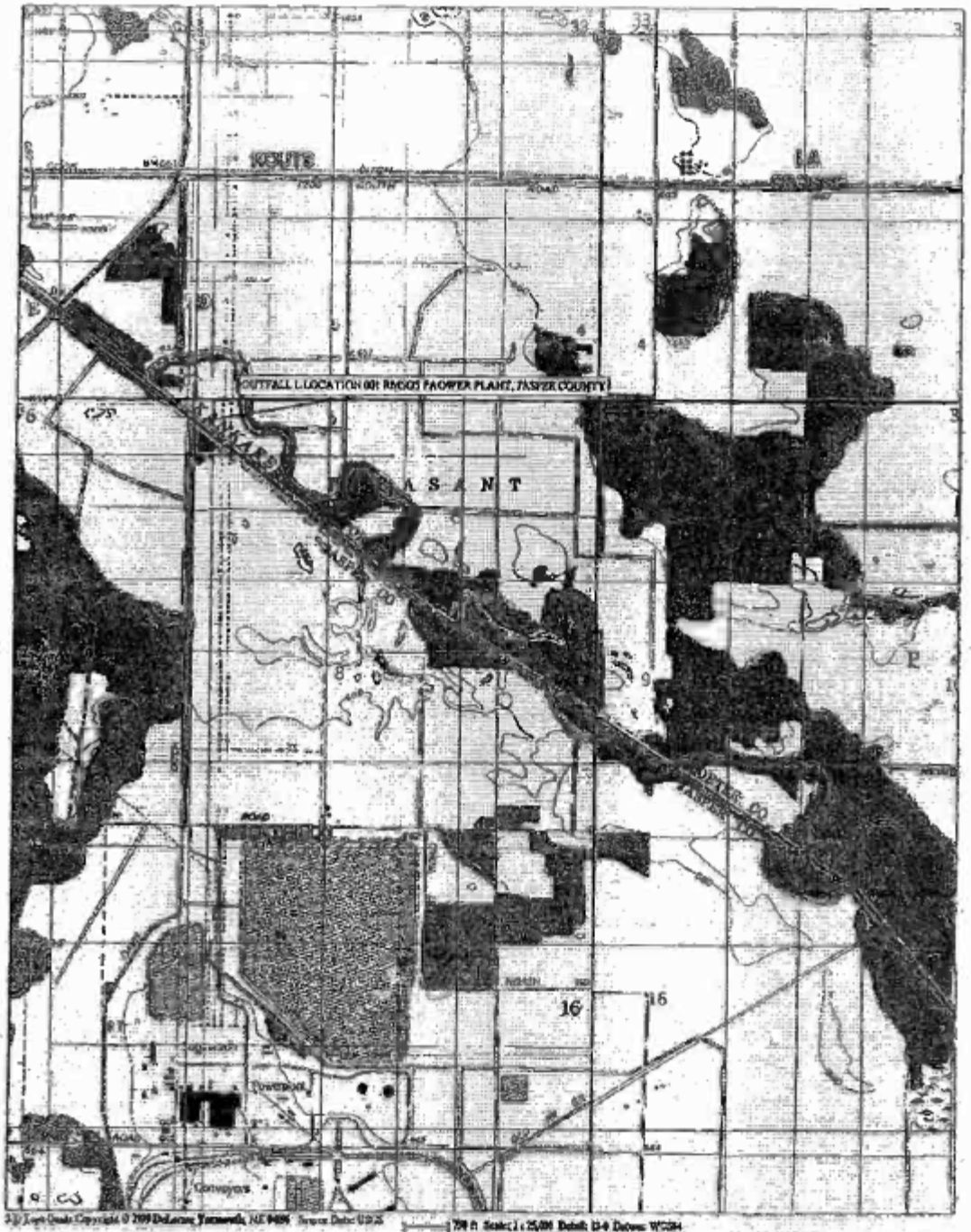
Calculation of Projected Effluent Quality

Effluent data collected from January 2005 through October 2008 as part of the current permit and effluent data reported on Form 2C of the permit renewal application were obtained from the facility in Excel Spreadsheet format. Effluent data for total cyanide were used to calculate PEQs for free cyanide. The RPE procedures under 327 IAC 5-2-11.5 were utilized. The PEQ for mercury is compared with a PEL based on an assumed monitoring frequency of once per month or less. Available mercury data were used in the analysis. The data used in the analysis are included in Attachments 6 and 7.

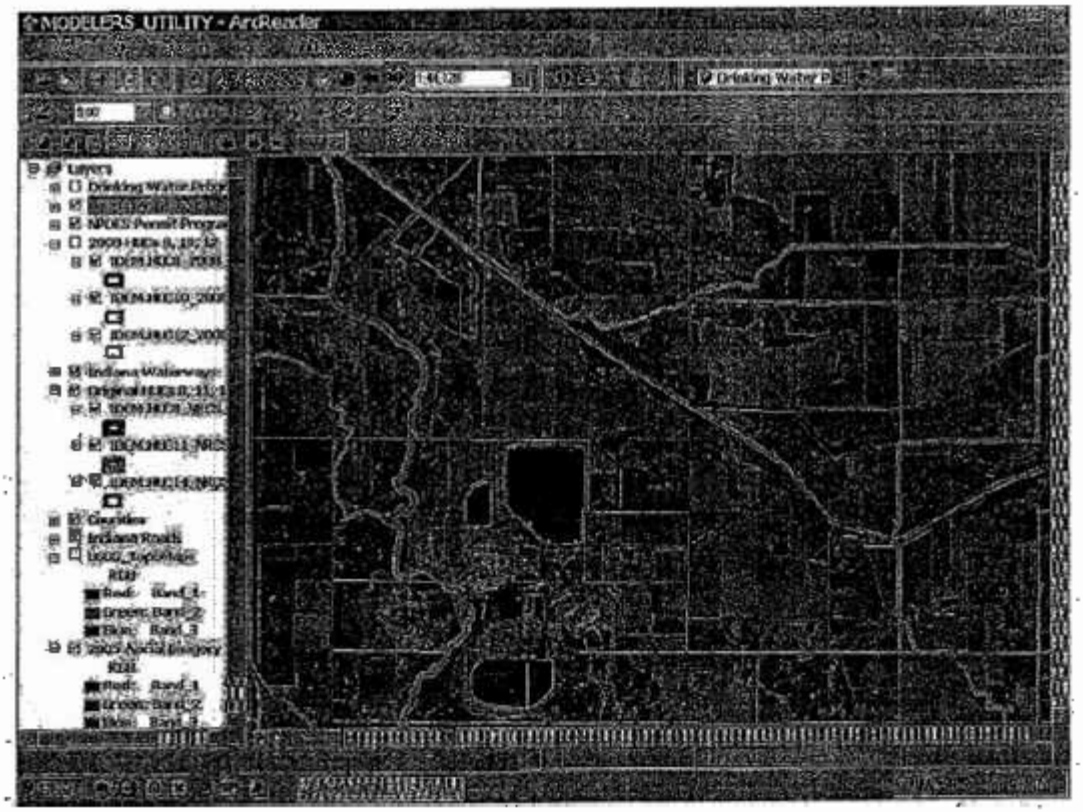
Comparison of PEQs to PELs

The reasonable potential analysis for the listed pollutants of concern is included in Attachment 8. The results of the analysis show that the discharge does not have the reasonable potential to exceed a water quality criterion for the pollutants of concern in the permit except mercury.

ATTACHMENT 1 Outfall Location for NIPSCO Rollin M. Schafer Generating Station



ATTACHMENT 1 Outfall Location for NIPSCO Rollin M. Schahfer Generating Station



ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Chromium (Total) (ug/L)				Corrected					Corrected	Zinc (Total) (ug/L)				Corrected	Sulfate (mg/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
12/12/2002	W	L	1.2	0.6						12/12/2002	W	L	6.0	5.4	12/12/2002	W		94	
2/20/2003	W	L	1.2	0.6						2/20/2003	W	L	6.0	5.4	2/20/2003	W		93	
3/5/2003	W	L	1.2	0.6						3/5/2003	W		56.9	56.9	3/5/2003	W		89	
4/16/2003	W		1.28	1.28						4/16/2003	W		9.9	9.9	4/16/2003	W		95	
5/1/2003	S		1.39	1.39						5/1/2003	S		730.0	730.0	5/1/2003	S		84	
6/18/2003	S	L	1.2	0.6						6/18/2003	S		105.0	105.0	6/18/2003	S		194	
7/9/2003	S		1.57	1.57						7/9/2003	S		474.0	474.0	7/9/2003	S		80	
8/6/2003	S		1.48	1.48						8/6/2003	S		127.0	127.0	8/6/2003	S		70	
9/15/2003	S	L	1.2	0.6						9/15/2003	S		50.9	50.9	9/15/2003	S		90	
10/1/2003	S	L	1.2	0.6						10/1/2003	S		268.0	268.0	10/1/2003	S		81	
11/3/2003	S	L	1.2	0.6						11/3/2003	S		22.5	22.5	11/3/2003	S		92	
12/17/2003	W	L	1.2	0.6						12/17/2003	W		24.9	24.9	12/17/2003	W		94	
1/7/2004	W	L	1.2	0.6						1/7/2004	W		55.4	55.4	1/7/2004	W		92	
2/23/2004	W	L	1.2	0.6						2/23/2004	W		17.4	17.4	2/23/2004	W		77	
3/4/2004	W		2.03	2.03						3/4/2004	W		11.2	11.2	3/4/2004	W		82	
4/1/2004	W	L	1.2	0.6						4/1/2004	W		6.6	6.6	4/1/2004	W		94	
5/26/2004	S		3.43	3.43						5/26/2004	S		34.8	34.8	5/26/2004	S		78	
6/28/2004	S	L	1.2	0.6						6/28/2004	S		7.0	7.0	6/28/2004	S		88	
7/26/2004	S		1.57	1.57						7/26/2004	S		13.6	13.6	7/26/2004	S		74	
8/10/2004	S	L	1.2	0.6						8/10/2004	S	L	6.0	5.4	8/10/2004	S		81	
9/2/2004	S	L	1.2	0.6						9/2/2004	S		8.9	8.9	9/2/2004	S		80	
10/14/2004	S	L	1.2	0.6						10/14/2004	S	L	6.0	5.4	10/14/2004	S		96	
11/10/2004	S	L	1.2	0.6						11/10/2004	S	L	6.0	5.4	11/10/2004	S		99	
12/7/2004	W	L	1.2	0.6						12/7/2004	W		18.6	18.6	12/7/2004	W		91	
1/18/2005	W		2.6	2.6						1/18/2005	W		14.8	14.8	1/18/2005	W		55	
2/1/2005	W	L	1.2	0.6						2/1/2005	W	L	6.0	5.4	2/1/2005	W		101	
3/8/2005	W	L	1.2	0.8						3/8/2005	W		19.8	19.8	3/8/2005	W		78	
4/18/2005	W	L	1.2	0.6						4/18/2005	W		8.2	8.2	4/18/2005	W		97	
5/4/2005	S	L	1.2	0.6						5/4/2005	S		12.0	12.0	5/4/2005	S		96	
6/7/2005	S	L	1.2	0.6						6/7/2005	S		17.9	17.9	6/7/2005	S		95	
6/30/2005	S	L	1.2	0.6						6/30/2005	S		25.1	25.1	6/30/2005	S		98	
8/8/2005	S	L	1.2	0.6						8/8/2005	S		7.9	7.9	8/8/2005	S		75	
9/19/2005	S	L	1.2	0.6						9/19/2005	S		14.3	14.3	9/19/2005	S		82	
10/11/2005	S	L	1.2	0.6						10/11/2005	S		29.4	29.4	10/11/2005	S		88	
11/2/2005	S	L	1.2	0.6						11/2/2005	S		7.6	7.6	11/2/2005	S		95	
12/6/2005	W	L	1.2	0.60						12/6/2005	W		9.5	9.5	12/6/2005	W		94	
1/3/2006	W	L	1.2	0.6						1/3/2006	W		12.6	12.8	1/3/2006	W		100	
2/15/2006	W	L	1.2	0.6						2/15/2006	W		14.5	14.5	2/15/2006	W		107	
3/8/2006	W	L	1.2	0.6						3/8/2006	W		11.7	11.7	3/8/2006	W		107	
4/6/2006	W	L	1.2	0.6						4/6/2006	W		27.9	27.9	4/6/2006	W		88	
5/1/2006	S	L	1.2	0.6						5/1/2006	S		9.2	9.2	5/1/2006	S		98	
6/1/2006	S	L	1.2	0.6						6/1/2006	S		226.0	226.0	6/1/2006	S		95	
7/11/2006	S	L	1.2	0.6						7/11/2006	S		21.5	21.5	7/11/2006	S		76	
8/3/2006	S	L	1.2	0.6						8/3/2006	S		102.0	102.0	8/3/2006	S		78	
9/28/2006	S	L	1.2	0.6						9/28/2006	S		9.5	9.5	9/28/2006	S		80	
10/12/2006	S	L	1.2	0.6						10/12/2006	S		22.6	22.8	10/12/2006	S		80	
11/8/2006	S	L	1.2	0.6						11/8/2006	S		7.4	7.4	11/8/2006	S		85	
12/28/2006	W	L	1.2	0.6						12/28/2006	W		23.6	23.6	12/28/2006	W		78	

ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Chromium (Total) (ug/L)				Corrected					Corrected	Zinc (Total) (ug/L)				Corrected	Sulfate (mg/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
1/11/2007	W	L	1.2	0.6						1/11/2007	W		68.5	68.5	1/11/2007	W		56	
2/1/2007	W	L	1.2	0.6						2/1/2007	W		121.0	121.0	2/1/2007	W		49	
3/1/2007	W	L	1.2	0.6						3/1/2007	W		72.8	72.8	3/1/2007	W		45	
4/23/2007	W	L	1.2	0.6						4/23/2007	W		21.7	21.7	4/23/2007	W		43	
5/7/2007	S	L	1.2	0.6						5/7/2007	S		49.8	49.8	5/7/2007	S		45	
6/18/2007	S	L	1.2	0.6						6/18/2007	S		67.2	67.2	6/18/2007	S		61	
7/19/2007	S	L	1.2	0.6						7/19/2007	S		12.8	12.8	7/19/2007	S		39	
8/6/2007	S	L	1.2	0.6						8/6/2007	S		41.2	41.2	8/6/2007	S		32.4	
9/27/2007	S	L	1.2	0.6						9/27/2007	S		27.6	27.6	9/27/2007	S		73	
10/2/2007	S	L	1.2	0.6						10/2/2007	S		59.3	59.3	10/2/2007	S		33.6	
11/1/2007	S	L	1.2	0.6						11/1/2007	S		40.8	40.8	11/1/2007	S		38	
12/6/2007	W	L	1.2	0.6						12/6/2007	W		16.70	16.7	12/6/2007	W		42	
Chromium (Total) (ug/L)										Zinc (Total) (ug/L)					Sulfate (mg/L)				
MF For Lab Data		0.13	Lab Test	Lab Result	MF For Lab Data			Lab Test	Lab Result	MF For Lab Data		0.93	Lab Test	Lab Result	MF For Lab Data			Lab Test	Lab Result
Samples		52	60	60	Samples					Samples		6	60	60	Samples			60	
Minimum			1.2	0.6	Minimum					Minimum			6.0	5.4	Minimum			32.4	
Average			1.3	0.8	Average					Average			56.5	56.4	Average			82.6	
Maximum			3.4	3.4	Maximum					Maximum			730.0	730.0	Maximum			194.0	
STD_Deviation			0.4	0.5	STD_Deviation					STD_Deviation			117.7	117.8	STD_Deviation			23.7	
CV			0.3	0.7	CV					CV			2.1	2.1	CV			0.3	
Geometric Mean			1.3	0.7	Geometric Mean					Geometric Mean			24	23	Geometric Mean			77	

ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Iron (Total) (ug/L)				Corrected	Arsenic (Total) (ug/L)				Corrected	Cadmium (Total) (ug/L)				Corrected	Copper (Total) (ug/L)				Correct
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Res
12/12/2002	W		554		12/12/2002	W		2.0		12/12/2002	W	L	1	0.5	12/12/2002	W	L	1	0.91
2/20/2003	W		669		2/20/2003	W		2.4		2/20/2003	W	L	1	0.5	2/20/2003	W	L	1	0.91
3/5/2003	W		557		3/5/2003	W		2.1		3/5/2003	W	L	1	0.5	3/5/2003	W		1.08	1.08
4/16/2003	W		2680		4/16/2003	W		4.5		4/16/2003	W	L	1	0.5	4/16/2003	W		2.3	2.30
5/1/2003	S		2760		5/1/2003	S		4.7		5/1/2003	S	L	1	0.5	5/1/2003	S		2.88	2.88
6/18/2003	S		1940		6/18/2003	S		2.0		6/18/2003	S	L	1	0.5	6/18/2003	S		1.61	1.61
7/9/2003	S		1840		7/9/2003	S		3.7		7/9/2003	S	L	1	0.5	7/9/2003	S		2.72	2.72
8/6/2003	S		1780		8/6/2003	S		3.7		8/6/2003	S	L	1	0.5	8/6/2003	S		2.5	2.50
9/15/2003	S		997		9/15/2003	S		3.3		9/15/2003	S	L	1	0.5	9/15/2003	S		1.45	1.45
10/1/2003	S		694		10/1/2003	S		2.6		10/1/2003	S	L	1	0.5	10/1/2003	S		1.64	1.64
11/3/2003	S		756		11/3/2003	S		2.6		11/3/2003	S	L	1	0.5	11/3/2003	S		1.4	1.40
12/17/2003	W		651		12/17/2003	W		2.1		12/17/2003	W	L	1	0.5	12/17/2003	W		1.47	1.47
1/7/2004	W		710		1/7/2004	W		2.1		1/7/2004	W	L	1	0.5	1/7/2004	W		1.43	1.43
2/23/2004	W		977		2/23/2004	W		3.2		2/23/2004	W	L	1	0.5	2/23/2004	W		2.29	2.29
3/4/2004	W		2240		3/4/2004	W		3.0		3/4/2004	W	L	1	0.5	3/4/2004	W		3.49	3.49
4/1/2004	W		1340		4/1/2004	W		2.7		4/1/2004	W	L	1	0.5	4/1/2004	W		1.97	1.97
5/26/2004	S		3720		5/26/2004	S		4.0		5/26/2004	S	L	1	0.5	5/26/2004	S		4.85	4.85
6/28/2004	S		1810		6/28/2004	S		3.5		6/28/2004	S	L	1	0.5	6/28/2004	S		1.96	1.96
7/26/2004	S		2110		7/26/2004	S		3.4		7/26/2004	S	L	1	0.5	7/26/2004	S		3.49	3.49
8/10/2004	S		1160		8/10/2004	S		2.9		8/10/2004	S	L	1	0.5	8/10/2004	S		1.54	1.54
9/2/2004	S		1600		9/2/2004	S		2.9		9/2/2004	S	L	1	0.5	9/2/2004	S		2.3	2.30
10/14/2004	S		560		10/14/2004	S		2.5		10/14/2004	S	L	1	0.5	10/14/2004	S	L	1	0.91
11/10/2004	S		526		11/10/2004	S		2.2		11/10/2004	S	L	1	0.5	11/10/2004	S		1.04	1.04
12/7/2004	W		708		12/7/2004	W		1.9		12/7/2004	W	L	1	0.5	12/7/2004	W		1.43	1.43
1/18/2005	W		2240		1/18/2005	W		1.7		1/18/2005	W	L	1	0.5	1/18/2005	W		3.24	3.24
2/1/2005	W		724		2/1/2005	W		1.9		2/1/2005	W	L	1	0.5	2/1/2005	W		1.29	1.29
3/8/2005	W		756		3/8/2005	W		1.5		3/8/2005	W	L	1	0.5	3/8/2005	W		1.57	1.57
4/18/2005	W		1020		4/18/2005	W		2.2		4/18/2005	W	L	1	0.5	5/4/2005	S		1.03	1.03
5/4/2005	S		614		5/4/2005	S		1.8		5/4/2005	S	L	1	0.5	6/7/2005	S		1.51	1.51
6/7/2005	S		893		6/7/2005	S		2.5		6/7/2005	S	L	1	0.5	6/30/2005	S		1.13	1.13
6/30/2005	S		454		6/30/2005	S		2.2		6/30/2005	S	L	1	0.5	8/8/2005	S		1.12	1.12
8/8/2005	S		449		8/8/2005	S		2.1		8/8/2005	S	L	1	0.5	9/19/2005	S	L	1	0.91
9/19/2005	S		510		9/19/2005	S		2.0		9/19/2005	S	L	1	0.5	10/11/2005	S		1.02	1.02
10/11/2005	S		781		10/11/2005	S		2.4		10/11/2005	S	L	1	0.5	11/2/2005	S	L	1	0.91
11/2/2005	S		527		11/2/2005	S		1.7		11/2/2005	S	L	1	0.5	12/6/2005	W	L	1	0.91
12/6/2005	W		571		12/6/2005	W		1.5		12/6/2005	W	L	1	0.5	1/3/2006	W		1.31	1.31
1/3/2006	W		662		1/3/2006	W		1.2		1/3/2006	W	L	1	0.5	2/15/2006	W		1.22	1.22
2/15/2006	W		700		2/15/2006	W		1.4		2/15/2006	W	L	1	0.5	3/8/2006	W		1.21	1.21
3/8/2006	W		702		3/8/2006	W		1.6		3/8/2006	W	L	1	0.5	4/6/2006	W		1.72	1.72
4/6/2006	W		1010		4/6/2006	W		2.5		4/6/2006	W	L	1	0.5	5/1/2006	S		1.53	1.53
5/1/2006	S		1080		5/1/2006	S		2.5		5/1/2006	S	L	1	0.5	6/1/2006	S		2.18	2.18
6/1/2006	S		1310		6/1/2006	S		3.1		6/1/2006	S	L	1	0.5	7/11/2006	S		4.32	4.32
7/11/2006	S		855		7/11/2006	S		3.0		7/11/2006	S	L	1	0.5	8/3/2006	S		2.01	2.01
8/3/2006	S		1280		8/3/2006	S		3.5		8/3/2006	S	L	1	0.5	9/28/2006	S		1.5	1.50
9/28/2006	S		703		9/28/2006	S		2.4		9/28/2006	S	L	1	0.5	10/12/2006	S		1.45	1.45
10/12/2006	S		526		10/12/2006	S		1.8		10/12/2006	S	L	1	0.5	11/8/2006	S		1.44	1.44
11/8/2006	S		692		11/8/2006	S		1.8		11/8/2006	S	L	1	0.5	12/28/2006	W		1.89	1.89
12/28/2006	W		645		12/28/2006	W		1.4		12/28/2006	W	L	1	0.5	1/11/2007	W		1.77	1.77

ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Iron (Total) (ug/L)				Corrected	Arsenic (Total) (ug/L)				Corrected	Cadmium (Total) (ug/L)				Corrected	Copper (Total) (ug/L)				Correct
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Res
1/11/2007	W		712		1/11/2007	W		1.5		1/11/2007	W	L	1	0.5	2/1/2007	W		1.62	1.62
2/1/2007	W		700		2/1/2007	W		1.6		2/1/2007	W	L	1	0.5	3/1/2007	W		1.87	1.87
3/1/2007	W		886		3/1/2007	W		1.9		3/1/2007	W	L	1	0.5	4/23/2007	W		1.66	1.66
4/23/2007	W		691		4/23/2007	W		2.0		4/23/2007	W	L	1	0.5	5/7/2007	S		2.02	2.02
5/7/2007	S		1130		5/7/2007	S		2.4		5/7/2007	S	L	1	0.5	6/18/2007	S		2.19	2.19
6/18/2007	S		1360		6/18/2007	S		2.8		6/18/2007	S	L	1	0.5	7/19/2007	S		1.68	1.68
7/19/2007	S		851		7/19/2007	S		2.6		7/19/2007	S	L	1	0.5	8/6/2007	S		1.72	1.72
8/6/2007	S		792		8/6/2007	S		2.9		8/6/2007	S	L	1	0.5	9/27/2007	S		1.05	1.05
9/27/2007	S		644		9/27/2007	S		2.71		9/27/2007	S	L	1	0.5	10/2/2007	S		1.15	1.15
10/2/2007	S		678		10/2/2007	S		2.53		10/2/2007	S	L	1	0.5	11/1/2007	S		1.15	1.15
11/1/2007	S		469		11/1/2007	S		2.19		11/1/2007	S	L	1	0.5	12/6/2007	W		1.46	1.46
12/6/2007	W		552		12/6/2007	W		1.99		12/6/2007	W	L	1	0.5					
Iron (Total) (ug/L)					Arsenic (Total) (ug/L)					Cadmium (Total) (ug/L)					Copper (Total) (ug/L)				
MF For Lab Data			Lab Test	Lab Result	MF For Lab Data			Lab Test	Lab Result	MF For Lab Data		0.00	Lab Test	Lab Result	MF For Lab Data		0.92	Lab Test	Lab Res
Samples			60		Samples			60		Samples		60	60	60	Samples		5	59	59
Minimum			449		Minimum			1.23		Minimum			1.0	0.5	Minimum			1.0	0.9
Average			1060		Average			2.46		Average			1.0	0.5	Average			1.8	1.8
Maximum			3720		Maximum			4.68		Maximum			1.0	0.5	Maximum			4.9	4.9
STD_Deviation			669		STD_Deviation			0.77		STD_Deviation			0.0	0.0	STD_Deviation			0.8	0.8
CV			0.6		CV			0.31		CV			0.0	0.0	CV			0.5	0.5
Geometric Mean			901		Geometric Mean			2.3		Geometric Mean			1.0	0.5	Geometric Mean			1.6	1.6

ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Lead (Total) (ug/L)				Corrected	Nickel (Total) (ug/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
12/12/2002	W	L	1	0.5	12/12/2002	W		2.8	2.8
2/20/2003	W	L	1	0.5	2/20/2003	W		2.6	2.6
3/5/2003	W	L	1	0.5	3/5/2003	W		2.7	2.7
4/16/2003	W		1.41	1.4	4/16/2003	W		3.8	3.8
5/1/2003	S		1.64	1.6	5/1/2003	S		4.2	4.2
6/18/2003	S	L	1	0.5	6/18/2003	S		4.6	4.6
7/9/2003	S		1.51	1.5	7/9/2003	S		4.3	4.3
8/6/2003	S		1.08	1.1	8/6/2003	S		2.5	2.5
9/15/2003	S	L	1	0.5	9/15/2003	S		2.1	2.1
10/1/2003	S	L	1	0.5	10/1/2003	S		2.1	2.1
11/3/2003	S	L	1	0.5	11/3/2003	S		2.2	2.2
12/17/2003	W	L	1	0.5	12/17/2003	W		2.4	2.4
1/7/2004	W	L	1	0.5	1/7/2004	W		2.2	2.2
2/23/2004	W	L	1	0.5	2/23/2004	W		2.4	2.4
3/4/2004	W		1.97	2.0	3/4/2004	W		3.3	3.3
4/1/2004	W	L	1	0.5	4/1/2004	W		2.2	2.2
5/26/2004	S		3.9	3.9	5/26/2004	S		4.4	4.4
6/28/2004	S		1.23	1.2	6/28/2004	S		2.4	2.4
7/26/2004	S		1.92	1.9	7/26/2004	S		3.1	3.1
8/10/2004	S	L	1	0.5	8/10/2004	S		1.8	1.8
9/2/2004	S		1.2	1.2	9/2/2004	S		2.7	2.7
10/14/2004	S	L	1	0.5	10/14/2004	S		1.8	1.6
11/10/2004	S	L	1	0.5	11/10/2004	S		1.7	1.7
12/7/2004	W	L	1	0.5	12/7/2004	W		1.7	1.7
1/18/2005	W		2	2.0	1/18/2005	W		3.0	3.0
2/1/2005	W	L	1	0.5	2/1/2005	W		1.9	1.9
3/8/2005	W	L	1	0.5	3/8/2005	W		1.6	1.6
4/18/2005	W	L	1	0.5	4/18/2005	W		1.4	1.4
5/4/2005	S	L	1	0.5	5/4/2005	S	L	1.4	1.2
6/7/2005	S	L	1	0.5	6/7/2005	S		1.5	1.5
6/30/2005	S	L	1	0.5	6/30/2005	S	L	1.4	1.2
8/8/2005	S	L	1	0.5	8/8/2005	S	L	1.4	1.2
9/19/2005	S	L	1	0.5	9/19/2005	S	L	1.4	1.2
10/11/2005	S	L	1	0.5	10/11/2005	S		1.5	1.5
11/2/2005	S	L	1	0.5	11/2/2005	S	L	1.4	1.2
12/6/2005	W	L	1	0.5	12/6/2005	W	L	1.4	1.2
1/3/2006	W	L	1	0.5	1/3/2006	W		1.8	1.8
2/15/2006	W	L	1	0.5	2/15/2006	W		1.4	1.4
3/8/2006	W	L	1	0.5	3/8/2006	W		1.4	1.4
4/6/2006	W	L	1	0.5	4/6/2006	W		1.6	1.6
5/1/2006	S	L	1	0.5	5/1/2006	S		1.5	1.5
6/1/2006	S	L	1	0.5	6/1/2006	S		2.1	2.1
7/11/2006	S	L	1	0.5	7/11/2006	S		1.7	1.7
8/3/2006	S	L	1	0.5	8/3/2006	S		1.9	1.9
9/28/2006	S	L	1	0.5	9/28/2006	S		1.8	1.8
10/12/2006	S	L	1	0.5	10/12/2006	S		1.7	1.7
11/8/2006	S	L	1	0.5	11/8/2006	S		2.2	2.2
12/28/2006	W	L	1	0.5	12/28/2006	W		2.3	2.3

ATTACHMENT 2 (UPSTREAM STATION)

STATION SITE SELECTED : KR-91 , Kankakee River , Dunns Bridge , Porter County

Lead (Total) (ug/L)				Corrected	Nickel (Total) (ug/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
1/11/2007	W	L	1	0.5	1/11/2007	W		2.3	2.3
2/1/2007	W	L	1	0.5	2/1/2007	W		2.0	2.0
3/1/2007	W	L	1	0.5	3/1/2007	W		2.1	2.1
4/23/2007	W	L	1	0.5	4/23/2007	W		1.8	1.8
5/7/2007	S	L	1	0.5	5/7/2007	S		2.4	2.4
6/18/2007	S	L	1	0.5	6/18/2007	S		2.2	2.2
7/19/2007	S	L	1	0.5	7/19/2007	S		1.8	1.8
8/6/2007	S	L	1	0.5	8/6/2007	S		1.8	1.8
9/27/2007	S	L	1	0.5	9/27/2007	S	L	1.4	1.24
10/2/2007	S	L	1	0.5	10/2/2007	S		1.46	1.46
11/1/2007	S	L	1	0.5	11/1/2007	S		1.53	1.53
12/6/2007	W	L	1		12/6/2007	W		1.72	1.72

Lead (Total) (ug/L)				Nickel (Total) (ug/L)				
MF For Lab Data	0.17	Lab Test	Lab Result	MF For Lab Data	0.89	Lab Test	Lab Result
Samples	50	60	59	Samples	7	60	60
Minimum		1.0	0.5	Minimum		1.40	1.24
Average		1.1	0.7	Average		2.16	2.14
Maximum		3.9	3.9	Maximum		4.57	4.57
STD_Deviation		0.4	0.6	STD_Deviation		0.80	0.83
CV		0.4	0.8	CV		0.37	0.39
Geometric Mean		1.1	0.6	Geometric Mean		2.0	2.0

TRACE METALS DATA - STATION SITE SELECTED : KR-68 , Kankakee River , SR 55, Shelby , Newton County ATTACHMENT 3

Aluminum (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Antimony (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Arsenic (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Barium (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		621		4/24/2002	W	L	0.73	0.37	4/24/2002	W		2.43		4/24/2002	W		40	
7/10/2002	S		296		7/10/2002	S	L	0.73	0.37	7/10/2002	S		3.06		7/10/2002	S		40	
10/23/2002	S		49.5		10/23/2002	S	L	0.73	0.37	10/23/02	S		2.09		10/23/2002	S		38	
5/20/2003	S		309		5/20/2003	S		0.23	0.23	5/20/2003	S		3.26		5/20/2003	S		65	
8/19/2003	S		208		8/19/2003	S	L	0.73	0.37	8/19/2003	S		3.09		8/19/2003	S		52	
11/19/2003	S		291		11/19/2003	S	L	0.73	0.37	11/19/2003	S		2.22		11/19/2003	S		58	
2/24/2004	W		174		2/24/2004	W	L	0.73	0.37	2/24/2004	W		1.96		2/24/2004	W		57	
9/8/2004	S		611		9/8/2004	S	L	0.73	0.37	9/8/2004	S		4.16		9/8/2004	S		63	
10/21/04	S		60.1		10/21/2004	S	L	0.73	0.37	10/21/2004	S		1.91		10/21/2004	S		53	
3/10/2005	W		293		3/10/2005	W	L	0.73	0.37	3/10/2005	W		1.92		3/10/2005	W		54	
6/23/2005	S		702		6/23/2005	S	L	0.73	0.37	6/23/2005	S		3.44		6/23/2005	S		60	
9/1/2005	S		354		9/1/2005	S	L	0.73	0.37	9/1/2005	S		3.08		9/1/2005	S		61	
12/8/2005	W		29		12/8/2005	W	L	0.73	0.37	12/8/2005	W		1.69		12/8/2005	W		61	
3/16/2006	W		4110		3/16/2006	W	L	0.73	0.37	3/16/2006	W		3.23		3/16/2006	W		90	

Aluminum (Total) (ug/L) MF For Lab Data		Trace Metal	Corrected Trace Meta	Antimony (Total) (ug/L) MF For Lab Data	0.1	Trace Metal	Corrected Trace Metal	Arsenic (Total) (ug/L) MF For Lab Data		Lab Test	Corrected Lab Result	Barium (Total) (ug/L) MF For Lab Data		Lab Test	Corrected Lab Result
Samples		14		Samples	13	14	14	Samples		14		Samples		14	
Minimum		29.0		Minimum		0.23	0.23	Minimum		1.7		Minimum		38.0	
Average		579.8		Average		0.69	0.36	Average		2.7		Average		56.8	
Maximum		4110.0		Maximum		0.73	0.37	Maximum		4.2		Maximum		90.0	
STD_Deviation		1037.9		STD_Deviation		0.13	0.04	STD_Deviation		0.7		STD_Deviation		13.1	
CV		1.8		CV		0.19	0.10	CV		0.3		CV		0.2	
Geometeric MEAN		268		Geometeric MEAN		0.67	0.35	Geometeric MEAN		2.6		Geometeric MEAN		55	

TRACE METALS DATA - STATION SITE SELECTED : KR-68 , Kankakee River , SR 55, Shelby , Newton County ATTACHMENT 3

Beryllium (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		0.0255	0.0255
7/10/2002	S		0.0214	0.0214
10/23/2002	S	L	0.033	0.0236
5/20/2003	S		0.0234	0.0234
8/19/2003	S		0.0203	0.0203
11/19/2003	S		0.0169	0.0169
2/24/2004	W	L	0.033	0.0236
9/8/2004	S		0.0461	0.0461
10/21/2004	S	L	0.033	0.0236
3/10/2005	W		0.0144	0.0144
06/23/05	S		0.0336	0.0336
9/1/2005	S		0.0159	0.0159
12/8/2005	W	L	0.033	0.0236
3/16/2006	W		0.144	0.1440

Manganese (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		125	
7/10/2002	S		146	
10/23/2002	S		80	
5/20/2003	S		201	
8/19/2003	S		130	
11/19/2003	S		138	
2/24/2004	W		113	
9/8/2004	S		278	
10/21/2004	S		102	
3/10/2005	W		116	
6/23/2005	S		241	
9/1/2005	S		186	
12/8/2005	W		140	
3/16/2006	W		371	

Nickel (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		2.46	
7/10/2002	S		2.51	
10/23/2002	S		2.01	
5/20/2003	S		3.37	
8/19/2003	S		2.45	
11/19/2003	S		1.87	
2/24/2004	W		1.96	
9/8/2004	S		4.16	
10/21/2004	S		3.17	
3/10/2005	W		3.51	
6/23/2005	S		2.59	
9/1/2005	S		2.82	
12/8/2005	W		3.03	
3/16/2006	W		6.7	

Selenium (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		0.9	0.9
7/10/2002	S	L	0.9	0.45
10/23/2002	S	L	0.9	0.45
5/20/2003	S	L	0.9	0.45
8/19/2003	S	L	0.9	0.45
11/19/2003	S	L	0.9	0.45
2/24/2004	W		0.4	0.4
9/8/2004	S	L	0.9	0.45
10/21/2004	S	L	0.9	0.45
3/10/2005	W		0.7	0.7
6/23/2005	S		0.5	0.5
9/1/2005	S		1.1	1.1
12/8/2005	W		1.1	1.1
3/16/2006	W		0.9	0.9

Beryllium (Total) (ug/L) MF For Lab Data	0.7	Lab Test	Corrected Lab Result
Samples	4	14	14
Minimum		0.0	0.0
Average		0.0	0.0
Maximum		0.1	0.1
STD_Deviation		0.0	0.0
CV		0.9	1.0
Geometeric MEAN		0.029	0.026

Manganese (Total) (ug/L) MF For Lab Data	Lab Test	Corrected Lab Result
Samples	14	
Minimum	80.0	
Average	169.1	
Maximum	371.0	
STD_Deviation	80.1	
CV	0.5	
Geometeric MEAN	155	

Nickel (Total) (ug/L) MF For Lab Data	Lab Test	Corrected Lab Result
Samples	14	
Minimum	1.9	
Average	3.0	
Maximum	6.7	
STD_Deviation	1.2	
CV	0.4	
Geometeric MEAN	2.9	

Selenium (Total) (ug/L) MF For Lab Data	0.5	Lab Test	Corrected Lab Result
Samples	7	14	14
Minimum		0.4	0.4
Average		0.9	0.6
Maximum		1.1	1.1
STD_Deviation		0.2	0.3
CV		0.2	0.4
Geometeric MEAN		0.8	0.6

TRACE METALS DATA - STATION SITE SELECTED : KR-68 , Kankakee River , SR 55, Shelby , Newton County ATTACHMENT 3

Silver (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Thallium (Total) (ug/L) Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Sample Date	Season	<	Trace Metal Data	Corrected Trace Data	Sample Date	Season	<	Trace Metal Data	Corrected Trace Data
4/24/2002	W		0.0079	0.0079	4/24/2002	W		0.0269	0.0269										
07/10/02	S		0.01	0.01	7/10/2002	S		0.029	0.029										
10/23/2002	S	L	0.014	0.011	10/23/2002	S		0.0121	0.0121										
5/20/2003	S		0.0144	0.0144	5/20/2003	S		0.0287	0.0287										
8/19/2003	S		0.0146	0.0146	8/19/2003	S		0.0246	0.0246										
11/19/2003	S		0.0101	0.0101	11/19/2003	S		0.0131	0.0131										
2/24/2004	W		0.0113	0.0113	2/24/2004	W		0.0094	0.0094										
9/3/2004	S		0.0198	0.0198	9/8/2004	S		0.031	0.031										
10/21/2004	S	L	0.014	0.011	10/21/2004	S		0.0089	0.0089										
3/10/2005	W		0.0086	0.0086	03/10/05	W		0.0174	0.0174										
6/23/2005	S		0.0175	0.0175	6/23/2005	S		0.0301	0.0301										
9/1/2005	S		0.0053	0.0053	9/1/2005	S		0.0237	0.0237										
12/8/2005	W	L	0.014	0.011	12/8/2005	W	L	0.017	0.016										
3/16/2006	W		0.024	0.024	3/16/2006	W		0.0665	0.0665										

Silver (Total) (ug/L)			Corrected	Thallium (Total) (ug/L)			Corrected
MF For Lab Data	0.8	Lab Test	Lab Result	MF For Lab Data	0.8	Lab Test	Lab Result
Samples	3	14	14	Samples	7	14	14
Minimum		0.0053	0.0053	Minimum		0.0089	0.0089
Average		0.013	0.013	Average		0.024	0.024
Maximum		0.024	0.024	Maximum		0.0665	0.0665
STD_Deviation		0.005	0.005	STD_Deviation		0.015	0.015
CV		0.4	0.4	CV		0.6	0.6
Geometeric MEAN		0.012	0.012	Geometeric MEAN		0.021	0.021

ATTACHMENT 4 (DOWN STREAM STATION)

STATION SITE SELECTED : KR-68 , Kankakee River , SR 55 Bridge 1 Mile S of Shelby , Newton County

Hardness (mg/l)				Corrected	Chloride (mg/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
11/6/2002	S		392		11/6/2002	S		40	
12/12/2002	W		348		12/12/2002	W		32	
3/5/2003	W		352		3/5/2003	W		32	
4/16/2003	W		375		4/16/2003	W		35	
5/1/2003	S		342		5/1/2003	S		28	
6/18/2003	S		366		6/18/2003	S		32	
7/9/2003	S		298		7/9/2003	S		23	
8/6/2003	S		323		8/6/2003	S		26	
9/15/2003	S		352		9/15/2003	S		36	
10/1/2003	S		317		10/1/2003	S		27	
11/3/2003	S		330		11/3/2003	S		29	
12/17/2003	W		363		12/17/2003	W		30	
1/7/2004	W		335		1/7/2004	W		33	
2/23/2004	W		323		2/23/2004	W		41	
3/4/2004	W		313		3/4/2004	W		33	
4/1/2004	W		327		4/1/2004	W		32	
5/26/2004	S		306		5/26/2004	S		27	
6/28/2004	S		325		6/28/2004	S		26	
7/26/2004	S		290		7/26/2004	S		27	
8/10/2004	S		340		8/10/2004	S		29	
9/2/2004	S		313		9/2/2004	S		25	
10/14/2004	S		384		10/14/2004	S		34	
11/10/2004	S		338		11/10/2004	S		27	
12/7/2004	W		326		12/7/2004	W		27	
1/18/2005	W		200		1/18/2005	W		20	
2/1/2005	W		351		2/1/2005	W		26	
3/8/2005	W		271		3/8/2005	W		28	
4/18/2005	W		316		4/18/2005	W		29	
5/4/2005	S		303		5/4/2005	S		26	
6/7/2005	S		284		6/7/2005	S		25	
6/30/2005	S		334		6/30/2005	S		26	
8/8/2005	S		349		8/8/2005	S		37	
9/19/2005	S		342		9/19/2005	S		34	
10/11/2005	S		313		10/11/2005	S		29	
11/2/2005	S		346		11/2/2005	S		37	
12/6/2005	W		377		12/6/2005	W		37	
1/3/2006	W		362		1/3/2006	W		35	
2/15/2006	W		334		2/15/2006	W		31	
3/8/2006	W		337		3/8/2006	W		29	
4/6/2006	W		352		4/6/2006	W		29	
5/1/2006	S		331		5/1/2006	S		29	
6/1/2006	S		355		6/1/2006	S		30	
7/11/2006	S		371		7/11/2006	S		36	
8/3/2006	S		348		8/3/2006	S		30	
9/28/2006	S		401		9/28/2006	S		28	
10/12/2006	S		346		10/12/2006	S		31	
11/8/2006	S		374		11/8/2006	S		27	
12/28/2006	W		305		12/28/2006	W		26	

ATTACHMENT 4 (DOWN STREAM STATION)

STATION SITE SELECTED : KR-68 , Kankakee River , SR 55 Bridge 1 Mile S of Shelby , Newton County

Hardness (mg/l)				Corrected	Chloride (mg/L)				Corrected
Sample Date	Season	<	Lab Test	Lab Result	Sample Date	Season	<	Lab Test	Lab Result
1/11/2007	W		361		1/11/2007	W		25	
2/1/2007	W		368		2/1/2007	W		24	
3/1/2007	W		362		3/1/2007	W		35	
4/23/2007	W		268		4/23/2007	W		26	
5/7/2007	S		257		5/7/2007	S		28	
6/18/2007	S		385		6/18/2007	S		28	
7/19/2007	S		310		7/19/2007	S		33	
8/6/2007	S		236		8/6/2007	S		26	
9/27/2007	S		252		9/27/2007	S		29	
10/2/2007	S		301		10/2/2007	S		31	
11/1/2007	S		299		11/1/2007	S		29	
12/6/2007	W		381		12/6/2007	W		26	
Hardness (mg/l)					Chloride (mg/L)				
MF For Lab Data			Lab Test	Lab Result	MF For Lab Data			Lab Test	Lab Result
Samples			60		Samples			60	
Minimum			200		Minimum			20	
Average			331		Average			30	
Maximum			401		Maximum			41	
STD_Deviation			39		STD_Deviation			4.4	
CV			0.1		CV			0.1	
Percentile	50%		336		Percentile	50%		29	

ATTACHMENT 5

Calculation of Preliminary Effluent Limitations for Discharges in the Non-Great Lakes System (Excluding Discharges to the Ohio River)

General Information	
Facility Name:	NIPSCO Rollin M. Schahfer Generating Station
County:	Jasper
NPDES Number:	IN0033201
WLA Number:	001668
WLA Report Date:	6/18/2020
Outfall:	001
Receiving Stream:	Kankakee River

Receiving Stream Questions (Yes or No)	
Acute Mixing Zone Allowed?	No
Public Water System (PWS) Intake Downstream?	No
Industrial Water Supply (IWS) Intake Downstream?	No
Interstate Wabash River Discharge?	No
Put-and-Take Trout Fishing?	No
Fish Early Life Stages Present?	Yes

Effluent Flow		
	=	33.6 mgd

Receiving Stream Design Flows		
Q7,10 (Outfall)	=	294 cfs
Q7,10 (Public Water System Intake)	=	cfs
Q7,10 (Industrial Water Supply Intake)	=	cfs
Q30,10 (Outfall)	=	331 cfs
Q30 (Outfall)	=	3160 cfs
Q30 (Public Water System Intake)	=	cfs

Ambient Downstream Water Quality Characteristics		
Hardness (50th percentile)	=	206 mg/l
Chloride (50th percentile)	=	29 mg/l
pH (90th percentile)	=	s.u.
Acute Ammonia-N		
Summer pH (75th percentile)	=	s.u.
Winter pH (75th percentile)	=	s.u.
Chronic Ammonia-N		
Summer Temperature (75th percentile)	=	C
Summer pH (75th percentile)	=	s.u.
Winter Temperature (75th percentile)	=	C
Winter pH (75th percentile)	=	s.u.

Mixing Zone Dilution				
Dilution Factor (for acute mixing zone)	=			
		Dilution Fraction	Flow	Location
Chronic Aquatic Life (Except Ammonia)	=	50%	Q7,10	Outfall
Chronic Aquatic Life (Ammonia Only)	=	50%	Q30,10	Outfall
Chronic WET	=	25%	Q7,10	Outfall
Human Noncancer Drinking Water	=	100%	Q7,10	PWS Intake
Human Noncancer Nondrinking Water	=	50%	Q7,10	Outfall
Human Cancer Drinking Water	=	100%	Q50	PWS Intake
Human Cancer Nondrinking Water	=	25%	Q50	Outfall
Public Water Supply	=	100%	Q7,10	PWS Intake
Industrial Water Supply	=	100%	Q7,10	PWS Intake

Metals Translators (dissolved to total recoverable)		
	Acute	Chronic
Aluminum	1.000	1.000
Antimony	1.000	1.000
Arsenic	1.000	1.000
Barium	1.000	1.000
Beryllium	1.000	1.000
Cadmium	0.893	0.858
Chromium III	0.316	0.860
Cobalt	1.000	1.000
Copper	0.960	0.960
Iron	1.000	1.000
Lead	0.614	0.614
Manganese	1.000	1.000
Molybdenum	1.000	1.000
Nickel	0.998	0.997
Silver	0.85	
Strontium	1.000	1.000
Thallium	1.000	1.000
Tin	1.000	1.000
Titanium	1.000	1.000
Vanadium	1.000	1.000
Zinc	0.978	0.986

Source of Criteria [1]							Ambient Upstream Conc. (Outfall) (ug/l)	Ambient Upstream Conc. (Intake) (ug/l)	Remove Mixing Zone? (Yes or Blank)	Sample/ Month	CV	Facility Specific CV? (Yes or No)	CAS Number	Parameters[2]	Indiana Water Quality Criteria for the Non-Great Lakes System (ug/l)							Preliminary Effluent Limitations					
A	B	C	D	E	F	G									A	B	C	D	E	F	G						
															Aquatic Life Criteria		Human Health Noncancer Criteria		Human Health Cancer Criteria		Add. PWS Criteria	Concentration (ug/l)[3]		Mass (lbs/day)		Criteria Type [4]	Basis
															Acute (AAC)	Chronic (CAC)	Drinking (HNC-D)	Nondrinking (HNC-N)	Drinking (HCC-D)	Nondrinking (HCC-N)	(PWS)	Average	Maximum	Average	Maximum		
7	7	3	8				268			1	0.6	No	7429905	Aluminum								170	290	31	52	SSC	CAC[9]
8	8	1	1			8	0.35			1	0.6	No	7440360	Antimony	987	174	970	4520				430	710	78	128	SV[8]	CAC[9]
1	1	8				8	2.9			1	0.6	No	7440382	Arsenic [5][5]	720	80	146	45000			6	490	720	88	130	Tier I	AAC
8	8	1	8			8	55			1	0.6	No	7440393	Barium [7]	360	190	5				10	6200	9100	1118	1640	SV[8]	AAC
8	8	8	8	1	1	8	0.026			1	0.6	No	7440417	Beryllium [5][7]	4329.68	1587.49	1000	160000			2000	6200	9100	1118	1640	SV[8]	AAC
1	1	1	8			8	0.5			1	0.6	No	7440439	Cadmium [5][7]	461.12	51.30	40	300	0.068	1.17	4	11	26	2	4.7	Tier I	HCC-N[9]
1	1	1	1			8	0.7			1	0.6	No	16065831	Chromium (III) [7]	13.75	2.52	10	1460			5	14	22	2.5	4	Tier I	CAC[9]
1	1	1	8				0			1	0.6	No	18540299	Chromium (VI)	148	480	170000	3433000			100	3012.35	4948.13	542.96	891.91	Tier I	CAC[9]
												No	7440473	Total Chromium	15.71	10.58	50	29000				22	31	4	5.6	Tier I	AAC
8	8	8	8				6.7			1	0.6	No	7440484	Cobalt								3000	5000	541	901	Tier I	CAC[9]
1	1	8	8				1.6			1	0.6	No	7440508	Copper [7]	130	19	140	11000				190	260	18	39	SV[8]	CAC[9]
7	7						901			1	0.6	No	7439896	Iron	55.31	31.97	280	56000				76	319	14	70	Tier I	AAC
1	1	1	8				0.6			1	0.6	No	7439921	Lead [5][7]	2744	2693						3800	5500	685	991	SSC	AAC
8	8	8	8				156			1	0.6	No	7439965	Manganese [7]	214.65	9.14	50	100				78	130	14	23	Tier I	CAC[9]
1	1	1	1			8	-		Yes	1	0.6	No	7439976	Mercury[6]	3300	1534	1300	39000				4500	6600	811	1192	SV[8]	AAC
5	6	8	8				10			1	0.6	No	7439987	Molybdenum	0.4	0.012	0.14	0.13			2	0.012	0.02	0.0022	0.0036	Tier I	CAC[9]
1	1	1	1				2			1	0.6	No	7440020	Nickel [7]	84000	1800	320	13000				20000	34000	3605	6129	Tier II	CAC[9]
1	1	1	8			8	0.6			1	0.6	No	7782492	Selenium	3945.06	438.34	13.4	100				530	1300	95	234	Tier I	HNC-N[9]
		1	8				0.012			4	0.6	No	7440224	Silver [7]	130	35	10	3400			50	190	260	32	47	Tier I	AAC
6	6	1	1			8	0.021			1	0.6	No	7440280	Thallium	13.87	-	50	36000				16	33	2.9	5.9	Tier I	AAC
8	8						7.5			1	0.6	No	7440315	Tin	86	35	13	48			2	120	190	22	31	Tier II	AAC
8	8						8.6			1	0.6	No	7440328	Titanium	1600	180						940	1500	169	270	SV[8]	CAC[9]
1	1	1	8				23			4	0.6	No	7440666	Zinc [7]	23000	2500						13000	22500	2343	3966	SV[8]	CAC[9]
5	5	8	8				190			1	0.6	No	7440428	Boron	319.58	291.82	9000	250000				330	650	59	117	Tier I	AAC
1	1					8	0			4	0.6	No	57125	Cyanide, Free	26000	8800	1900	160000				41000	60000	7390	10815	Tier I	AAC
		1	8				0			4	0.6	No	57125	Cyanide, Total	22	5.2					200	22	44	4	7.9	Tier I	AAC
	2					1	77000			4	9.6	No	14808798	Sulfate [7]			200,000	48000				250000	450000	45085	113559	SV[8]	HNC-N[9]
																200,000					250000	8600000	17000000	1590167	3064284	Tier I	SMR

[1] Source of Criteria
1) Indiana numeric water quality criterion in 327 IAC 2-1-6(a)(2), Table 6-1, or in 327 IAC 2-1-6(g).
2) "Shall not exceed" (SNE) criterion in 327 IAC 2-1-6(a)(2); Table 6-1 or 327 IAC 2-1-6(a)(3). The criterion is viewed as a 4-day average criterion and is implemented in the same manner as the chronic aquatic life criterion.
3) Industrial water supply (IWS) criterion in 327 IAC 2-1-6(a)(4); Table 6-1 or 327 IAC 2-1-6(a)(5). The criterion is viewed as a 4-day average criterion and is implemented in the same manner as the chronic aquatic life criterion.
4) Acute (1-hour average) and chronic (30-day average) criteria for total ammonia nitrogen is "1999 Update of Ambient Water Quality Criteria for Ammonia," EPA-822-R-99-014, December 1999.
5) Tier I criterion derived using the methodology in 327 IAC 2-1-6.3 or 327 IAC 2-1-6.3 when the Method I data set is available, or using the methodology in 327 IAC 2-1-6.4, 327 IAC 2-1-6.5 or 327 IAC 2-1-6.6.
6) Tier II criterion derived using the methodology in 327 IAC 2-1-6.3 or 327 IAC 2-1-6.3 when the Method I data set is not available.
7) Site-specific water quality criterion (SSC) in 327 IAC 2-1-6.9, Table 6-3-1 or developed under 327 IAC 2-1-6.8.
8) Screening value (SV).
9) Numeric interpretation of narrative criterion for toxicity using U.S. EPA recommended water quality criteria for whole effluent toxicity (WET).
[2] The "chronic life criteria and screening values for chromium are for the form of dissolved metal. The values for all the metals are in the form of total recoverable metal.
The human health criteria and screening values and the public water supply screening value for all the metals are in the form of total recoverable metal.
[3] The preliminary effluent limitations (PELs) for the metals are in the form of total recoverable metal (with the exception of Chromium (VI) which is in the form of dissolved metal).
[4] See the table "Indiana Water Quality Criteria for the Non-Great Lakes System" for information on the type and source of criteria.
[5] The above-noted substances are pesticide or known human carcinogens.
[6] The above-noted substances are bioaccumulative chemicals of concern (BCCs). Beginning January 1, 2004, the water quality criteria for a BCC shall be applied directly to the undiluted discharge for all discharges of a BCC.
To apply the water quality criteria for a BCC directly to the undiluted discharge, enter "Yes" in the "Mixing Using Zone" column.
[7] The above-noted substances have a criterion that is a function of the effluent chemistry. See the table "Indiana Water Quality Criteria for the Non-Great Lakes System" for information on the criterion equation.
[8] Limits based on screening values (as indicated by SV) ARE NOT to be used as water quality-based effluent limitations. These are solely to be used as preliminary effluent limitations.
[9] The monthly average PEL was set equal to the most stringent WLA because the calculated monthly average PEL exceeded the most stringent WLA and a facility-specific CV was not determined.

Last revised: July 15, 2009

ATTACHMENT 6 MRO Data

For NIPSCO Rollin M. Schahfer Generating Station in Jasper County

DATE		Silver (mg/l) Daily	Silver (mg/l) Monthly	DATE		Zinc (mg/l) Daily	Zinc (mg/l) Monthly	Sulfate (mg/l) Daily	Sulfate (mg/l) Monthly	Cyanide (mg/l) Daily	Cyanide (mg/l) Monthly	DATE		Chromium (mg/l) Daily	Chromium (mg/l) Monthly	Mercury (ng/l) Daily	Mercury (ng/l) Monthly	DATE
1/5/2005	<	0.010	0.0100	1/5/2005		0.21	0.21	630	630	0.005	0.005	1/5/2005	<	0.003	0.0030	1.75		10/6/2005
2/3/2005	<	0.010	0.0100	2/3/2005		0.300	0.300	590	590	0.0058	0.006	2/3/2005	<	0.003	0.0030	11.2		12/7/2005
3/9/2005	<	0.010	0.0100	3/9/2005		0.290	0.290	700	700	0.005	0.005	3/9/2005	<	0.003	0.0030	9.01		2/7/2006
4/3/2005	<	0.010	0.0100	4/3/2005		0.24	0.24	490	490	0.005	0.005	4/3/2005	<	0.003	0.0030	12.8		4/7/2006
5/9/2005	<	0.010	0.0100	5/9/2005		0.130	0.130	740	740	0.0077	0.008	6/10/2005	<	0.003	0.0030	0.50		6/9/2006
6/10/2005	<	0.010	0.0100	6/10/2005		0.084	0.084	840	840	0.011	0.011	7/1/2005	<	0.003	0.0030	0.787		8/10/2006
7/1/2005	<	0.010	0.0100	7/1/2005		0.072	0.072	680	680	0.005	0.005	8/4/2005	<	0.003	0.0030	3.40		10/6/2006
8/4/2005	<	0.010	0.0100	8/4/2005		0.092	0.092	590	590	0.005	0.005	9/1/2005	<	0.003	0.0030	3.43		12/8/2006
9/1/2005	<	0.010	0.0100	9/1/2005		0.087	0.087	648	648	0.006	0.006	10/3/2005	<	0.003	0.0030	8.05		2/16/2007
10/3/2005	<	0.010	0.0100	10/3/2005		0.057	0.057	440	440	0.005	0.005	11/3/2005	<	0.003	0.0030	4.0		4/12/2007
11/3/2005	<	0.010	0.0100	11/3/2005		0.056	0.056	495	495	0.005	0.005	12/9/2005	<	0.003	0.0030	3.15		6/14/2007
12/9/2005	<	0.010	0.0100	12/9/2005		0.062	0.062	872	872	0.005	0.005	1/4/2006	<	0.003	0.0030	4.20		8/9/2007
1/4/2006	<	0.010	0.0100	1/4/2006		0.13	0.13	429	429	0.005	0.005	2/3/2006	<	0.003		4.16		10/16/2007
2/3/2006	<	0.010		2/3/2006		0.15		340		0.005		2/22/2006	<	0.003		8.67		12/19/2007
2/22/2006	<	0.010		2/22/2006		0.18		278		0.005		2/28/2006	<	0.003	0.0030	16.5		2/22/2008
2/28/2006	<	0.010	0.0100	2/28/2006		0.17	0.1667	373	330	0.0064	0.005	3/9/2006	<	0.003		7.27		4/15/2008
3/9/2006	<	0.010		3/9/2006		0.160		303		0.005		3/14/2006	<	0.003		7.15		6/19/2008
3/14/2006	<	0.010		3/14/2006		0.170		400		0.01		3/22/2006	<	0.003	0.0030	8.38		8/13/2008
3/22/2006	<	0.010	0.0100	3/22/2006		0.120	0.1500	420	374	0.013	0.009	4/5/2006	<	0.003		6.79		10/15/2008
4/5/2006	<	0.010		4/5/2006		0.083		335				4/12/2006	<	0.003				
4/12/2006	<	0.010		4/12/2006		0.061		430		0.006		4/23/2006	<	0.003	0.0030			
4/23/2006	<	0.010	0.0100	4/23/2006		0.056	0.0667	347	371	0.005	0.006	5/5/2006	<	0.003				
5/5/2006	<	0.010		5/5/2006		0.022		255		0.017		5/7/2006	<	0.003				
5/7/2006	<	0.010		5/7/2006		0.028		280		0.009		5/15/2006	<	0.003				
5/15/2006	<	0.010		5/15/2006		0.027		582		0.012		5/23/2006	<	0.003				
5/23/2006	<	0.010		5/23/2006		0.034		271		0.006		5/29/2006	<	0.003	0.0030			
5/29/2006	<	0.010	0.0100	5/29/2006	<	0.020	0.0262	326	343	0.005	0.010	6/8/2006	<	0.003				
6/8/2006	<	0.010		6/8/2006		0.033		272		0.005		6/26/2006	<	0.003	0.0030			
6/14/2006	<	0.010		6/14/2006		0.042		302		0.005		7/7/2006	<	0.003				
6/21/2006	<	0.010		6/21/2006		0.038		316		0.0078		7/14/2006	<	0.003				
6/26/2006	<	0.010	0.0100	6/26/2006		0.110	0.0558	588	370	0.005	0.006	7/24/2006	<	0.003	0.0030			
7/7/2006	<	0.010		7/7/2006		0.082						8/1/2006	<	0.003				
7/14/2006	<	0.010		7/14/2006		0.028						8/18/2006	<	0.003				
7/19/2006	<	0.010		7/19/2006		0.037						8/29/2006	<	0.003	0.0030			
7/24/2006	<	0.010	0.0100	7/24/2006	<	0.020	0.0418					9/8/2006		0.0032				
8/1/2006	<	0.010		8/1/2006		0.038		275		0.005		9/13/2006	<	0.003				
8/8/2006	<	0.010		8/8/2006	<	0.020		310		0.005		9/18/2006	<	0.003	0.0031			
8/18/2006	<	0.010		8/18/2006	<	0.020		295		0.005		10/3/2006		0.0056				
8/22/2006	<	0.010		8/22/2006		0.042		414		0.0056		10/20/2006	<	0.003				
8/29/2006	<	0.010	0.0100	8/29/2006		0.036	0.0312	375	334	0.005	0.005	10/24/2006		0.0031	0.0039			

ATTACHMENT 6 MRO Data

For NIPSCO Rollin M. Schahfer Generating Station in Jasper County

DATE	Silver (mg/l)			DATE	Zinc (mg/l)			Sulfate (mg/l)			Cyanide (mg/l)			DATE	Chromium (mg/l)			Mercury (ng/l)		DATE
		Daily	Monthly			Daily	Monthly		Daily	Monthly		Daily	Monthly			Daily	Monthly	Daily	Monthly	
9/8/2006	<	0.010		9/8/2006		0.052			320			0.005		11/1/2006	<	0.003				
9/13/2006	<	0.010		9/13/2006		0.022			319			0.005		11/10/2006	<	0.003				
9/18/2006	<	0.010	0.0100	9/18/2006	<	0.020	0.0313		306	315		0.005	0.005	11/17/2006	<	0.003				
10/3/2006	<	0.010		10/3/2006	<	0.020			392			0.012		11/21/2006	<	0.003	0.0030			
10/12/2006	<	0.010		10/12/2006	<	0.020			364			0.012		12/6/2006	<	0.003	0.0030			
10/20/2006	<	0.010		10/20/2006	<	0.020			314			0.005		1/11/2007	<	0.003	0.0030			
10/24/2006	<	0.010	0.0100	10/24/2006	<	0.020	0.0200		321	348		0.0079	0.009	2/9/2007	<	0.003	0.0030			
11/1/2006	<	0.010		11/1/2006	<	0.020			342			0.005		3/13/2007	<	0.001	0.0010			
11/10/2006	<	0.010		11/10/2006		0.036			304			0.0056		4/9/2007	<	0.001				
11/17/2006	<	0.010		11/17/2006	<	0.020			274			0.0073		4/30/2007	<	0.001	0.0010			
11/21/2006	<	0.010	0.0100	11/21/2006	<	0.020	0.0240		301	305		0.014	0.008	5/8/2007	<	0.001	0.0010			
12/6/2006	<	0.010		12/6/2006		0.027			374			0.005		6/4/2007	<	0.001				
12/10/2006	<	0.010		12/10/2006		0.120			330			0.005		6/13/2007		0.0034	0.0022			
12/19/2006	<	0.010	0.0100	12/19/2006		0.020	0.0557		313	339		0.0052	0.005	7/3/2007		0.0012				
1/11/2007	<	0.010	0.0100	1/11/2007		0.085	0.0850		374	374		0.005	0.005	7/11/2007	<	0.001				
2/9/2007	<	0.010		2/9/2007		0.13			431			0.005		7/19/2007	<	0.0020				
2/15/2007	<	0.010		2/15/2007		0.14			398			0.005		7/23/2007	<	0.001				
2/21/2007	<	0.010		2/21/2007		0.11			447			0.005		7/31/2007	<	0.001	0.0012			
2/26/2007	<	0.010	0.0100	2/26/2007		0.12	0.1250		415	423		0.0069	0.005	8/8/2007	<	0.001				
3/13/2007	<	0.001		3/13/2007		0.096			475			0.0076		8/13/2007	<	0.001				
3/19/2007	<	0.001	0.0010	3/19/2007		0.089	0.0925		480	478		0.005	0.006	8/28/2007	<	0.001	0.0010			
4/9/2007	<	0.001		4/9/2007		0.070			438			0.005		9/12/2007	<	0.003				
4/17/2007	<	0.001		4/17/2007		0.078			491			0.005		9/28/2007	<	0.003	0.0023			
4/30/2007	<	0.001	0.0010	4/30/2007		0.057	0.0683		544	491		0.005	0.005	10/2/2007	<	0.003	0.0030			
5/8/2007	<	0.001		5/8/2007		0.031			644			0.0078		11/1/2007	<	0.003	0.0030			
5/16/2007	<	0.001		5/16/2007		0.019			488			0.005		12/13/2007	<	0.003	0.0030			
5/24/2007	<	0.001	0.0010	5/24/2007		0.013	0.0210		515	549		0.005	0.006	1/10/2008	<	0.003	0.0030			
6/4/2007	<	0.001		6/4/2007		0.0093			396			0.005		2/11/2008	<	0.003	0.0030			
6/13/2007	<	0.001		6/13/2007		0.0140			446			0.012		3/4/2008	<	0.003	0.0030			
6/26/2007	<	0.001	0.0010	6/26/2007		0.0120	0.0118		493	445		0.0062	0.008	4/2/2008	<	0.003	0.0030			
7/3/2007	<	0.001		7/3/2007		0.012			310					5/4/2008	<	0.003	0.0030			
7/11/2007	<	0.001		7/11/2007		0.010								6/18/2008	<	0.003	0.0030			
7/19/2007	<	0.001		7/19/2007		0.007								7/3/2008	<	0.003	0.0030			
7/23/2007	<	0.001		7/23/2007		0.005								8/6/2008	<	0.003	0.0030			
7/31/2007	<	0.001	0.0010	7/31/2007	<	0.005	0.0077			310				9/2/2008		0.0047				
8/8/2007	<	0.001		8/8/2007		0.0082			307			0.005		9/11/2008	<	0.003	0.0039			
8/13/2007	<	0.001		8/13/2007	<	0.005			464			0.005		10/8/2008	<	0.003	0.0030			
8/20/2007	<	0.001		8/20/2007	<	0.005			418			0.005								
8/28/2007	<	0.001	0.0010	8/28/2007		0.0078	0.0065		392	395		0.005	0.005							

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For NIPSCO Rollin M. Schahfer Generating Station in Jasper County

DATE	Silver (mg/l)		DATE	Zinc (mg/l)		Sulfate (mg/l)		Cyanide (mg/l)		DATE	Chromium (mg/l)		Mercury (mg/l)		DATE
	Daily	Monthly		Daily	Monthly	Daily	Monthly	Daily	Monthly		Daily	Monthly	Daily	Monthly	
9/12/2007	< 0.010		9/12/2007	< 0.020		309		0.011							
9/20/2007	< 0.010		9/20/2007	< 0.020		444		0.005							
9/28/2007	< 0.010	0.0100	9/28/2007	< 0.020	0.0200	428	394	0.005	0.007						
10/2/2007	< 0.010		10/2/2007	< 0.020		427		0.005							
10/11/2007	< 0.010		10/11/2007	< 0.020		341		0.0099							
10/18/2007	< 0.010		10/18/2007	< 0.020		341		0.008							
10/25/2007	< 0.010	0.0100	10/25/2007	< 0.020	0.0200	298	352	0.0097	0.008						
11/1/2007	< 0.010		11/1/2007	< 0.020		449		0.0061							
11/12/2007	< 0.010		11/12/2007	< 0.020		610		0.005							
11/21/2007	< 0.010		11/21/2007	< 0.020		514		0.01							
11/28/2007	< 0.010	0.0100	11/28/2007	< 0.020	0.0200	494	517	0.005	0.007						
12/13/2007	< 0.010		12/13/2007	< 0.022		295		0.005							
12/18/2007	< 0.010		12/18/2007	< 0.020		418		0.005							
12/28/2007	< 0.010	0.0100	12/28/2007	< 0.024	0.0220	433	382	0.005	0.005						
1/10/2008	< 0.010		1/10/2008	< 0.036		426		0.005							
1/14/2008	< 0.010		1/14/2008	< 0.031		488		0.0071							
1/29/2008	< 0.010	0.0100	1/29/2008	< 0.045	0.0373	520	478	0.005	0.006						
2/11/2008	< 0.010		2/11/2008	< 0.035		495		0.005							
2/19/2008	< 0.010	0.0100	2/19/2008	< 0.035	0.0350	482	489	0.0052	0.005						
3/4/2008	< 0.010		3/4/2008	< 0.037		354		0.005							
3/10/2008	< 0.010		3/10/2008	< 0.037		554		0.005							
3/26/2008	< 0.010	0.0100	3/26/2008	< 0.023	0.0323	365	424	0.005	0.005						
4/2/2008	< 0.010		4/2/2008	< 0.026		490		0.005							
4/11/2008	< 0.010		4/11/2008	< 0.020		351		0.005							
4/15/2008	< 0.010		4/15/2008	< 0.020		433		0.005							
4/25/2008	< 0.010		4/25/2008	< 0.049		470		0.005							
4/29/2008	< 0.010	0.0100	4/29/2008	< 0.030	0.0290	491	447	0.005	0.005						
5/4/2008	< 0.010		5/4/2008	< 0.029		654		0.019							
5/13/2008	< 0.010		5/13/2008	< 0.040		628		0.017							
5/27/2008	< 0.010	0.0100	5/27/2008	< 0.020	0.0297	352	545	0.005	0.014						
6/3/2008	< 0.010		6/3/2008	< 0.020		370		0.005							
6/10/2008	< 0.010		6/10/2008	< 0.020		346		0.005							
6/18/2008	< 0.010		6/18/2008	< 0.020		326		0.005							
6/30/2008	< 0.010	0.0100	6/30/2008	< 0.023	0.0208	319	340	0.005	0.005						
7/3/2008	< 0.010		7/3/2008	< 0.033		580		0.005							
7/8/2008	< 0.010		7/8/2008	< 0.032		382		0.005							
7/16/2008	< 0.010		7/16/2008	< 0.020		458		0.005							
7/21/2008	< 0.010		7/21/2008	< 0.020		522		0.005							
7/30/2008	< 0.010	0.0100	7/30/2008	< 0.020	0.0250	289	446	0.005	0.005						

ATTACHMENT 6 MRO Data

For NIPSCO Rollin M. Schahfer Generating Station in Jasper County

DATE	Silver (mg/l)			DATE	Zinc (mg/l)			Sulfate (mg/l)			Cyanide (mg/l)			DATE	Chromium (mg/l)		Mercury (ng/l)		DATE
		Daily	Monthly			Daily	Monthly		Daily	Monthly		Daily	Monthly			Daily	Monthly	Daily	Monthly	
8/6/2008	<	0.010		8/6/2008	<	0.020			476			0.005								
8/13/2008	<	0.010		8/13/2008	<	0.020			482			0.005								
8/22/2008	<	0.010		8/22/2008	<	0.020			502			0.005								
8/25/2008	<	0.010	0.0100	8/25/2008	<	0.020	0.0200		385	461		0.005	0.005							
9/2/2008	<	0.010		9/2/2008	<	0.020			466			0.005								
9/11/2008	<	0.010		9/11/2008	<	0.020			296			0.005								
9/18/2008	<	0.010		9/18/2008	<	0.020			284			0.005								
9/23/2008	<	0.010	0.0100	9/23/2008	<	0.020	0.0200		389	359		0.005	0.005							
10/8/2008	<	0.010		10/8/2008	<	0.020														
10/13/2008	<	0.010		10/13/2008	<	0.020														
10/20/2008	<	0.010		10/20/2008	<	0.020														
10/27/2008	<	0.010	0.0100	10/27/2008	<	0.020	0.0200													

	Silver (mg/l)		Zinc (mg/l)		Sulfate (mg/l)		Cyanide (mg/l)		Chromium (mg/l)		Mercury (ng/l)		
	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	
COUNT	130	46	130	46	118	44	116	43	77	45	19		COUNT
Average	0.009	0.009	0.050	0.071	427	470	0.006	0.006	0.003	0.003	6.38		Average
Maximum (mg/l)	0.010	0.010	0.300	0.300	872	872	0.019	0.014	0.006	0.004	16.5		Maximum (ng/
Maximum (ug/l)	10	10	300	300	872000	872000	19	14	5.6	3.9	0.0165		Maximum (ug/
Minimum	0.001	0.001	0.005	0.007	255	305	0.005	0.005	0.002	0.001	0.002		Minimum
STDEV	0.003	0.003	0.055	0.072	122	140	0.003	0.002	0.001	0.001	4.20		STDEV
CV	0.4	0.3	1.1	1.0	0.3	0.3	0.4	0.3	0.3	0.2	0.7		CV

ATTACHMENT 7 Permit Renewal Application Data

For NIPSCO Rollin M. Schafer Generating Station in Jasper County

Date	Aluminum, Total (mg/l)	Aluminum, Dissolved (mg/l)	Barium, Total (mg/l)	Boron, Total (mg/l)	Cobalt, Total (mg/l)	Iron, Total (mg/l)	Iron, Dissolved (mg/l)	Magnesium, Total (mg/l)	Molybdenum, Total (mg/l)	Manganese, Total (mg/l)	Tin, Total (mg/l)
February 27, 2007	0.062		0.13	12	0.0018	0.57		74	0.017	0.94	0.00012
June 14, 2007	0.074		0.16	14	0.0014	0.12			0.017	1.1	0.00023
September 13, 2007			0.14	11	0.0006	0.037			0.01	0.54	0.0036
October 16, 2007			0.14	9.8	0.0006	0.088			0.0069	0.72	0.0045
November 16, 2007			0.14	11	0.0006	0.25			0.011	0.75	0.0036
December 13, 2007											
December 15, 2007											
December 19, 2007			0.12	11	0.0006	0.34			0.014	0.59	0.0036
January 11, 2008			0.12	10	0.0006	0.4			0.015	0.55	0.0036
April 30, 2008			0.13	11	0.0006	0.39			0.031	0.86	0.0036
May 15, 2008			0.14	11	0.0006	0.36			0.028	0.88	0.0036
June 11, 2008			0.13	9.7	0.0006	0.12			0.026	0.50	0.0036
July 9, 2008	0.023	0.0096		9.1		0.26	0.041				
August 13, 2008	0.014	0.0035		8.6		0.096	0.021				
September 10, 2008	0.0061	0.0035		13		0.10	0.021				
October 17, 2008	0.0170	0.0053		7.5		0.28	0.13				
November 19, 2008	0.0180	0.0045		6.7		0.30	0.11				

	Aluminum, Total (mg/l)	Aluminum, Dissolved (mg/l)	Barium, Total (mg/l)	Boron, Total (mg/l)	Cobalt, Total (mg/l)	Iron, Total (mg/l)	Iron, Dissolved (mg/l)	Magnesium, Total (mg/l)	Molybdenum, Total (mg/l)	Manganese, Total (mg/l)	Tin, Total (mg/l)
COUNT	7	5	10	15	10	15	5	1	10	10	10
Average	0.031	0.005	0.135	10.360	0.0008	0.247	0.065	74	0.018	0.743	0.003
Maximum (mg/l)	0.074	0.010	0.160	14.000	0.0018	0.570	0.130	74	0.031	1.100	0.005
Maximum (ug/l)	74	10	160	14000	1.8	570	130	74000	31	1100	4.5
Minimum	0.006	0.004	0.120	6.700	0.001	0.037	0.021	74	0.007	0.500	0.000
STDEV	0.026	0.003	0.012	1.929	0.000	0.151	0.052		0.008	0.200	0.002
CV	0.6	0.6	0.1	0.2	0.5	0.6	0.6	0.6	0.5	0.3	0.5

ATTACHMENT 7 Permit Renewal Application Data

For NIPSCO Rollin M. Schafer Generating Station in Jasper County

Date	Titanium, Total (mg/l)	Antimony, Total (mg/l)	Arsenic, Total (mg/l)	Beryllium, Total (mg/l)	Cadmium, Total (mg/l)	Copper, Total (mg/l)	Copper, Dissolved (mg/l)	Lead, Total (mg/l)	Nickel, Total (mg/l)	Selenium, Total (mg/l)	Thallium, Total (mg/l)
February 27, 2007	0.0042	0.0024	0.0019	0.000053	0.000055	0.0094		0.0004	0.022	0.017	0.000037
June 14, 2007	0.0013	0.00056	0.0018	0.000053	0.000055	0.010		0.0002	0.016	0.012	0.00014
September 13, 2007	0.0057	0.0077	0.0025	0.00014	0.0003	0.028		0.020	0.012	0.0078	0.0043
October 16, 2007	0.0057	0.0077	0.005	0.00014	0.0007	0.022		0.0026	0.015	0.018	0.0043
November 16, 2007	0.0057	0.0077	0.0025	0.00014	0.0026	0.022		0.0035	0.016	0.014	0.0043
December 13, 2007											
December 15, 2007											
December 19, 2007	0.0057	0.0077	0.0025	0.00014	0.0003	0.018		0.012	0.018	0.019	0.0043
January 11, 2008	0.0057	0.0077	0.0025	0.00014	0.0012	0.022		0.0025	0.027	0.0053	0.0043
April 30, 2008	0.0057	0.0077	0.0088	0.00014	0.0003	0.025		0.0025	0.022	0.0053	0.0043
May 15, 2008	0.0057	0.0079	0.0025	0.00014	0.0003	0.017		0.0036	0.021	0.0089	0.0043
June 11, 2008	0.0057	0.0077	0.010	0.00014	0.0003	0.016		0.0075	0.0085	0.0053	0.015
July 9, 2008			0.0059	**Cu - value considerd as an outlier wrt to Cu (Dissolved), is not used in the analysis.**		**Total Cu = 0.17**	**0.015**			0.0054	
August 13, 2008			0.0044			0.016	0.00011			0.0061	
September 10, 2008			0.0053			0.015	0.013			0.010	
October 17, 2008			0.0034			0.012	0.01			0.0069	
November 19, 2008			0.0048			0.018	0.015			0.017	

	Titanium, Total (mg/l)	Antimony, Total (mg/l)	Arsenic, Total (mg/l)	Beryllium, Total (mg/l)	Cadmium, Total (mg/l)	Copper, Total (mg/l)	Copper, Dissolved (mg/l)	Lead, Total (mg/l)	Nickel, Total (mg/l)	Selenium, Total (mg/l)	Thallium, Total (mg/l)
COUNT	10	10	15	10	10	14	5	10	10	15	10
Average	0.005	0.006	0.004	0.00012	0.001	0.018	0.011	0.005	0.018	0.011	0.005
Maximum (mg/l)	0.006	0.008	0.010	0.00014	0.003	0.028	0.015	0.020	0.027	0.019	0.015
Maximum (ug/l)	5.7	7.9	10	0.14000	2.6	28	15	20	27	19	15
Minimum	0.001	0.001	0.002	0.00005	0.000	0.009	0.000	0.000	0.009	0.005	0.000
STDEV	0.001	0.003	0.002	0.00004	0.001	0.005	0.006	0.006	0.005	0.005	0.004
CV	0.3	0.4	0.6	0.3	1.3	0.3	0.6	1.1	0.3	0.5	0.9

ATTACHMENT 8

Reasonable Potential Statistical Procedure for Discharges in the Non-Great Lakes System (Excluding Discharges to the Ohio River)

Facility Name: NIPSCO Rollin M. Schahfer Generating St
NPDES Number: IN0053201
WLA Number: 001668
WLA Report Date: 6/18/2009
Outfall: 001
Receiving Stream: Kankakee River

		Monthly Average Determination							Daily Maximum Determination						
Parameters	Reasonable Potential to Exceed? (Yes or No)*	Maximum Monthly Average (ug/l)	Number of Monthly Averages	CV	MF	PEQ (ug/l)	PEL (ug/l)	PEQ > PEL?	Maximum Daily Sample (ug/l)	Number of Daily Samples	CV	MF	PEQ (ug/l)	PEL (ug/l)	PEQ > PEL?
Aluminum	No					150	170	No	74	7	0.6	2	150	290	No
Antimony	No					12	430	No	7.9	10	0.4	1.5	12	730	No
Arsenic III	No					15	490	No	10	15	0.6	1.5	15	720	No
Barium	No					180	6200	No	160	10	0.1	1.1	180	9100	No
Beryllium	No					0.18	11	No	0.14	10	0.3	1.3	0.18	26	No
Cadmium	No					7	14	No	2.6	10	1.3	2.7	7	22	No
Total Chromium	No	3.9	45	0.2	1	3.9	3000	No	5.6	77	0.3	1	5.6	5000	No
Cobalt	No					2.9	100	No	1.8	10	0.5	1.6	2.9	160	No
Copper	No					36	76	No	28	14	0.3	1.3	36	110	No
Iron	No					860	3800	No	570	15	0.6	1.5	860	5500	No
Lead	No					48	78	No	20	10	1.1	2.4	48	130	No
Manganese	No					1400	4500	No	1100	10	0.3	1.3	1400	6600	No
Mercury	Yes I					0.025	0.012	Yes	0.0165	19	0.7	1.5	0.025	0.02	Yes
Molybdenum	No					50	20000	No	31	10	0.5	1.6	50	34000	No
Nickel	No					35	530	No	22	10	0.3	1.3	35	1300	No
Selenium	No					27	180	No	19	15	0.5	1.4	27	260	No
Silver	No	10	46	0.3	1	10	16	No	10	130	0.4	0.9	9	33	No
Thallium	No					33	120	No	15	10	0.9	2.2	33	170	No
Tin	No					7.2	940	No	4.5	10	0.5	1.6	7.2	1500	No
Titanium	No					7.4	15000	No	5.7	10	0.3	1.3	7.4	22000	No
Zinc	No	300	46	1	1.1	330	330	No	300	130	1.1	0.8	240	650	No
Boron	No					17000	41000	No	14000	15	0.2	1.2	17000	60000	No
Cyanide, Free	No	14	43	0.3	1	14	22	No	19	116	0.4	0.9	17	44	No
Cyanide, Total	No	14	43	0.3	1	14	259000	No	19	116	0.4	0.9	17	630000	No
Sulfite	No	872000	44	0.3	1	872000	9600000	No	872000	118	0.3	0.9	785000	17000000	No

* Reasonable Potential to Exceed:

1) "Yes I" means that a projected effluent quality (PEQ) exceeded a preliminary effluent limitation (PEL) based on a Tier I criterion.
2) "Yes II" means that a PEQ exceeded a PEL based on a Tier II criterion.
3) "Yes SSC" means that a PEQ exceeded a PEL based on a site-specific criterion.
4) "No" means that a PEQ did not exceed a PEL.
5) "Evaluate Criteria" means that a PEQ exceeded a PEL based on a screening value.

Attachment C:

COOLING WATER INTAKE STRUCTURE REQUIREMENTS §122.21(R)(2) – (R)(8) 2020 NPDES PERMIT APPLICATION UPDATES

Project name	**NiSource: Schahfer NPDES Permit Renewal Support**
Project no.	**1690015757**
Version	**Original**
Date	**February 28, 2020**
Prepared by	**Ramboll US Corporation**

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1. Introduction

Facility Background

The R. M. Schahfer Generating Station (RMS) is permitted to draw from an intake on the Kankakee River in Wheatfield, Jasper County, Indiana pursuant to National Pollutant Discharge Elimination System (NPDES) Permit No. IN0053201. RMS has four coal-fired boilers (Units 14, 15, 17, and 18) which began operating in 1976 when Unit 14 came online followed by Unit 15 (1979), Unit 17 (1983) and Unit 18 (1986). All four units feature close-cycle cooling via a single multi-cell mechanical draft cooling tower per unit.

Makeup water for the recirculating water system comes from the Kankakee River via Davis Ditch through a single cooling water intake structure (CWIS). The CWIS is located on Davis Ditch approximately two miles north of the plant. Makeup water is drawn through CWIS by a set of three circulating water pumps, each with a capacity of 20,000 gallons per minute (gpm); however, only two of the pumps can be operated together at any one time, thus the maximum Design Intake Flow (DIF) for RMS is approximately 40,000 gpm (57.6 MGD). Nonetheless, the maximum intake flow registered by RMS is 39.0 MGD.

Makeup water is pulled into the service water pump house through a pair of steel bar trash racks then into two separate bays, each containing one traveling screen with stainless steel mesh panels. From the CWIS, makeup water travels via underground pipe to the Intake Basin (IB). Water from the IB is pumped into the plants to be used as cooling tower makeup water, as well as makeup water to the recycle line, and to provide water to the boilers and the Flue-Gas Desulfurization (FGD) equipment. After passing through the plant processes, all water is routed to the Final Setting Basin (FB) located on the north side of the plant. The FB contains a primary outfall to the Kankakee River (Outfall 001) and an emergency outfall to the Davis Ditch.

Regulatory Applicability

The United States Environmental Protection Agency (USEPA) promulgated the Clean Water Act (CWA) Section 316(b) Rule (316(b) Rule) for existing facilities in August 2014, under Title 40 of the Code of the Federal Register (CFR) Parts 122 and 125, as part of the National Pollutant Discharge Elimination System (NPDES) program. Under the 316(b) Rule, which became effective on October 14, 2014, applicable facilities with cooling water intake structures (CWISs) are required to locate, design, and operate their CWIS to minimize adverse environmental impact (AEI) from impingement and entrainment mortality. In accordance with the 316(b) Rule, existing facilities that withdraw greater than a Design Intake Flow (DIF) of 2 million gallons per day (MGD) of water from "waters of the U.S." and utilize greater than 25 percent of the water withdrawn for cooling purposes are subject to the rule requirements under the NPDES Permit Program.

As per 40 CFR 122.21(r)(1)(ii), existing facilities are required to provide cooling water intake information to the regulatory authority related to the intake and source water. As an existing facility with surface water intakes withdrawing greater than 2 MGD based on cumulative design intake flow, but withdrawing less than 125 MGD based on cumulative actual intake flow, and more than 25 percent of the actual intake flow used exclusively for cooling purposes, RMS must address the required information published in 40 CFR Part 122.21(r)(2) through (r)(8). Corresponding federal regulation citations include:

- Physical Information for Source Water (§122.21(r)(2))
- Physical description of CWIS (§122.21(r)(3))
- Biological Information for Source Water (§122.21(r)(4))

- Cooling Water System Data (§122.21(r)(5))
- Impingement Mortality BTA Demonstration (§122.21(r)(6))
- Entrainment Performance Studies (§122.21(r)(7))
- Operational Status (§122.21(r)(8))

Pursuant to 40 CFR 125.95(a)(1), existing facilities whose currently effective permit expires after July 14, 2018 are required to submit the information required in applicable sections of 40 CFR 122.21(r) when applying for a subsequent permit. This information was originally submitted to the Indiana Department of Environmental Management (IDEM) in March 2015 in the report titled "Schahfer Generating Station NPDES Permit Application Submittal Requirements §122.21(r)(2) – (r)(8)" authored by Golder Associates, Inc (referred to herein as the March 2015 CWIS Report).

After the initial submission of the 40 CFR 122.21(r) permit application studies, the permittee may request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Per federal regulations detailed in 40 CFR 125.94(c), the owner or operator of a facility is required to submit its request for reduced cooling water intake structure and waterbody application information to the Director at least two years and six months prior to the expiration of its NPDES permit. RMS did not request reduced application information, however based on technical review select conditions detailed in the March 2015 CWIS Report continue to be substantially unchanged. This short form report serves as a supplement to the March 2015 CWIS Report (included as Appendix 1) and provides updates for applicable conditions.

2. Source Water Physical Data [40 CFR §122.21(r)(2)]

The description and water quality regime of the Kankakee River has not been modified since the March 2015 CWIS Report. See Appendix 1, Section 2.

3. Cooling water Intake Structure Data [40 CFR §122.21(r)(3)]

The cooling water intake structure configuration has not been modified since the March 2015 CWIS Report. See Appendix 1, Section 3.

4. Source Water baseline Biological Characterization Data [40 CFR §122.21(r)(4)]

No previous impingement or entrainment studies have been performed at RMS; therefore, historic plant impingement and entrainment is not available for this section.

To assess substantially changed conditions from the information submitted in the March 2015 CWIS Report, Ramboll conducted a review of publicly-available information from published and online sources. Rule guidance documents, including the U.S. Fish and Wildlife Service (USFWS)/National Marine Fisheries Service (NMFS) Biological Opinion, as well as USEPA and USFWS online resources/databases, were utilized to guide this data search.

The extensive electrofishing surveys within Indiana portions of the main branch of the Kankakee performed by Price and Robertson.[1] in 2001 continues to be the most recent, representative reference of species and relative abundance in the vicinity of the cooling water intake structure.

Since March 2015 CWIS Report, the Indiana Department of Natural Resources (IDNR) has updated the available Endangered, Threatened and Rare Species list. This list has been expanded from the March 2015 CWIS Report to include Jasper and neighboring counties, La Porte and Porter.

Table 1. Threatened and Endangered (T&E) Species with Potential to Impact [A]

County	Aquatic Life	Species Name	Common Name	T&E Status [B]
La Porte	Mussel	Lymnaea stagnalis	Swamp Lymnaea	SSC
Jasper / Porter	Mussel	Plethobasus cyphyus	Sheepnose	LE, SE
Porter	Mussel	Venustaconcha ellipsiformis	Ellipse	SSC
La Porte / Porter	Fish	Acipenser fulvescens	Lake Sturgeon	SE
La Porte	Fish	Ichthyomyzon fossor	Northern Brook Lamprey	SE
Jasper / La Porte	Fish	Moxostoma valenciennesi	Greater Redhorse	SE
La Porte/ Porter	Fish	Rhinichthys cataractae	Longnose Dace	SSC
La Porte	Amphibian	Acris blanchardi	Blanchard's Cricket Frog	SSC
Jasper / Porter	Amphibian	Ambystoma laterale	Blue-spotted Salamander	SSC
Jasper	Amphibian	Cryptobranchus alleganiensis	Eastern Hellbender	SE
La Porte / Porter	Amphibian	Hemidactylium scutatum	Four-toed Salamander	SSC
Jasper	Amphibian	Lithobates blairi	Plains Leopard Frog	SE
La Porte / Porter	Amphibian	Necturus maculosus	Common mudpuppy	SSC

NOTES:
(A): Indiana Department of Natural Resources (May 9, 2019): County Endangered, Threatened and Rare Species List (Jasper, La Porte, and Porter County): https://www.in.gov/dnr/naturepreserve/4666.htm
(B): LE: Federally Endangered; SE: State Endangers; SSC: State Special Concern

5. Cooling Water System Data [40 CFR §122.21(r)(5)]

The RMS operates a recirculating water closed-cycle cooling system, only withdrawing water from the Kankakee River as makeup water, with a maximum intake of 39 MGD. For the period 2008 through 2014, average daily intake flow was 26.2 MGD (Table 2).

The actual intake volumes associated with the RMS CWIS are reported annually to the Indiana Department of Natural Resources (IDNR) as a Significant Water Withdrawal Facility (SWWF). Surface water withdrawal rates are identified under Registration No. 37-01145-EP as Intake 1. Monthly intake volumes from 2016, 2017, and 2018 are summarized in Table 1.

[1] Price and Robertson. 2005. Fishery, Habitat, and Recreational Use Surveys for the Kankakee River, Indiana. Indiana Department of Natural Resources – Division of Fish and Wildlife Final Report – Workplans #200766, #202766. 31 pp.

Table 2. RMS Intake Volume

Month/Year	Day per Month	Intake Volume (1,000 gals per month)	Average Intake Volume (MGD)	Annual Average
Jan-15	31	636401	20.53	
Feb-15	28	644517	23.02	
Mar-15	31	500451	16.14	
Apr-15	30	602534	20.08	
May-15	31	570162	18.39	
Jun-15	30	753237	25.11	22.03 (2015)
Jul-15	31	1047509	33.79	
Aug-15	31	1006353	32.46	
Sep-15	30	913923	30.46	
Oct-15	31	594264	19.17	
Nov-15	30	451809	15.06	
Dec-15	31	313880	10.13	
Jan-16	31	308880	9.96	
Feb-16	29	466810	16.10	
Mar-16	31	362980	11.71	
Apr-16	30	379320	12.64	
May-16	31	700840	22.61	
Jun-16	30	725590	24.19	18.79 (2016)
Jul-16	31	817933	26.38	
Aug-16	31	468780	15.12	
Sep-16	30	831340	27.71	
Oct-16	31	735230	23.72	
Nov-16	30	614620	20.49	
Dec-16	31	459200	14.81	
Jan-17	31	643062	20.74	
Feb-17	28	578302	20.65	
Mar-17	31	648458	20.92	
Apr-17	30	725041	24.17	
May-17	31	623927	20.13	
Jun-17	30	666956	22.23	20.26 (2017)
Jul-17	31	973910	31.42	
Aug-17	31	786027	25.36	
Sep-17	30	491610	16.39	
Oct-17	31	303430	9.79	
Nov-17	30	488651	16.29	
Dec-17	31	466239	15.04	
Jan-18	31	653358	21.08	
Feb-18	28	439007	15.68	24.56 (2018)
Mar-18	31	464079	14.97	

Month/Year	Day per Month	Intake Volume (1,000 gals per month)	Average Intake Volume (MGD)	Annual Average
Apr-18	30	565346	18.84	
May-18	31	767792	24.77	
Jun-18	30	932382	31.08	
Jul-18	31	1010795	32.61	
Aug-18	31	1081148	34.88	
Sep-18	30	865822	28.86	
Oct-18	31	724876	23.38	
Nov-18	30	715841	23.86	
Dec-18	31	766261	24.72	
Jan-19	31	669582	21.60	
Feb-19	28	463301	16.55	
Mar-19	31	813127	26.23	
Apr-19	30	665709	22.19	
May-19	31	866541	27.95	
Jun-19	30	703959	23.47	22.93 (2019)
Jul-19	31	665828	21.48	
Aug-19	31	884732	28.54	
Sep-19	30	838733	27.96	
Oct-19	31	692020	22.32	
Nov-19	30	543954	18.13	
Dec-19	31	582696	18.80	

The actual intake flow (AIF) is defined as the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years. The maximum observed intake flow and AIF are summarized in Table 2 below with the corresponding through-screen velocity (TSV).

Table 3. Calculated TSV

Design Intake Flow, MGD =	**39.00**	**TSV @ DIF, fps =**	**0.39**
Actual Intake Flow (2015-2017), MGD =	20.36	**TSV @ 2017 AIF, fps =**	0.20
Actual Intake Flow (2016-2018), MGD =	21.20	**TSV @ 2018 AIF, fps =**	0.21
Actual Intake Flow (2017-2019), MGD =	22.58	**TSV @ 2019 AIF, fps =**	0.23

6. Chosen Method of Compliance with Impingement Mortality Standard [40 CFR §122.21(r)(6)]

The RMS will continue to comply with the Impingement Mortality Standard by maintaining an AIF of less than 0.50 fps. Compliance monitoring will continue via monitoring and reporting daily intake flow.

7. Entrainment Performance Studies [40 CFR §122.21(r)(7)]

No entrainment performance studies have been conducted at RMS.

8. Operational Status [40 CFR §122.21(r)(8)]

RMS is equipped with four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. Individual unit characteristics from the 2018 NIPSCO Integrated Resource Plan (IRP) are shown in Table 3.

Table 4 RMS Individual Unit Characteristics

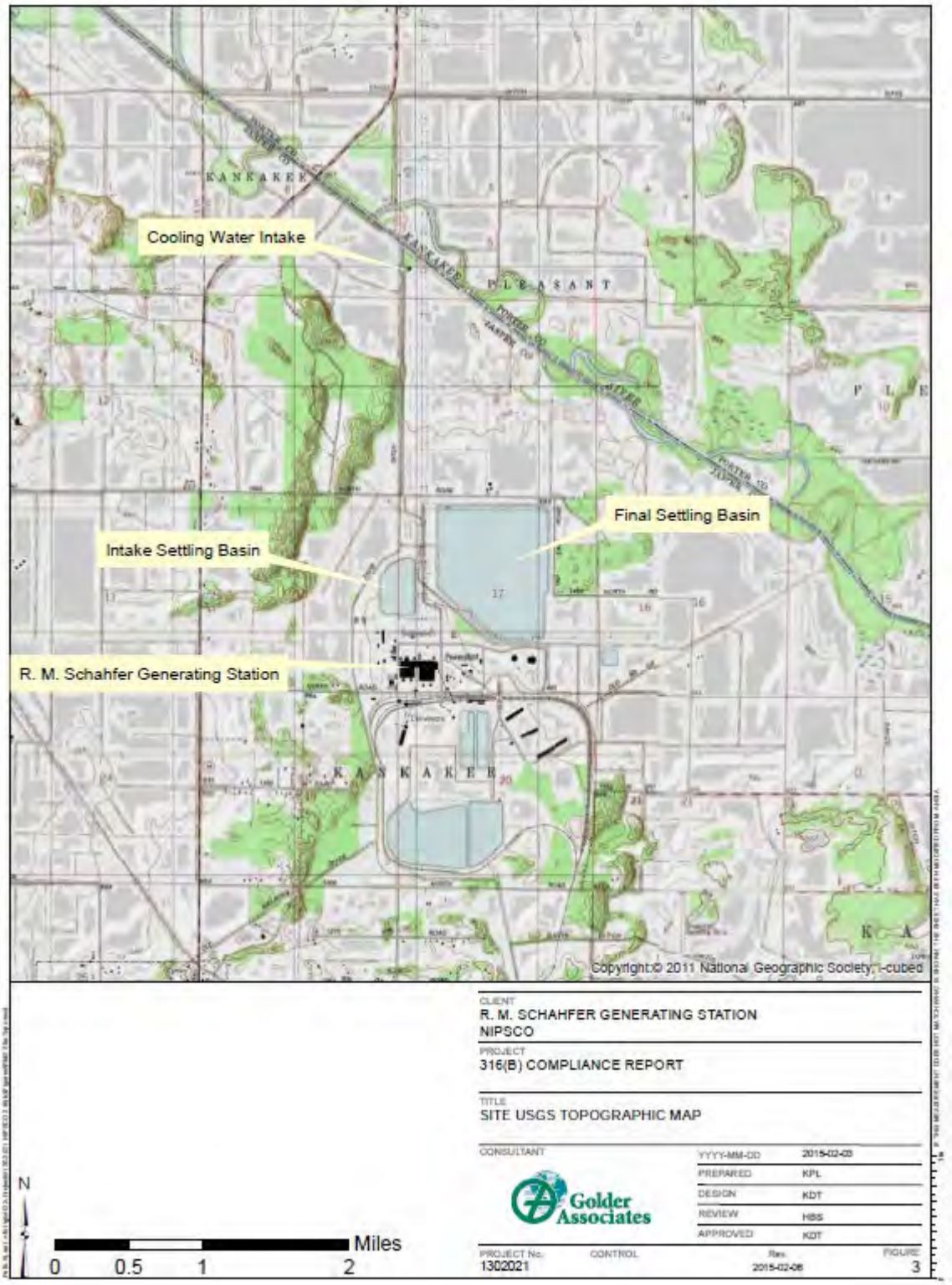
	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979

The 2018 IRP identified the preferred retire path which included the retirements of Schahfer Units 14, 15, 17, 18. NIPSCO's short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the Schahfer 14, 15, 17, 18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire the Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.

Attachment D: Aerial View of CWIS



Attachment E: Topographic Map of CWIS



STATE OF INDIANA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PUBLIC NOTICE NO. 20200924 – IN0053201
DATE OF NOTICE: SEPTEMBER 24, 2020

The Office of Water Quality issues the following NPDES FINAL PERMIT.

MAJOR– RENEWAL

NIPSCO R.M. SCHAHFER GENERATING STATION, Permit No. IN0053201 JASPER COUNTY, 2723 E. 1500 N., Wheatfield, IN. This industrial facility discharges 0.5 million gallons daily of sanitary, stormwater, process and non-process wastewater to Kankakee River. Permit Manager: Trisha Williams, 317/234-8210, twilliam@idem.in.gov.

Notice of Right to Administrative Review [Permits]

If you wish to challenge this Permit, you must file a Petition for Administrative Review with the Office of Environmental Adjudication (OEA), and serve a copy of the Petition upon IDEM. The requirements for filing a Petition for Administrative Review are found in IC 4-21.5-3-7, IC 13-15-6-1 and 315 IAC 1-3-2. A summary of the requirements of these laws is provided below.

A Petition for Administrative Review must be filed with the Office of Environmental Adjudication (OEA) within fifteen (15) days of the issuance of this notice (eighteen (18) days if you received this notice by U.S. Mail), and a copy must be served upon IDEM. Addresses are:

Director
Office of Environmental Adjudication
Indiana Government Center North
100 North Senate Avenue - Room N103
Indianapolis, Indiana 46204

Commissioner
Indiana Department of Environmental Management
Indiana Government Center North
100 North Senate Avenue - Room 1301
Indianapolis, Indiana 46204

The Petition must contain the following information:

1. The name, address and telephone number of each petitioner.
2. A description of each petitioner's interest in the Permit.
3. A statement of facts demonstrating that each petitioner is:
    a. a person to whom the order is directed;
    b. aggrieved or adversely affected by the Permit;
    c. entitled to administrative review under any law.
4. The reasons for the request for administrative review.
5. The particular legal issues proposed for review.
6. The alleged environmental concerns or technical deficiencies of the Permit.
7. The Permit terms and conditions that the petitioner believes would be appropriate and would comply with the law.
8. The identity of any persons represented by the petitioner.
9. The identity of the person against whom administrative review is sought.
10. A copy of the Permit that is the basis of the petition.
11. A statement identifying petitioner's attorney or other representative, if any.

Failure to meet the requirements of the law with respect to a Petition for Administrative Review may result in a waiver of your right to seek administrative review of the Permit. Examples are:

1. Failure to file a Petition by the applicable deadline;
2. Failure to serve a copy of the Petition upon IDEM when it is filed; or
3. Failure to include the information required by law.

If you seek to have a Permit stayed during the Administrative Review, you may need to file a Petition for a Stay of Effectiveness. The specific requirements for such a Petition can be found in 315 IAC 1-3-2 and 315 IAC 1-3-2.1.
Pursuant to IC 4-21.5-3-17, OEA will provide all parties with Notice of any pre-hearing conferences, preliminary hearings, hearings, stays, or orders disposing of the review of this action. If you are entitled to Notice under IC 4-21.5-3-5(b) and would like to obtain notices of any pre-hearing conferences, preliminary hearings, hearings, stays, or orders disposing of the review of this action without intervening in the proceeding you must submit a written request to OEA at the address above.
More information on the appeal review process is available on the website for the Office of Environmental Adjudication at http://www.in.gov/oea.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

REPLY TO THE ATTENTION OF: WP-16J

September 15, 2020

Nikki Gardner, Section Chief
Industrial NPDES Permits
Office of Water Quality
Indiana Department of Environmental Management
100 North Senate Avenue
Indianapolis, IN 46204-2251

Re: Review of NPDES Permit, NIPSCO R.M. Schahfer Generating Station, Wheatfield, IN (IN0053201)

Dear Ms. Gardner:

The U.S. Environmental Protection Agency has reviewed the proposed National Pollutant Discharge Elimination System Permit (permit), fact sheet, and supporting documents for the NIPSCO R.M. Schahfer Generating Station, that was submitted to EPA on September 14, 2020. Based on our review of the permit, EPA has no objections and the permit may be issued in accordance with the Memorandum of Agreement and pursuant to the Clean Water Act. The Region reserves the right to object to any other permit changes that have not been identified by IDEM or to any further permit changes that might occur prior to issuance of the final permit. The Region must be notified of any further changes made to the permit before finalization.

When the final permit is issued, please forward a copy to this office at r5NPDES.gov. Please include the permittee name and permit number in the Subject line and cc: Ackerman.Mark@epa.gov, and Rosenberg.Kathryn@epa.gov. If you have any technical questions related to EPA's review, please contact Mark Ackerman at 312-353-4145 or Ackerman.Mark@epa.gov, and Kathryn Rosenberg at 312-886-6774 or Rosenberg.Kathryn@epa.gov.

Thank you for your cooperation during the review process and your thoughtful consideration of our comments.

Sincerely,

for
Stephen M. Jann, Chief
Permits Branch, Water Division

cc: Trisha Williams, Permit Writer, IDEM, electronically

bc: Andrea Schaller, Chief, Section 1
Mark Ackerman, Environmental Engineer, Section 2
Kathryn Rosenberg, Environmental Scientist, Section 1

https://usepa.sharepoint.com/sites/R5/wd/NPDES/RealTimeRvws/Reviews/IN0053201_Review/IN0053201_NIPSCO R M Schahfer Generating Station_PropPerLtr_20200915.docx

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NIPSCO

September 4, 2020

Ms. Trisha Williams
Indiana Department of Environmental Management
Office of Water Quality / Industrial Permits Section, MC 65-42
100 North Senate Avenue
Indianapolis, IN 46204-2251

RE: **NPDES Draft Permit**
Public Notice No. 20200805 – IN0053201 – D
Permit No. IN0053201
NIPSCO – R. M. Schahfer Generating Station
Wheatfield, Indiana, Jasper County

Ms. Williams:

The Northern Indiana Public Service Company LLC (NIPSCO) is submitting the enclosed comments for your consideration.

Thank you for your assistance in this matter. If you have any questions or require additional information, please do not hesitate to contact me at jloewe@nisource.com or 219-647-5249.

Sincerely,

Jeffrey M. Loewe
Principal
NiSource Environmental

ENCLOSURES
1. Comment, three (3) pages

RECEIVED
SEP 09 2020
IDEM/OWQ

Part I.A.1, Table 1, Intake Flow – NIPSCO requests removal of the daily maximum limit of 39 MGD for Intake Flow. While our 2015 316(b) report as well as our current NPDES permit renewal application identify 39 MGD as the maximum observed intake flow, NIPSCO believes it is inappropriate to limit the intake flow to a daily volume which corresponds to a calculated through screen velocity (TSV) of less than the maximum allowable (i.e. 0.39 fps versus <0.5 fps). Intake values up to 50 MGD correlate to a TSV less than 0.5 fps (i.e. 0.4988 fps) and remain compliant with the impingement BTA standard. As an alternative to a numerical limit, the daily maximum Intake Flow can be designated as "Report". In addition to this requested change for Part I.A.1 Table 1, the same request applies to Part IV.B.7 as well and should also be revised to allow a maximum of 50 MGD intake volume.

Parts I.A.1 and I.A.3 – In light of the August 31, 2020 pre-publication notice of the final Steam Electric Reconsideration Rule ("final Rule") applicable to the Federal Effluent Limits Guidelines (ELGs) at 40 CFR 423 for flue gas desulfurization (FGD) and bottom ash (BA) transport discharges, NIPSCO acknowledges that IDEM may choose to revise certain sections of the draft permit. Under the final Rule, the facility meets the definition of a facility that will cease combustion of coal no later than December 31, 2028 (40 CFR 423.11(w)). As such, once the rule is published and officially effective, the only applicable best available technology economically achievable (BAT) ELGs for both FGD wastewater and bottom ash transport wastewater (40 CFR 432.13(g)(2)(i)) and 40 CFR 432.13(g)(2)(i)), respectively) are those for Total Suspended Solids (TSS) and Oil & Grease (O&G).

Note: the applicable best practicable control technology currently available (BPT) ELGs under 40 CFR 423.12 for TSS and Oil & Grease and these wastewaters remain unchanged.

Provided the timing of the final Rule aligns with IDEM's schedule of permit reissuance, NIPSCO requests the following three draft permit revisions be considered:

1. Part I.A.1., Footnote 19 – should be modified to also address bottom ash transport wastewater. NIPSCO offers the following suggested revised verbiage:

   In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

   In lieu of establishing new internal outfalls for low volume waste and bottom ash wastewater, should the permittee require a permit to continue operations beyond December 31, 2023, the permittee must submit an evaluation of alternate limitations for TSS and Oil & Grease developed using the combine wastestream formula (CWF), modified CWF, or building block approach and provide supporting documentation.

2. Part I.A.1., Footnote 20 – "The permittee shall comply with the requirements of the effluent limitation guidelines for Steam Electric Generating Stations, 40 CFR 423.13(k)(1)(i), for bottom ash transport water by December 31, 2023." should be removed, as it is no longer valid in the final Rule.

3. Part I.A.3. – The interim and final requirements/limits for arsenic, mercury, selenium, and nitrate/nitrite (as well as Footnotes [2], [4], and [5]) should be removed for both current Outfall 201 and proposed new Outfall 301.

Part I.A.3, Outfall 301 – If IDEM decides not to address the final Rule at this time (as requested above) then NIPSCO requests the following permit revisions for Part I.A.3 be implemented into the renewed permit. Moreover, to provide clarity NIPSCO requests the suggested verbiage provided below in comment to Part 1.F.6, IDEM decides not to address the final Rule at this time.

> The limits and monitoring requirements in this table apply to both Outfall 201 and Outfall 301. However, Outfall 301 is a new outfall and there is currently no flow metering or sample collection infrastructure in place to assess parameter concentrations or effluent discharge flowrate. Additionally, the Unit 17/18 FGD wastewater currently comingles with other wastewaters and, therefore, an isolated, representative sampling port for Outfall 301 compliance assessment is necessary and may require significant re-piping to isolate this discharge. As such, NIPSCO requests a 3-year compliance schedule to design, procure, install, and debug the necessary power supply and equipment to properly monitor the required parameters at Outfall 301 as well as to properly segregate Unit 17/18 FGD wastewater from other sources at the new outfall location. Further, for the new Outfall 301 (only), monitoring for all parameters should not be required during the three year compliance schedule. After the compliance schedule expires, the numerical limitations for TSS and O&G would become effective when the Outfall 301 sampling equipment is properly configured and operational. Monitoring for all other parameters (i.e., "Report") would also resume at this time. Ultimately, the limits for arsenic, mercury, selenium, and NO2+NO3 established under 40 CFR 423.13(g)(1)(i) shall apply no later than December 31, 2023 for both Outfalls 201 and 301.

Part I.A.3, Mercury – NIPSCO requests that the monitoring frequency for Mercury be reduced from 2 X Monthly to 6 X Yearly. The 6 X Yearly frequency is consistent with the existing permit for Outfall 201, as well as this draft permit for Outfall 001. IDEM has presented no specific rationale in the Fact Sheet for increasing the monitoring frequency of Mercury. NIPSCO respectfully requests the rationale should the frequency remain as proposed.

Part I.A.4 – In the Draft Permit, NIPSCO believes IDEM has erroneously removed the reference to stormwater Outfall 005S and Outfall 006S in the introductory description as well as removed Footnote [5] in its entirety. Both references to outfalls 005S and 006S were in the July 6, 2020 Pre-public notice draft permit as well as the existing permit. These two outfalls still exist and continue to discharge. Accordingly, NIPSCO requests they be reinserted into this section with the acknowledgment that they are representatively sampled at Outfall 004. This request does not change any of the compliance requirements of the existing permit.

Part I.B.1 – NIPSCO requests the renewed permit retain the verbiage in the current permit. While the proposed verbiage is largely a simple restructuring from the current permit, the rewording for this section does change the meaning. The current permit verbiage addresses "the discharge not causing receiving waters to contain.." whereas the proposed verbiage focuses on the discharge itself as being free from substances, materials, floating debris, etc.

Part I.C.2 – Page 15 of 58 (beginning of page through section f) is redundant with the verbiage on page 14 of 58 and should be deleted. NIPSCO believes to be an editorial oversight and removing the verbiage will result in zero effect to the requirements within the permit.

Part I.C.2.b – NIPSCO requests this section be revised to state that an "approved statistical method" includes replacing values reported as <LOQ with 0 (zero) when calculating monthly averages for concentration. This technique is consistent with the provisions given in the current permit.

Part I.C.4 – NIPSCO requests "or the most recently approved version of 40 CFR 136." be added to the end of the first sentence in this section. The 327 IAC 5 reference (327 IAC 5-2-1.5 Incorporation by reference) does not specify a version of 40 CFR 136. However, 327 IAC 1 (specifically 1-1-2 References to the CFR) indicates that the CFR is the July 1, 2016 edition. NIPSCO believes not including the requested revision could potentially be problematic if there is a situation to use more recently approved methods.

Part I.F.6 – NIPSCO requests this section be revised to include the following or similar verbiage "This provision also allows the permittee to request appropriate permit modifications applicable from any newly promulgated Federal Effluent Limitation Guidelines for Steam Electric Generating Stations under 40 CFR 423."

----- END OF COMMENTS -----

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

REPLY TO THE ATTENTION OF:
WP-16J

August 5, 2020

Nikki Gardner, Section Chief
Industrial NPDES Permits
Office of Water Quality
Indiana Department of Environmental Management
100 North Senate Avenue
Indianapolis, IN 46204-2251

Re: Review of the Pre-Public Notice Draft of NPDES Permit No. IN0053201, for the NIPSCO R.M. Schahfer Generating Station, Wheatfield, IN

Dear Ms. Gardner:

The U.S. Environmental Protection Agency has reviewed the pre-public notice draft National Pollutant Discharge Elimination System Permit (Permit), fact sheet, and supporting documents for the NIPSCO R.M. Schahfer Generating Station Permit No. IN0053201, that was submitted to EPA on July 6th, 2020. Based on our review to date, EPA would not object to issuance of that permit. However, our position could change if any of the following occurs:

a. Prior to the actual date of issuance of a Proposed Permit, an effluent guideline or standard is promulgated which is applicable to the permit and which would require revision or modification of a limitation or condition set forth in the Draft Permit;

b. A variance is granted and the Permit is modified to incorporate the results of that variance;

c. There are additional revisions to be incorporated into the Permit which have not been agreed to by EPA; or

d. EPA learns of new information, including as the result of public comments, that causes EPA to reconsider its position.

Subject to the above conditions, the permit may be issued in accordance with the Memorandum of Agreement and pursuant to the Clean Water Act. Although we currently do not intend to object, EPA recommends you consider and address the comments identified in Enclosure A in order to improve the overall permit.[1]

1 All cited federal regulations are made applicable to states by 33 U.S.C. §§ 1314(i) and 1342(c)(2) and 40 C.F.R. § 123.25.

When the Proposed Permit is prepared, please forward one copy and any significant comments received during any public notice period to this office at r5NPDES.gov. Please include the Permittee name and permit number in the Subject line and cc: Ackerman.Mark@epa.gov, and Rosenberg.Kathryn@epa.gov. If you have any technical questions related to EPA's review, please contact Mark Ackerman at 312-353-4145 or Ackerman.Mark@epa.gov; and Kathryn Rosenberg at 312-886-6774 or Rosenberg.Kathryn@epa.gov.

Thank you for your cooperation during the review process and your thoughtful consideration of our comments.

Sincerely,

for Stephen M. Jann, Chief
Permits Branch, Water Division

Enclosure

cc: Trisha Williams, Permit Writer, IDEM, electronically

Enclosure A

U.S. Environmental Protection Agency
NPDES Permit Received July 6th, 2020
Draft NPDES Permit Dated October 1st, 2020
NIPSCO R.M. Schahfer Generating Facility
NPDES Permit No. IN0053201

Please consider the following comments to clarify and improve the fact sheet and proposed permit:

1. Please revise effluent table for Outfall 001/002 to include the monthly average effluent limitation for chromium. Note this is the same as the daily maximum effluent limitation. See 40 C.F.R. 423.13(d)(1).

2. Please revise permit note [20] for the effluent table for Outfall 001/002 to include the regulatory reference (40 C.F.R. 423.13(k)(1)(i)) for the bottom ash transport best available technology economically achievable (BAT) requirements.

3. Page 11 of 58 in the permit includes an authorization to discharge storm water from several outfalls, including 005S, and 006S. However, these two Outfalls are not identified in the list of storm water outfalls with their corresponding latitude/longitude coordinates, nor are they listed in the subsequent monitoring table. Please revise this section of the permit so that it accurately represents the permitted storm water outfalls by either omitting any reference to 005S, and 006S, or revise the section to include the latitude/longitude coordinates for these two outfalls, and list them under the “Discharge Limitations.”

July 20, 2020

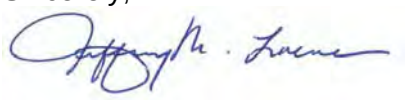
Ms. Nicole Gardner
Indiana Department of Environmental Management
Office of Water Quality / Industrial Permits Section, MC 65-42
100 North Senate Avenue
Indianapolis, IN 46204-2251

RE: **Pre-Public Notice Draft Response**
Permit # IN0053201
NIPSCO – R. M. Schahfer Generating Station
Wheatfield, Indiana, Jasper County

Thank you for proving the draft/proposed version of the above-referenced NPDES permit. The Northern Indiana Public Service Company LLC (NIPSCO) is submitting the enclosed comments for your consideration.

Thank you for your assistance in this matter. If you have any questions or require additional information, please do not hesitate to contact me at jloewe@nisource.com or 219-647-5249.

Sincerely,



Jeffrey M. Loewe
Principal
NiSource Environmental

ENCLOSURES
1. Comment, two (2) pages

Part I.A.1 Table 1 – NIPSCO requests removal of the “Report” requirement for Flow and Cycles of Concentration. Coupled with proposed permit Section IV, NIPSCO requests clarification for the new reporting requirements. As addressed in our 2015 316(b) report, our through screen velocity (TSV) calculations indicate 39 MGD (maximum observed intake flow) is equivalent to an intake TSV of 0.39 fps, while a 50 MGD maximum flow remains under the 0.5 fps threshold (0.4988 fps). See further discussion below in response to Part IV.B. items 7-8.

Part I.A.3 – The outfall detail paragraph is missing minutes symbol in the lat/long coordinates for Outfall 002 (The permittee is authorized to discharge from Internal Outfall 201, located at Latitude 41° 13’ 3”, Longitude -87° 1’ 14”.)

Part I.A.3 – Pursuant to the flexibility allowable in the ELG requirements at 423.13(g)(1)(i), NIPSCO requests the permitting authority define the applicability date for the BAT numeric limitations at Outfall 201 as no later than December 31, 2023.

Part I.A.3 – To address the proposed status of Outfall 301, NIPSCO requests a compliance schedule identifying the applicability date for the limitations at Outfall 301 as no later than December 31, 2023.

Part I.B.1 – NIPSCO requests the new permit retain the verbiage in the current permit. While the proposed verbiage is largely a simple restructuring from the current permit, the rewording for this section does change the meaning. The current permit verbiage addresses “the discharge not causing receiving waters to contain..” whereas the proposed verbiage focuses on the discharge itself as being free from substances, materials, floating debris, etc.

Part I.C.1 – NIPSCO is inquiring to the intention of the revised verbiage. Does the requirement that samples “reflect the full range and concentration” imply or specifically require the permittee to collect samples at times of suspected elevated levels?

Part I.C.2 – NIPSCO requests inclusion of current permit language related to use of zeros when doing certain calculations.

Part I.C.3.c – NIPSCO requests verbiage from the current permit regarding "Temperature Basis” be retained in the definition of Daily Maximum.

Part I.C.4 – NIPSCO suggest “or the most recently approved version of 40 CFR 136.” be added. The 327 IAC 5 reference (327 IAC 5-2-1.5 Incorporation by reference) does not specify a version of 40 CFR 136. However, 327 IAC 1 (specifically 1-1-2 References to the CFR) indicates that the CFR is the July 1, 2016 edition. We feel this could be problematic if we want to use more recently approved methods.

Part IV.B.7 and B.8 – While our 2015 316(b) report and the recent NPDES permit renewal application indicate 39 MGD as the maximum observed intake flow, NIPSCO believes it is inappropriate to limit the intake flow to a daily volume which corresponds to a calculated through screen velocity (TSV) of less than the maximum allowable (i.e. 0.39 fps versus <0.5 fps). Intake values up to 50 MGD correlate to a TSV less than 0.5 fps and remain compliant with the impingement BTA standard. NIPSCO requests Part I.A.1 Table 1 and Part IV.B.7 be revised to allow a maximum of 50 MGD intake volume.

Fact Sheet 2.5 – references our on-site landfill as a “Restricted Waste Site Type II Landfill (RWS II)”. The facility classification is a RWS Type I landfill and should be corrected.

Fact Sheet 2.5 – references storm water management "except that which is related to the FGD construction". The FGD construction project is complete and this verbiage is no longer applicable.

Fact Sheet 5.1 – the section Requirements applicable to all wastewater streams identifies “eight (8) separate wastewater streams that are regulated by 40 CFR Part 423, they are:

1. Once through non-contact cooling water for a plant with a total rated electric generating capacity of 25 or more megawatts”.

While the regulatory reference includes all wastewater streams applicable to a steam electric generation facility we feel including reference to “once through noncontact cooling water” may be confusing for a reader and should be removed or clarified.

----- END OF COMMENTS -----

From: jloewe@nisource.com <jloewe@nisource.com>
Sent: Wednesday, June 17, 2020 5:54 PM
To: Gardner, Nicole <ngardner@idem.IN.gov>
Cc: Gavin, Brad <BGavin@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>; Williams, Trisha <TWilliam@idem.IN.gov>
Subject: Re: Fw: FW: Quick question

**** This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. ****

Nikki Brad / Paul / Trisha,

Sorry for the delay but I have finally collected all the information to answer the questions included in the e-mail string. Also, if I missed something I'm sure you'll let me know.

Bromination
We no longer brominate at Schahfer. The use of the bromine chemical (MIOX) was terminated in 2018. Accordingly, I see no reason to retain and would support I removing it from the permit.

Cycles of Concentration
As previously mentioned, the four cooling towers at the Schahfer Station average 1.7 COC. The actual COC has varied at times throughout the history of the Station but our current chemistry plan has been optimized around the design and operating parameters of this facility. The primary goal of our chemistry program is to prevent scaling within the condensers. The current chemistry plan is designed to target 2.0 - 2.2 COC while the average (as mentioned) is currently 1.7. Previous attempts to cycle as high as 3 have failed. This was largely due to the scaling issue experienced under such operating conditions. Water from the Kankakee River is brought into the Intake Settling Basin (ISB) as the source of service water used throughout the facility. The Kankakee has a fairly high concentration of calcium, which left untreated results in our scaling issue. There is no chemical pretreatment performed on the water in the ISB. Accordingly, controlling the FGD blow down rate moderates the COC. The plant engineers routinely monitor the chloride levels within the scrubber to best maximize the system (i.e. to blow down the scrubbers at little as possible; less BD results in increased COC). As an ancillary note to our chemistry control, a purposeful factor in the design of our program is to not increase the sulfate (and other ions) levels in the Final Settling Basin (FSB). All internal ponds and process water combine in the FSB prior to discharge at final outfall 001. The FSB has an engineered capability of providing water directly (if and as needed) into the ISB under low flow conditions in the Kankakee River. Adding unwanted salts into the ISB would only exacerbate the scaling potential and prove problematic in limiting blow down (which results in lower cycles of concentration).

% Reduction
Using real world data and recent operating conditions (such as run times of the various Units), we estimate a Once-Through system would require 1.044B gallons of water per day. We calculate an estimated water use of 48.5M gallons per day at 1.7 COC, and 40M gpd at 2.0 COC. The 1.7 COC results in a 95.4% reduction when compared to a once-through system (and 96.2% at 2.0 COC). We are aware of the 316(b) guidance document reference to reducing actual intake flows (AIF) by 97.5 percent with a closed cycle cooling tower system being operated at a minimum 3.0 cycles of concentration. As affected by the circumstances mentioned above, despite minimizing blow down (thus minimizing make up flow), employing an appropriate chemistry control program, and operating a closed cycle system we are unable to replicate these COC levels or percent flow reduction.

Chemistry Control Program Guidance

The following is feedback from our chemical provider (Suez) after discussing the design of our program with respect to potentially increasing cycles of concentration.

The current target cycles at NIPSCO Schahfer Station is 2 cycles with pH control to pH 8.4 (*via* acid feed). A gauge for the "treatability" of the water from a calcium carbonate scaling perspective is the Langelier Saturation index (LSI), with typical treatable LSIs < 2.6. It is critical to keep the condensers clean of deposit, with calcium carbonate being the main potential culprit at these conditions. Under the abovementioned operating parameters and typical water compositions, LSIs are generally < 2.6, and treatable.

With an increase in cycles and the strict maintenance at the appropriate pH, elevated cycles can be achieved. However, with an upset such as a loss of acid feed or pH measurement issue, calcium carbonate scale and silicate scales can be issues; please refer to Figure 1, below. Note that a modest deviation from the target pH would lead to elevated LSIs and exceedances of limits of select mineral salts. In addition, effluent turbidities will increase, which may pose a challenge with regard to TSS permit limit requirements.

In brief, operating at higher cycles poses more risk and potential negative consequences to the operation.

Figure 1. Water chemistry composition and the associated limits for NIPSCO Schahfer Station as a function of cycles; ***** indicates "over limit".

CYCLES FACTOR	STARTING CYCLES	pH / Alkalinity Relationship	Maximum L.S
0.50	1.00	1.84	2.60

CYCLES FACTOR	STARTING CYCLES	pH / Alkalinity Relationship	Maximum L.S.I.	Maximum Silica
0.50	1.00	1.84	2.60	200

Print Cycle-Up | Print MakeUps | Help | E-Mail

Enter values into the shaded boxes. Enter Cu Enter Customer Name, Location and Account Number Over Labels.

suez

TOWER WATER CYCLING ANALYSIS

NIPSCO SS
Unit 17 or 18
6/1/2020

VOL	3,450,000	(gal)	
RR	165,000	(gpm)	
D T	21.00	(deg F)	
EVAP	3,119	(gpm)	
F	0.90		
Drift	0.0010%	(% of RR)	

150 °F (Hotest Skin) **130** °F (Bulk Water)
0.9 M-ALK FACTOR

CYCLES	pH	M-ALK as CaCO3	Ca as CaCO3	Mg as CaCO3	SiO2	o-PO4	Na	COND uM hos	Cl	SO4	Fe	TDS ppm	LSI	MgSi	CMSi	RT75 (day)	B.D. (gpm)	M.U. (gpm)
	8.10	**206.0**	**189.0**	**85.5**	**10.30**	**0.0**	**25.6**	**761.0**	**29.3**	**102.00**	**0.50**	**494.65**	1.40					
1.5	8.58	278	284	128	15	0.00	38	1142	44	153	0.8	742.0	2.16	ok	ok	0.53	6,238	9,357
2.0	8.81	371	378	171	21	0.00	51	1522	59	204	1.0	989.3	*****	ok	*****	1.06	3,119	6,238
2.5	8.99	464	473	214	26	0.00	64	1903	73	255	1.3	1236.6	*****	ok	*****	1.60	2,079	5,198
3.0	9.13	556	567	257	31	0.00	77	2283	88	306	1.5	1484.0	*****	*****	*****	2.13	1,560	4,679
3.5	9.25	649	662	299	36	0.00	90	2664	103	357	1.8	1731.3	*****	*****	*****	2.66	1,248	4,367
4.0	9.36	742	756	342	41	0.00	102	3044	117	408	2.0	1978.6	*****	*****	*****	3.19	1,040	4,159

MAKE UP: 8.10 206 M-ALK as CaCO3
WITH pH CONTROL: **8.40** 223 M-ALK as CaCO3

1.5 Lbs Cl2 / 1000 g al Recirc

CYCLES	ACID (ppm)	ACID #/day	as CaCO3 Ca	as CaCO3 Mg	SiO2	o-PO4	Bleach Adjusted Na	Acid and Bleach Adjusted COND	Bleach Adjusted Cl	Acid Adjusted SO4	LSI	MgSi	CMSi	Acid and Bleach Adjusted TDS
0.0			189	86	10	0.00	26	761	29	102				495
1.5	55	4143	284	128	15	0.00	42	1184	47	204	1.89	ok	ok	799
2.0	148	5541	378	171	21	0.00	58	1627	65	339	2.01	ok	ok	1138
2.5	241	6007	473	214	26	0.00	74	2070	83	475	2.09	ok	ok	1476
3.0	333	6240	567	257	31	0.00	90	2513	101	610	2.17	ok	ok	1815
3.5	426	6380	662	299	36	0.00	106	2956	119	746	2.23	ok	ok	2153
4.0	519	6473	756	342	41	0.00	122	3399	137	882	2.28	ok	ok	2492

WITH pH CONTROL: **8.80** 367 M-ALK

ACID (ppm)	ACID #/day	LSI	MgSi	CMSi
0	0	2.50	ok	ok
3	125	*****	ok	*****
96	2396	*****	ok	*****
189	3532	*****	ok	*****
281	4213	*****	ok	*****
374	4668	*****	ok	*****

I trust this answers your questions. Should you have additional questions, please do not hesitate....

Thank you,

Jeff Loewe | NiSource | Environmental
P: 219.647.5249 | C: 219.742.1979

From: "Gardner, Nicole" <ngardner@idem.IN.gov>
To: "jloewe@nisource.com" <jloewe@nisource.com>
Cc: "Gavin, Brad" <BGavin@idem.IN.gov>, "Novak, Paul" <PNovak@idem.IN.gov>, "Williams, Trisha" <TWilliam@idem.IN.gov>
Date: 06/17/2020 08:33 AM
Subject: Re: Fw: FW: Quick question

Good morning Jeff! Just checking in with you on the information request below. If you can give us a status update we would appreciate it.

Thank you,

Nikki

From: Gardner, Nicole <ngardner@idem.IN.gov>
Sent: Friday, June 12, 2020 7:07 AM
To: jloewe@nisource.com <jloewe@nisource.com>
Subject: Re: Fw: FW: Quick question

Good morning Jeff, I hope you are doing well!

I wanted to let you know that we are very close to being finished with a draft. I believe the final pieces are the COC and percent reduction calculation. Do you know if those will be available soon?

Nikki

From: Gardner, Nicole <ngardner@idem.IN.gov>
Sent: Wednesday, June 3, 2020 1:41 PM
To: jloewe@nisource.com <jloewe@nisource.com>
Subject: Re: Fw: FW: Quick question

Thank you!

From: jloewe@nisource.com <jloewe@nisource.com>
Sent: Wednesday, June 3, 2020 1:40 PM
To: Gardner, Nicole <ngardner@idem.IN.gov>
Cc: Gavin, Brad <BGavin@idem.IN.gov>; Carlino, Jennifer <JCarlino@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>; Williams, Trisha <TWilliam@idem.IN.gov>
Subject: Re: Fw: FW: Quick question

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Nikki et al, I anticipate some time this week. I requested the percent reduction calculation be performed and was told they would likely have that number to me some time this week. After I receive that value I will be able to complete my response and will submit it to this group.

Thank you,
-Jeff

Jeff Loewe | NiSource | Environmental
P: 219.647.5249 | C: 219.742.1979

From: "Gardner, Nicole" <ngardner@idem.IN.gov>
To: Jeff Loewe <jloewe@nisource.com>,
Cc: "Carlino, Jennifer" <JCarlino@idem.IN.gov>, "Gavin, Brad" <BGavin@idem.IN.gov>, "Novak, Paul" <PNovak@idem.IN.gov>, "Williams, Trisha" <TWilliam@idem.IN.gov>
Date: 06/03/2020 12:33 PM
Subject: Fw: FW: Quick question

Jeff,

Good afternoon! With regard to the email below (cycles of concentration), do you have a timeframe in mind when we might receive a response?

Will you please include the following people on your response: Brad Gavin, Paul Novak, Jennifer Carlino, and Trisha Williams? Trisha will be taking the project over for Jennifer as her maternity leave begins this week.

Thank you,

Nikki

From: jloewe@nisource.com <jloewe@nisource.com>
Sent: Thursday, May 21, 2020 1:40 PM
To: Carlino, Jennifer
Subject: Re: FW: Quick question

**** This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. ****

Jennifer,
I am attempting to gather the appropriate staff for a discussion regarding the cycles of concentration. It appears this is becoming an issue as opposed to a simple question and I do not want to provide an inadequate or erroneous reply. I will get back to you as soon as possible.

Thank you,
-Jeff

Jeff Loewe | NiSource | Environmental
P: 219.647.5249 | C: 219.742.1979

From: "Carlino, Jennifer" <JCarlino@idem.IN.gov>
To: "jloewe@nisource.com" <jloewe@nisource.com>,
Date: 05/20/2020 11:05 AM
Subject: FW: Quick question

USE CAUTION: This email was sent from an external source. Think before you click links or open attachments. If suspicious, please forward to security@nisource.com for review.

Jeff, one of our engineers has a question. It is highlighted below.

Also, the previous permit mentions "bromination" in the fact sheet, along with the chlorination justification, but neither the application, nor the table in the previous permit mention it. Is Bromination something the Schahfer facility does, or could I remove it from the permit?

Thanks!

Jennifer Carlino
Senior Environmental Manager
IDEM Office of Water Quality
NPDES Permits
Government Center North
100 N Senate Ave.
Indianapolis, IN 46201
(317) 232-8702 * Jcarlino@idem.in.gov

Indiana Department of Environmental Management

IDEM values your feedback.
Please take two minutes and complete this brief survey.

From: Novak, Paul <PNovak@idem.IN.gov>
Sent: Wednesday, May 20, 2020 8:37 AM
To: Gavin, Brad <BGavin@idem.IN.gov>; Carlino, Jennifer <JCarlino@idem.IN.gov>; Gardner, Nicole <ngardner@idem.IN.gov>
Subject: RE: Quick question

Brad – thanks for providing EPA RTC. Very helpful.

The rule provides flexibility in determining whether a facility is considered closed cycle or not. The determination seems to be based on whether the system is "well operated" . See pages 158 -161 of the RTC.

I suggest we ask NIPSCO why they are operating at the 1.7 COC and if they can re-look at providing a percent reduction in AIF.

From: Gavin, Brad
Sent: Tuesday, May 19, 2020 2:44 PM
To: Carlino, Jennifer <JCarlino@idem.IN.gov>; Gardner, Nicole <ngardner@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>
Subject: Re: Quick question

The below is an excerpt from the document I have now attached.

As an example, in the case of a facility that uses makeup water from a freshwater source, a Director may determine that a closed-cycle recirculating system can generally be deemed to minimize makeup and blowdown flows if it reduces actual intake flows (AIF) by 97.5 percent as compared to a once-through cooling system or if its cooling tower is operated at a minimum cycles of concentration of 3.0. .... These reductions and cycles of concentration are illustrative. A Director may determine that other levels near these numbers could also constitute a closed-cycle system. The final rule further recognizes that in certain unavoidable circumstances, these levels for COC or percent flow reduction might not be achievable at all facilities. Such circumstances could include situations where water quality-based discharge limits might limit the concentration of a pollutant that is not readily treatable in the cooling tower blowdown or situations where varying source water quality could lead to unavoidable problems concerning scale formation, solids buildup, corrosion, or media fouling. Such facilities should demonstrate these circumstances to their Director and indicate the measures they have taken to minimize makeup flows. The Director will retain the discretion to conclude that the particular facility employs a closed-cycle recirculating system when the benchmarks are not met.

They don't meet the COC of 3.0 or 97.5% flow reduction. That is probably why they did not mention their closed cycle recirculating system as an impingement BTA option.

Brad Gavin, Environmental Engineer
Permits Branch
Office of Water Quality
Indiana Department of Environmental Management
bgavin@idem.in.gov

From: Gavin, Brad <BGavin@idem.IN.gov>
Sent: Tuesday, May 19, 2020 2:20 PM
To: Carlino, Jennifer <JCarlino@idem.IN.gov>; Gardner, Nicole <ngardner@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>
Subject: Re: Quick question

I have attached Essay 17A Closed Cycle Recirculating Cooling from EPA's response to comment on the proposed rule. It discusses the issue in detail.

Brad Gavin, Environmental Engineer
Permits Branch
Office of Water Quality
Indiana Department of Environmental Management
bgavin@idem.in.gov
317-234-4155

From: Gavin, Brad <BGavin@idem.IN.gov>
Sent: Tuesday, May 19, 2020 12:51 PM
To: Carlino, Jennifer <JCarlino@idem.IN.gov>; Gardner, Nicole <ngardner@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>
Subject: Re: Quick question

Thanks, Jennifer. 1.7 is low. In the paragraph before the table that he referenced, it states that fresh water cooling towers typically operate at 3.0 cycles and a flow reduction of 97.5 (at a delta T of 20 degrees F).

Brad Gavin, Environmental Engineer
Permits Branch
Office of Water Quality
Indiana Department of Environmental Management
bgavin@idem.in.gov
317-234-4155

From: Carlino, Jennifer <JCarlino@idem.IN.gov>
Sent: Tuesday, May 19, 2020 11:08 AM
To: Gardner, Nicole <ngardner@idem.IN.gov>; Gavin, Brad <BGavin@idem.IN.gov>; Novak, Paul <PNovak@idem.IN.gov>
Subject: Fw: Quick question

Below is Jeff's response

From: jloewe@nisource.com <jloewe@nisource.com>
Sent: Tuesday, May 19, 2020 10:57 AM
To: Carlino, Jennifer <JCarlino@idem.IN.gov>
Subject: Re: Quick question

**** This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. ****

Jennifer, the annual average of the four (4) CTs at Schahfer is 1.7 cycles of concentration. I do not have (nor have ever seen) the calculated Percent Reduction. According to Exhibit 6-6 in the TDD, 1.7 COC appears to be approximately a 96-97% reduction.

Thank you,
-Jeff

Jeff Loewe | NiSource | Environmental
P: 219.647.5249 | C: 219.742.1979

April 3, 2020

Ms. Charnell Carter
Indiana Department of Environmental Management
Office of Water Quality / Industrial Permits Section, MC 65-42
100 North Senate Avenue
Indianapolis, IN 46204-2251

RE: **NPDES Permit Renewal**
Permit # IN0053201
NIPSCO – R. M. Schahfer Generating Station
Wheatfield, Indiana, Jasper County

The Northern Indiana Public Service Company LLC (NIPSCO) is submitting the enclosed Application and associated attachments for the renewal of the above referenced NPDES permit. Pursuant to 327 IAC 5-3-2, NIPSCO is filing for reissuance of this permit at least 180 days prior to the expiration of the current permit.

Under my direction and supervision, the enclosed application and all attachments were prepared by Ramboll. Based on my review, the information submitted is, to the best of my knowledge, true, accurate, and complete unless otherwise noted.

In accordance with IC 13-18-20-12, an application fee of $50 must be paid. Check number 5059004841was submitted to the Department under separate cover on March 6, 2020.

Thank you for your attention to this matter. If you have any questions or require additional information, please do not hesitate to contact me at jloewe@nisource.com or 219-647-5249.

Sincerely,



Jeffrey M. Loewe
Principal
NiSource Environmental

EXECUTIVE SUMMARY

This Executive Summary and subsequent attachments constitute the application by Northern Indiana Public Service Co. LLC – R.M. Schahfer Generating Station (RMSGS) for renewal of its existing National Pollutant Discharge Elimination System (NPDES) Permit No. IN0053201. This summary contains a brief description of the source of materials contained in this application and a general overview of the renewal request.

The NPDES permit application consists of the following:

- Identification of Potentially Affected Persons
- IDEM General Information Form - the general application that applies to all applicants
- IDEM Request for Information Form
- IDEM Owner/Operator Affidavit
- Form 2C - applies to all existing industrial facilities with process wastewater
- Form 2F – applicable for stormwater discharges associated with industrial activity
- Application fee

The application also contains the following additional information and/or other requests:

- Request for continued authorization for previously approved water treatment additives; Request for continued authorization for continuous chlorination of the Unit 14 cooling tower;
- Request for continued Best Technology Available (BTA) recognition for 316(b) requirements;
- Description of scheduled plant retirement; and
- Description of proposed waste stream pipe redirection activities.

For convenience, and directly following this Executive Summary, is a listing of documents that provides the general order of the application materials.

RAMBOLL

OUTFALL INVENTORY

The existing NPDES Permit, which became effective October 1, 2015 authorizes RMSGS to discharge the following wastewaters. Renewal is requested for the continued discharge of these waters.

Table 1. Inventory of Process and Stormwater Outfalls

Location Identification	Description	Location Latitude/ Longitude	Receiving Water
Outfall 001	Cooling tower blowdown, treated sanitary wastewater (Outfall 101), treated FGD wastewater (Outfall 201), low volume wastes, bottom ash transport water, coal pipe run-off, construction dewatering water, and stormwater	N 41 15' 2.34" W 87 1' 40.55"	Kankakee River
Outfall 002	Outfall 001 Emergency Overflow	N 41 13' 35.87" W 87 1' 18.43"	Kankakee River
Outfall 101	Treated Sanitary Wastewater	N 41 15' 2.34" W 87 0' 40.55"	Kankakee River via Outfall 001
Outfall 201	Treated Landfill Leachate and FGD Wastewater from Units 14/15	N 41 13' 3" W 87 1' 14"	Kankakee River via Outfall 001
Outfall 003S	Stormwater associated with industrial activity; surface water runoff from a perimeter storm water network from the onsite restricted waste landfill	N 41 13' 8.55" W 87 0' 20"	Stalbaum Ditch
Outfall 004S	Stormwater associated with industrial activity; drainage from coal car tracks exiting the plant and the perimeter security road (representative of Outfalls 005S and 006S)	N 41 12' 22" W 87 1' 38"	Davis Ditch
Outfall 005S	Stormwater associated with industrial activity; drainage from coal car tracks exiting the plant and the perimeter security road	N 41 12' 31" W 87 1' 38"	Davis Ditch
Outfall 006S	Stormwater associated with industrial activity; drainage for the perimeter security road and emergency overflow from the Intake Basin	N 41 13' 31" W 87 1' 36"	Davis Ditch
Outfall 007S	Stormwater associated with industrial activity; roof drain runoff and storm water collected from the area surrounding the main buildings of the generating facility	N 41 12' 17.46" W 87 1' 47.3"	Davis Ditch

Please note, the current Permit includes a requirement for a new internal monitoring location (Outfall 301) for FGD blowdown wastewaters from Units 17 and 18 prior to commingling with non-FGD wastewater in the MSRB. The Permit (as issued on September 16, 2015) allowed 12 months to identify a representative sampling location and develop a sampling plan. However the revised Effluent Limitation Guideline (ELG) Rule finalized in November 2015 defines numeric limits as well as an applicability date for FGD wastewater. Therefore, the intention of the Outfall 301 and the proposed 12-month compliance schedule identified in the Permit has been superseded by the Rule. Per correspondence from IDEM in November 2016, the agency concurred there are no compliance requirements for Outfall 301 in the current Permit.

In the current permit, IDEM noted shallow groundwater has the potential to discharge to surface water by the way of the two primary drainage ditches (Stalbaum and Davis Ditch) that flow through the property. Therefore, permit monitoring was required at various stream monitoring sites (SMS).

Table 2. Stream Monitoring Sites

Location Identification	Description	Location Latitude/ Longitude
SMS 010S	Stormwater in Davis Ditch	N 41 12' 5.22" W 87 0' 56.4"
SMS 011S	Stormwater in Davis Ditch	N 41 13' 19.21" W 87 1' 47.3"
SMS 012S	Stormwater in Stalbaum Ditch	N 41 12' 29.88" W 87 0' 3.9"
SMS 013S	Stormwater in Stalbaum Ditch	N 41 13' 24.52" W 87 1' 21.3"

EFFLUENT CHARACTERIZATION

Section V of Form 2C requires the presentation of effluent characterization data (concentration and mass) for select constituents. As part of this characterization, a "Believed Absent and Believed Present" assessment for constituents is required in Form 2C Part V-B. RMSGS used the following steps to determine whether a constituent would be "Believed Present" in outfall effluent:

1. Is there an identifiable RMSGS source of constituent?
2. Is it anticipated that the constituent would not be removed or degraded by wastewater treatment system?

3. Was a constituent analytically detected for that monitoring location?

If the answer to any step was "yes", then the constituent was considered to have potential to be present in the discharge.

In regards to sampling and analyses, permit-required conditions were followed. Where no permit requirements were listed, sampling and analyses followed 40 CFR Part 136. A summary of effluent characterization procedures is provided below:

<u>For all data:</u>

- For temperatures, summer was defined as April 1 through November 30 and winter was defined as December 1 through March 31.
- The number of analyses have been presented for both the daily values and the monthly average values.
- Monthly average values were generated only if there was more than one sample in the calendar month.
- Mass values were not calculated if all data for a parameter were non-detect.
- The presence of a "<" flag indicates that all results for that parameter were non-detect.
- Data were used as reported by the analytical laboratory: the majority of data were reported to the method reporting limit, but some data were reported to the method detection limit. The appropriate detection limit (with a "<" symbol) was conservatively substituted for non-detect results.
- When reported by the laboratory, estimated values between the method detection limit and method reporting limit were used as reported.
- Data from split analyses (for non-DMR parameters) and field duplicate analyses (mercury only) were averaged prior to use and counted as 1 sample result. For DMR parameters, individual data were reported as the original sample result (no averaging of duplicates).
- For parameter data sets containing detections and non-detections, all results were used in the calculation of the long term average, but only detections were used to determine the maximum statistics. Therefore, in some cases the maximum (daily or monthly) listed may be less than the calculated average. Data for which elevated non-detects were replaced by the highest detection are:
    - Outfall 004S Total Recoverable Zinc

For parameters currently monitored under the NPDES Permit:

- The MMR/DMR database from January 2016 to December 31, 2019 was utilized for permitted discharges:
  - Form 2C related Outfalls 001, 101, 201, 201 influent;
  - Form 2F related Outfalls 003S, 004S, 007S; and
  - Stream Monitoring Sites (SMS) 010S, SMS 011S, SMS 012S, SMS 013S.

For parameters not currently monitored under the NPDES Permit:

- Samples were collected for the required Form 2C or Form 2F parameters for the following locations on the respective dates.

  - Outfall 001, 101, 201: March 2, 2020 (except for $cBOD_5$ and Fecal Coliform at Outfalls 001 and 201)
  - Outfall 001 & 201 $cBOD_5$: March 17, 2020
  - Outfall 001 & 201 Fecal Coliform: March 27, 2020 (results pending)
  - Outfall 003S: No discharge has been recorded during the permit term and none is anticipated.
  - Outfall 004S: No additional discharge characterization data exists for Outfall 004S, 005S, or 006S at this time as the discharge is very intermittent and may only discharge during extreme rain events.
  - Outfall 007S: March 26, 2020 (results pending)

RAMBOLL

OTHER PERMIT RENEWAL ITEMS

Water Treatment Additives

Attachment I contains the list of all approved water treatment additives for use at RMSGS. Required materials (e.g., MSDSs, dosage information) for the already approved water treatment additives listed in Attachment I have been submitted to IDEM previously and are on file with the agency. Approvals for use of new chemicals are not requested at this time. NIPSCO requests continued approval for the use of the water treatment additives for which approval has already been provided.

Continuous Chlorination for the Unit 14 Cooling Tower

RMSGS requests continued recognition and approval of the continuous chlorination operations for the Unit 14 Cooling Tower. This provides for more effective biological control of cooling tower waters.

316(b) Requirements

RMSGS requests continued recognition that their existing cooling water intake structures (CWIS) represent the best technology available (BTA) for minimizing Adverse Environmental Impact (AEI) in accordance with Section 316(b) of the Clean Water Act. There have been no material changes to the existing CWIS nor any change in facility operations that would require additional intake flow. RMSGS believes their existing CWIS still represents BTA for minimizing AEI from Impingement Mortality (IM) and Entrainment Mortality (EM) impacts pursuant to the Final Section 316(b) Regulations for Existing Facilities, which were promulgated in August 2014 and effective in October 2014. RMSGS full-flow design withdrawal volumes of 50 MGD. Additional details and updates are provide in Attachment II.

Scheduled Plant Retirement

Announced through NIPSCO's 2018 Integrated Resource Plan released October 31, 2018, the Northern Indiana Public Service Company LLC has publicly announced the planned retirement of all coal-fired generation at the R.M. Schahfer Generating Station (RMSGS). Actions supporting this goal have already been initiated. The short term action plan includes the initiation of activities in preparation for the retirement of RMSGS Units 14, 15, 17, and 18 by 2023 thereby aligning with NIPSCO's long term action plan to fully retire the RMSGS Units 14, 15, 17, and 18 by the end of 2023.

Waste Stream Pipe Redirect

To implement the Coal Combustion Residual (CCR) rule compliance plan for NIPSCO's R. M. Schahfer Generating Station (RMSGS) piping will be rerouted from the Metal Cleaning Waste Basin (MCWB) and Material Storage Runoff Basin (MSRB), collectively referred to as the Multi-cell Unit (MCU), to the larger Waste Disposal Area (WDA) or Recycle Basin (RB). Engineering design is currently being finalized. The following information is PROPOSED / DRAFT and subject to change pursuant to final engineering specifications. CCR waste streams (flue gas desulfurization blowdown from Units 17 and 18 [i.e. U17/18 FGD WW]) currently going to the MCU will be routed to the WDA. Non-CCR waste streams currently going to the MCU will be routed to the RB. Pipe redirects will employ a combination of new and existing collection sumps as well as new and existing pipelines. Work also includes the installation of an additional cross-

tie between the Recycle Basin discharge lines and the MSRB/MCWB discharge line to the Final Settling Basin (FSB) to allow for greater blowdown capacity to the FSB.

The following table presents the disposition of the waste streams to be redirected and the peak flow rates from their respective sources. The peak flows rates can occur simultaneously; although most are intermittent, with the exception of the FGD Filter Building Sump Pumps which always have some level of flow in order to minimize solids deposition.

Table 3. Draft Waste Stream Pipe Redirect Summary

Contributing Streams	Re-Piped from WDA to Recycle Basin	Re-Piped To Recycle Basin via Coal Pile Runoff (CPR) Sump	Re-Piped To WDA via Existing Ash Piping[1]
	(gpm)	(gpm)	(gpm)
Non-CCR Streams to (WDA)			
Yard Drains	1,200		
U14 Boiler Room Sump	4,000		
U14 Boiler Room Sump	3,000		
Material Storage Runoff Basin (MSRB) Streams			
U17 & 18 FGD Filter Building North Sump			1,500
U17 & 18 FGD Filter Building South Sump			1,500
Coal Pile Run Off		6,000	
Unit 14/15 Chimney Drain[2]		0	
Run Off Retention Pond		500	
Metal Cleaning Waste Basin (MCWB) Streams			
U17 Fly Ash Truck Scale Sump		200	
U18 Fly Ash Truck Scale Sump		200	
U14 Fly Ash Silo Sump		200	
U17/18 Chimney Drain		125	
U14 Waste Neutralization		450	
U17 Make Up Demineralizer Sump		400	
U17/18 Metal Cleaning Waste Sumps		3,400	
U14/15 WWT Emergency Bypass			0
U14/15 Storm Water Run Off[3]		820	
Totals	8,200	12,295	3,000

[1] Deleted

[2] NIPSCO confirmed U14/15 Chimney Drain had no flow. This pipe will be capped.

[3] The U14/15 WWT Emergency Bypass and Storm Water Runoff currently discharge to the MCWB through a common line. The storm Water flow will be redirected to the Recycle Pond and the WWT Emergency Bypass will be disconnected.

Order of Materials

Identification of Potentially Affected Persons Form

General Information Form
- Figure 1. Site Location Map

IDEM Request for Information

IDEM Owner/Operator Affidavit

Form 2C Materials
- Outfall 001/002, 101, 201: Form 2C Pages 1 – 4

- Figure RMS-WF (07-02-2019): Water Flow Diagram – Current
- Figure RMS-WF (Proposed): Waste Stream Pipe Redirect
- Figure RMS-TREAT: Treatment Schematic for the FGD Wastewater Treatment System

- Outfall 001: Form 2C Part V
- Outfall 101: Form 2C Part V
- Outfall 201: Form 2C Part V
- Outfall 201 Influent DMR/MMR Data

- Method Information For Permit Required Sample Analyses
- Method Information for Non-Permit Required Sample Analyses

Form 2F Materials

- Stormwater Outfalls (003S, 004S, 005S, 006S, 007S): Form 2F Pages 1 – 3
  - 003S: Discharge Information
  - 004S: Discharge Information
  - 007S: Discharge Information

- Figure RMS-DRAIN: Site Drainage Map

Stream Monitoring Locations (010S, 011S, 012S, 013S) DMR/MMR Data

Supporting Attachments

- Attachment 1: Listing of Water Treatment Additives

- Attachment 2: 316(b) Cooling Water Intake Structure Updates

Identification of Potentially Affected Persons Form

I. Identification of Potentially Affected Persons

Please list here any and all persons whom you have reason to believe have a substantial or proprietary interest in this matter, or could otherwise be considered to be potentially affected under the law. Failure to notify any person who is later determined to be potentially affected could result in voiding our decision on procedural grounds. To ensure conformance with AOPA and to avoid reversal of a decision, please list all such parties. The letter attached to this form will further explain the requirements under the AOPA. Attach additional names and addresses on a separate sheet of paper, as needed. Please indicate below the type of action you are requesting.

Name: Herman Stanley		Name: Jane Campbell
Street address: 2100 E. 1300 North		Street address: 407 S. East Street
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Knox, IN 46534
Name: Rollin Hay		Name: Corey Partin
Street address: 2063 E. 1350 North		Street address: 621 S. Marshall Street
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: John Monroe		Name: Rosita Garrett
Street address: 2313 E.1350 North		Street address: P.O. Box 304
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Boone Grove, IN 46302
Name: Jean Hunter		Name: Christopher Hunter
Street address: 2837 E. 1350 North		Street address: 13288 N. 300 East
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Robert Boonstra		Name: Francis Tenta
Street address: 13460 N. 300 East		Street address: 3304 E. 1350 North
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Edward Deardorff		Name: Adelaide Deardorff
Street address: 1808 E. 1500 North		Street address: 1808 E. 1500 North
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Georgia Pacific Gypsum		Name: Darwin Whited
Street address: 484 E. 1400 North		Street address: 109 W Grove
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Sammy Wireman		Name: Richard & Linda Duttlinger
Street address: P.O. Box 279		Street address: 3743 E. State Road 10
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Jonathon Wendt		Name: The Nature Conservancy
Street address: 14113 N. State Road 10		Street address: 620 E. Ohio Street
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Indianapolis, IN 46202
Name: John & Patricia Mize		Name: William Davis
Street address: 3032 E. 1100 North		Street address: 686 E. 1350 North
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392

I. Identification of Potentially Affected Persons

Please list here any and all persons whom you have reason to believe have a substantial or proprietary interest in this matter, or could otherwise be considered to be potentially affected under the law. Failure to notify any person who is later determined to be potentially affected could result in voiding our decision on procedural grounds. To ensure conformance with AOPA and to avoid reversal of a decision, please list all such parties. The letter attached to this form will further explain the requirements under the AOPA. Attach additional names and addresses on a separate sheet of paper, as needed. Please indicate below the type of action you are requesting.

Name: Ben Corrett		Name: Ricarda Perez Trust
Street address: 439 E. 1350 North		Street address: 3105 Hedgerow Lane
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Homewood, IL 60430
Name: Walter & Michelle Howes		Name: Sarah Ann Bailey
Street address: 659 E. 1300 North		Street address: 75 W. 890 North
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Anthony & Joyce Boyle Indihar		Name: Matthew Hunter
Street address: 2301 Knox Avenue		Street address: 1369 E. 1300 North
City/State/ZIP code: Chicago, IL 60639		City/State/ZIP code: Wheatfield, IN 46392
Name: Vera Vukadinovic		Name: Chandler & Toni Smith
Street address: 1129 E. 1300 North		Street address: 1504 E. 1275 North
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Wheatfield, IN 46392
Name: Gerald & Catherine Smith		Name: Elizabeth Herzog
Street address: 1461 E. 1275 North		Street address: 340 E. Dewey
City/State/ZIP code: Wheatfield, IN 46392		City/State/ZIP code: Northlake, IL 60164
Name: Norfolk Southern Railroad Company		Name: Duggleby Farms LLC
Street address: 110 Franklin Road SE		Street address: 12552 N. 300 East
City/State/ZIP code: Roanoke, VA 24042-0028		City/State/ZIP code: Wheatfield, IN 46392
Name: Corey & Lisa Hamstra		Name: Stuart Orr, the Nature Conservancy
Street address: 10281 N. 1100 North		Street address: 436 Northwest Street
City/State/ZIP code: Demotte, IN 46310		City/State/ZIP code: Winamac, IN 46996
Name: John Kelly Hall (in care of V. Cavinder Estate)		Name: INDR Div. of Fish & Wildlife
Street address: 3451 E. 153rd Road		Street address: 402 W. Washington, Room W273
City/State/ZIP code: Hebron, IN 46341		City/State/ZIP code: Indianapolis, IN 46204
Name:		Name:
Street address:		Street address:
City/State/ZIP code:		City/State/ZIP code:
Name:		Name:
Street address:		Street address:
City/State/ZIP code:		City/State/ZIP code:

II. Please complete this form by signing the following statement.

I certify to the best of my knowledge I have listed all potentially affected parties, as defined by IC 4-21.5.			
Signature:	Bertil Valenkamph		
Printed name:	Bertil Valenkamph, Director Station Chemistry & Environmental Compliance	Date:	3/25/2020
Facility name:	NIPSCO R. M. Schahfer Generating Station		
Facility address:	2723 E. 1500 N.		
Facility city:	Wheatfield	Facility state: IN	ZIP code: 46392

III. Type of Action (check one)

- [x] NPDES Permit-327 IAC 5
- [ ] Pretreatment Permit -327 IAC 5
- [ ] Construction Permit-327 IAC 3

A $50.00 fee is required for a New permit, a Renewal or a Modification; if this is a renewal or modification request, include NPDES permit No. on check and return to:
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
Cashiers Office – Mail Code 50-10C
100 North Senate Avenue
Indianapolis, IN 46204-2251

If No Fee Is Required (Fee has previously been paid), Return To:
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
Office of Water Quality – Mail Code 65-42
Room N1255
Permits Branch
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

General Information Form

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)

GENERAL INFORMATION FORM

(TO BE SUBMITTED WITH FORMS 2C, 2D AND 2E)

(Replaces EPA General Form 1)

Revised 4/12/12

1. Name of Facility: R.M. Schahfer Generating Station

2. Facility Contact

Name: Nicholas Babbitt

Address: R.M Schahfer Generating Station. 2723 E. 1500 N.

City or Town: Wheatfield State: IN Zip Code: 46392

County: Jasper

Telephone: Work: 219-956-5385 Email: nbabbitt@nisource.com

3. Certified Operator

Name: Mark Hein

Certification #: WW019499 Classification: D

Address: R.M Schahfer Generating Station. 2723 E. 1500 N.

City or Town: Wheatfield State: IN Zip Code: 46392

Telephone: Work: 219-956-5310 Email: mhein@nisource.com

4. Facility Mailing Address

Street or P.O. Box: R.M Schahfer Generating Station. 2723 E. 1500 N.

City or Town: Wheatfield State: IN Zip Code: 46392

5. Facility Location

Street, Route No.,County,Other Specific Identifier: R.M Schahfer Generating Station. 2723 E. 1500 N.

6. Type of Permit Action:

New ___ Renewal _X_ Modification ___

7. EPA I.D. Number: IND082859455

8. Does or will this facility (either existing or proposed) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters of the state? (Form 2B)

Yes ___ No _X_ Form Attached ___

9. Is this a facility which currently results in discharges to waters of the state other than described in 8? (Form 2C-Process Wastewater or Form 2E-Nonprocess Wastewater)

Yes _X_ No ___ Form Attached _X_____

10. Is this a proposed facility (other than described in 8) which will result in a discharge to waters of the state? (Form 2D)

Yes ___ No_X_Form Attached ___

11. SIC Codes (4-digit, in order of priority)

First: 4911 Specify: Electric Power Services
Second:___ Specify: _____
Third: ____ Specify: _____
Fourth: ___ Specify: _____

12. Existing Environmental Permits (Identification #)

NPDES (Discharges to Surface Waters): IN0053201

UIC (Underground Injection of Fluids): NA

RCRA (Hazardous Wastes): IND082859455

PSD (Air Emissions from Proposed Sources): NA

Other: 180730008 and 1807300040 Specify: Air (Operating Majors)

Other:_____ Specify: _____

Other: _____ Specify:_____

13. Nature of Business (Provide a Brief Description)

Electric Power Generation – coal fired, in addition to natural gas, boilers covert water to high pressure steam which drives turbines directly connected to electrical generators.

14. Map
Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluid underground. Include all springs, rivers and other surface water bodies in the map area.

SEE FIGURE 1

15. Signature Block:

This application must be signed by a person in responsible charge to be valid. This signature attests to the following:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations".

Bertil C. Valenkamph, Director Station Chemistry & Environmental Compliance
(Printed Name) (Title)

Bertil C Valenkamph 3/25/2020
(Signature) (Date Signed)

Return Completed Application, Fee and Associated Materials to:
Indiana Department of Environmental Management
Cashiers Office – Mail Code 50-10C
100 North Senate Avenue
Indianapolis, Indiana 46204-2251



NIPSCO R.M. Schahfer Generating Station

FIGURE 1. SITE LOCATION MAP - Outfall, Stormwater and Stream Monitoring Site Locations

IDEM Request for Information

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

REQUEST FOR INFORMATION

We request that you fill in the blanks on this form and return it along with your NPDES PERMIT application. The information provided will be helpful in our personal contact with officials of your municipality, industry, or other facility in assuring prompt delivery of correspondence, etc. Thank you for your cooperation.

I. Current NPDES Permit Number IN0053201
(New applicants will be assigned a number later)

II. WASTEWATER TREATMENT FACILITY LOCATION ADDRESS

Name of Facility: NIPSCO R. M. Schahfer Generating Station
Address: 2723 East 1500 North
City: Wheatfield State: IN Zip code: 46392
Telephone: NA Email: NA

III. DISCHARGE MONITORING REPORT (DMR) MAILING ADDRESS (ADDRESS WHERE IDEM IS TO SEND PRE-PRINTED DMRS)

Name: Craig A. Myers Title: Manager, Environmental Compliance
Address: 2755 Raystone Drive
City: Valparaiso State: IN Zip code: 46383
Telephone: 219-286-8465 Email: camyers@nisource.com
Cognizant Official (Representative responsible for completing DMR):
Craig A. Myers Title: Manager, Environmental Compliance

IV. OWNER ADDRESS

Name of Owner: Bertil Valenkamph Title: Station Chemistry & Environmental Compliance
Address: 2755 Raystone Drive
City: Valparaiso State: IN Zip code: 46383
Telephone: 219-477-6265 Email: bcvalenkamph@nisource.com

V. WASTEWATER TREATMENT PLANT OPERATOR/SUPERINTENDENT ADDRESS

Name of Operator: Mark Hein Certificate Number: WW019499
Address: R.M. Schahfer Generating Station, 2723 E 1500 N
City: Wheatfield State: IN Zip code: 46392
Telephone: Work: 219-956-5310 Email: mhein@nisource.com

IDEM Owner / Operator Affidavit

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OWNER/OPERATOR AFFIDAVIT TO DETERMINE THE APPROPRIATE NPDES PERMITTEE(S)

327 IAC 5-2-3(c) requires the operator to apply for and obtain the NPDES permit for the NPDES discharge, unless the operator is an employee of the owner of the facility (in which case it is the owner's responsibility to apply for and obtain the NPDES permit). This is consistent with the federal regulations at 40 CFR 122.21(b). Additionally, pursuant to 327 IAC 5-2-6(c), the permittee is required to notify the IDEM if there is a change in either the ownership or the operation of the wastewater treatment plant.

When an NPDES permittee contracts with a private firm to operate its wastewater treatment plant, and the contractual agreement is one in which the private entity is not an employee of the owner, the permit should be issued to the private firm. Some contractual arrangements may have been made without the knowledge of this rule requirement, and the contract may not have been adequately set up to reflect this private firm as the sole permittee. Or the private contractor may not want to be the sole permittee. Therefore, in such instances EPA has suggested that the permit be issued to both the owner and to the private contractor, as co-permittees.

In order to help us determine who should be listed on the NPDES permit as the permittee(s), please complete the following information:

1. Name of Facility: NIPSCO R.M. Schahfer Generating Station
2. NPDES Permit Number: IN0053201
3. Name of Owner: Northern Indiana Public Service Company, LLC
   (individual or legal business name)

   Mailing Address of Owner: 801 E. 86th Avenue, Merrillville, IN 46410
4. Name of Operator:: Mark Hein
   (individual or legal business name)

   Mailing Address of Owner: 2723 E. 1500 N, Wheatfield, IN 46392
5. Is the operator an employee of the owner: ■ YES ☐ NO
6. If the answer to #5 is "No", is the operator willing to be the sole permittee?

   ☐ YES ☐ NO ☐ N/A
7. If the answer to #6 is "No", the NPDES permit will be issued to both the owner and the operator as co-permittees.

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(Signature of Owner) (Signature of Operator)

Please complete this form and return it to the IDEM, Office of Water Quality, Municipal NPDES Permits Section 100 North Senate Ave. Indianapolis, IN 46204

Outfall 001/002, 101, 201: Form 2C Pages 1 – 4

APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER

EXISTING MANUFACTURING, COMMERCIAL, MINING, AND SILVICULTURAL OPERATIONS

(OWQ Industrial NPDES Application 2C)

EPA Identification Number *(copy from Item 1 of Form 1)*
110000493706

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER *(name)*
	1 DEG	2 MIN	3 SEC	1 DEG	2 MIN	3 SEC	
Outfall 001	N 41°	15'	2.34"	W 87°	1'	40.55"	Kankakee River (Main Outfall)
Outfall 002	N 41°	13'	35.87"	W 87°	1'	18.43"	Kankakee River (FSB Emergency Overflow)
Outfall 101	N 41°	15'	2.34"	W 87°	0'	40.55"	Final Settling Basin (Internal to Outfall 001)
Outfall 201	N 41°	13'	3"	W 87°	1'	14"	Final Settling Basin (Internal to Outfall 001)

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (e.g. for certain mining activities) provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NUMBER	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT	
	a. OPERATION	b. AVERAGE FLOW *(Include units)*	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1
001	Low Volume Wastewater Bottom Ash Transport Water Cooling Tower Blowdown Coal Pile Runoff Treated Sanitary Wastewater (internal Outfall 101) Treated FGD Wastewater and landfill leachate (internal Outfall 201) Stormwater Construction Dewater Water	20.3 MGD	Sedimentation, Dechlorination	1-U, 2-E
002	Emergency Overflow from Final Settling Basin (FSB)	None Anticipated	Same as Outfall 001	Same as Outfall 001
101	Treated sanitary wastewater	0.0092 MGD	Preaeration, Activated Sludge, Sedimentation, UV Disinfection	3-E, 3-A, 1-U, 2-H
201	Treated FGD Wastewater (Unit 14/15 blowdown) Landfill Leachate	0.05 MGD	Neutralization, Chemical Precipitation, Coagulation, Flocculation, Sedimentation, Filtration, Ion Exchange, Sludge Thickening	2-K, 2-C, 2-D, 1-G, 1-U, 1-Q, 2-J, 5-L
OFFICAL USE ONLY *(effluent guidelines sub-categories)*				

EPA Identification Number *(copy from Item 1 of Form 1*
110000493706

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

■ Yes *(complete the following table)* ☐ NO *(go to Section III)*

1. OUTFALL NUMBER	2. OPERATION(s) CONTRIBUTING FLOW	3. FREQUENCY		4. FLOW				
		a DAYS PER WEEK *(specify average)*	b MONTHS PER YEAR *(specify average)*	a. FLOW RATE *(in mgd)*		b. TOTAL VOLUME *(specify with units)*		c. DURATION *(in days)*
				1 LONG TERM AVERAGE	2 MAXIMUM DAILY	1 LONG TERM AVERAGE	2 MAXIMUM DAILY	
002	Final Settling Basin Overflow							
001	Construction Dewatering							
201	FGD Wastewater and landfill leachate							

III. PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

■ YES *(complete Item III-B)* ☐ NO *(go to Section IV)*

B. Are the limitations in the applicable effluent guideline expressed in terms of production (or other measure of operation)?

☐ YES *(complete Item III-C)* ■ NO *(go to Section IV)*

C. If you answered "yes" to Item III-B, list the quantity which represents an actual measurement of your level of production, expressed in the terms and units used in the applicable effluent guidelines, and indicate the affected outfalls.

1. AVERAGE DAILY PRODUCTION			2. AFFECTED OUTFALLS *(list outfall numbers)*
a QUANTITY PER DAY	b UNITS OF MEASURE	c OPERATION, PRODUCT, MATERIAL, ETC *(specify)*	

IV. IMPROVEMENTS

A. Are you now required by any Federal, State, or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in the application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

☐ YES *(complete the following table)* ■ NO *(go to Section IV)*

1 IDENTIFICATION OF CONDITION, AGREEMENT, ETC	2 AFFECTED OUTFALLS		3 BRIEF DESCRIPTION OF PROJECT	4 FINAL COMPLIANCE DATE	
	a NO	b SOURCE OF DISCHARGE		a REQUIRED	b PROJECTED

B. Optional : You may attach additional sheets describing any additional water pollutant control programs *(or other environmental projects which may affect your discharges)* you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction. ☐ MARK "X" IF DESCRIPTION OF ADDITIONAL CONTROL PROGRAMS IS ATTACHED

EPA Identification Number *(copy from Item 1 of Form 1)*
110000493706

V. INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding - Complete one set of tables for each outfall - Annotate the outfall number in the space provided. NOTE: Tables V-A, V-B, and V-C are included on separate sheets numbered V-1 through V-10.

D. Use the space below to list any of the pollutants listed in Table 2C-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1 POLLUTANT	2 SOURCE	1 POLLUTANT	2 SOURCE
None known			

VI. POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item V-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or byproduct?

☐ YES *(list all such pollutants below)* ■ NO *(go to Item VI-B)*

EPA Identification Number *(copy from Item 1 of Form 1)*
IN000049370o

VII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☐ YES *(identify the test(s) and describe their purpose below)* ■ NO *(go to Section VIII)*

VIII. CONTRACT ANALYSIS INFORMATION

Were any of the analysis reported in Item V performed by a contract laboratory or consulting firm?

☐ YES *(list the name, address, and telephone number of, and pollutants analyzed by, each such laboratory or firm below)* ☐ NO *(go to Section IX)*

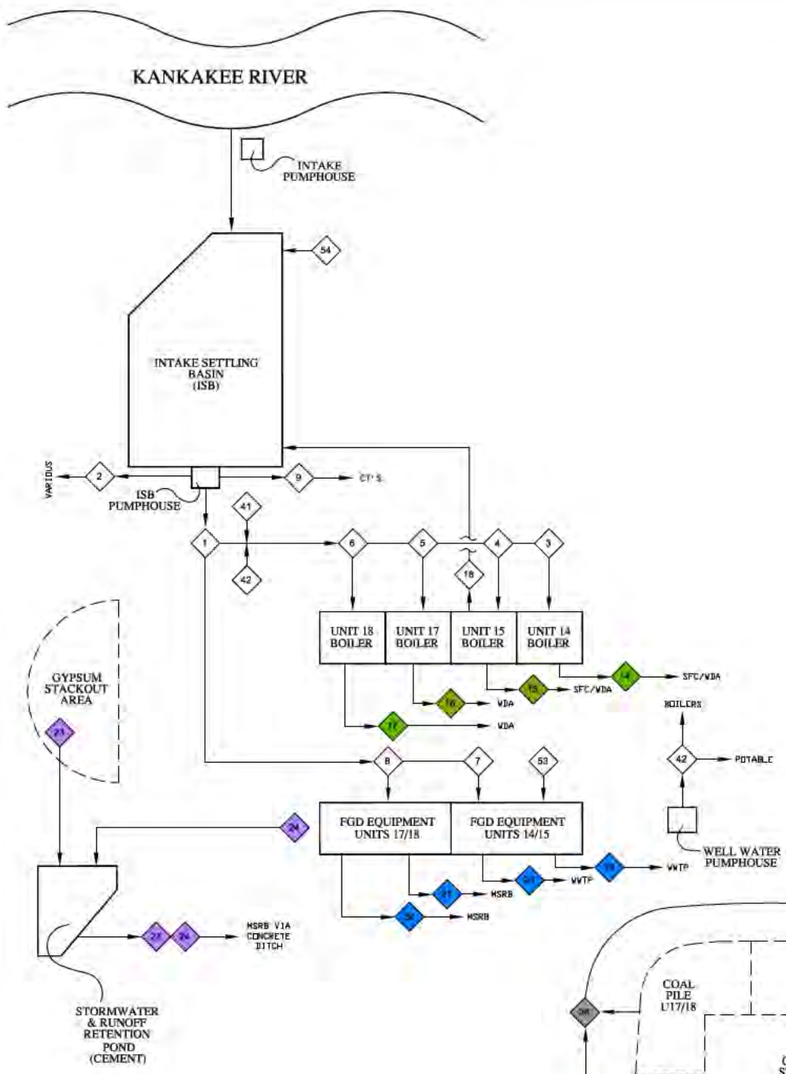
A. NAME	B. ADDRESS	C. TELEPHONE *(area code & no.)*	D. POLLUTANT ANALYZED
Microbac Laboratories	250 West 84th Drive Merrillville, IN 46410	219-769-8378	All parameters, except free cyanide
	158 Starlite Dr Marietta, OH 45750	800-373-4071	
	3323 Gilmore Industrial Blvd Louisville, KY 40213	502-962-6400	
ALS Environmental	3352 128th Ave Holland, MI 49424	616-399-6070	Free Cyanide

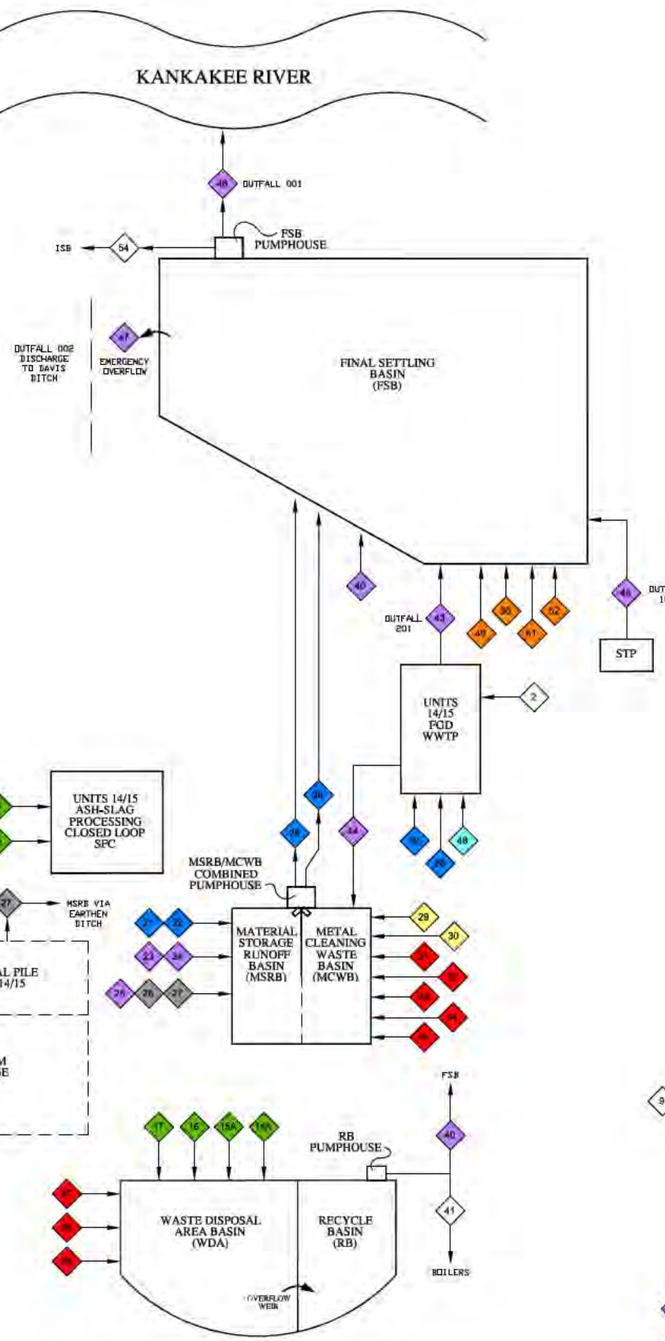
IX. CERTIFICATION

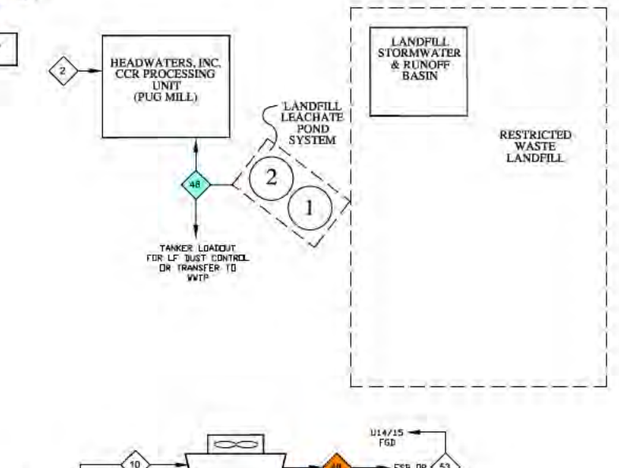
"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

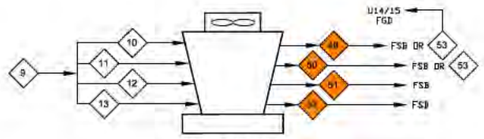
A. NAME & OFFICIAL TITLE *(type or print)*	B. PHONE NO. *(area code & no.)*
Bertil C Valenkamph, Director Station Chemistry & Environmental Compliance	219-256-8403
C. SIGNATURE Bertil Valenkamph	D. DATE SIGNED 3/25/2020

Figure RMS-WF (07-02-2019): Water Flow Diagram – Current









ITEM	DESCRIPTION
1	SERVICE WATER HEADER FROM ISB
2	SERVICE WATER SUPPLY TO VARIOUS
3	U14 BOILER MAKE-UP WATER
4	U15 BOILER MAKE-UP WATER
5	U17 BOILER MAKE-UP WATER
6	U18 BOILER MAKE-UP WATER
7	U14/15 FGD MAKE-UP WATER
8	U17/18 FGD MAKE-UP WATER
9	COOLING TOWER MAKE-UP WATER
10	U14 COOLING TOWER MAKE-UP WATER

ITEM	DESCRIPTION
11	U15 COOLING TOWER MAKE-UP WATER
12	U17 COOLING TOWER MAKE-UP WATER
13	U18 COOLING TOWER MAKE-UP WATER
14	U14 ASH/SLAG SLUICE
14A	U14 ASH/SLAG SLUICE (ALTERNATE)
15	U15 ASH/SLAG SLUICE
15A	U15 ASH/SLAG SLUICE (ALTERNATE)
16	U17 ASH/SLAG SLUICE
17	U18 ASH/SLAG SLUICE

ITEM	DESCRIPTION
18	U14/15 SFC HEAT EXCHANGER NONCONTACT COOLING WATER
19	U14 FGD BLOWDOWN
20	U15 FGD BLOWDOWN
21	U17 FGD BLOWDOWN, ABSORBER SUMPS, AND STACK DRAINS
22	U18 FGD BLOWDOWN, ABSORBER SUMPS, AND STACK DRAINS
23	GYPSUM STACKOUT AREA STORMWATER RUNOFF
24	FGD PROCESSING AREA STORMWATER RUNOFF
25	GYPSUM STORAGE AREA STORMWATER RUNOFF
26	U17/18 COAL PILE RUNOFF
27	U14/15 COAL PILE RUNOFF

ITEM	DESCRIPTION
28	MATERIAL STORAGE RUNOFF BASIN DISCHARGE TO FSB
29	U17/18 BOILER ROOM SUMPS (4 SEE ITEM 38)
30	U17/18 AIR HEATER WASH
31	U14 CONDENSATE SUMP & DEMINERALIZER WASTE
32	U17/18 BOILER BLOWDOWN
33	U17/18 CONDENSATE POLISHER SUMP
34	U17/18 CONDENSATE PIT SUMP
35	U17/18 RO REJECT
36	METAL CLEANING WASTE BASIN DISCHARGE TO FSB
37	U15 BOILER BD, CONDENSATE OVERFLOW TANKS, D/W SEP, TURBINE ROOM SUMPS
38	U14 BOILER BD, U14 RO REJECT, U14/15 AHW, FLY ASH SUMPS
39	U17/18 BOILER BLOWDOWN @ (ALTERNATE PATH)
40	RECYCLE BASIN DISCHARGE TO FSB
41	RECYCLE BASIN RE-USE (SERVICE WATER ALT SOURCE)
42	WELL WATER (U14/15/17/18 BOILER MAKE-UP, ALT. SOURCE)
43	WWTP EFFLUENT
44	WWTP AREA STORMWATER & EMERGENCY BYPASS RECYCLE
45	SEWAGE TREATMENT PLANT EFFLUENT
46	FINAL SETTLING BASIN DISCHARGE TO RIVER
47	FINAL SETTLING BASIN EMERGENCY OVERFLOW
48	LANDFILL LEACHATE
49	U14 COOLING TOWER BLOWDOWN
50	U15 COOLING TOWER BLOWDOWN
51	U17 COOLING TOWER BLOWDOWN
52	U18 COOLING TOWER BLOWDOWN
53	U14/15 CT BD TO U14/15 FGD MAKE-UP (ALT SOURCE)
54	FINAL SETTLING BASIN RE-USE (ISB ALT SOURCE)

COLOR KEY

- STORM/OTHER WATER
- SERVICE/RE-USE WATER
- LOW VOLUME WW
- ASH TRANSPORT WATER (CCR IMPACTED)
- NON-CHEMICAL METAL CLEANING WW
- FGD WW (CCR IMPACTED)
- COAL PILE RUNOFF
- LEACHATE
- COOLING TOWER BLOWDOWN

WATER FLOW DIAGRAM

NOT TO SCALE

REV.	W.O.	DESCRIPTION	DATE	APP'D DRAFT	APP'D ENGR	FILM
A		UPDATE WATER FLOW	7-12-2019	GA	JL	

Northern Indiana Public Service Company
A NiSource Company

DRAWN:	GA/JL
ENGINEER:	
APPROVED:	
DATE:	7-12-2019
SCALE:	NONE

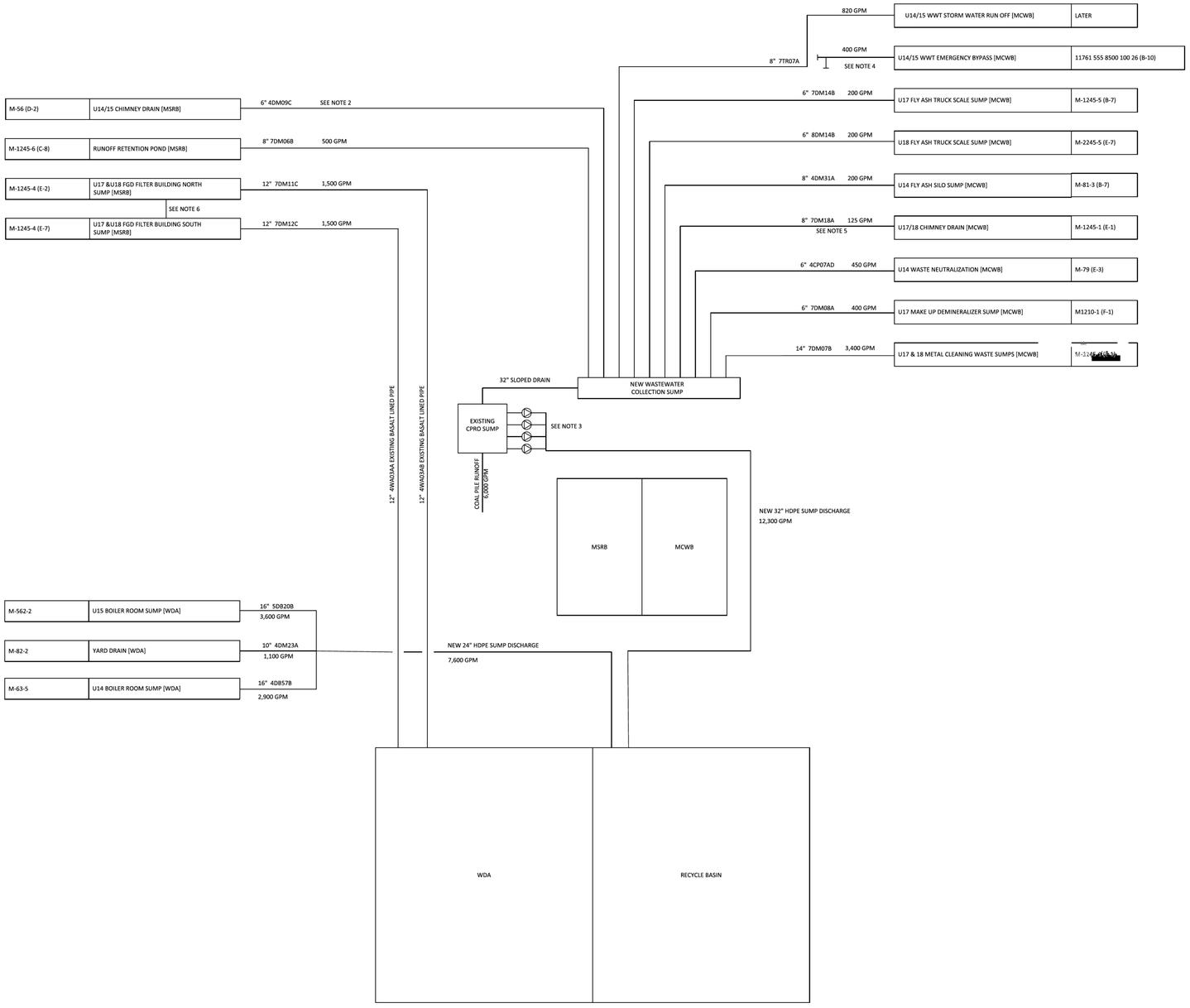
TITLE: ROLLIN M. SCHAHFER GEN. STA.
LOCATION: WHEATFIELD, INDIANA
DETAIL: WATER FLOW DIAGRAM
W.O./ACCT. NO.

NIPSCO DRAWING NO.: RMS-WF
REV.: A
SHEET

Figure RMS-WF (Proposed): Waste Stream Pipe Redirect

SHEET 1
M-1260

P O O DR N



NOTES:
1. ALL FLOWS ARE PEAK VALUES. THE LABELS WITHIN SQUARE BRACKETS, [ ], INDICATE THE BASIN INTO WHICH THE WASTE STREAM DISCHARGED PRIOR TO THIS PROJECT.
2. NIPSCO CONFIRMED U14/15 CHIMNEY DRAIN HAD NO FLOW. THIS LINE WILL NOT BE CONNECTED TO THE NEW SUMP.
3. REPLACE EXISTING COAL PILE RUNOFF PUMPS WITH FOUR NEW NON-CCR SUMP PUMPS 4,100 GPM 40FT TDH 75HP EACH (3) OPERATING (1) STANDBY
4. A TEE CONNECTION IS PROVIDED IN LINE 7TR07A TO REDIRECT DISCHARGE OF WWT EMERGENCY BYPASS TO TEMPORARY STORAGE.
5. LINE IDENTIFIED ON COMPOSITE PIPING DRAWINGS AS ABANDONED.
6. U17 &U18 FGD FILTER BUILDING NORTH AND SOUTH SUMPS ARE INTERCONNECTED.

REV.	W.O.	DESCRIPTION	DATE	APP'D DRAFT	APP'D ENGR.	FILM
8						
7						
6						
5						
4						
3						
2	B	ISSUED FOR BID	1/17/20	DWP	KM	
1	A	ISSUED FOR REVIEW	11/6/19	DWP	KM	

NIPSCO

DRAWN:	DWP
ENGINEER:	J. MAGEE
APPROVED:	
DATE:	11/6/19
SCALE:	NONE

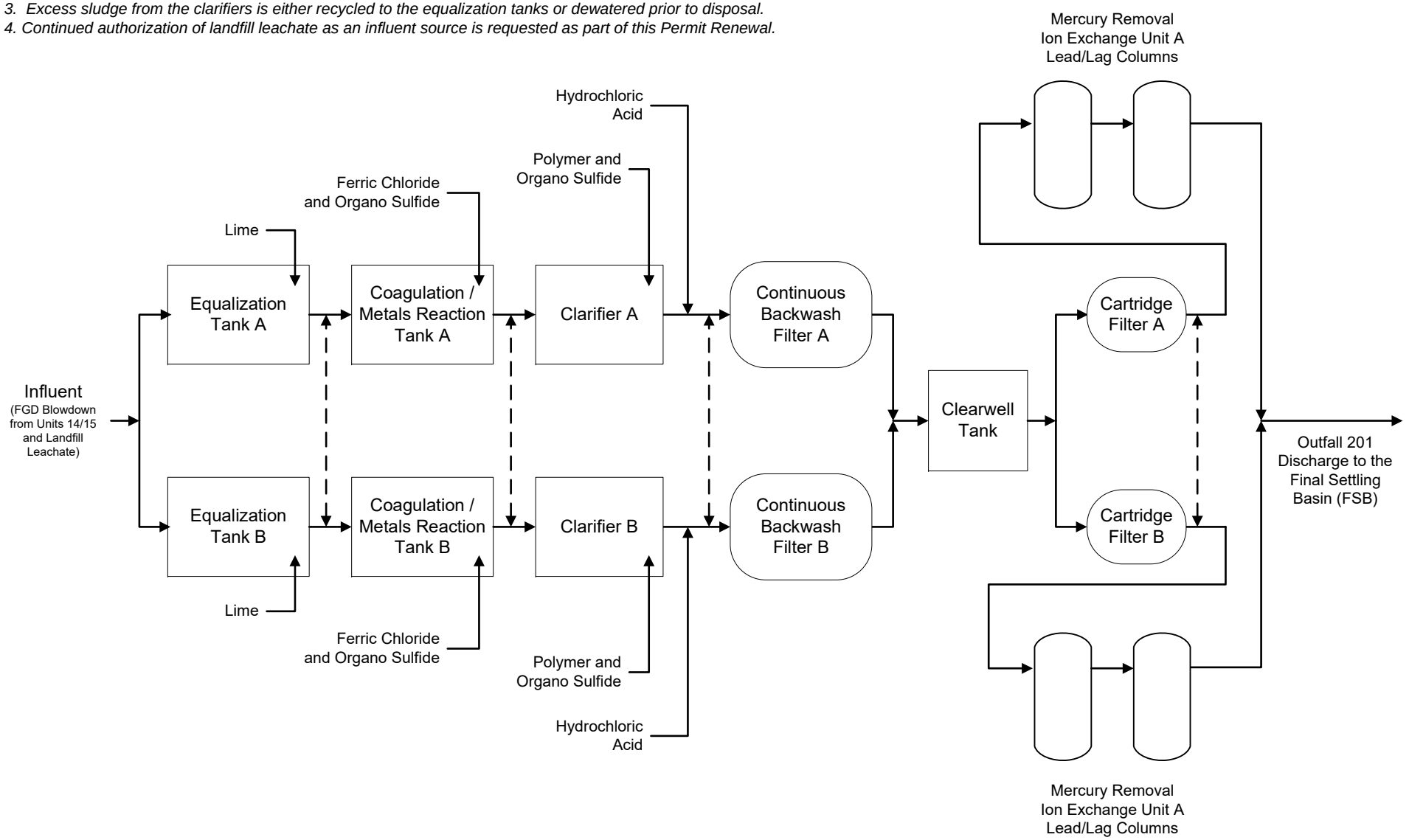
TITLE	ROLLIN M. SCHAHFER GEN. STA.
LOCATION	WHEATFIELD, INDIANA
DETAIL	PIPING REDIRECT PROJECT PROCESS FLOW DIAGRAM
W.O./ACCT. NO.	80156-72

NIPSCO DRAWING NO.	REV.
M-1260	B
SHEET 1	

Figure RMS-TREAT: Treatment Schematic - FGD Wastewater Treatment System

Notes:

1. *The figure is not intended to show all details, but provides an overview of the treatment system. For example, associated backwash flows and filter press water are also recycled to or sent to the equalization tanks.*
2. *The treatment system design includes redundancy and interconnectivity (dashed lines).*
3. *Excess sludge from the clarifiers is either recycled to the equalization tanks or dewatered prior to disposal.*
4. *Continued authorization of landfill leachate as an influent source is requested as part of this Permit Renewal.*



Prepared for:

R.M. Schahfer Generating Station

NPDES Permit IN0053201

Prepared by:

RAMBOLL

FIGURE RMS-TREAT
Treatment Schematic for the
FGD Wastewater Treatment System

02/24/2020

Form 2C Part V – Outfall 001, 101, 201

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3)

OUTFALL NO. 001

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Maximum Daily Values		b Maximum 30 Day Values *(if available)*		c Long Term Average *(if available)*		d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)*		b No of Analysis	a Method	b **Reporting** Limit
	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
a. Biochemical Oxygen Demand, Carbonaceous Cas No. E10106	1.77	315.9					1	mg/L	lb/day					
b. Escherichia coli (E-coli - units in count/100ml) Cas No. I-1000	4.1						1	MPN/100mL						
Fecal coliform (units in count/100 ml) Cas No. I-1000	TBD						1	cfu/100mL						
Chemical Oxygen Demand (COD) Cas No. E10107	20.0	3,570					1	mg/L	lb/day					
Dissolved Oxygen (DO) Cas No. E-14539	11.02						1	mg/L	lb/day					
Total Dissolved Solids (TDS) Cas No. E-10173	880.0	157,059					1	mg/L	lb/day					
Total Organic Carbon (TOC) Cas No. E-10195	5.0	892					1	mg/L	lb/day					
Total Suspended Solids (TSS) Cas No. E-10162	42.8	7,638.8	28.7	5,115.8	10.4	1,787.2	168/47	mg/L	lb/day					
Ammonia (as N) Cas No. 7664-41-7	2.0	360.0	1.1	195.0	0.4	60.0	163/47	mg/L	lb/day					
Flow	VALUE 23		VALUE 21.2		VALUE 20.3		975/48	MGD		VALUE				
Temperature (Winter) Cas No. E-14540	VALUE 54		VALUE 52		VALUE 41		114/32	°F		VALUE				
Temperature (Summer) Cas No. E-14540	VALUE 84		VALUE 83		VALUE 69		163/47	°F		VALUE				
Hardness, Total (as (CaCO3) Cas No. E-11778	570.0	101,731						mg/L	lb/day					
pH (S.U.) Cas No. E-10139	MINIMUM 7.4	MAXIMUM 8.9	MINIMUM 7.7	MAXIMUM 8.8			163/47	s.u.						

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	001

PART B - Mark "X" in column 2-a for each pollutant you know or have reason to believe is present Mark "X" in column 2-b for each pollutant you believe to be absent Pollutants for which you mark column 2-a , you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months) You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern Please provide the method used and detection limit achieved by the laboratory You must provide data or an explanation for the presence of the pollutant in your discharge Complete one table for each outfall See the instructions for additional details and requirements

1. POLLUTANT	2. MARK (X)		2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Be-lieved Pre-sent	b Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Bromide Cas No. 7726-95-6	X		2.3	410					1	mg/L	lb/day					
Chloride Cas No. 1688-70-6	X		363	65,392	245	39,280	133	22,679	164 / 47	mg/L	lb/day					
Chlorine, Total Residual Cas No. 7782-50-5		X	< 0.02						944/48	mg/L						
Color (C.U.) Cas No. E-11712	X		20.0						1	CU						
Fluoride Cas No. 16984-48-8	X		0.76	136					1	mg/L	lb/day					
Nitrate/Nitrite (as N) Cas No. E-10128	X		1.90	339					1	mg/L	lb/day					
Nitrogen, Total Organic (as N) Cas No. 7727-37-9	X		1.13	201.0					1	mg/L	lb/day					
Oil & Grease Cas No. E-10140		X	< 5.0						162/47	mg/L						
Phosphorus, Total Cas No. 7723-14-0	X		0.08	14.3					1	mg/L	lb/day					
Radioactivity																
(1) Radioactivity: Alpha, Total (pCi/L) Cas No. 12587-46-1		X	---	---												
(2) Radioactivity: Beta, Total (pCi/L) Cas No. 12587-47-2		X	---	---												
(3) Radioactivity: Radium ,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
(4) Radioactivity: Radium 226,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
Sulfate (as SO4) Cas No. 14808-79-8	X		646.0	115,295.0	622.0	111,012.0	372.8	63,561.0	162 / 47	mg/L	lb/day					
Sulfide (as S) Cas No. 18496-25-8		X	< 0.015						1	mg/L						
Sulfite (as SO3) Cas No. 14264-45-3		X	< 1.0	Sample was analyzed past holding time.					1	mg/L						
Surfactants (MBAS) Cas No. 61-73-4		X	< 0.2						1	mg/L						
Aluminum Cas No. 7429-90-5	X		0.025	4.46					1	mg/L	lb/day					
Barium Cas No. 7440-39-3	X		0.068	12.1					1	mg/L	lb/day					
Boron Cas No. 7440-42-8	X		35,000	6,305	13,867	2,498	6,405	1,089	162 / 47	ug/L	lb/day					
Cobalt Cas No. 7440-48-4	X		0.00056	0.100					1	mg/L	lb/day					
Iron Cas No. 7439-89-6	X		0.15	26.8					1	mg/L	lb/day					
Magnesium Cas No. 7439-95-4	X		47.0	8,388					1	mg/L	lb/day					
Molybdenum Cas No. 7439-98-7	X		0.18	32.1					1	mg/L	lb/day					

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	001

1. POLLUTANT	2. MARK (*X*)		2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Be-lieved Pre-sent	b Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Manganese Cas No. 7439-96-5	X		100.0	17,848.0	34.0	6,066.4	1.2	203.0	162/47	mg/L	lb/day					
Tin Cas No. 74400-31-5		X	< 0.00050						1	mg/L						
Titanium Cas No. 7440-32-6		X	< 0.00370						1	mg/L						
OTHER CONVENTIONAL																
Kjeldahl Nitrogen, Total Cas No. E-10264	X		1.20	214					1	mg/L	lb/day					
Nitrate Cas No. 14797-55-8	X		1.90	339					1	mg/L	lb/day					
Nitrite Cas No. 14797-65-0	X		0.016	2.86					1	mg/L	lb/day					

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	001

Part C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2C-2 in the instructions to determine which of the GC/MS fractions you must test for Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. Pollutants for which you mark column 2-a or 2-b, you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months). You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern. Please provide the method used and the detection limit achieved by the laboratory. You must provide data or an explanation for the presence of the pollutant in your discharge. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis daily / monthly average	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
METALS																	
Antimony Cas No. 7440-36-0	X		X	< 0.0005						1	mg/L						
Arsenic Cas No. 7440-38-2	X	X		0.0051	0.9	0.0035	0.6	0.0049	2.3	162/47	mg/L	lb/day					
Beryllium Cas No. 7440-41-7	X		X	< 0.00011						1	mg/L						
Cadmium Cas No. 7440-43-9	X		X	< 0.00014						1	mg/L						
Chromium Cas No. 7440-47-3	X	X		0.021	3.75	0.007	1.31	0.0008	0.13	162/47	mg/L	lb/day					
Chromium, Hex. (dissolved) Cas No. 18540-29-9	X	X		0.0055	0.98					1	mg/L	lb/day					
Copper Cas No. 7440-50-8	X	X		0.016	2.86					1	mg/L	lb/day					
Lead Cas No. 7439-92-1	X		X	< 0.00026						1	mg/L						
Mercury Cas No. 7439-97-6	X	X		6.7	0.0012			2.3	0.00040	22	ng/L	lb/day					
Nickel Cas No. 7440-02-0	X	X		0.012	2.14					1	mg/L	lb/day					
Selenium Cas No. 7782-49-2	X	X		0.013	2.3	0.0127	2.3	0.0068	1.2	162/47	mg/L	lb/day					
Silver Cas No. 7440-22-4	X		X	< 0.00005						1	mg/L						
Thallium Cas No. 7440-28-0	X		X	< 0.00010						1	mg/L						
Vanadium Cas No. 7440-62-2	X	X		0.0016	0.29					1	mg/L	lb/day					
Zinc Cas No. 7440-66-6	X	X		0.4	70.3	0.1	24.2	0.029	4.9	162/47	mg/L	lb/day					
CYANIDE																	
Cyanide, Free Cas No. 57-12-5	X		X	< 0.91						1	ug/L						
Cyanide, Total Cas No. 57-12-5	X		X	< 4.0						1	ug/L						
TOTAL PHENOLS																	
Phenols, Total (4AAP) Cas No. E-10253	X		X	< 6.0						1	ug/L						
DIOXIN																	
2,3,7,8-Tetrachloro dibenzo-P-Dioxin Cas No. 1746-01-6	X		X	Negative						1	--						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 001

1. POLLUTANT	2. MARK (X) a Testing Required	b Believed Present	c Believed Absent	2. EFFLUENT a Maximum Daily Values (1) Concentration	a (2) Mass	b Maximum 30 Day Values (if available) (1) Concentration	b (2) Mass	c Long Term Average (if available) (1) Concentration	c (2) Mass	d No of Analysis	3. UNITS (specify if blank) a Concentration	b Mass	4. INTAKE (optional) a Long Term Average Value (if available) (1) Concentration	a (2) Mass	b No of Analysis	5. ANALYTICAL METHOD (list method used and detection limit achieved by lab.) a Method	b Reporting Limit
OTHER																	
4-Methylphenol Cas No. 106-44-5	X		X	< 0.92						1	ug/L						
Acetaldehyde Cas No. 75-07-0	X		X	< 50						1	ug/L						
Bis(chloromethyl)ether Cas No. 542-88-1	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutant List.													
Dibutyl amine * Cas No. 111-92-2	X			No test method available for analysis.													
Dimethylpropyl phenol * Cas No. 80-46-6	X			No test method available for analysis.													
Formaldehyde Cas No. 5-00-0	X		X	< 50						1	ug/L						
Tributyl tin oxide * Cas No. 56-35-9	X			No test method available for analysis.													
VOLATILE ORGANIC																	
1,1,2,2-Tetrachloroethane Cas No. 79-34-5	X		X	< 0.32						1	ug/L						
1,1,2-Trichloroethane Cas No. 79-00-5	X		X	< 0.26						1	ug/L						
1,1,1-Trichloroethane Cas No. 71-55-6	X		X	< 0.23						1	ug/L						
1,1-Dichloroethane Cas No. 75-34-3	X		X	< 0.25						1	ug/L						
1,1-Dichloroethene Cas No. 75-35-4	X		X	< 0.23						1	ug/L						
1,2,4-Trimethylbenzene Cas No. 95-63-6	X		X	< 0.24						1	ug/L						
1,2-Dichlorethane Cas No. 107-06-2	X		X	< 0.38						1	ug/L						
1,2-Dichloroethene, Trans Cas No. 156-60-5	X		X	< 0.22						1	ug/L						
1,2-Dichloropropane Cas No. 78-87-5	X		X	< 0.19						1	ug/L						
1,3,5-Trimethylbenzene Cas No. 108-67-8	X		X	< 0.25						1	ug/L						
1,3-Dichloropropane Cas No. 142-28-9	X		X	< 0.29						1	ug/L						
1,3-Dichloropropene, Cis Cas No. 10061-01-5	X		X	< 0.26						1	ug/L						
1,3-Dichloropropene, Trans Cas No. 10061-02-6	X		X	< 0.26						1	ug/L						
1,3-Dichloropropylene Cas No. 542-75-6	X		X	< 0.26	Listed separately as cis and tras 1,3-dichloropropene					1	ug/L						
2-Butanone (Methyl Ethyl Ketone) Cas No. 78-93-3	X		X	< 0.18						1	ug/L						
2-Chloroethyl vinyl ether Cas No. 110-75-8	X		X	< 0.19						1	ug/L						
Acetone Cas No. 67-64-1	X	X		2.7	0.482					1	ug/L	lb/day					
Acrolein Cas No. 1070-20-8	X		X	< 2.20						1	ug/L						
Acrylonitrile Cas No. 107-13-1	X		X	< 1.90						1	ug/L						
Benzene Cas No. 71-43-2	X		X	< 0.15						1	ug/L						
Bromoform Cas No. 75-25-2	X		X	< 0.25						1	ug/L						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 001

1. POLLUTANT	2. MARK (X) a Testing Required	b Believed Present	c Believed Absent	2. EFFLUENT a Maximum Daily Values (1) Concentration	a (2) Mass	b Maximum 30 Day Values (if available) (1) Concentration	b (2) Mass	c Long Term Average (if available) (1) Concentration	c (2) Mass	d No of Analysis	3. UNITS (specify if blank) a Concentration	b Mass	4. INTAKE (optional) a Long Term Average Value (if available) (1) Concentration	a (2) Mass	b No of Analysis	5 ANALYTICAL METHOD (list method used and detection limit achieved by lab.) a Method	b Reporting Limit
Carbon disulfide Cas No. 75-15-0	X		X	< 0.22						1	ug/L						
Carbon Tetrachloride Cas No. 56-23-5	X		X	< 0.25						1	ug/L						
Chlorobenzene Cas No. 108-90-7	X		X	< 0.26						1	ug/L						
Chlorodibromomethane Cas No. 124-48-1	X		X	< 0.24						1	ug/L						
Chloroethane Cas No. 75-00-3	X		X	< 0.22						1	ug/L						
Dichlorobromomethane Cas No. 75-27-4	X		X	< 0.21						1	ug/L						
Dichlorodifluoromethane Cas No. 75-71-8	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutant List.													
Ethylbenzene Cas No. 100-41-4	X		X	< 0.25						1	ug/L						
Ethylene glycol Cas No. 107-21-1	X		X	< 5	Sample was analyzed past holding time.					1	mg/L						
Methanol Cas No. 67-56-1	X		X	< 1						1	mg/L						
Methyl Bromide (Bromomethane) Cas No. 74-83-9	X		X	< 0.29						1	ug/L						
Methyl chloride (Chloromethane) Cas No. 74-87-3	X		X	< 0.24						1	ug/L						
Methyl tert-butyl ether (MTBE) Cas No. 1634-04-4	X		X	< 0.26						1	ug/L						
Methylamine * Cas No. 74-89-5	X			No test method available for analysis.													
Methylene chloride Cas No. 75-09-2	X		X	< 10						1	ug/L						
Propylene glycol Cas No. 57-55-6	X		X	< 5	Sample was analyzed past holding time.					1	mg/L						
Tetrachloroethene Cas No. 127-18-4	X		X	< 0.26						1	ug/L						
Trichloroethene Cas No. 79-01-6	X		X	< 0.26						1	ug/L						
Trichlorofluoromethane Cas No. 75-69-4	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutant List.													
Toluene Cas No. 108-88-3	X		X	< 0.30						1	ug/L						
Vinyl chloride Cas No. 75-01-4	X		X	< 0.26						1	ug/L						
Xylene Cas No. 1330-20-7	X		X	< 0.75						1	ug/L						
SEMI-VOLATILE ORGANIC-ACID																	
2,4-Dichlorophenol Cas No. 120-83-2	X		X	< 0.68						1	ug/L						
2,4-Dimethylphenol Cas No. 105-67-9	X		X	< 0.76						1	ug/L						
2,4-Dinitrophenol Cas No. 51-28-5	X		X	< 0.33						1	ug/L						
2,4,6-Trichlorophenol Cas No. 88-06-2	X		X	< 0.82						1	ug/L						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 001

1. POLLUTANT	2. MARK (X)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
2-Chlorophenol Cas No. 95-57-8	X		X	< 0.80						1	ug/L						
2-Nitrophenol Cas No. 88-75-5	X		X	< 1.00						1	ug/L						
4-Nitrophenol Cas No. 100-02-7	X		X	< 0.92						1	ug/L						
4,6-Dmitro-o-cresol (2-methyl-4,6-dinitrophenol) Cas No. 534-52-1	X		X	< 0.38						1	ug/L						
Benzoic acid Cas No. 65-85-0	X		X	< 0.56						1	ug/L						
p-Chloro-m-cresol (4-chloro-3-methylphenol) Cas No. 59-50-7	X		X	< 0.84						1	ug/L						
Pentachlorophenol Cas No. 87-86-5	X		X	< 0.34						1	ug/L						
Phenol Cas No. 108-95-2	X		X	< 0.41						1	ug/L						
SEMI-VOLATILE ORGANIC-BASE																	
1,2,4-Trichlorobenzene Cas No. 120-82-1	X		X	< 0.66						1	ug/L						
1,2-Dichlorobenzene Cas No. 95-50-1	X		X	< 0.81						1	ug/L						
1,2-Diphenylhydrazine Cas No. 122-66-7	X		X	< 1.10						1	ug/L						
1,3-Dichlorobenzene Cas No. 541-73-1	X		X	< 0.71						1	ug/L						
1,4-Dichlorobenzene Cas No. 106-46-7	X		X	< 0.69						1	ug/L						
2-Chloronaphthalene Cas No. 91-58-7	X		X	< 0.79						1	ug/L						
2-Methylnaphthalene Cas No. 91-57-6	X		X	< 0.77						1	ug/L						
2,4-Dinitrotoluene Cas No. 121-14-2	X		X	< 0.52						1	ug/L						
2,6-Dinitrotoluene Cas No. 606-20-2	X		X	< 0.63						1	ug/L						
3,3-Dichlorobenzidine Cas No. 91-94-1	X		X	< 1.40						1	ug/L						
3,4-Benzofluoranthene (benzo(b)fluoranthene) Cas No. 205-99-2	X		X	< 0.0067						1	ug/L						
4-Bromophenyl phenyl ether Cas No. 101-55-3	X		X	< 0.74						1	ug/L						
4-Chlorophenyl phenyl ether Cas No. 7005-72-3	X		X	< 0.77						1	ug/L						
Acenaphthene Cas No. 83-32-9	X		X	< 0.013						1	ug/L						
Acenaphthylene Cas No. 208-96-8	X		X	< 0.0033						1	ug/L						
Anthracene Cas No. 120-12-7	X		X	< 0.0078						1	ug/L						
Benzidine Cas No. 92-87-5	X		X	< 56.00						1	ug/L						
Benzo(a)anthracene Cas No. 56-55-3	X		X	< 0.0044						1	ug/L						
Benzo(a)pyrene Cas No. 50-32-8	X		X	< 0.0067						1	ug/L						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 001

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
Benzo(ghi)perylene Cas No. 191-24-2	X		X	< 0.0056						1	ug/L						
Benzo(k)fluoranthene Cas No. 207-06-9	X		X	< 0.0078						1	ug/L						
Bis(2-chloroethoxy)methane Cas No. 111-91-1	X		X	< 0.94						1	ug/L						
Bis(2-chloroethyl) ether Cas No. 111-44-4	X		X	< 0.86						1	ug/L						
Bis(2-chloroisopropyl) ether Cas No. 108-60-1	X		X	< 0.76						1	ug/L						
Bis(2-ethylhexyl)phthalate Cas No. 117-81-7	X		X	< 1.30						1	ug/L						
Butyl benzyl phthalate Cas No. 85-68-7	X		X	< 1.00						1	ug/L						
Chrysene Cas No. 218-01-9	X		X	< 0.0067						1	ug/L						
Di-n-butyl phthalate Cas No. 84-74-2	X		X	< 0.91						1	ug/L						
Di-n-octyl phthalate Cas No. 117-84-0	X		X	< 0.78						1	ug/L						
Dibenzo(a,h)anthracene Cas No. 53-70-3	X		X	< 0.0067						1	ug/L						
Dibenzofuran Cas No. 132-64-9	X		X	< 0.76						1	ug/L						
Diethylphthalate Cas No. 84-66-2	X		X	< 1.40						1	ug/L						
Dimethylphthalate Cas No. 131-11-3	X		X	< 0.76						1	ug/L						
Fluoranthene Cas No. 206-44-0	X		X	< 0.0056						1	ug/L						
Fluorene Cas No. 86-73-7	X		X	< 0.0044						1	ug/L						
Hexachlorobenzene Cas No. 118-74-1	X		X	< 1.10						1	ug/L						
Hexachlorobutadiene Cas No. 87-68-3	X		X	< 1.10						1	ug/L						
Hexachlorocyclopentadiene Cas No. 77-47-4	X		X	< 0.44						1	ug/L						
Hexachloroethane Cas No. 67-72-1	X		X	< 1.10						1	ug/L						
Indeno(1,2,3-cd) Pyrene Cas No. 193-39-5	X		X	< 0.0044						1	ug/L						
Isophorone Cas No. 78-59-1	X		X	< 0.89						1	ug/L						
N-nitrosodi-n-propyl amine Cas No. 621-64-7	X		X	< 1.10						1	ug/L						
N-nitrosodimethyl amine Cas No. 62-75-9	X		X	< 1.00						1	ug/L						
N-nitrosodiphenyl amine Cas No. 86-30-6	X			< 0.80						1	ug/L						
Naphthalene Cas No. 91-20-3	X		X	< 0.01						1	ug/L						
Nitrobenzene Cas No. 98-95-3	X		X	< 0.88						1	ug/L						
Phenanthrene Cas No. 85-01-8	X		X	< 0.0078						1	ug/L						
Pyrene Cas No. 129-00-0	X		X	< 0.0056						1	ug/L						

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	001

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Styrene Cas No. 100-42-5	X		X	< 0.22						1	ug/L						
PESTICIDES																	
2,4-Dichlorophenoxy Acetic Acid Cas No. 94-75-7			X														
Alachlor Cas No. 15972-60-8			X														
Aldrin Cas No. 309-00-2			X														
Atrazine Cas No. 1912-24-9			X														
BHC-Alpha Cas No. 319-84-6			X														
BHC-Beta Cas No. 319-85-7			X														
BHC-Gamma (Lindane) Cas No. 58-89-9			X														
BHC-Delta Cas No. 319-86-8			X														
Chlordane Cas No. 57-74-9			X														
DDD Cas No. 72-54-8			X														
DDE Cas No. 72-55-9			X														
DDT Cas No. 50-29-3			X														
Dieldrin Cas No. 60-57-1			X														
Endosulfan Sulfate Cas No. 1031-07-8			X														
Endosulfan, Alpha Cas No. 959-98-8			X														
Endosulfan, Beta Cas No. 33213-65-9			X														
Endrin Cas No. 72-20-8			X														
Endrin Aldehyde Cas No. 7421-93-4			X														
Heptachlor Cas No. 76-44-8			X														
Heptachlor Epoxide Cas No. 1024-57-3			X														
Methoxychlor Cas No. 72-43-5			X														
Metolachlor Cas No. 51218-45-2			X														
Mirex Cas No. 2385-85-5			X														
Parathion ethyl Cas No. 56-38-2			X														
Parathion methyl Cas No. 56-38-2			X														
Simazine Cas No. 122-34-9			X														

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	001

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT						d No of Analysis	3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass		a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
PCB-1242 Cas No. 534469-21-9			X	< 0.43				< 0.253		2	ug/L						
PCB-1254 Cas No. 11097-69-1			X	< 0.43				< 0.290		2	ug/L						
PCB-1221 Cas No. 11104-28-2			X	< 0.43				< 0.405		2	ug/L						
PCB-1232 Cas No. 11141-16-5			X	< 0.43				< 0.285		2	ug/L						
PCB-1248 Cas No. 12672-29-6			X	< 0.43				< 0.237		2	ug/L						
PCB-1260 Cas No. 11096-82-5			X	< 0.43				< 0.295		2	ug/L						
PCB-1016 Cas No. 12674-11-2			X	< 0.43				< 0.285		2	ug/L						
Toxaphene Cas No. 8001-35-2																	
WHOLE EFFLUENT TOXICITY																	
Acute, Freshwater Organisms Cas No. I-1100			X														
Chronic Freshwater Organisms Cas No. I-1101			X														
ADDITIONAL ANALYSES																	
Chloroform			X	< 0.26						1	ug/L						

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V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3)

OUTFALL NO. 101

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Maximum Daily Values		b Maximum 30 Day Values *(if available)*		c Long Term Average *(if available)*		d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)*		b No of Analysis	a Method	b **Reporting** Limit
	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
a. Biochemical Oxygen Demand, Carbonaceous Cas No. E10106	57.1	4.4	35.9	2.3	4.8	0.2	99/47	mg/L	lb/day					
b. Escherichia coli (E-coli - units in count/100ml) Cas No. I-1000	>2419.6						1	MPN/100mL						
Fecal coliform (units in count/100 ml) Cas No. I-1000	>600						1	cfu/100mL						
Chemical Oxygen Demand (COD) Cas No. E10107	66.0	1.9					1	mg/L	lb/day					
Dissolved Oxygen (DO) Cas No. E-14539	9.08						1	mg/L						
Total Dissolved Solids (TDS) Cas No. E-10173	510.0	14.9					1	mg/L	lb/day					
Total Organic Carbon (TOC) Cas No. E-10195	7.0	0.20					1	mg/L	lb/day					
Total Suspended Solids (TSS) Cas No. E-10162	67.6	17.2	30.5	8.7	14.2	0.9	98/47	mg/L	lb/day					
Ammonia (as N) Cas No. 7664-41-7	0.08	0.002					1	mg/L	lb/day					
Flow	VALUE 0.3		VALUE 0.15		VALUE 0.009		113/47	MGD		VALUE				
Temperature (Winter) Cas No. E-14540	VALUE 50.1		VALUE		VALUE		1	F		VALUE				
Temperature (Summer) Cas No. E-14540	VALUE		VALUE		VALUE					VALUE				
Hardness, Total (as (CaCO3) Cas No. E-11778	240.0	7.006					1	mg/L	lb/day					
pH (S.U.) Cas No. E-10139	MINIMUM	MAXIMUM 7.1	MINIMUM	MAXIMUM			1	s.u.						

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PART B - Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. Pollutants for which you mark column 2-a, you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months). You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern. Please provide the method used and detection limit achieved by the laboratory. You must provide data or an explanation for the presence of the pollutant in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT	2. MARK (X)		2. EFFLUENT							3. UNITS (specify if blank)		4. INTAKE (optional)			5. ANALYTICAL METHOD (list method used and detection limit achieved by lab.)	
	a Be-lieved Pre-sent	b Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values (if available) (1) Concentration	b Maximum 30 Day Values (if available) (2) Mass	c Long Term Average (if available) (1) Concentration	c Long Term Average (if available) (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value (if available) (1) Concentration	a Long Term Average Value (if available) (2) Mass	b No of Analysis	a Method	b Reporting Limit
Bromide Cas No. 7726-95-6		X	< 0.5						1	mg/L						
Chloride Cas No. 1688-70-6	X		82.0	2.39					1	mg/L	lb/day					
Chlorine, Total Residual Cas No. 7782-50-5		X	< 0.02						1	mg/L						
Color (C.U.) Cas No. E-11712	X		30.0						1	CU						
Fluoride Cas No. 16984-48-8	X		0.47	0.014					1	mg/L	lb/day					
Nitrate/Nitrite (as N) Cas No. E-10128	X		35.0	1.02					1	mg/L	lb/day					
Nitrogen, Total Organic (as N) Cas No. 7727-37-9		X	< 0.32						1	mg/L						
Oil & Grease Cas No. E-10140		X	< 5.0						1	mg/L						
Phosphorus, Total Cas No. 7723-14-0	X		1.0	0.030					1	mg/L	lb/day					
Radioactivity																
(1) Radioactivity: Alpha, Total (pCi/L) Cas No. 12587-46-1		X	---	---												
(2) Radioactivity: Beta, Total (pCi/L) Cas No. 12587-47-2		X	---	---												
(3) Radioactivity: Radium ,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
(4) Radioactivity: Radium 226,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
Sulfate (as SO4) Cas No. 14808-79-8	X		94.9	2.77					1	mg/L	lb/day					
Sulfide (as S) Cas No. 18496-25-8	X		0.027	0.0008					1	mg/L	lb/day					
Sulfite (as SO3) Cas No. 14264-45-3		X	< 1.0	Sample was analyzed past holding time					1	mg/L						
Surfactants (MBAS) Cas No. 61-73-4		X	< 0.2						1	mg/L						
Aluminum Cas No. 7429-90-5	X		0.180	0.005					1	mg/L	lb/day					
Barium Cas No. 7440-39-3	X		0.036	0.0011					1	mg/L	lb/day					
Boron Cas No. 7440-42-8	X		0.4	0.012					1	mg/L	lb/day					
Cobalt Cas No. 7440-48-4	X		0.00072	0.000021					1	mg/L	lb/day					
Iron Cas No. 7439-89-6	X		0.43	0.013					1	mg/L	lb/day					
Magnesium Cas No. 7439-95-4	X		17.0	0.50					1	mg/L	lb/day					
Molybdenum Cas No. 7439-98-7	X		0.015	0.0004					1	mg/L	lb/day					

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	101

1. POLLUTANT	2. MARK (*X*)		2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Be-lieved	b Be-lieved	a Maximum Daily Values		b Maximum 30 Day Values *(if available)*		c Long Term Average *(if available)*		d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)*		b No of Analysis	a Method	b Reporting Limit
	Pre-sent	Ab-sent	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
Manganese Cas No. 7439-96-5	X		0.08	0.0023					1	mg/L	lb/day					
Tin Cas No. 74400-31-5		X	< 0.0005						1	mg/L						
Titanium Cas No. 7440-32-6	X		0.0091	0.00027					1	mg/L	lb/day					
OTHER CONVENTIONAL																
Kjeldahl Nitrogen, Total Cas No. E-10264		X	< 0.44						1	mg/L						
Nitrate Cas No. 14797-55-8	X		35.0	1.02					1	mg/L	lb/day					
Nitrite Cas No. 14797-65-0		X	< 0.016						1	mg/L						

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Part C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2C-2 in the instructions to determine which of the GC/MS fractions you must test for Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. Pollutants for which you mark column 2-a or 2-b, you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months). You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern. Please provide the method used and the detection limit achieved by the laboratory. You must provide data or an explanation for the presence of the pollutant in your discharge. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis daily / monthly average	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
METALS																	
Antimony Cas No. 7440-36-0	X		X	< 0.0005						1	mg/L						
Arsenic Cas No. 7440-38-2	X	X		0.0054	0.00016					1	mg/L	lb/day					
Beryllium Cas No. 7440-41-7	X		X	< 0.00011						1	mg/L						
Cadmium Cas No. 7440-43-9	X		X	< 0.00014						1	mg/L						
Chromium Cas No. 7440-47-3	X	X		0.00082	0.00002					1	mg/L	lb/day					
Chromium, Hex. (dissolved) Cas No. 18540-29-9	X	X		0.0075	0.00022					1	mg/L	lb/day					
Copper Cas No. 7440-50-8	X	X		0.039	0.0011					1	mg/L	lb/day					
Lead Cas No. 7439-92-1	X	X		0.0010	0.00003					1	mg/L	lb/day					
Mercury Cas No. 7439-97-6	X		X	< 0.000093						1	mg/L						
Nickel Cas No. 7440-02-0	X	X		0.0045	0.00013					1	mg/L	lb/day					
Selenium Cas No. 7782-49-2	X		X	< 0.00055						1	mg/L						
Silver Cas No. 7440-22-4	X	X		0.00010	0.0000029					1	mg/L	lb/day					
Thallium Cas No. 7440-28-0	X		X	< 0.00010						1	mg/L						
Vanadium Cas No. 7440-62-2	X	X		0.0020	0.00006					1	mg/L	lb/day					
Zinc Cas No. 7440-66-6	X	X		0.16	0.0047					1	mg/L	lb/day					
CYANIDE																	
Cyanide, Free Cas No. 57-12-5	X	X		1.1	0.00003					1	ug/L	lb/day					
Cyanide, Total Cas No. 57-12-5	X		X	< 4						1	ug/L						
TOTAL PHENOLS																	
Phenols, Total (4AAP) Cas No. E-10253	X		X	< 6						1	mg/L						
DIOXIN																	
2,3,7,8-Tetrachloro dibenzo-P-Dioxin Cas No. 1746-01-6			X														

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 101

1. POLLUTANT	2. MARK (X)			2. EFFLUENT							3. UNITS (specify if blank)		4. INTAKE (optional)			5. ANALYTICAL METHOD (list method used and detection limit achieved by lab.)	
	a Testing Required	b Believed Present	c Believed Absent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values (if available) (1) Concentration	b Maximum 30 Day Values (if available) (2) Mass	c Long Term Average (if available) (1) Concentration	c Long Term Average (if available) (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value (if available) (1) Concentration	a Long Term Average Value (if available) (2) Mass	b No of Analysis	a Method	b Reporting Limit
OTHER																	
4-Methylphenol Cas No. 106-44-5			X														
Acetaldehyde Cas No. 75-07-0			X														
Bis(chloromethyl)ether Cas No. 542-88-1			X														
Dibutyl amine * Cas No. 111-92-2			X														
Dimethylpropyl phenol * Cas No. 80-46-6			X														
Formaldehyde Cas No. 5-00-0			X														
Tributyl tin oxide * Cas No. 56-35-9			X														
VOLATILE ORGANIC																	
1,1,2,2-Tetrachloroethane Cas No. 79-34-5			X														
1,1,2-Trichloroethane Cas No. 79-00-5			X														
1,1,1-Trichloroethane Cas No. 71-55-6			X														
1,1-Dichloroethane Cas No. 75-34-3			X														
1,1-Dichloroethene Cas No. 75-35-4			X														
1,2,4-Trimethylbenzene Cas No. 95-63-6			X														
1,2-Dichlorethane Cas No. 107-06-2			X														
1,2-Dichloroethene, Trans Cas No. 156-60-5			X														
1,2-Dichloropropane Cas No. 78-87-5			X														
1,3,5-Trimethylbenzene Cas No. 108-67-8			X														
1,3-Dichloropropane Cas No. 142-28-9			X														
1,3-Dichloropropene, Cis Cas No. 10061-01-5			X														
1,3-Dichloropropene, Trans Cas No. 10061-02-6			X														
1,3-Dichloropropylene Cas No. 542-75-6			X														
2-Butanone (Methyl Ethyl Ketone) Cas No. 78-93-3			X														
2-Chloroethyl vinyl ether Cas No. 110-75-8			X														
Acetone Cas No. 67-64-1			X														
Acrolein Cas No. 1070-20-8			X														
Acrylonitrile Cas No. 107-13-1			X														
Benzene Cas No. 71-43-2			X														
Bromoform Cas No. 75-25-2			X														

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	101

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
Carbon disulfide Cas No. 75-15-0			X														
Carbon Tetrachloride Cas No. 56-23-5			X														
Chlorobenzene Cas No. 108-90-7			X														
Chlorodibromomethane Cas No. 124-48-1			X														
Chloroethane Cas No. 75-00-3			X														
Dichlorobromomethane Cas No. 75-27-4			X														
Dichlorodifluoromethane Cas No. 75-71-8			X														
Ethylbenzene Cas No. 100-41-4			X														
Ethylene glycol Cas No. 107-21-1			X														
Methanol Cas No. 67-56-1			X														
Methyl Bromide (Bromomethane) Cas No. 74-83-9			X														
Methyl chloride (Chloromethane) Cas No. 74-87-3			X														
Methyl tert-butyl ether (MTBE) Cas No. 1634-04-4			X														
Methylamine * Cas No. 74-89-5			X														
Methylene chloride Cas No. 75-09-2			X														
Propylene glycol Cas No. 57-55-6			X														
Tetrachloroethene Cas No. 127-18-4			X														
Trichloroethene Cas No. 79-01-6			X														
Trichlorofluoromethane Cas No. 75-69-4			X														
Toluene Cas No. 108-88-3			X														
Vinyl chloride Cas No. 75-01-4			X														
Xylene Cas No. 1330-20-7			X														
SEMI-VOLATILE ORGANIC-ACID																	
2,4-Dichlorophenol Cas No. 120-83-2			X														
2,4-Dimethylphenol Cas No. 105-67-9			X														
2,4-Dinitrophenol Cas No. 51-28-5			X														
2,4,6-Trichlorophenol Cas No. 88-06-2			X														

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 101

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Testing Required	b Believed Present	c Believed Absent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
2-Chlorophenol Cas No. 95-57-8			X														
2-Nitrophenol Cas No. 88-75-5			X														
4-Nitrophenol Cas No. 100-02-7			X														
4,6-Dmitro-o-cresol (2-methyl-4,6-dinitrophenol) Cas No. 534-52-1			X														
Benzoic acid Cas No. 65-85-0			X														
p-Chloro-m-cresol (4-chloro-3-methylphenol) Cas No. 59-50-7			X														
Pentachlorophenol Cas No. 87-86-5			X														
Phenol Cas No. 108-95-2			X														
SEMI-VOLATILE ORGANIC-BASE																	
1,2,4-Trichlorobenzene Cas No. 120-82-1			X														
1,2-Dichlorobenzene Cas No. 95-50-1			X														
1,2-Diphenylhydrazine Cas No. 122-66-7			X														
1,3-Dichlorobenzene Cas No. 541-73-1			X														
1,4-Dichlorobenzene Cas No. 106-46-7			X														
2-Chloronaphthalene Cas No. 91-58-7			X														
2-Methylnaphthalene Cas No. 91-57-6			X														
2,4-Dinitrotoluene Cas No. 121-14-2			X														
2,6-Dinitrotoluene Cas No. 606-20-2			X														
3,3-Dichlorobenzidine Cas No. 91-94-1			X														
3,4-Benzofluoranthene (benzo(b)fluoranthene) Cas No. 205-99-2			X														
4-Bromophenyl phenyl ether Cas No. 101-55-3			X														
4-Chlorophenyl phenyl ether Cas No. 7005-72-3			X														
Acenaphthene Cas No. 83-32-9			X														
Acenaphthylene Cas No. 208-96-8			X														
Anthracene Cas No. 120-12-7			X														
Benzidine Cas No. 92-87-5			X														
Benzo(a)anthracene Cas No. 56-55-3			X														
Benzo(a)pyrene Cas No. 50-32-8			X														

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	101

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
Benzo(ghi)perylene Cas No. 191-24-2			X														
Benzo(k)fluoranthene Cas No. 207-06-9			X														
Bis(2-chloroethoxy)methane Cas No. 111-91-1			X														
Bis(2-chloroethyl) ether Cas No. 111-44-4			X														
Bis(2-chloroisopropyl) ether Cas No. 108-60-1			X														
Bis(2-ethylhexyl)phthalate Cas No. 117-81-7			X														
Butyl benzyl phthalate Cas No. 85-68-7			X														
Chrysene Cas No. 218-01-9			X														
Di-n-butyl phthalate Cas No. 84-74-2			X														
Di-n-octyl phthalate Cas No. 117-84-0			X														
Dibenzo(a,h)anthracene Cas No. 53-70-3			X														
Dibenzofuran Cas No. 132-64-9			X														
Diethylphthalate Cas No. 84-66-2			X														
Dimethylphthalate Cas No. 131-11-3			X														
Fluoranthene Cas No. 206-44-0			X														
Fluorene Cas No. 86-73-7			X														
Hexachlorobenzene Cas No. 118-74-1			X														
Hexachlorobutadiene Cas No. 87-68-3			X														
Hexachlorocyclopentadiene Cas No. 77-47-4			X														
Hexachloroethane Cas No. 67-72-1			X														
Indeno(1,2,3-cd) Pyrene Cas No. 193-39-5			X														
Isophorone Cas No. 78-59-1			X														
N-nitrosodi-n-propyl amine Cas No. 621-64-7			X														
N-nitrosodimethyl amine Cas No. 62-75-9			X														
N-nitrosodiphenyl amine Cas No. 86-30-6			X														
Naphthalene Cas No. 91-20-3			X														
Nitrobenzene Cas No. 98-95-3			X														
Phenanthrene Cas No. 85-01-8			X														
Pyrene Cas No. 129-00-0			X														

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 101

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Styrene Cas No. 100-42-5			X														
PESTICIDES																	
2,4-Dichlorophenoxy Acetic Acid Cas No. 94-75-7			X														
Alachlor Cas No. 15972-60-8			X														
Aldrin Cas No. 309-00-2			X														
Atrazine Cas No. 1912-24-9			X														
BHC-Alpha Cas No. 319-84-6			X														
BHC-Beta Cas No. 319-85-7			X														
BHC-Gamma (Lindane) Cas No. 58-89-9			X														
BHC-Delta Cas No. 319-86-8			X														
Chlordane Cas No. 57-74-9			X														
DDD Cas No. 72-54-8			X														
DDE Cas No. 72-55-9			X														
DDT Cas No. 50-29-3			X														
Dieldrin Cas No. 60-57-1			X														
Endosulfan Sulfate Cas No. 1031-07-8			X														
Endosulfan, Alpha Cas No. 959-98-8			X														
Endosulfan, Beta Cas No. 33213-65-9			X														
Endrin Cas No. 72-20-8			X														
Endrin Aldehyde Cas No. 7421-93-4			X														
Heptachlor Cas No. 76-44-8			X														
Heptachlor Epoxide Cas No. 1024-57-3			X														
Methoxychlor Cas No. 72-43-5			X														
Metolachlor Cas No. 51218-45-2			X														
Mirex Cas No. 2385-85-5			X														
Parathion ethyl Cas No. 56-38-2			X														
Parathion methyl Cas No. 56-38-2			X														
Simazine Cas No. 122-34-9			X														

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 101

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
PCB-1242 Cas No. 534469-21-9			X														
PCB-1254 Cas No. 11097-69-1			X														
PCB-1221 Cas No. 11104-28-2			X														
PCB-1232 Cas No. 11141-16-5			X														
PCB-1248 Cas No. 12672-29-6			X														
PCB-1260 Cas No. 11096-82-5			X														
PCB-1016 Cas No. 12674-11-2			X														
Toxaphene Cas No. 8001-35-2			X														
WHOLE EFFLUENT TOXICITY																	
Acute, Freshwater Organisms Cas No. I-1100			X														
Chronic Freshwater Organisms Cas No. I-1101			X														

ADDITIONAL ANALYSES																	

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3)

OUTFALL NO. 201

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Maximum Daily Values		b Maximum 30 Day Values *(if available)*		c Long Term Average *(if available)*		d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)*		b No of Analysis	a Method	b **Reporting** Limit
	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
a. Biochemical Oxygen Demand, Carbonaceous Cas No. E10106	1.32	0.29					1	mg/L	lb/day					
b. Escherichia coli (E-coli - units in count/100ml) Cas No. I-1000	< 1.0						1	MPN/ 100 mL						
Fecal coliform (units in count/100 ml) Cas No. I-1000	TBD						1	cfu/100mL						
Chemical Oxygen Demand (COD) Cas No. E10107	110.0	25.7					1	mg/L	lb/day					
Dissolved Oxygen (DO) Cas No. E-14539	9.52						1	mg/L						
Total Dissolved Solids (TDS) Cas No. E-10173	11,000.0	2,567					1	mg/L	lb/day					
Total Organic Carbon (TOC) Cas No. E-10195	1.9	0.44					1	mg/L	lb/day					
Total Suspended Solids (TSS) Cas No. E-10162	45.0	11.1	28.1	10.6	6.0	2.6	97/48	mg/L	lb/day					
Ammonia (as N) Cas No. 7664-41-7	615.0	290.1	457.5	193.4	158.1	67.7	98/48	mg/L	lb/day					
Flow	VALUE 0.12		VALUE 0.1		VALUE 0.05		97/48	MGD		VALUE				
Temperature (Winter) Cas No. E-14540	VALUE 59		VALUE		VALUE		1	F		VALUE				
Temperature (Summer) Cas No. E-14540	VALUE		VALUE		VALUE					VALUE				
Hardness, Total (as (CaCO3) Cas No. E-11778	1,900.0	443					1	mg/L	lb/day					
pH (S.U.) Cas No. E-10139	MINIMUM 5.9	MAXIMUM 9.6	MINIMUM 7.1	MAXIMUM 9.3			97/48	S.U.						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 201

PART B - Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. Pollutants for which you mark column 2-a , you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months). You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern. Please provide the method used and detection limit achieved by the laboratory. You must provide data or an explanation for the presence of the pollutant in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT	2. MARK (X)		2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Be-lieved Pre-sent	b Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Bromide Cas No. 7726-95-6	X		65.0	15.2					1	mg/L	lb/day					
Chloride Cas No. 1688-70-6	X		7,113.0	3,138.2	6,549.0	2,971.7	2,379.8	1,007.9	97/48	mg/L	lb/day					
Chlorine, Total Residual Cas No. 7782-50-5		X	< 0.02						1	mg/L						
Color (C.U.) Cas No. E-11712	X		15.0						1	CU						
Fluoride Cas No. 16984-48-8	X		7.8	1.82					1	mg/L	lb/day					
Nitrate/Nitrite (as N) Cas No. E-10128	X		33.0	7.7					1	mg/L	lb/day					
Nitrogen, Total Organic (as N) Cas No. 7727-37-9	X		1.0	0.23					1	mg/L	lb/day					
Oil & Grease Cas No. E-10140	X		16.5	12.4	10.8	7.5	5.4	2.4	97/48	mg/L	lb/day					
Phosphorus, Total Cas No. 7723-14-0	X		0.056	0.01					1	mg/L	lb/day					
Radioactivity																
(1) Radioactivity: Alpha, Total (pCi/L) Cas No. 12587-46-1		X	---	---												
(2) Radioactivity: Beta, Total (pCi/L) Cas No. 12587-47-2		X	---	---												
(3) Radioactivity: Radium ,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
(4) Radioactivity: Radium 226,Total (pCi/L) Cas No. 13982-63-3		X	---	---												
Sulfate (as SO4) Cas No. 14808-79-8	X		5,728	1,337					1	mg/L	lb/day					
Sulfide (as S) Cas No. 18496-25-8		X	< 0.015						1	mg/L						
Sulfite (as SO3) Cas No. 14264-45-3		X	< 1.0	Sample was analyzed past holding time.					1	mg/L						
Surfactants (MBAS) Cas No. 61-73-4		X	< 0.2						1	mg/L						
Aluminum Cas No. 7429-90-5		X	< 0.007						1	mg/L						
Barium Cas No. 7440-39-3	X		75.0	52.5	74.0	32.5	25.0	11.5	97/48	mg/L	lb/day					
Boron Cas No. 7440-42-8	X		34.0	7.9					1	mg/L	lb/day					
Cobalt Cas No. 7440-48-4	X		0.00034	0.00008					1	mg/L	lb/day					
Iron Cas No. 7439-89-6		X	< 0.0095						1	mg/L						
Magnesium Cas No. 7439-95-4	X		230.0	53.7					1	mg/L	lb/day					
Molybdenum Cas No. 7439-98-7	X		38.0	8.9					1	mg/L	lb/day					

EPA Identification Number *(copy from Item 1 of Form 1)*	110000493706	Outfall Number	201

1. POLLUTANT	2. MARK (*X*)		2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Be-lieved Pre-sent	b Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
Manganese Cas No. 7439-96-5	X		2.3	1.0	2.0	0.6	0.1	0.1	97/48	mg/L	lb/day					
Tin Cas No. 74400-31-5		X	< 0.001						1	mg/L						
Titanium Cas No. 7440-32-6		X	< 0.0074						1	mg/L						
OTHER CONVENTIONAL																
Kjeldahl Nitrogen, Total Cas No. E-10264	X		46.0	10.7					1	mg/L	lb/day					
Nitrate Cas No. 14797-55-8	X		34.0	7.9					1	mg/L	lb/day					
Nitrite Cas No. 14797-65-0	X		0.56	0.13					1	mg/L	lb/day					

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Part C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2C-2 in the instructions to determine which of the GC/MS fractions you must test for Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. Pollutants for which you mark column 2-a or 2-b, you must provide a minimum of twelve (12) samples (three (3) samples per month for a period of four (4) months). You must use, or require your contract laboratory to use, an analytical method with detection level low enough to provide a detectable value for the pollutant of concern. Please provide the method used and the detection limit achieved by the laboratory. You must provide data or an explanation for the presence of the pollutant in your discharge. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis daily / monthly average	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
METALS																	
Antimony Cas No. 7440-36-0	X	X		0.00057	0.00013					1	mg/L	lb/day					
Arsenic Cas No. 7440-38-2	X	X		0.017	0.0094	0.015	0.0100	0.0069	0.0028	97/48	mg/L	lb/day					
Beryllium Cas No. 7440-41-7	X		X	< 0.00022						1	mg/L						
Cadmium Cas No. 7440-43-9	X	X		0.0073	0.0017					1	mg/L	lb/day					
Chromium Cas No. 7440-47-3	X	X		0.002	0.00047					1	mg/L	lb/day					
Chromium, Hex. (dissolved) Cas No. 18540-29-9	X		X	< 0.001						1	mg/L						
Copper Cas No. 7440-50-8	X	X		0.00078	0.00018					1	mg/L	lb/day					
Lead Cas No. 7439-92-1	X		X	< 0.00052						1	mg/L						
Mercury Cas No. 7439-97-6	X	X		265	0.00014			54.6	0.00001	24	ng/L	lb/day					
Nickel Cas No. 7440-02-0	X	X		0.00094	0.00022					1	mg/L	lb/day					
Selenium Cas No. 7782-49-2	X	X		2.90	0.94	2.25	0.79	0.77	0.32	97/48	mg/L	lb/day					
Silver Cas No. 7440-22-4	X		X	< 0.00010						1	mg/L						
Thallium Cas No. 7440-28-0	X		X	< 0.00021						1	mg/L						
Vanadium Cas No. 7440-62-2	X	X		0.00220	0.00051					1	mg/L	lb/day					
Zinc Cas No. 7440-66-6	X	X		0.084	0.030	0.052	0.020	0.013	0.010	96/48	mg/L	lb/day					
CYANIDE																	
Cyanide, Free Cas No. 57-12-5	X	X		13.0	0.0030					1	**ug/L**	lb/day					
Cyanide, Total Cas No. 57-12-5	X	X		11.0	0.0026					1	**ug/L**	lb/day					
TOTAL PHENOLS																	
Phenols, Total (4AAP) Cas No. E-10253	X		X	< 6						1	**ug/L**						
DIOXIN																	
2,3,7,8-Tetrachloro dibenzo-P-Dioxin Cas No. 1746-01-6	X		X	Negative													

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1. POLLUTANT	2. MARK (X) a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	2. EFFLUENT a Maximum Daily Values (1) Concentration	a (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b (2) Mass	c Long Term Average *(if available)* (1) Concentration	c (2) Mass	d No of Analysis	3. UNITS *(specify if blank)* a Concentration	b Mass	4. INTAKE *(optional)* a Long Term Average Value *(if available)* (1) Concentration	a (2) Mass	b No of Analysis	5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)* a Method	b Reporting Limit
OTHER																	
4-Methylphenol Cas No. 106-44-5	X		X	< 0.89						1	ug/L						
Acetaldehyde Cas No. 75-07-0	X		X	< 50						1	ug/L						
Bis(chloromethyl)ether Cas No. 542-88-1	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutants List.													
Dibutyl amine * Cas No. 111-92-2	X			No test method available for analysis													
Dimethylpropyl phenol * Cas No. 80-46-6	X			No test method available for analysis													
Formaldehyde Cas No. 5-00-0	X		X	< 50						1	ug/L						
Tributyl tin oxide * Cas No. 56-35-9	X			No test method available for analysis													
VOLATILE ORGANIC																	
1,1,2,2-Tetrachloroethane Cas No. 79-34-5	X		X	< 0.32						1	ug/L						
1,1,2-Trichloroethane Cas No. 79-00-5	X		X	< 0.26						1	ug/L						
1,1,1-Trichloroethane Cas No. 71-55-6	X		X	< 0.23						1	ug/L						
1,1-Dichloroethane Cas No. 75-34-3	X		X	< 0.25						1	ug/L						
1,1-Dichloroethene Cas No. 75-35-4	X		X	< 0.23						1	ug/L						
1,2,4-Trimethylbenzene Cas No. 95-63-6	X		X	< 0.24						1	ug/L						
1,2-Dichlorethane Cas No. 107-06-2	X		X	< 0.38						1	ug/L						
1,2-Dichloroethene, Trans Cas No. 156-60-5	X		X	< 0.22						1	ug/L						
1,2-Dichloropropane Cas No. 78-87-5	X		X	< 0.19						1	ug/L						
1,3,5-Trimethylbenzene Cas No. 108-67-8	X		X	< 0.25						1	ug/L						
1,3-Dichloropropane Cas No. 142-28-9	X		X	< 0.29						1	ug/L						
1,3-Dichloropropene, Cis Cas No. 10061-01-5	X		X	< 0.26						1	ug/L						
1,3-Dichloropropene, Trans Cas No. 10061-02-6	X		X	< 0.26						1	ug/L						
1,3-Dichloropropylene Cas No. 542-75-6	X		X	< 0.26	Reported separately as cis and trans 1,3-dichloropropene					1	ug/L						
2-Butanone (Methyl Ethyl Ketone) Cas No. 78-93-3	X		X	< 0.18						1	ug/L						
2-Chloroethyl vinyl ether Cas No. 110-75-8	X		X	< 0.19						1	ug/L						
Acetone Cas No. 67-64-1	X	X		6.2	0.0014					1	ug/L	lb/day					
Acrolein Cas No. 1070-20-8	X		X	< 2.20						1	ug/L						
Acrylonitrile Cas No. 107-13-1	X		X	< 1.90						1	ug/L						
Benzene Cas No. 71-43-2	X		X	< 0.15						1	ug/L						
Bromoform Cas No. 75-25-2	X	X		3.2	0.0007					1	ug/L	lb/day					

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1. POLLUTANT	2. MARK (X) a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	2. EFFLUENT a Maximum Daily Values (1) Concentration	a (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b (2) Mass	c Long Term Average *(if available)* (1) Concentration	c (2) Mass	d No of Analysis	3. UNITS *(specify if blank)* a Concentration	b Mass	4. INTAKE *(optional)* a Long Term Average Value *(if available)* (1) Concentration	a (2) Mass	b No of Analysis	5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)* a Method	b Reporting Limit
Carbon disulfide Cas No. 75-15-0	X	X		40.0	0.009					1	ug/L	lb/day					
Carbon Tetrachloride Cas No. 56-23-5	X		X	< 0.25						1	ug/L						
Chlorobenzene Cas No. 108-90-7	X		X	< 0.26						1	ug/L						
Chlorodibromomethane Cas No. 124-48-1	X		X	< 0.24						1	ug/L						
Chloroethane Cas No. 75-00-3	X		X	< 0.22						1	ug/L						
Dichlorobromomethane Cas No. 75-27-4	X	X		0.47	0.00011					1	ug/L	lb/day					
Dichlorodifluoromethane Cas No. 75-71-8	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutants List.													
Ethylbenzene Cas No. 100-41-4	X		X	< 0.25						1	ug/L						
Ethylene glycol Cas No. 107-21-1	X		X	< 5	Sample was analyzed past holding time.					1	mg/L						
Methanol Cas No. 67-56-1	X		X	< 1						1	mg/L						
Methyl Bromide (Bromomethane) Cas No. 74-83-9	X		X	< 0.29						1	ug/L						
Methyl chloride (Chloromethane) Cas No. 74-87-3	X		X	< 0.24						1	ug/L						
Methyl tert-butyl ether (MTBE) Cas No. 1634-04-4	X		X	< 0.26						1	ug/L						
Methylamine * Cas No. 74-89-5	X			No test method available for analysis.													
Methylene chloride Cas No. 75-09-2	X		X	< 10						1	ug/L						
Propylene glycol Cas No. 57-55-6	X		X	< 5	Sample was analyzed past holding time.					1	mg/L						
Tetrachloroethene Cas No. 127-18-4	X		X	< 0.26						1	ug/L						
Trichloroethene Cas No. 79-01-6	X		X	< 0.26						1	ug/L						
Trichlorofluoromethane Cas No. 75-69-4	X			Per 46 Federal Register 2264, this analyte was removed from the Priority Pollutants List.													
Toluene Cas No. 108-88-3	X		X	< 0.30						1	ug/L						
Vinyl chloride Cas No. 75-01-4	X		X	< 0.26						1	ug/L						
Xylene Cas No. 1330-20-7	X		X	< 0.75						1	ug/L						
SEMI-VOLATILE ORGANIC-ACID																	
2,4-Dichlorophenol Cas No. 120-83-2	X		X	< 0.66						1	ug/L						
2,4-Dimethylphenol Cas No. 105-67-9	X		X	< 0.73						1	ug/L						
2,4-Dinitrophenol Cas No. 51-28-5	X		X	< 0.32						1	ug/L						
2,4,6-Trichlorophenol Cas No. 88-06-2	X		X	< 0.80						1	ug/L						

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1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5. ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b Reporting Limit
2-Chlorophenol Cas No. 95-57-8	X		X	< 0.77						1	ug/L						
2-Nitrophenol Cas No. 88-75-5	X		X	< 0.98						1	ug/L						
4-Nitrophenol Cas No. 100-02-7	X		X	< 0.89						1	ug/L						
4,6-Dmitro-o-cresol (2-methyl-4,6-dinitrophenol) Cas No. 534-52-1	X		X	< 0.37						1	ug/L						
Benzoic acid Cas No. 65-85-0	X		X	< 0.54						1	ug/L						
p-Chloro-m-cresol (4-chloro-3-methylphenol) Cas No. 59-50-7	X		X	< 0.82						1	ug/L						
Pentachlorophenol Cas No. 87-86-5	X		X	< 0.33						1	ug/L						
Phenol Cas No. 108-95-2	X		X	< 0.40						1	ug/L						
SEMI-VOLATILE ORGANIC-BASE																	
1,2,4-Trichlorobenzene Cas No. 120-82-1	X		X	< 0.63						1	ug/L						
1,2-Dichlorobenzene Cas No. 95-50-1	X		X	< 0.78						1	ug/L						
1,2-Diphenylhydrazine Cas No. 122-66-7	X		X	< 1.10						1	ug/L						
1,3-Dichlorobenzene Cas No. 541-73-1	X		X	< 0.69						1	ug/L						
1,4-Dichlorobenzene Cas No. 106-46-7	X		X	< 0.67						1	ug/L						
2-Chloronaphthalene Cas No. 91-58-7	X		X	< 0.76						1	ug/L						
2-Methylnaphthalene Cas No. 91-57-6	X		X	< 0.74						1	ug/L						
2,4-Dinitrotoluene Cas No. 121-14-2	X		X	< 0.51						1	ug/L						
2,6-Dinitrotoluene Cas No. 606-20-2	X		X	< 0.61						1	ug/L						
3,3-Dichlorobenzidine Cas No. 91-94-1	X		X	< 1.40						1	ug/L						
3,4-Benzofluoranthene (benzo(b)fluoranthene) Cas No. 205-99-2	X		X	< 0.0065						1	ug/L						
4-Bromophenyl phenyl ether Cas No. 101-55-3	X		X	< 0.72						1	ug/L						
4-Chlorophenyl phenyl ether Cas No. 7005-72-3	X		X	< 0.74						I	ug/L						
Acenaphthene Cas No. 83-32-9	X		X	< 0.013						1	ug/L						
Acenaphthylene Cas No. 208-96-8	X		X	< 0.0032						I	ug/L						
Anthracene Cas No. 120-12-7	X		X	< 0.0075						1	ug/L						
Benzidine Cas No. 92-87-5	X		X	< 54						I	ug/L						
Benzo(a)anthracene Cas No. 56-55-3	X		X	< 0.0043						1	ug/L						
Benzo(a)pyrene Cas No. 50-32-8	X		X	< 0.0065						I	ug/L						

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	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
Benzo(ghi)perylene Cas No. 191-24-2	X		X	< 0.0054						1	ug/L						
Benzo(k)fluoranthene Cas No. 207-06-9	X		X	< 0.0075						1	ug/L						
Bis(2-chloroethoxy)methane Cas No. 111-91-1	X		X	< 0.91						1	ug/L						
Bis(2-chloroethyl) ether Cas No. 111-44-4	X		X	< 0.83						1	ug/L						
Bis(2-chloroisopropyl) ether Cas No. 108-60-1	X		X	< 0.73						1	ug/L						
Bis(2-ethylhexyl)phthalate Cas No. 117-81-7	X		X	< 1.30						1	ug/L						
Butyl benzyl phthalate Cas No. 85-68-7	X		X	< 0.98						1	ug/L						
Chrysene Cas No. 218-01-9	X		X	< 0.0065						1	ug/L						
Di-n-butyl phthalate Cas No. 84-74-2	X		X	< 0.88						1	ug/L						
Di-n-octyl phthalate Cas No. 117-84-0	X		X	< 0.75						1	ug/L						
Dibenzo(a,h)anthracene Cas No. 53-70-3	X		X	< 0.0065						1	ug/L						
Dibenzofuran Cas No. 132-64-9	X		X	< 0.73						1	ug/L						
Diethylphthalate Cas No. 84-66-2	X		X	< 1.40						1	ug/L						
Dimethylphthalate Cas No. 131-11-3	X		X	< 0.73						1	ug/L						
Fluoranthene Cas No. 206-44-0	X		X	< 0.0054						1	ug/L						
Fluorene Cas No. 86-73-7	X		X	< 0.0043						1	ug/L						
Hexachlorobenzene Cas No. 118-74-1	X		X	< 1.0						1	ug/L						
Hexachlorobutadiene Cas No. 87-68-3	X		X	< 1.0						1	ug/L						
Hexachlorocyclopentadiene Cas No. 77-47-4	X		X	< 0.43						1	ug/L						
Hexachloroethane Cas No. 67-72-1	X		X	< 1.1						1	ug/L						
Indeno(1,2,3-cd) Pyrene Cas No. 193-39-5	X		X	< 0.0043						1	ug/L						
Isophorone Cas No. 78-59-1	X		X	< 0.86						1	ug/L						
N-nitrosodi-n-propyl amine Cas No. 621-64-7	X		X	< 1.1						1	ug/L						
N-nitrosodimethyl amine Cas No. 62-75-9	X		X	< 0.0065						1	ug/L						
N-nitrosodiphenyl amine Cas No. 86-30-6	X		X	< 0.77						1	ug/L						
Naphthalene Cas No. 91-20-3	X		X	< 0.0065						1	ug/L						
Nitrobenzene Cas No. 98-95-3	X		X	< 0.85						1	ug/L						
Phenanthrene Cas No. 85-01-8	X		X	< 0.0075						1	ug/L						
Pyrene Cas No. 129-00-0	X		X	< 0.0054						1	ug/L						

EPA Identification Number *(copy from Item 1 of Form 1)* 110000493706 | Outfall Number 201

1. POLLUTANT	2. MARK (*X*) a Test-ing Re-quired	2. MARK (*X*) b Be-lieved Pre-sent	2. MARK (*X*) c Be-lieved Ab-sent	2. EFFLUENT a Maximum Daily Values (1) Concentration	2. EFFLUENT a Maximum Daily Values (2) Mass	2. EFFLUENT b Maximum 30 Day Values *(if available)* (1) Concentration	2. EFFLUENT b Maximum 30 Day Values *(if available)* (2) Mass	2. EFFLUENT c Long Term Average *(if available)* (1) Concentration	2. EFFLUENT c Long Term Average *(if available)* (2) Mass	2. EFFLUENT d No of Analysis	3. UNITS *(specify if blank)* a Concentration	3. UNITS *(specify if blank)* b Mass	4. INTAKE *(optional)* a Long Term Average Value *(if available)* (1) Concentration	4. INTAKE *(optional)* a Long Term Average Value *(if available)* (2) Mass	4. INTAKE *(optional)* b No of Analysis	5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)* a Method	5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)* b Reporting Limit
Styrene Cas No. 100-42-5	X		X	< 0.22						1	ug/L						
PESTICIDES																	
2,4-Dichlorophenoxy Acetic Acid Cas No. 94-75-7			X														
Alachlor Cas No. 15972-60-8			X														
Aldrin Cas No. 309-00-2			X														
Atrazine Cas No. 1912-24-9			X														
BHC-Alpha Cas No. 319-84-6			X														
BHC-Beta Cas No. 319-85-7			X														
BHC-Gamma (Lindane) Cas No. 58-89-9			X														
BHC-Delta Cas No. 319-86-8			X														
Chlordane Cas No. 57-74-9			X														
DDD Cas No. 72-54-8			X														
DDE Cas No. 72-55-9			X														
DDT Cas No. 50-29-3			X														
Dieldrin Cas No. 60-57-1			X														
Endosulfan Sulfate Cas No. 1031-07-8			X														
Endosulfan, Alpha Cas No. 959-98-8			X														
Endosulfan, Beta Cas No. 33213-65-9			X														
Endrin Cas No. 72-20-8			X														
Endrin Aldehyde Cas No. 7421-93-4			X														
Heptachlor Cas No. 76-44-8			X														
Heptachlor Epoxide Cas No. 1024-57-3			X														
Methoxychlor Cas No. 72-43-5			X														
Metolachlor Cas No. 51218-45-2			X														
Mirex Cas No. 2385-85-5			X														
Parathion ethyl Cas No. 56-38-2			X														
Parathion methyl Cas No. 56-38-2			X														
Simazine Cas No. 122-34-9			X														

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1. POLLUTANT	2. MARK (*X*)			2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*			5 ANALYTICAL METHOD *(list method used and detection limit achieved by lab.)*	
	a Test-ing Re-quired	b Be-lieved Pre-sent	c Be-lieved Ab-sent	a Maximum Daily Values (1) Concentration	a Maximum Daily Values (2) Mass	b Maximum 30 Day Values *(if available)* (1) Concentration	b Maximum 30 Day Values *(if available)* (2) Mass	c Long Term Average *(if available)* (1) Concentration	c Long Term Average *(if available)* (2) Mass	d No of Analysis	a Concentration	b Mass	a Long Term Average Value *(if available)* (1) Concentration	a Long Term Average Value *(if available)* (2) Mass	b No of Analysis	a Method	b **Reporting** Limit
PCB-1242 Cas No. 534469-21-9			X														
PCB-1254 Cas No. 11097-69-1			X														
PCB-1221 Cas No. 11104-28-2			X														
PCB-1232 Cas No. 11141-16-5			X														
PCB-1248 Cas No. 12672-29-6			X														
PCB-1260 Cas No. 11096-82-5			X														
PCB-1016 Cas No. 12674-11-2			X														
Toxaphene Cas No. 8001-35-2			X														
WHOLE EFFLUENT TOXICITY																	
Acute, Freshwater Organisms Cas No. I-1100			X														
Chronic Freshwater Organisms Cas No. I-1101			X														
ADDITIONAL ANALYSES																	
Chloroform		X		1.1	0.00026					1	ug/L	lb/day					

Outfall 201 Influent DMR/MMR Data

Influent 201

Monthly Averages only calculated if more than one result in a month.

Summary Values

Date	Flow	pH	Suspended Solids, Total	Oil & Grease (Avg)	Ammonia (as N)	Chloride	Nitrate	Arsenic, Total Rec	Mercury	Zinc, Total Rec	Boron, Total Rec	Selenium, Total Rec	Manganese , Total Rec
	MGD	SU	mg/L	mg/L	mg/L	mg/L	µg/L	µg/L	ng/L	mg/L	µg/L	µg/L	mg/L
Min (all data)	0.01	5.1	4.40	5.00	0.0	56.0	14.00	1.80	1390.00	0.048	580.00	0.360	0.0290
Max (all data)	0.43	8.8	128792.00	40.00	1220.0	10880.0	790000.00	2600.00	80200.00	20.000	190000.00	7300.00	7100.0000
Average (all data)	0.05	6.2	26359.85	5.45	391.6	3566.3	215603.62	139.63	15421.67	3.841	56629.79	1483.10	117.5951
Max Monthly Average	0.2	8.0	119025.50	16.67	937.3	7278.5	510000.00	1435.00	No MMA	11.900	180000.00	4700.00	3557.5000
No. of Results (all data)	103	97	102	97	173	97	97	97	24	97	97	97	97
No. of Monthly Avgs	48	48	48	48	48	48	47	48	0	48	48	48	48

Monthly Averages: Jan 2016 to Dec 2019

Jan-16	0.03	5.65	14780.00	6.90	265.00	3800.00	305.00	55.00	No MA	2.75	24500.00	4050.00	42.50
Feb-16	0.04	6.90	810.00	5.00	65.50	3450.00	No MA	50.50	No MA	0.79	15500.00	4700.00	27.85
Mar-16	0.04	6.27	18969.80	16.67	12.67	1686.67	181.67	24.93	No MA	0.78	11326.67	1380.00	18.00
Apr-16	0.04	6.60	754.80	5.00	5.00	1190.00	107.50	27.50	No MA	1.83	7750.00	260.00	4.95
May-16	0.03	6.50	25960.50	5.00	82.50	4700.00	370.00	46.80	No MA	0.71	30500.00	700.43	10.51
Jun-16	0.03	7.95	15984.00	5.00	129.67	2900.00	195.50	29.00	No MA	0.80	14650.00	1200.18	13.25
Jul-16	0.03	5.65	12020.00	5.00	415.00	6350.00	375000.00	115.00	No MA	2.20	16450.00	2900.00	36.50
Aug-16	0.03	6.55	< 25016.00	< 5.00	310.00	6150.00	340000.00	115.00	No MA	1.70	20500.00	3050.00	32.50
Sep-16	0.03	5.80	< 22844.00	< 5.00	560.00	3330.00	305000.00	130.00	No MA	2.75	21000.00	4150.00	31.00
Oct-16	0.03	6.05	< 1586.50	< 5.00	101.00	6950.00	295000.00	102.50	No MA	1.90	52500.00	1090.00	44.00
Nov-16	0.03	6.68	1454.00	5.00	74.00	5500.00	240000.00	130.00	No MA	1.25	46500.00	795.00	38.50
Dec-16	0.06	6.80	5300.00	5.00	50.15	2000.00	226500.00	49.00	No MA	0.52	12000.00	590.00	12.30
Jan-17	0.05	7.20	21892.00	5.00	47.35	744.00	53450.00	6.35	No MA	0.94	6290.00	168.50	5.95
Feb-17	0.04	5.70	65945.00	5.00	530.00	4750.00	250000.00	90.00	No MA	4.40	28500.00	1130.00	35.00
Mar-17	0.08	7.65	2298.00	5.00	24.00	940.00	80500.00	54.00	No MA	1.40	11100.00	165.00	3557.50
Apr-17	0.09	5.95	1022.00	5.00	16.53	3650.00	196666.67	84.00	No MA	1.85	46000.00	765.00	14.50
May-17	0.11	6.25	1262.00	5.00	9.00	4650.00	175000.00	100.50	No MA	1.20	42000.00	915.00	12.30
Jun-17	0.06	6.60	2679.00	5.00	60.00	3300.00	230000.00	96.50	No MA	2.00	29000.00	835.00	13.00
Jul-17	0.04	6.30	16970.00	5.00	164.00	2150.00	160500.00	50.50	No MA	4.90	17500.00	360.00	14.45
Aug-17	0.04	5.85	12799.00	5.00	260.00	4150.00	240000.00	79.00	No MA	3.95	31000.00	760.00	30.00
Sep-17	0.04	6.75	35963.00	5.00	340.00	4300.00	220000.00	43.50	No MA	2.70	22500.00	1150.00	24.00
Oct-17	0.03	7.65	5325.00	5.00	48.72	3100.00	150155.00	190.00	No MA	1.21	22000.00	855.00	10.05
Nov-17	0.04	8.00	52720.00	5.00	200.00	1086.50	355000.00	54.50	No MA	4.55	16000.00	655.00	24.00
Dec-17	0.06	6.65	2195.00	5.00	20.00	358.50	170000.00	74.00	No MA	2.70	12500.00	385.00	11.00
Jan-18	0.06	5.70	67054.00	5.00	335.00	1071.50	455000.00	59.50	No MA	6.80	33500.00	1110.00	30.00
Feb-18	0.09	7.05	1393.00	5.00	76.45	595.50	130000.00	71.50	No MA	1.61	19815.00	956.00	8.75
Mar-18	0.08	6.10	48202.00	5.00	235.00	1499.50	275000.00	43.50	No MA	10.35	24500.00	1100.00	22.00
Apr-18	0.06	6.00	1760.00	5.00	154.00	493.00	195000.00	130.50	No MA	4.00	84500.00	1800.00	16.50
May-18	0.04	5.45	25047.33	5.00	360.00	616.50	195000.00	220.00	No MA	4.65	68000.00	1600.00	20.00
Jun-18	0.04	5.80	6238.00	5.00	405.00	715.00	230000.00	158.50	No MA	3.85	67000.00	1550.00	26.00
Jul-18	0.03	5.80	29098.00	5.00	665.00	5657.50	210000.00	280.00	No MA	11.90	79000.00	4350.00	76.50
Aug-18	0.05	5.45	39687.00	5.00	495.00	581.00	180110.00	154.00	No MA	5.40	105000.00	2000.00	42.00
Sep-18	0.05	5.75	54176.00	5.00	610.00	7056.00	215000.00	131.50	No MA	4.95	135000.00	2050.00	44.50
Oct-18	0.23	5.95	57540.00	5.00	167.00	836.50	260000.00	42.50	No MA	2.50	66500.00	930.00	36.50
Nov-18	0.04	5.80	119025.50	5.00	460.00	1080.50	510000.00	45.50	No MA	4.65	42500.00	695.00	36.00
Dec-18	0.05	5.70	63398.00	5.00	640.00	4625.00	400000.00	82.50	No MA	5.75	106000.00	1450.00	40.50
Jan-19	0.07	6.55	41600.50	5.35	415.50	2201.50	212750.00	244.00	No MA	6.65	86500.00	1015.00	21.00
Feb-19	0.03	5.65	48095.00	5.00	291.07	6875.00	234500.00	221.50	No MA	8.60	120000.00	1050.00	27.50
Mar-19	0.05	5.95	7734.00	7.20	122.92	6722.00	204950.00	330.00	No MA	9.85	180000.00	1250.00	16.50
Apr-19	0.06	5.85	28916.00	5.00	750.50	6814.50	286100.00	82.00	No MA	5.30	140000.00	1600.00	22.00
May-19	0.06	5.70	93910.50	5.00	651.86	3162.00	278450.00	37.70	No MA	2.48	74000.00	975.00	861.00
Jun-19	0.06	5.65	70674.00	5.00	608.04	3361.00	219950.00	60.50	No MA	4.40	91500.00	1450.00	25.00
Jul-19	0.06	6.00	47182.50	5.00	412.00	7224.50	250600.00	1435.00	No MA	6.45	140000.00	1800.00	144.00
Aug-19	0.06	5.50	35440.50	5.00	151.33	4675.50	327400.00	185.00	No MA	4.10	100500.00	1300.00	21.50
Sep-19	0.04	5.70	7236.00	5.00	177.50	6698.50	224100.00	265.00	No MA	5.50	130000.00	2150.00	23.50
Oct-19	0.05	5.60	15091.35	5.00	560.00	7278.50	281000.00	260.00	No MA	4.70	130000.00	2500.00	24.50
Nov-19	0.05	6.95	14403.00	5.00	480.00	4920.50	313700.00	111.50	No MA	4.45	79000.00	1650.00	16.50
Dec-19	0.05	5.45	20416.00	5.00	937.31	6177.00	205550.00	310.00	No MA	7.25	80500.00	1900.00	28.50

Analytical Method Information

Method Information For Permit Required Sample Analyses

Parameter	Analytical Method	Reporting Limit	Units
Carbonaceous Biochemical Oxygen Demand (cBOD)	5210 B	1	mg/L
Escherichia coli (E-coli)	9221B	1	col/100 ml
Total Suspended Solids (TSS)	2540D	0.1	mg/L
Ammonia as N	4500 NH3 G	0.015	mg/L
Temperature	2550 B	0.1 sensitivity	°C
pH	4500-H^+ B	0.01 sensitivity	s.u.
Chloride	300.0	1	mg/L
Chlorine, Total Residual	4500-Cl D, E, or G	0.02	mg/L
Nitrate	300.0	0.5	mg/L
Oil and Grease (hexane)	(Hexane) 1664	1.5	mg/L
Sulfate (as SO4)	300.0	1	mg/L
Boron, Total	200.8	50	ug/L
Manganese, Total	200.8	1	ug/L
Arsenic, Total	200.8	1	ug/L
Cadmium, Total	200.8	1	ug/L
Chromium, Total	200.8	1	ug/L
Copper, Total	200.8	1	ug/L
Lead, Total	200.8	1	ug/L
Mercury, Total for non-sw locations	1631E	0.2	ng/L
Nickel, Total	201	1	ug/L
Selenium, Total	200.8	1	ug/L
Zinc, Total	200.8	0.2	ug/L

Method Information for Non-Permit Required Sample Analyses

Parameter	Analytical Method	Reporting Limit	
PART V. IDEM TABLE A.			
Carbonaceous Biochemical Oxygen Demand (cBOD)	5210 B	1	mg/L
Escherichia coli (E-coli)	SM 9223 B	1	MPN/100mL
Fecal Coliform	SM 9222 D	10	cfu/100mL
Chemical Oxygen Demand (COD)	EPA 410.4	10	mg/L
Dissolved Oxygen	4500-O G (probe)	0.1	mg/L
Total Dissolved Solids	EPA 160.1	20	mg/L
Total Organic Carbon (TOC)	SM 5310C	0.5	mg/L
Ammonia as N	EPA 350.1	0.1	mg/L
Temperature	2550 B	0.1	°C
Total Hardness	SM 2340 B	160	mg/L
pH	SM 4500 H+ B	2	S.U.
PART V. IDEM TABLE B.			
Bromide	EPA 300.0	0.5	mg/L
Chloride	EPA 300.0	1	mg/L
Chlorine, Total Residual	4500-Cl D, E, or G	0.02	mg/L
Color	SM 2120 B	5	Color Units (CU)
Fluoride	SM 4500-F	0.1	mg/L
Nitrate + Nitrite (as N)	EPA 353.2	0.1	mg/L
Nitrate	EPA 353.2	0.1	mg/L
Nitrite	EPA 353.2	0.1	mg/L
Nitrogen, Total Organic (as N)	Calc (TKN - Amm-N)		
Total Kjeldahl Nitrogen (Amm-N + Org-N)	EPA 351.2	0.5	mg/L
Nitrogen, Total (TKN+Nitrate+Nitrite)	Calc (NO2 + NO3 + TKN)	0.6	mg/L
Oil and Grease (hexane)	1664	1.5	mg/L
Phosphorus (as P), Total	EPA 365.1	0.2	mg/L
Sulfate (as SO4)	EPA 300.0	1	mg/L
Sulfide (as S)	SM 4500-S2	0.05	mg/L
Sulfite (as SO3)	SM 4500 SO3 B	1	mg/L
Surfactants (MBAS)	SM 5540C	0.2	mg/L
Aluminum, Total	EPA 200.8	0.2	mg/L
Barium, Total	EPA 200.8	0.005	mg/L
Boron, Total	EPA 200.8	0.02	mg/L
Cobalt, Total	EPA 200.8	0.003	mg/L
Iron, Total	EPA 200.8	0.5	mg/L
Magnesium, Total	EPA 200.8	0.5	mg/L
Molybdenum, Total	EPA 200.8	0.02	mg/L
Manganese, Total	EPA 200.8	0.002	mg/L
Tin, Total	EPA 200.8	0.02	mg/L
Titanium, Total	EPA 200.8	0.03	mg/L

Parameter	Analytical Method	Reporting Limit	
PART V. IDEM TABLE C. Priority Pollutant Metals, Cyanide, Phenols			
Antimony, Total	EPA 200.8	0.02	mg/L
Arsenic, Total	EPA 200.8	0.01	mg/L
Beryllium, Total	EPA 200.8	0.001	mg/L
Cadmium, Total	EPA 200.8	0.002	mg/L
Chromium, Total	EPA 200.8	0.003	mg/L
Chromium, Hexavalent (dissolved)	SM 3500-Cr B	0.01	mg/L
Copper, Total	EPA 200.8	0.01	mg/L
Lead, Total	EPA 200.8	0.0075	mg/L
Mercury, Total for non-sw locations	EPA 1631E	0.5	ng/L
Mercury, Total for sw locations	245.1	analysis pending	mg/L
Nickel, Total	EPA 200.8	0.01	mg/L
Selenium, Total	EPA 200.8	0.03	mg/L
Silver, Total	EPA 200.8	0.01	mg/L
Thallium, Total	EPA 200.8	0.05	mg/L
Vanadium	EPA 200.8	0.008	mg/L
Zinc, Total	EPA 200.8	0.02	mg/L
Cyanide, Free	EPA OIA 1677	2	ug/L
Cyanide, Total	SM 4500-CN	5	ug/L
Phenols, Total ("4AAP Phenolics")	EPA 420.4	10	ug/L
PART V. IDEM TABLE C. OTHER			
Bis (Chloromethyl) Ether	No longer required for Form 2C		
Dibutyl amine*	Test method not available		
Dimethylpropyl phenol*	Test method not available		
Tributyl tin oxide*	Test method not available		
Methylamine*	Test method not available		

Parameter	Analytical Method	Reporting Limit	
PART V. IDEM TABLE C. Volatile Compounds			
Acetaldehyde	EPA 8315A	50	ug/L
Formaldehyde	EPA 8315A	50	ug/L
Ethylene glycol	EPA 8015D	5	ug/L
Methanol	EPA 8015C	1	mg/L
Propylene glycol	EPA 8015D	5	ug/L
Methyl tert-butyl ether (MTBE)	EPA 624.1	5	ug/L
Xylene	EPA 624.1	5	ug/L
1,1,2,2-Tetrachloroethane	EPA 624.1	5	ug/L
1,1,2-Trichloroethane	EPA 624.1	5	ug/L
1,1,1-Trichloroethane	EPA 624.1	5	ug/L
1,1-Dichloroethane	EPA 624.1	5	ug/L
1,1-Dichloroethene	EPA 624.1	5	ug/L
1,2,4-Trimethylbenzene	EPA 624.1	5	ug/L
1,2-Dichloroethane	EPA 624.1	5	ug/L
1,2-Dichloroethylene, Trans	EPA 624.1	5	ug/L
1,2-Dichloropropane	EPA 624.1	5	ug/L
1,3,5-Trimethylbenzene	EPA 624.1	5	ug/L
1,3-Dichloropropane	EPA 624.1	5	ug/L
1,3-Dichloropropene, Cis	EPA 624.1	5	ug/L
1,3-Dichloropropene, Trans	EPA 624.1	5	ug/L
1,3-Dichloropropylene	EPA 624.1	5	ug/L
2-Butanone (Methyl Ethyl Ketone)	EPA 624.1	10	ug/L
2-Chloroethylvinyl Ether	EPA 624.1	10	ug/L
Acetone	EPA 624.1	50	ug/L
Acrolein	EPA 624.1	100	ug/L
Acrylonitrile	EPA 624.1	100	ug/L
Benzene	EPA 624.1	5	ug/L
Bromoform	EPA 624.1	5	ug/L
Carbon disulfide	EPA 624.1	10	ug/L
Carbon Tetrachloride	EPA 624.1	5	ug/L
Chlorobenzene	EPA 624.1	5	ug/L
Chlorodibromomethane	EPA 624.1	5	ug/L
Chloroethane	EPA 624.1	10	ug/L
Chloroform	EPA 624.1	2	ug/L
Dichlorobromomethane	EPA 624.1	5	ug/L
Dichlorodifluoromethane	EPA 624.1	No longer required for Form 2C	
Ethylbenzene	EPA 624.1	5	ug/L
Methyl Bromide (Bromomethane)	EPA 624.1	10	ug/L
Methyl Chloride (Chloromethane)	EPA 624.1	10	ug/L
Methylene Chloride	EPA 624.1	10	ug/L
Styrene	EPA 624.1	5	ug/L
Tetrachloroethene	EPA 624.1	5	ug/L
Trichloroethene	EPA 624.1	5	ug/L
Trichlorofluoromethane	EPA 624.1	No longer required for Form 2C	
Toluene	EPA 624.1	5	ug/L
Vinyl Chloride	EPA 624.1	2	ug/L

Parameter	Analytical Method	Reporting Limit	
PART V. IDEM TABLE C. Semi-Volatile Organic Acid Compounds			
2,4-Dichlorophenol	EPA 625.1	11	ug/L
2,4-Dimethylphenol	EPA 625.1	11	ug/L
2,4-Dinitrophenol	EPA 625.1	56	ug/L
2,4,6-Trichlorophenol	EPA 625.1	11	ug/L
2-Chlorophenol	EPA 625.1	11	ug/L
2-Nitrophenol	EPA 625.1	11	ug/L
4-Nitrophenol	EPA 625.1	56	ug/L
4,6-Dinitro-o-cresol (2-methyl-4,6-dinitrophenol)	EPA 625.1	28	ug/L
Benzoic Acid	EPA 625.1	56	ug/L
p-Chloro-m-cresol (4-chloro-3-methylphenol)	EPA 625.1	22	ug/L
Pentachlorophenol	EPA 625.1	56	ug/L
Phenol	EPA 625.1	11	ug/L

Parameter	Analytical Method	Reporting Limit	
PART V. IDEM TABLE C. Semi-Volatile Organic Base Compounds			
1,2,4-Trichlorobenzene	EPA 625.1	11	ug/L
1,2-Dichlorobenzene	EPA 625.1	11	ug/L
1,2-Diphenyl hydrazine (Azobenzene)	EPA 625.1	11	ug/L
1,3-Dichlorobenzene	EPA 625.1	11	ug/L
1,4-Dichlorobenzene	EPA 625.1	11	ug/L
2-Chloronaphthalene	EPA 625.1	11	ug/L
2-Methylnaphthalene	EPA 625.1	11	ug/L
4-Methylphenol	EPA 625.1	11	ug/L
2,4-Dinitrotoluene	EPA 625.1	11	ug/L
2,6-Dinitrotoluene	EPA 625.1	11	ug/L
3,3'-Dichlorobenzidine	EPA 625.1	54	ug/L
3,4-Benzofluoranthene (benzo [b] fluoranthene)	EPA 625.1	11	ug/L
4-Bromophenyl Phenyl Ether	EPA 625.1	11	ug/L
4-Chlorophenyl Phenyl Ether	EPA 625.1	11	ug/L
Acenaphthene	EPA 625.1	11	ug/L
Acenaphthylene	EPA 625.1	11	ug/L
Anthracene	EPA 625.1	11	ug/L
Benzidine	EPA 625.1	54	ug/L
Benzo (a) anthracene	EPA 625.1	11	ug/L
Benzo (a) pyrene	EPA 625.1	11	ug/L
Benzo (ghi) perylene	EPA 625.1	11	ug/L
Benzo (k) fluoranthene	EPA 625.1	11	ug/L
Bis (2-Chloroethoxy) Methane	EPA 625.1	11	ug/L
Bis (2-Chloroethyl) Ether	EPA 625.1	11	ug/L
Bis (2-Chloroisopropyl) Ether	EPA 625.1	11	ug/L
Bis (2-Ethylhexyl) Phthalate	EPA 625.1	11	ug/L
Butyl Benzyl Phthalate	EPA 625.1	11	ug/L
Chrysene	EPA 625.1	11	ug/L
Di-N-Butyl Phthalate	EPA 625.1	11	ug/L
Di-N-Octyl Phthalate	EPA 625.1	11	ug/L
Dibenzo (a,h) anthracene	EPA 625.1	11	ug/L
Dibenzofuran (CAS # 132-64-9)	EPA 625.1	11	ug/L
Diethyl Phthalate	EPA 625.1	11	ug/L
Dimethyl Phthalate	EPA 625.1	11	ug/L
Fluoranthene	EPA 625.1	11	ug/L
Fluorene	EPA 625.1	11	ug/L
Hexachlorobenzene	EPA 625.1	11	ug/L
Hexachlorobutadiene	EPA 625.1	11	ug/L
Hexachlorocyclopentadiene	EPA 625.1	11	ug/L
Hexachloroethane	EPA 625.1	11	ug/L
Indeno(1,2,3-cd) pyrene	EPA 625.1	11	ug/L
Isophorone	EPA 625.1	11	ug/L
N-Nitrosodi-N-propylamine	EPA 625.1	11	ug/L
N-Nitrosodimethylamine	EPA 625.1	11	ug/L
N-Nitrosodiphenylamine	EPA 625.1	11	ug/L
Naphthalene	EPA 625.1	11	ug/L
Nitrobenzene	EPA 625.1	11	ug/L
Phenanthrene	EPA 625.1	11	ug/L
Pyrene	EPA 625.1	11	ug/L

Form 2F Materials

Please print or type in the unshaded areas only

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)
110000493706

Form Approved OMB No 2040-0086
Approval expires 5-31-92

FORM **2F** NPDES

EPA

United States Environmental Protection Agency

Application for Permit To Discharge Stormwater Discharges Associated with Industrial Activity

Paperwork Reduction Act Notice

Public reporting burden for this application is estimated to average 28.6 hours per application, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate, any other aspect of this collection of information, or suggestions for improving this form, including suggestions which may increase or reduce this burden to: Chief, Information Policy Branch, PM 223, U.S. Environmental Protection Agency, 401 M St., SW, Washington, DC 20460, or Director, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER *(list)*	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER *(name)*
	1. DEG	2. MIN	3. SEC	1. DEG	2. MIN	3. SEC	
003S	N41	13	8.55	W87	0	20	Stalbaum Ditch
004S	N41	12	22	W87	1	38	Davis Ditch
005S	N41	12	31	W87	1	38	Davis Ditch
006S	N41	13	31	W87	1	36	Davis Ditch
007S	N41	13	17.46	W87	1	47.3	Davis Ditch

A. Are you now required by any Federal, State, or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

1. Identification of Conditions, Agreements, Etc.	2. Affected Outfalls		3. Brief Description of Project	4. Final Compliance Date	
	number	source of discharge		a. req.	b. proj.

B. You may attach additional sheets describing any additional water pollution (or other environmental projects which may affect your discharges) you now have under way or which you plan. Indicate whether each program is now under way or planned, and indicate your actual or planned schedules for construction.

III. Site Drainage Map

Attach a site map showing topography (or indicating the outline of drainage areas served by the outfall(s) covered in the application if a topographic map is unavailable) depicting the facility including: each if its intake and discharge structures; the drainage area of each storm water outfall; paved areas and buildings within the drainage area of each storm water outfall, each known past or present areas used for outdoor storage or disposal of significant materials, each existing structural control measure to reduce pollutants in storm water runoff, materials loading and access areas, areas where pesticides, herbicides, soil conditioners and fertilizers are applied; each of its hazardous waste treatment, storage or disposal units (including each area not required to have a RCRA permit which is used for accumulating hazardous waste under 40 CFR 262.34); each well where fluids from the facility are injected underground; springs, and other surface water bodies which receive stormwater discharges from the facility. **See Figure RMS-DRAIN: Site Drainage Map**

Continued on Page 2

Continued from the Front

IV. Narrative Description of Pollutant Sources

A. For each outfall, provide an estimate of the area (include units) of surfaces (including paved areas and building roofs) drained to the outfall, and an estimate of the total surface area drained by the outfall.

Outfall Number	Area of Impervious Surface *(provide units)*	Total Area Drained *(provide units)*			
003S		1,400,000 sqft			
004S		245,000 sqft			
005S		290,000 sqft			
006S		46,500 sqft			
007S		2,520,000 sqft			

B. Provide a narrative description of significant materials that are currently or in the past three years have been treated, stored or disposed in a manner to allow exposure to storm water; method of treatment, storage, or disposal; past and present materials management practices employed in the last three years, to minimize contact by these materials with storm water runoff; materials loading and access areas; and the location, manner, and frequency in which pesticides, herbicides, soil conditioners, and fertilizers are applied.

There have been no significant materials that in the past three years have been treated, stored, or disposed of on-site in a manner to allow exposure to stormwater in the drainage areas of these stormwater outfalls.

Outfall 004 drainage area includes emergency spillway of Waste Disposal Area (WDA) Pond
Outfall 005 drainage area includes emergency spillway of Waste Disposal Area (WDA) Pond
Outfall 006 drainage area includes emergency spillway of Intake Settling Basin

C. For each outfall, provide the location and a description of existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and a description of the treatment the storm water receives, including the schedule and type of maintenance for control and treatment measures and the ultimate disposal of any solid or fluid wastes other than by discharge.

Outfall Number	Treatment	List Codes from Table 2F-1
003S	Stormwater flows through vegetation down the capped sides of the closed landfill segments into perimeter ditches which feed the runoff pond. No stormwater treatment occurs.	4-A
004S/005S	Stormwater flows through wooded area northwest of WDA Pond under railroad tracks and perimeter road to Davis Ditch Outfalls 004S and 005S provide drainage from coal car railroad tracks exiting the plant and the perimeter security road. No stormwater treatment occurs.	4-A
006S	Stormwater flows through grassy area northeast of ISB along and under perimeter road to Davis Ditch. Outfall 006 provides drainage for a different section of the perimeter security road. No stormwater treatment occurs.	4-A
007S	Stormwater flows through gravel areas to an underground 36" pipe, no stormwater treatment occurs.	4-A

V. Nonstormwater Discharges

A. I certify under penalty of law that the outfall(s) covered by this application have been tested or evaluated for the presence of nonstormwater discharges, and that all nonstormwater discharges form these outfall(s) are identified in either an accompanying Form 2C or Form 2E application for the outfall.

Name and Official Title *type or print)*	Signature	Date Signed
Bertil Valenkamph - Director, Station Chemistry & Environmental Compliance	Bertil Valenkamph	3/25/2020

B. Provide a description of the method used, the date of any testing, and the onsite drainage points that were directly observed during a test.

A comprehensive site evaluation confirming the accuracy of the description of potential pollution sources and the effectiveness of the Stormwater Pollution Prevention Plan (SWPPP) is conducted annually as specified within the permit. Records of these inspections are maintained within the SWPPP.

VI. Significant Leaks or Spills

Provide existing information regarding the history of significant leaks or spills of toxic or hazardous pollutant at the facility in the last three years, including the approximate date and location of the spill or leak, and the type and amount of material released.

No significant leaks or spills of toxic or hazardous pollutants have occurred into the stormwater discharges at the Schahfer Generating Station in the last three years.

EPA ID Number *(Copy from Item I of Form 1)*
110000493706

VII. Discharge Information

A, B, C, & D: See instructions before proceeding. Complete one set of tables for each outfall. Annotate the outfall number in the space provided. Tables VII-A, VII-B, and VII-C are included on separate sheets numbered VII-1 and VII-2.

E. Potential discharges not covered by analysis - is any pollutant listed in Table 2F-2, 2F-3, 2F-4 a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or byproduct?

[ ] Yes *(list all such pollutants below)* [X] No *(go to Section IX)*

Adequate information to assess potential stormwater pollutants is provided in the following:

Form 2C, Section V's

Form 2F, Pages VII-1 and VII-2

VIII. Biological Toxicity Testing Data

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

[ ] Yes *(list all such pollutants below)* [X] No *(go to Section IX)*

IX. Contract Analysis Information

Were any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

[X] Yes *(list the name, address, and telephone number of, and pollutants analyzed by, each such laboratory or firm below)* [ ] No *(go to Section X)*

A. Name	B. Address	C. Area Code & Phone No.	Pollutants Analyzed
Microbac Laboratories	250 West 84th Drive Merrillville IN 46410	(219)769-8378	All analytes.

X. Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

A. Name & Official Title *(type or print)*	B. Area Code & Phone No.
Bertil Valenkamph - Director Station Chemistry & Environmental Compliance	256-842-3 219-~~477~~-6265
C. Signature	**D. Date Signed**
Bertil Valenkamph	3/25/2020

Outfall 003S

EPA ID Number *(copy from Item I of Form 1)*
110000493706

Form Approved. OMB No. 2040-0086
Approval expires 5-31-92

VII. Discharge Information *(Continued from page 3 of Form 2F)*

Part A. You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Oil and Grease	Outfall 003S is surface water runoff from a perimeter storm water nextwork from the onsite restricted waste landfill. To date no discharge of Outfall 003S has been recorded.					
Biological Oxygen Demand (BOD5)						
Chemical Oxygen Demand (COD)						
Total Suspended Solids (TSS)						
Total Nitrogen						
Total Phosphorus						
pH	Minimum (grab)	Maximum (grab)	Minimum (comp)	Maximum (comp)		

Part B. List each pollutant that is limited in an effluent guideline which the facility is subject to or any pollutant listed in the facility's NPDES permit for its process wastewater (if the facility is operating under an existing NPDES permit). Complete one table for each outfall. See the instructions for additional details and requirements.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Sulfate	Outfall 003S is surface water runoff from a perimeter storm water nextwork from the onsite restricted waste landfill. To date no discharge of Outfall 003S has been recorded.					
Arsenic, Total						
Chromium, Total						
Selenium, Total						
Zinc, Total						
Boron, Total						
Manganese, Total						
Mercury, Total						
Chloride, Total						
Ammonia, N Total						
Temperature						

Continued from the Front

Outfall 003S

Part C. List each pollutant shown in Tables 2F-2. 2F-3, and 2F-4 that you know or have reason to believe is present. See the instructions for additional details and requirements. Complete one table for each outfall.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Units	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite			
Cadmium, Total	Outfall 003S is surface water runoff from a perimeter storm water nextwork from the onsite restricted waste landfill. To date no discharge of Outfall 003S has been recorded.						
Copper, Total							
Lead, Total							
Nickel, Total							
Organic N, Total							

Part D. Provide data for the storm event(s) which resulted in the maximum values for the flow weighted composite sample.

1. Date of Storm Event	2. Duration of Storm *(in minutes)*	3. Total rainfall during storm event *(in inches)*	4. Number of hours between beginning of storm meas-ured and end of previous measurable rain event	5. Maximum flow rate during rain event *(gallons/minute or specify units)*	6. Total flow from rain event *(gallons or specify units)*
2016	N/A	N/A	N/A	No Flow; Discharge valve from pond overflow is closed	
2017	N/A	N/A	N/A	No Flow; Discharge valve from pond overflow is closed	
2018	N/A	N/A	N/A	No Flow; Discharge valve from pond overflow is closed	
2019	N/A	N/A	N/A	No Flow; Discharge valve from pond overflow is closed	

9. Provide a description of the method of flow measurement or estimate.

The discharge from outfall is monitored by visual inspection and includes the internal perimeter ditches that feed the runoff pond which subsequently feeds Outfall 003S. When the runoff pond water level reaches a specific height it will flow through a culvert pipe as Outfall 003S. In general, the source of the discharge is precipitation; however, the actual release via the Outfall is not necessarily dictated by individual storm events. To date there has not been a discharge recorded at Outfall 003S.

Outfall 004S, 005S, and 006S

EPA ID Number *(copy from Item I of Form 1)*
110000493706

Form Approved. OMB No. 2040-0086
Approval expires 5-31-92

VII. Discharge Information *(Continued from page 3 of Form 2F)*

Part A. You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Oil and Grease	< 5.0 mg/L		< 5.0 mg/L		2	Outfalls 004S and 005S provide drainage from coal car tracks exiting the plant and ther perimeter security road. Outfall 006S provides drainage for a different section of the perimeter security road. Per the Permit, Outfall 004S discharge is representative of Outfalls 005S and 006S.
Biological Oxygen Demand (BOD5)						
Chemical Oxygen Demand (COD)						
Total Suspended Solids (TSS)	8.0 mg/L		6.3 mg/L		2	
Total Nitrogen						
Total Phosphorus						
pH	Minimum (grab) 7.4	Maximum (grab) 7.5	Minimum (comp)	Maximum (comp)	2	

Part B. List each pollutant that is limited in an effluent guideline which the facility is subject to or any pollutant listed in the facility's NPDES permit for its process wastewater (if the facility is operating under an existing NPDES permit). Complete one table for each outfall. See the instructions for additional details and requirements.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Sulfate	62 mg/L		32.42 mg/L		2	Outfalls 004S and 005S provide drainage from coal car tracks exiting the plant and ther perimeter security road. Outfall 006S provides drainage for a different section of the perimeter security road. Per the Permit, Outfall 004S discharge is representative of Outfalls 005S and 006S.
Arsenic, Total	10 mg/L		5.01 mg/L		2	
Chromium, Total	< 0.001 mg/L		< 0.001 mg/L		2	
Selenium, Total	0.0016 mg/L		0.0013 mg/L		2	
Zinc, Total	0.015 mg/L		0.0175 mg/L		2	
Boron, Total	Data presented above is from Permit-required sampling from extreme precipitation events in 2018 and 2019. No additional discharge characterization data exists for Outfall 004S, 005S, or 006S at this time as the discharge is very intermittent and may only discharge during extreme rain events. These parameters are currently monitored at Outall 001 and/or Outfall 201 in the NPDES Permit.					
Manganese, Total						
Mercury, Total						
Chloride, Total						
Ammonia, N Total						
Temperature						

Continued from the Front

Outfall 004S, 005S, and 006S

Part C. List each pollutant shown in Tables 2F-2. 2F-3, and 2F-4 that you know or have reason to believe is present. See the instructions for additional details and requirements. Complete one table for each outfall.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Cadmium, Total	< 0.001 mg/L		< 0.001 mg/L		2	Outfalls 004S and 005S provide drainage from coal car tracks exiting the plant and ther perimeter security road. Outfall 006S provides drainage for a different section of the perimeter security road.
Copper, Total	0.0011 mg/L		0.00105 mg/L		2	
Lead, Total	< 0.001 mg/L		< 0.001 mg/L		2	
Nickel, Total	< 0.001 mg/L		< 0.001 mg/L		2	
Organic N, Total	Data presented above is from Permit-required sampling from extreme precipitation events in 2018 and 2019. No additional discharge characterization data exists for Outfall 004S, 005S, or 006S at this time as the discharge is very intermittent and may only discharge during extreme rain events.					

Part D. Provide data for the storm event(s) which resulted in the maximum values for the flow weighted composite sample.

1. Date of Storm Event	2. Duration of Storm *(in minutes)*	3. Total rainfall during storm event *(in inches)*	4. Number of hours between beginning of storm meas-ured and end of previous measurable rain event	5. Maximum flow rate during rain event *(gallons/minute or specify units)*	6. Total flow from rain event *(gallons or specify units)*
06/15/16	128	0.17	336 hours	no discharge observed	
08/22/17	420	1.12	288 hours	no discharge observed	
11/30/18	69	0.19	< 75 hours	0.0315 MGD	
05/09/19	155	0.65	96 hours	0.0012 MGD	

9. Provide a description of the method of flow measurement or estimate.

The discharge from Outfalls 004S, 005S, and 006S are monitored by visual inspection.

Outfall 007S

EPA ID Number *(copy from Item I of Form 1)*
110000493706

Form Approved. OMB No. 2040-0086
Approval expires 5-31-92

VII. Discharge Information *(Continued from page 3 of Form 2F)*

Part A. You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Oil and Grease	< 5.0 mg/L		< 5.0 mg/L		4	Outfall 007S consists of roof drain runoff and stormwater collected from the area surrounding the generating facility building (except that which is related to the FGD construction - this is routed to 001).
Biological Oxygen Demand (BOD5)	TBD				1	
Chemical Oxygen Demand (COD)	TBD				1	
Total Suspended Solids (TSS)	84.4 mg/L		25 mg/L		4	
Total Nitrogen	TBD				1	
Total Phosphorus	TBD				1	
pH	Minimum (grab) 7.3	Maximum (grab) 7.7	Minimum (comp)	Maximum (comp)	4	

Part B. List each pollutant that is limited in an effluent guideline which the facility is subject to or any pollutant listed in the facility's NPDES permit for its process wastewater (if the facility is operating under an existing NPDES permit). Complete one table for each outfall. See the instructions for additional details and requirements. Note: Part A compounds are not repeated in Part B.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Sulfate	59.7 mg/L		42.6 mg/L		4	Outfall 007S consists of roof drain runoff and stormwater collected from the area surrounding the generating facility building (except that which is related to the FGD construction - this is routed to 001).
Arsenic, Total	0.0023 mg/L		0.0015 mg/L		4	
Chromium, Total	0.011 mg/L		0.0041 mg/L		4	
Selenium, Total	0.0092 mg/L		0.003 mg/L		4	
Zinc, Total	0.42 mg/L		0.17 mg/L		4	
Boron, Total	TBD				1	
Manganese, Total	TBD				1	
Mercury, Total	TBD				1	
Chloride, Total	TBD				1	
Ammonia, N Total	TBD				1	
Temperature	TBD				1	

Outfall 007S

Part C. List each pollutant shown in Tables 2F-2. 2F-3, and 2F-4 that you know or have reason to believe is present. See the instructions for additional details and requirements. Complete one table for each outfall.

Pollutant and CAS Number *(if available)*	Maximum Values *(include units)*		Average Values *(include units)*		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite	Grab Sample Taken During First 20 Minutes	Flow-Weighted Composite		
Cadmium, Total	< 0.001 mg/L		< 0.00058 mg/L		4	Outfall 007S consists of roof drain runoff and stormwater collected from the area surrounding the generating facility building (except that which is related to the FGD construction - this is routed to 001).
Copper, Total	0.0077 mg/L		0.0034 mg/L		4	
Lead, Total	0.0048 mg/L		0.0017 mg/L		4	
Nickel, Total	0.004 mg/L		0.0023 mg/L		4	
Organic N, Total	TBD				1	

Part D. Provide data for the storm event(s) which resulted in the maximum values for the flow weighted composite sample.

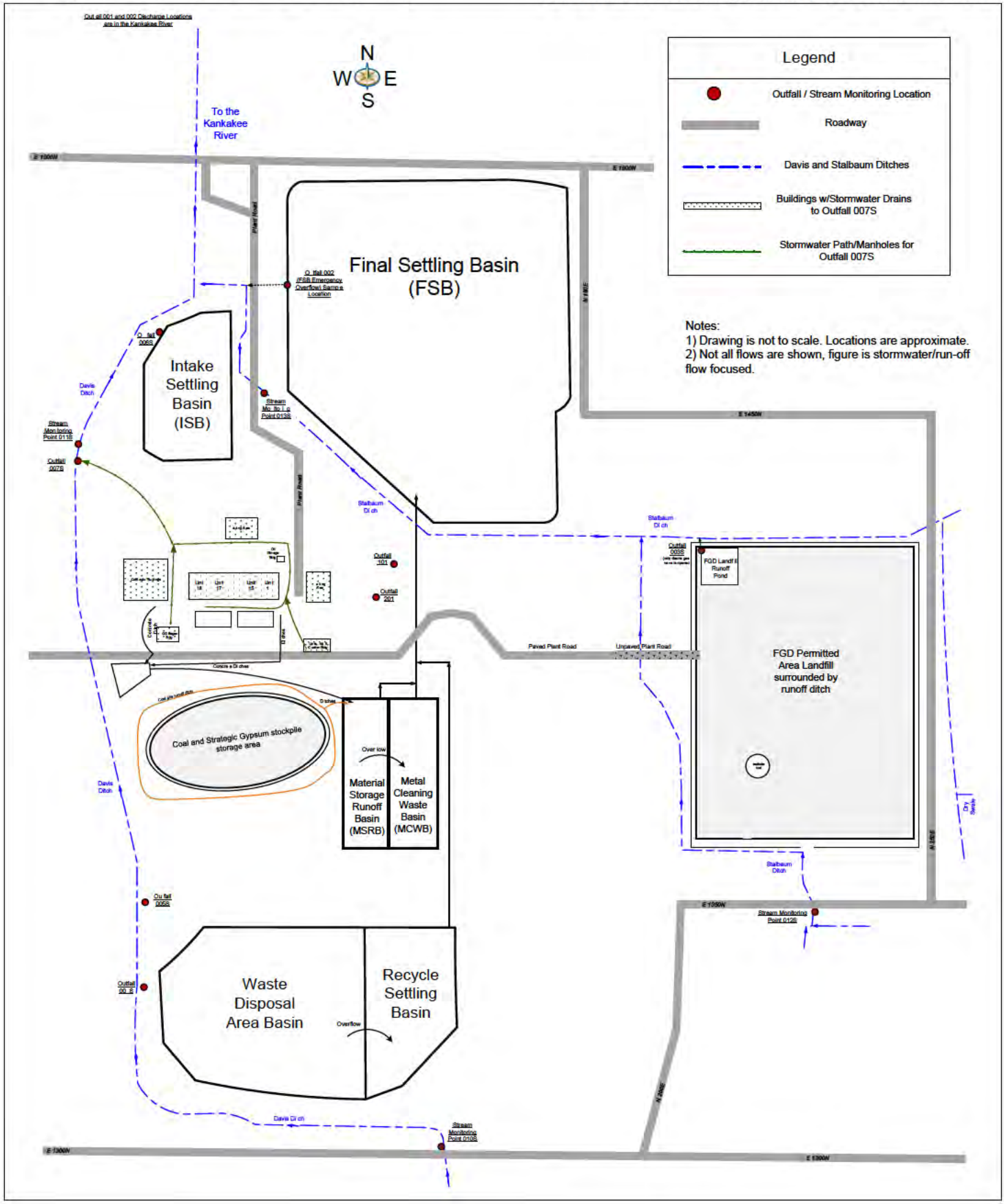
1. Date of Storm Event	2. Duration of Storm *(in minutes)*	3. Total rainfall during storm event *(in inches)*	4. Number of hours between beginning of storm measured and end of previous measurable rain event	6. Total flow from rain event *(gallons or specify units)*
06/15/16	128	0.17	336 hours	0.0976 MGD
08/22/17	420	1.12	288 hours	0.1048 MGD
08/20/18	60	0.21	83 hours	0.0111 MGD
05/09/19	155	0.65	96 hours	0.4918 MGD

9. Provide a description of the method of flow measurement or estimate.

Contractor measures the depth of the water & pipe width to calculate flow using an open channel flow equation. Time of discharge is measured to determine total volume.

Figure RMS-DRAIN: Site Drainage Map

R.M. Schahfer Generating Station NPDES Permit IN0053201



RAMBOLL

Stream Monitoring Locations (010S, 011S, 012S, 013S) Data

STREAM MONITORING LOCATION DATA

Stream Monitoring Sites	Location	Receiving Water	Date	Flow (MGD)	pH	TSS (mg/L)	Oil & Grease (mg/L)	Sulfate (mg/L)	Arsenic, total (mg/L)	Selenium, total (mg/L)	Nickel, total (mg/L)	Zinc, total (mg/L)	Cadmium, total (mg/L)	Lead, total (mg/L)	Chromium, total (mg/L)	Copper, total (mg/L)
010S	N 41 12' 5.22" W 87 0' 56.4"	Davis Ditch	6/15/2016	0.1094	7.6	10.0	< 5.00	45.20	0.0025	< 0.0009	0.0019	0.0100	< 0.00016	0.00051	0.00097	0.00093
			8/22/2017	0.3665	7.74	3.2	< 5.00	31.01	0.0018	< 0.0005	0.00086	0.00064	< 0.00015	0.00011	< 0.0005	0.0045
			8/20/2018	0.0106	7.6	2.0	< 5.00	37.34	0.0030	< 0.0010	0.0013	0.0049	< 0.001	< 0.001	< 0.001	< 0.001
			5/9/2019	0.4139	7.7	4.8	< 5.00	45.57	0.0012	< 0.0010	0.0013	0.0082	< 0.001	< 0.001	< 0.001	< 0.001
			max	**0.4139**	**7.74 (max) / 7.6 (min)**	**10.0**	**< 5.00**	**45.57**	**0.003**	**< 0.0010**	**0.0019**	**0.01**	**< 0.0010**	**0.00051**	**0.00097**	**0.0045**
			avg	**0.2251**	**7.7**	**5.0**	**< 5.00**	**39.78**	**0.0021**	**< 0.0008**	**0.0013**	**0.0059**	**< 0.0006**	**0.00066**	**0.00087**	**0.0019**
011S	N 41 13' 19.21" W 87 1' 47.3"	Davis Ditch	6/15/2016	0.2916	7.6	10.4	< 5.00	39.10	0.0016	< 0.0009	0.0026	0.13	< 0.00016	0.00021	0.014	0.00068
			8/22/2017	0.5938	7.7	9.2	< 5.00	75.99	0.0012	0.00053	0.0012	0.11	< 0.00015	0.0013	0.00055	0.0055
			8/20/2018	0.0337	7.6	8.0	< 5.00	97.64	0.0024	< 0.001	0.0014	0.028	< 0.001	< 0.001	< 0.001	< 0.001
			5/9/2019	0.3696	7.25	15.2	< 5.00	74.69	0.0015	< 0.001	0.0015	0.059	< 0.001	< 0.001	< 0.001	0.0013
			max	**0.5938**	**7.7 (max) / 7.25 (min)**	**15.2**	**< 5.00**	**97.64**	**0.0024**	**0.00053**	**0.0026**	**0.13**	**< 0.0010**	**0.0013**	**0.014**	**0.0055**
			avg	**0.322175**	**7.5375**	**10.7**	**< 5.00**	**71.86**	**0.0017**	**0.00085**	**0.0017**	**0.082**	**< 0.0006**	**0.00088**	**0.0041**	**0.0021**
012S	N 41 12' 29.88" W 87 0' 3.9"	Stalbaum Ditch	6/15/2016	0.2751	7.3	3.2	< 5.00	67.4	0.0023	< 0.00086	0.0021	0.0086	< 0.00016	< 0.00016	0.00067	0.00041
			8/22/2017	0.1325	7.61	6.8	< 5.00	49.48	0.002	< 0.0005	0.0014	0.0014	< 0.00015	0.00015	< 0.0005	0.00042
			8/20/2018	0.0424	7.4	3.2	< 5.00	48.84	0.0028	< 0.001	0.0013	0.0047	< 0.001	< 0.001	< 0.001	< 0.001
			5/9/2019	0.5737	7.6	0.4	< 5.00	50.53	< 0.001	< 0.001	0.0012	0.0027	< 0.001	< 0.001	< 0.001	< 0.001
			max	**0.5737**	**7.61 (max) / 7.3 (min)**	**6.8**	**< 5.00**	**67.4**	**0.0028**	**< 0.001**	**0.0021**	**0.0086**	**< 0.0010**	**0.00015**	**0.00067**	**0.00042**
			avg	**0.255925**	**7.4775**	**3.4**	**< 5.00**	**54.06**	**0.0020**	**< 0.00084**	**0.0015**	**0.00435**	**< 0.0006**	**0.00058**	**0.00079**	**0.00071**
013S	N 41 13' 24.52" W 87 1' 21.3"	Stalbaum Ditch	6/15/2016	0.0692	7.4	3.6	< 5.00	276.00	0.0084	< 0.00086	0.0019	0.015	< 0.00016	0.00033	0.0015	0.00057
			8/22/2017	0.1202	7.62	7.6	< 5.00	105.18	0.0035	< 0.0005	0.00071	< 0.0002	< 0.00015	0.00006	< 0.0005	< 0.0003
			8/20/2018	0.0106	7.7	6.4	< 5.00	126.48	0.0051	< 0.001	0.0011	0.018	< 0.001	< 0.001	< 0.001	0.0013
			5/9/2019	0.0044	7.4	< 1.0	< 5.00	402.50	0.0016	< 0.001	< 0.001	0.0021	< 0.001	< 0.001	< 0.001	< 0.001
			max	**0.1202**	**7.7 (max) / 7.4 (min)**	**7.6**	**< 5.00**	**402.50**	**0.0084**	**< 0.001**	**0.0019**	**0.018**	**< 0.001**	**0.00033**	**0.0015**	**0.0013**
			avg	**0.0511**	**7.53**	**4.65**	**< 5.00**	**227.54**	**0.0047**	**< 0.00084**	**0.00118**	**0.0088**	**< 0.0006**	**0.00060**	**0.0010**	**0.00079**

Note: For parameter data sets containing detections and non-detections, all results were used in the calculation of the long term average, but only detections were used to determine the maximum statistics. Instances in which maximum detections were manually populated are shown in blue text.

Attachment 1: Listing of Water Treatment Additives

Attachment 1. Water Treatment Additive Listing

Additive Name	Supplier	Injection Points	Purpose
Sodium Hypochlorite	Rowe	U17, U18 Cooling Tower Basin	Algaecide and b oc de
Nalco 90005	Nalco	U14, U15, U17, U18 Cooling Tower	Algaecide and b oc de
Sulfuric Acid	Wilson	U14, U15, U17, U18 Cooling Tower	pH control
Mixed Oxidant	MIOX	U14, U15 Cooling Tower	Algaecide and b oc de
3D Trasar 3DT198	Nalco	U14, U17, U18 Condenser	Cooling Tower treatment
Nalco 7385	Nalco	U14, U15, U17, U18 Cooling Tower	Scale inhibitor
AGS Plus DBA	Solutia	FGD specific	FGD process additive
Nalco 7408	Nalco	RO un ts, Feedw ater Ion Exchange Unit, Wastewater	Boiler chlorine scavenger
Perma Treat PC-191T	Nalco	Reverse Osmosis system	Boiler antiscalant
Nalco 8735	Nalco	RO systems	RO system pH stabilizer
Trasar Trac 109	Nalco	FGD, Boiler, RO, and cooling towers	Cooling Tower corros on inhibitor
Nalco PermaClean PC-11	Nalco	RO systems	RO system biocide
Nalco 7468	Nalco	Cooling towers	Cooling tower Antifoam (used in conjunction with Nalco 73550)
Ammonium Hydroxide	Wilson	North of Un t 14, 17	Boiler pH control
Citric Acid (anhydrous)	Wilson	Unit 14, 15 basement	RO system maintenance
Sodium Hydroxide	Rowe	Unit 14 basement	pH control
Ferric Chloride	PVS Chemical	14 / 15 FGD WWTP	Wastewater treatment chemical
Hydrated Lime	Mississippi Lime	14 / 15 FGD WWTP	Wastewater treatment chemical
Hydrochloric Acid	PVS Chemical	14 / 15 FGD WWTP	Wastewater treatment pH control
Nalmet 1689	Nalco	14 / 15 FGD WWTP	Wastewater treatment chemical
Nalclear 7763	Nalco	14 / 15 FGD WWTP	Wastewater treatment chemical
CL5828	ChemTreat	Circ Water System	Cooling Water Treatment Dispersant
CL206	ChemTreat	Circ Water System	Cooling Water and Reserve Osmosis
CL4125	ChemTreat	Circ Water System	Cooling Water Treatment
CL4704	ChemTreat	Circ Water System	Cooling Water Treatment
CL1370	ChemTreat	Circ Water System	Cooling Water Treatment
RL9005	ChemTreat	U14/15/17/18 RO Systems	Reverse Osmosis Treatment
P8200L	ChemTreat	Circ Water System	Metal Precipitant
FCT42	ChemTreat	U14/15/17/18 Coal Feeders	Fuel Additive
CL2840	ChemTreat	Circ Water System	Closed System Treatment
PE2505	Suez	Circ Water System	Corrosion/scale inhibitor
3DT138	NALCO	Circ Water System	Water Chemistry control
CL5450	ChemTreat	Circ Water System	Cooling Water Treatment
2877	NALCO	Recycle Basin	Algaecide
3DT337	NALCO	U14/17/18 Condensers	Corrosion control
RL124	ChemTreat	U14/15/17/18 RO Systems	Dechlorination
AZ8100	Suez	U14/17/18 Condensers	Corrosion control
CT1300	Suez	U14/15/17/18 CTs	Algaecide
RL9007	ChemTreat	U14/15/17/18 CTs	Corrosion/scale inhibitor
BL1304	ChemTreat	U14/17 RO Systems	pH control

Attachment 2: 316(b) Cooling Water Intake Structure Updates

COOLING WATER INTAKE STRUCTURE REQUIREMENTS §122.21(R)(2) – (R)(8) 2020 NPDES PERMIT APPLICATION UPDATES

Project name	**NiSource: Schahfer NPDES Permit Renewal Support**
Project no.	**1690015757**
Version	**Original**
Date	**February 28, 2020**
Prepared by	**Ramboll US Corporation**

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1. Introduction

Facility Background

The R. M. Schahfer Generating Station (RMS) is permitted to draw from an intake on the Kankakee River in Wheatfield, Jasper County, Indiana pursuant to National Pollutant Discharge Elimination System (NPDES) Permit No. IN0053201. RMS has four coal-fired boilers (Units 14, 15, 17, and 18) which began operating in 1976 when Unit 14 came online followed by Unit 15 (1979), Unit 17 (1983) and Unit 18 (1986). All four units feature close-cycle cooling via a single multi-cell mechanical draft cooling tower per unit.

Makeup water for the recirculating water system comes from the Kankakee River via Davis Ditch through a single cooling water intake structure (CWIS). The CWIS is located on Davis Ditch approximately two miles north of the plant. Makeup water is drawn through CWIS by a set of three circulating water pumps, each with a capacity of 20,000 gallons per minute (gpm); however, only two of the pumps can be operated together at any one time, thus the maximum Design Intake Flow (DIF) for RMS is approximately 40,000 gpm (57.6 MGD). Nonetheless, the maximum intake flow registered by RMS is 39.0 MGD.

Makeup water is pulled into the service water pump house through a pair of steel bar trash racks then into two separate bays, each containing one traveling screen with stainless steel mesh panels. From the CWIS, makeup water travels via underground pipe to the Intake Basin (IB). Water from the IB is pumped into the plants to be used as cooling tower makeup water, as well as makeup water to the recycle line, and to provide water to the boilers and the Flue-Gas Desulfurization (FGD) equipment. After passing through the plant processes, all water is routed to the Final Setting Basin (FB) located on the north side of the plant. The FB contains a primary outfall to the Kankakee River (Outfall 001) and an emergency outfall to the Davis Ditch.

Regulatory Applicability

The United States Environmental Protection Agency (USEPA) promulgated the Clean Water Act (CWA) Section 316(b) Rule (316(b) Rule) for existing facilities in August 2014, under Title 40 of the Code of the Federal Register (CFR) Parts 122 and 125, as part of the National Pollutant Discharge Elimination System (NPDES) program. Under the 316(b) Rule, which became effective on October 14, 2014, applicable facilities with cooling water intake structures (CWISs) are required to locate, design, and operate their CWIS to minimize adverse environmental impact (AEI) from impingement and entrainment mortality. In accordance with the 316(b) Rule, existing facilities that withdraw greater than a Design Intake Flow (DIF) of 2 million gallons per day (MGD) of water from “waters of the U.S.” and utilize greater than 25 percent of the water withdrawn for cooling purposes are subject to the rule requirements under the NPDES Permit Program.

As per 40 CFR 122.21(r)(1)(ii), existing facilities are required to provide cooling water intake information to the regulatory authority related to the intake and source water. As an existing facility with surface water intakes withdrawing greater than 2 MGD based on cumulative design intake flow, but withdrawing less than 125 MGD based on cumulative actual intake flow, and more than 25 percent of the actual intake flow used exclusively for cooling purposes, RMS must address the required information published in 40 CFR Part 122.21(r)(2) through (r)(8). Corresponding federal regulation citations include:

- Physical Information for Source Water (§122.21(r)(2))
- Physical description of CWIS (§122.21(r)(3))
- Biological Information for Source Water (§122.21(r)(4))

- Cooling Water System Data (§122.21(r)(5))
- Impingement Mortality BTA Demonstration (§122.21(r)(6))
- Entrainment Performance Studies (§122.21(r)(7))
- Operational Status (§122.21(r)(8))

Pursuant to 40 CFR 125.95(a)(1), existing facilities whose currently effective permit expires after July 14, 2018 are required to submit the information required in applicable sections of 40 CFR 122.21(r) when applying for a subsequent permit. This information was originally submitted to the Indiana Department of Environmental Management (IDEM) in March 2015 in the report titled "Schahfer Generating Station NPDES Permit Application Submittal Requirements §122.21(r)(2) – (r)(8)" authored by Golder Associates, Inc (referred to herein as the March 2015 CWIS Report).

After the initial submission of the 40 CFR 122.21(r) permit application studies, the permittee may request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Per federal regulations detailed in 40 CFR 125.94(c), the owner or operator of a facility is required to submit its request for reduced cooling water intake structure and waterbody application information to the Director at least two years and six months prior to the expiration of its NPDES permit. RMS did not request reduced application information, however based on technical review select conditions detailed in the March 2015 CWIS Report continue to be substantially unchanged. This short form report serves as a supplement to the March 2015 CWIS Report (included as Appendix 1) and provides updates for applicable conditions.

2. Source Water Physical Data [40 CFR §122.21(r)(2)]

The description and water quality regime of the Kankakee River has not been modified since the March 2015 CWIS Report. See Appendix 1, Section 2.

3. Cooling water Intake Structure Data [40 CFR §122.21(r)(3)]

The cooling water intake structure configuration has not been modified since the March 2015 CWIS Report. See Appendix 1, Section 3.

4. Source Water baseline Biological Characterization Data [40 CFR §122.21(r)(4)]

No previous impingement or entrainment studies have been performed at RMS; therefore, historic plant impingement and entrainment is not available for this section.

To assess substantially changed conditions from the information submitted in the March 2015 CWIS Report, Ramboll conducted a review of publicly-available information from published and online sources. Rule guidance documents, including the U.S. Fish and Wildlife Service (USFWS)/National Marine Fisheries Service (NMFS) Biological Opinion, as well as USEPA and USFWS online resources/databases, were utilized to guide this data search.

The extensive electrofishing surveys within Indiana portions of the main branch of the Kankakee performed by Price and Robertson[1] in 2001 continues to be the most recent, representative reference of species and relative abundance in the vicinity of the cooling water intake structure.

Since March 2015 CWIS Report, the Indiana Department of Natural Resources (IDNR) has updated the available Endangered, Threatened and Rare Species list. This list has been expanded from the March 2015 CWIS Report to include Jasper and neighboring counties, La Porte and Porter.

Table 1. Threatened and Endangered (T&E) Species with Potential to Impact [A]

County	Aquatic Life	Species Name	Common Name	T&E Status [B]
La Porte	Mussel	Lymnaea stagnalis	Swamp Lymnaea	SSC
Jasper / Porter	Mussel	Plethobasus cyphyus	Sheepnose	LE, SE
Porter	Mussel	Venustaconcha ellipsiformis	Ellipse	SSC
La Porte / Porter	Fish	Acipenser fulvescens	Lake Sturgeon	SE
La Porte	Fish	Ichthyomyzon fossor	Northern Brook Lamprey	SE
Jasper / La Porte	Fish	Moxostoma valenciennesi	Greater Redhorse	SE
La Porte/ Porter	Fish	Rhinichthys cataractae	Longnose Dace	SSC
La Porte	Amphibian	Acris blanchardi	Blanchard's Cricket Frog	SSC
Jasper / Porter	Amphibian	Ambystoma laterale	Blue-spotted Salamander	SSC
Jasper	Amphibian	Cryptobranchus alleganiensis	Eastern Hellbender	SE
La Porte / Porter	Amphibian	Hemidactylium scutatum	Four-toed Salamander	SSC
Jasper	Amphibian	Lithobates blairi	Plains Leopard Frog	SE
La Porte / Porter	Amphibian	Necturus maculosus	Common mudpuppy	SSC

NOTES:

(A): Indiana Department of Natural Resources (May 9, 2019): County Endangered, Threatened and Rare Species List (Jasper, La Porte, and Porter County); https://www.in.gov/dnr/naturepreserve/4666.htm

(B): LE: Federally Endangered; SE: State Endangers; SSC: State Special Concern

5. Cooling Water System Data [40 CFR §122.21(r)(5)]

The RMS operates a recirculating water closed-cycle cooling system, only withdrawing water from the Kankakee River as makeup water, with a maximum intake of 39 MGD. For the period 2008 through 2014, average daily intake flow was 26.2 MGD (Table 2).

The actual intake volumes associated with the RMS CWIS are reported annually to the Indiana Department of Natural Resources (IDNR) as a Significant Water Withdrawal Facility (SWWF). Surface water withdrawal rates are identified under Registration No. 37-01145-EP as Intake 1. Monthly intake volumes from 2016, 2017, and 2018 are summarized in Table 1.

[1] Price and Robertson. 2005. Fishery, Habitat, and Recreational Use Surveys for the Kankakee River, Indiana. Indiana Department of Natural Resources – Division of Fish and Wildlife Final Report – Workplans #200766, #202766. 31 pp.

Table 2. RMS Intake Volume

Month/Year	Day per Month	Intake Volume (1,000 gals per month)	Average Intake Volume (MGD)	Annual Average
Jan-15	31	636401	20.53	
Feb-15	28	644517	23.02	
Mar-15	31	500451	16.14	
Apr-15	30	602534	20.08	
May-15	31	570162	18.39	
Jun-15	30	753237	25.11	22.03 (2015)
Jul-15	31	1047509	33.79	
Aug-15	31	1006353	32.46	
Sep-15	30	913923	30.46	
Oct-15	31	594264	19.17	
Nov-15	30	451809	15.06	
Dec-15	31	313880	10.13	
Jan-16	31	308880	9.96	
Feb-16	29	466810	16.10	
Mar-16	31	362980	11.71	
Apr-16	30	379320	12.64	
May-16	31	700840	22.61	
Jun-16	30	725590	24.19	18.79 (2016)
Jul-16	31	817933	26.38	
Aug-16	31	468780	15.12	
Sep-16	30	831340	27.71	
Oct-16	31	735230	23.72	
Nov-16	30	614620	20.49	
Dec-16	31	459200	14.81	
Jan-17	31	643062	20.74	
Feb-17	28	578302	20.65	
Mar-17	31	648458	20.92	
Apr-17	30	725041	24.17	
May-17	31	623927	20.13	
Jun-17	30	666956	22.23	20.26 (2017)
Jul-17	31	973910	31.42	
Aug-17	31	786027	25.36	
Sep-17	30	491610	16.39	
Oct-17	31	303430	9.79	
Nov-17	30	488651	16.29	
Dec-17	31	466239	15.04	
Jan-18	31	653358	21.08	
Feb-18	28	439007	15.68	24.56 (2018)
Mar-18	31	464079	14.97	

Month/Year	Day per Month	Intake Volume (1,000 gals per month)	Average Intake Volume (MGD)	Annual Average
Apr-18	30	565346	18.84	
May-18	31	767792	24.77	
Jun-18	30	932382	31.08	
Jul-18	31	1010795	32.61	
Aug-18	31	1081148	34.88	
Sep-18	30	865822	28.86	
Oct-18	31	724876	23.38	
Nov-18	30	715841	23.86	
Dec-18	31	766261	24.72	
Jan-19	31	669582	21.60	
Feb-19	28	463301	16.55	
Mar-19	31	813127	26.23	
Apr-19	30	665709	22.19	
May-19	31	866541	27.95	
Jun-19	30	703959	23.47	22.93 (2019)
Jul-19	31	665828	21.48	
Aug-19	31	884732	28.54	
Sep-19	30	838733	27.96	
Oct-19	31	692020	22.32	
Nov-19	30	543954	18.13	
Dec-19	31	582696	18.80	

The actual intake flow (AIF) is defined as the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years. The maximum observed intake flow and AIF are summarized in Table 2 below with the corresponding through-screen velocity (TSV).

Table 3. Calculated TSV

Design Intake Flow, MGD =	**39.00**	**TSV @ DIF, fps =**	**0.39**
Actual Intake Flow (2015-2017), MGD =	20.36	**TSV @ 2017 AIF, fps =**	0.20
Actual Intake Flow (2016-2018), MGD =	21.20	**TSV @ 2018 AIF, fps =**	0.21
Actual Intake Flow (2017-2019), MGD =	22.58	**TSV @ 2019 AIF, fps =**	0.23

6. Chosen Method of Compliance with Impingement Mortality Standard [40 CFR §122.21(r)(6)]

The RMS will continue to comply with the Impingement Mortality Standard by maintaining an AIF of less than 0.50 fps. Compliance monitoring will continue via monitoring and reporting daily intake flow.

7. Entrainment Performance Studies [40 CFR §122.21(r)(7)]

No entrainment performance studies have been conducted at RMS.

8. Operational Status [40 CFR §122.21(r)(8)]

RMS is equipped with four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. Individual unit characteristics from the 2018 NIPSCO Integrated Resource Plan (IRP) are shown in Table 3.

Table 4 RMS Individual Unit Characteristics

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979

The 2018 IRP identified the preferred retire path which included the retirements of Schahfer Units 14, 15, 17, 18. NIPSCO's short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the Schahfer 14, 15, 17, 18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire the Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.