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August 15, 2024
INDIANA UTILITY
REGULATORY COMMISSION

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**

<u>SUBMISSION OF CAC'S PUBLIC EXCEPTIONS TO PROPOSED ORDER</u>

Citizens Action Coalition of Indiana, Inc. ("CAC"), respectfully submits its redacted Exceptions to Petitioner's Proposed Order. The confidential pages of CAC's Exceptions to Proposed Order were simultaneously submitted, under seal, pursuant to the Commission's February 8 and May 13, 2024 docket entries.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 15th day of August, 2024, to the following:

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REDLINE VERSION (REDACTED)

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**

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]

Also on September 12, 2023, Petitioner filed the testimony and attachments of the following

[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. Pet. Ex. 1, Attachment 1-E.

(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 (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 of Procedural Schedule, which was granted by docket entry dated January 25, 2024.

On January 16, 2024, Petitioner filed 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 in the in-service date of the proposed generation project.

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 and Primary Energy did not file 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

[2] Petitioner originally prefiled the Verified Direct Testimony of Andrew S. Campbell~~.~~ as Pet. Ex. 6. NIPSCO filed a Notice of Substitution of Witness on January 16, 2024 whereby witness Mr. Stanley adopted Mr. Campbell's direct testimony.

[3] Petitioner originally prefiled the Verified Rebuttal Testimony of Robert C. Sears. NIPSCO filed a Notice of Substitution of Witness on May 29, 2024~~.~~ whereby witness Ms. Becker adopted Mr. Sears's rebuttal testimony.

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. <u>Notice and Commission Jurisdiction.</u> Notice of the evidentiary hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of that term as used in Ind. Code § 8-1-2-1 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. NIPSCO is also an "eligible business" as that term is defined in Ind. Code § 8-1-8.8-6. NIPSCO is also an "energy utility" within the meaning of Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO also is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics.</u> NIPSCO is a limited liability company organized and existing under the laws of the State of Indiana with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is authorized by the Commission to provide 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. Pursuant to the Commission's Order dated September 24, 2003, in Cause No. 42349, NIPSCO has transferred functional control of its transmission facilities to the Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under the authority of FERC, which administers the use of NIPSCO's transmission system and the economic dispatching of NIPSCO's generating units pursuant to MISO's FERC approved tariff provisions. NIPSCO also engages in power purchase transactions through MISO as necessary to meet the demands of its customers. Pet. Ex. 1, Attachment 1-A, at 3-5.

3. <u>Relief Requested.</u> In this Cause, NIPSCO has petitioned the Commission for (1) issuance of a CPCN pursuant to Ind. Code ch. 8-1-8.5 to construct the 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 ("CWIP") 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 ("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.

4. The Proposed CT Project. The CT Project for which NIPSCO seeks approval would be an approximately 400 MW gas combustion turbine that, as proposed, would consist of one F-class frame turbine and three aeroderivative turbines. Pet. Ex. 5 at 3-5. While NIPSCO's initial application identified an in-service date by the end of 2026 for the CT Project, due to supply chain challenges, the in-service date has been delayed to the end of 2027. NIPSCO cites an estimated cost for the project of $641,223,000 not including Allowance for Funds Used During Construction ("AFUDC"), which is approximately $1,600 per kW. CAC Ex. 3 at 25. Under NIPSCO's proposal, the cost of the CT Project to a residential customer using 1,000 kWh per month would be $8.94 per month when the project would be rolled into rate base. Pub. Ex. 5 at 7.

~~4.~~5. 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 NIPSCO's resource planning analyses over the last several years, particularly the Integrated Resource Plan submitted November 15, 2021 (the "2021 IRP"). He also reviewed major market developments since NIPSCO's submission of 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~~Portfolio Analysis"). Mr. Augustine ~~described how~~contended that the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by the additional analyses NIPSCO has performed since the submission of the 2021 IRP. Pet. Ex. 7 at 5-6.

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~~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 that NIPSCO's Flexible Resource Analysis ("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 that NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by~~Portfolio Analysis projected that pivoting towards a larger-sized, cost-effective thermal resource would lead to a total portfolio cost of $11.4 billion on a 30-year NPVRR basis, as compared to ~~more expensive~~$11.643 billion if 650 MW of storage ~~additions.~~were pursued instead. Pet. Ex. 7 at 40. Mr.

[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.

Augustine noted that the cost difference between the gas CT and battery storage portfolios was largely due to the assumption that the capacity accreditation of storage would decline to 70% by 2040, while the capacity accreditation of a gas CT would remain stable around 95%. Pet. Ex. 7 at 34-35.

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 NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP. Pet. Ex. 7 at 42.

In his supplemental testimony, Mr. Augustine presented updated information from MISO related to planning reserve margin requirements ("PRMR"), capacity accreditation, and NIPSCO's supply/demand balance. Pet. Ex. 7-S at 2. He explained that while the 2021 IRP and the 2023 ~~portfolio analysis~~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 the 2023 ~~portfolio analysis~~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~~.~~." Pet. Ex. 7-S at 3. 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.~~Portfolio Analysis." Pet. Ex. 7-S at 14. 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 that "overall, 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~~Portfolio Analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP~~.~~." Pet. Ex. 7-S at 14-15.

IG witness Gorman recommended rejection of the CPCN, in part because, "[i]nstead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study." IG Ex. 1 at 4. As Mr. Gorman noted, the 2021 IRP had included up to 300 MW of new gas peaking capacity, NIPSCO is seeking approval for an approximately 400 MW gas peaker. *Id.* at 4-5. IG witness Gorman explained that the Flexible Resource Analysis failed to take into account a "several material developments" since the 2021 IRP, including MISO's seasonal resource construct, the Inflation Reduction Act, issues like supply constraints, tariff uncertainty, and inflation, and the latest market data from additional Requests for Proposals ("RFPs"). *Id.* at 5. IG witness Gorman testified that NIPSCO has failed to account for the expected changes in Rate 531 Tier 1 demand, which could lead to a reduction in 100 MW of contracted load that NIPSCO would need to serve, and has therefore failed to "right size" the CT Project. *Id.* at 7-8.

CAC witness Anna Sommer identified additional shortcomings in the Flexible Resource Analysis. That analysis found that NIPSCO's 2021 resource plan would result in periods of market exposure, the majority of which would last less than an hour but a few dozen of which were projected to last longer than four hours in duration. CAC Ex. 1 at 19. However, while the Flexible Resource Analysis found that an additional 100-200 MW of flexible capacity (beyond up to 300 MW gas peaker included in the 2021 IRP) could reduce such market exposure, it did not quantify the cost of the potential market exposure or of the resources that could reduce that exposure. CAC Ex. 1 at 19-20. Nor did the Analysis provide any evaluation of the costs or effectiveness of alternative options for reducing the market exposure, such as battery storage combined with demand response, or different turbine configurations for the CT Project. CAC Ex. ~~OUCC witness Hanks had concerns that NIPSCO's incorporation of misaligned results of an all-source RFP – together with and RFP that solicited bids for a particular technology configuration – inflates the cost of the thermal peaking resource incorporated into the 2023 portfolio analysis that has the potential to distort the results of the resource selection process used within the IRP. OUCC witness Hanks argued that 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.~~1 at 20.

With regards to NIPSCO's 2023 Portfolio Analysis, witness Sommer explained that such analysis did not include re-optimization of capacity expansion plans to determine a lowest cost portfolio. CAC Ex. 1 at 17. Instead, NIPSCO merely used portfolios from its 2021 IRP, which the company then updated to reflect changes in project costs and PPA prices, MISO seasonal planning reserve margins and capacity accreditation, commodity ~~Pub. Ex. 2 at 14-15. OUCC witness Hanks also suggested that the capital costs for the CT Project used in NIPSCO's analysis understate the costs of the project by excluding indirect costs. *Id.* at 6.~~

~~CAC witness Sommer noted that the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market~~ price inputs, tax credits for solar, wind, and storage under the Inflation Reduction Act. CAC Ex. ~~risk exposure or compare the costs of resources that could reduce the net load exposure~~1 at 16-17. ~~. CAC Ex. 1 at 20. CAC witness 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. *Id.*~~ CAC witness Sommer ~~suggested~~also contended that under ~~the~~MISO's proposed direct loss of load ("D-LOL") capacity accreditation structure, ~~battery resources will have stronger capacity accreditation than natural gas peaker resources and that NIPSCO's~~ NIPSCO's capacity calculations likely "overstate both summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources." *Id.* at 23. In particular, while NIPSCO had assumed accreditation of 97% for the gas peakers and 82.63% for storage, MISO's D-LOL proposal had gas at 88% in summer and 66% in winter, while storage was at 94% in summer and 91% in winter.

In light of MISO's proposed D-LOL capacity accreditation values, Ms. Sommer testified that NIPSCO would likely need additional capacity in 2028 when the Michigan City plant is scheduled to retire even if the CT Project is approved and comes online. *Id.* at 23-24. Ms. ~~CAC~~ Sommer urged NIPSCO to pursue two types of resources – demand response and battery storage – both of which could be brought online in a shorter timeframe than a combustion turbine project. *Id.* at 25-28. With regards to demand response, witness Sommer included with her testimony an analysis from the Cadeo Group that found NIPSCO could add 90 MW of summer and 46 MW of winter capacity from demand response by 2027, with additional amounts in the years thereafter. CAC Ex. 1 at 27 and Attachment AS-3. Ms. ~~performed a~~ Sommer testified that the levelized cost of capacity from such demand response programs would be $27,480/MW-yr or $75/MW-day, while the CT Project has a levelized capacity cost of $133,721/MW-yr or $367/MW-day. CAC Ex. 1 at 25, Table 4. Ms. Sommer recommended that the Commission direct NIPSCO to make a filing by the end of 2024 for additional cost-effective demand response resources to add to its portfolio. *Id.* at 37.

As for battery storage, CAC witness Sommer detailed that even if the CT Project were approved, NIPSCO would have excess interconnection injections rights left at the Schahfer site from the retirement of Units 17 and 18. Those rights, along with additional rights that will become available when Schahfer Units 16A and 16B retire, could be transferred to battery storage and other no- or low-carbon resources that NIPSCO should explore building at the Schahfer site. CAC Ex. 1 at 25-26. Those injection rights are extremely valuable assets that should be reutilized given that they enable the avoidance of the current delays in MISO's injection queue. Reutilizing the excess injection rights that will be available at the Schahfer site for battery storage makes sense given that storage has a shorter development timeframe than the CT Project and would benefit from the energy community bonus adder under the Inflation Reduction Act. *Id.* at 26-28. Especially given the potential for changes to MISO rules regarding the reutilization of injection rights, witness Sommer opined that it is important that NIPSCO quickly develop a plan for how it can fully utilize the Schahfer injection point. *Id.* at 27. As such, Ms. Sommer recommended that the Commission direct NIPSCO to file by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so. *Id.* at 37.

CAC witness Sommer testified that NIPSCO did not provide any opportunity for stakeholder involvement or input in conducting the Flexible Resource Analysis or the 2023 Portfolio Analysis. CAC Ex. 1 at 18-19. Ms. Sommer further expressed serious concerns over the continued use of the Aurora resource planning model absent resolution of recent transparency and access concerns for the model. Due to an inability to secure a license for the Aurora modeling software, CAC was unable to recreate or modify the modeling NIPSCO performed in its 2023 Portfolio Analysis. *Id.* at 18. Ms. Sommer explained that Aurora's vendor, Energy Exemplar, only allowed short-term, project-based licenses by going through an existing licensee. *Id.* at 32. While not ideal, Ms. Sommer stated that she had successfully navigated such a process with utilities in the past. However, the language of the licensing agreement here prevented CAC from executing any of its own simulations in the Aurora model. To conduct their own modeling with Aurora, CAC would be required to purchase a full license that would be entirely cost-prohibitive for intervenor clients and non-utility stakeholders. *Id.* Ms. Sommer explained that a continued inability to recreate or modify the modeling that NIPSCO performs in Aurora will substantially hinder the engagement of intervenors and other non-utility stakeholders.

Ms. Sommer raised similar concerns about the lack of transparency and stakeholder engagement in NIPSCO's RFP process. Ms. ~~analysis to compare the costs of~~ Sommer stated that the Schahfer development RFP issued in 2022 was singularly focused on gas-fired technologies, as evidenced by S&L's development of technical specifications for only gas turbines specifically for that RFP. CAC Ex. 1 at 33. Because CAC was not invited to provide feedback on NIPSCO's resource procurement RFP, CAC was unable to flag concerns about the RFP until after the fact. Ms. ~~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.~~Sommer testified that NIPSCO has acknowledged its failure to give intervenors the opportunity to review the Schahfer RFP. *Id* ~~*Id.* at 28, Table 7~~.

~~IG witness Gorman stated that, "[i]nstead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study." IG Ex. 1 at 4. IG witness Gorman suggested that NIPSCO failed to take into account the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year~~

~~. *Id.* at 6. IG witness Gorman testified that 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. *Id.* at 7-8.~~

In rebuttal, Mr. Augustine testified that "overall, while the parties directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, no party has testified that 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~~.~~." Pet. Ex. 7-R at 2. Mr. Augustine addressed the parties' testimonies in relation to the 2023 ~~portfolio analysis~~Portfolio Analysis, the Flexible Resource Analysis, NIPSCO's future supply-demand balance, and additional analysis and considerations that were introduced.

In response to Mr. Gorman's testimony 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 testified that Mr. Gorman has 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~~Portfolio Analysis to assess the performance of alternative portfolio options against updated market conditions and the latest available information. Pet. Ex. 7-R at 5.

In responding to Mr. Gorman's suggestion that NIPSCO failed to take into account 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 testified 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 in order to develop portfolios based on capacity requirements for both the summer and winter seasons. Pet. Ex. 7-R at ~~10~~7, citing Pet. Ex. 7 at 13-15, 26 and Pet. Ex. Attachment 7-A (2021 IRP), Section 4.5, Section 8.2.4, Section 9.2, and Section 9.3. He also stated that NIPSCO's 2023 ~~portfolio analysis~~Portfolio Analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after FERC approved MISO's seasonal construct. *Id.* at 10, citing Pet. Ex. 7 at 26. He testified that higher winter reserve margin targets contributed to higher requirements for dispatchable thermal or storage capacity additions in the 2023 ~~portfolio analysis~~Portfolio Analysis relative to the levels evaluated in NIPSCO's 2021 IRP, which was directly accounted for in the portfolio construction. Pet. Ex. 7-R at 7-8, citing Pet. Ex. 7 at 31-32.

In responding to Ms. Sommer's testimony that she did not perform independent modeling~~ in part due~~, Mr. Augustine highlights Ms. Sommer's reference to "concerns about the portfolios that were examined since they include projects that NIPSCO has canceled" (CAC Ex. 1 at 18), which he suggests provides an inaccurate assessment~~Mr. Augustine testified that while some~~ of the portfolios that were evaluated in the 2023 Portfolio Analysis. Pet. Ex. 7-R at 8-9. Mr. ~~did include projects that NIPSCO has since canceled,~~Augustine explains that preferred Portfolio 3 was explicitly developed to incorporate the risk of such project cancellations, Pet. Ex. ~~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." Pet. Ex.~~ 7-R at 8-9, citing Pet. Ex. 7 at 30~~. He stated~~, and that consistent with these assumptions, NIPSCO has since filed termination notices for these four projects ~~(Elliott project, the Brickyard PPA, the Greensboro PPA,~~ and ~~the Gibson PPA (though the Gibson project remains in~~

~~NIPSCO's portfolio at a smaller project size and different ownership structure) and has~~ used the 2023 ~~portfolio analysis~~Portfolio Analysis to support replacement of these projects with incremental wind and solar capacity,[5] as explicitly modeled in preferred Portfolio 3. Contrary to Mr. ~~Augustine testified~~Augustine's critique, however, Ms. Sommer did not dispute that ~~the Commission has since approved these projects, including relying specifically upon the 2023 portfolio analysis in doing so.~~ project cancellations had occurred; instead, her concerns were that it would be challenging to assess the impact of those cancellations without re-optimization of the portfolios, which is something that NIPSCO's input database was not set up to do. CAC~~Pet.~~ Ex. 1 at 18. Ms. Sommer's testimony was also clear that she did not perform independent modeling "due to an inability to secure a license" for the Aurora modeling software. *Id.* ~~7-R at 8-9.~~

In response to Ms. Sommer's concerns about the ability for intervenors to use Aurora in this proceeding, Mr. Augustine acknowledged that the language of clauses within the proposed limited license agreement with Energy Exemplar may be interpreted differently by different parties. Pet. Ex. 7-R at ~~In responding to Mr. Hanks' argument that 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 testified that~~ 31. However, Mr. Augustine reiterated that NIPSCO and CRA are committed to continuing to work with Energy Exemplar in the 2024 IRP process to provide the opportunity for stakeholders to license the model with the purpose of running independent simulations. *Id.* at 32.

~~Mr. Hanks appears 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, the comparisons Mr. Hanks attempts to make are inappropriate. He stated that contrary to Mr. Hanks' claims, NIPSCO's Schahfer Development or EPC RFP was not technology and configuration restricted. He explained that 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. Pet. Ex. 7-R at 9-10.~~

~~Mr. Augustine testified that 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, in order 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. He testified that 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 more meaningful and is a reasonable approach. Pet. Ex. 7-R at 11-12.~~

In responding to Ms. Sommer that 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

~~[5] NIPSCO filed a CPCN for the 200 MW Appleseed solar project and the 200 MW Templeton wind project in Cause No. 45887 and a CPCN for the 200 MW Carpenter wind project in Cause No. 45908.~~

the net load exposure, Mr. Augustine testified 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~~.~~." Pet. Ex. 7-R at 14-15. Mr. Augustine testified that "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—something Ms. Sommer did not challenge. Pet. Ex. 7-R at 16.

With regards to ~~Mr. Augustine testified that~~ Ms. Sommer's argument ~~there was no evaluation of an alternative approach to mitigate potential risks identified in~~ that the Flexible Resource Analysis~~, such as a portfolio with battery storage and more demand response, is inaccurate. He stated that in addition to the~~ did not evaluate different resource ~~attribute needs identified in the Flexible Resource Analysis,~~ options for mitigating the potential risks identified therein, CAC Ex. 1 at 20, Mr. Augustine notes that NIPSCO's 2023 ~~portfolio analysis~~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, which concluded that the portfolio with new peaking capacity was lower cost for customers. Pet. Ex. 7-R at 16-17. He noted that NIPSCO's 2021 IRP did the same and concluded that the portfolio with new peaker capacity performed similarly or better on the cost-based metrics than a portfolio relying only on storage and best on the reliability metrics (2021 IRP, Figure 9-42 and Section 9.2.7). Mr. Augustine testified that NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project. Pet. Ex. 7-R at 16-17.

Mr. Augustine responded to Mr. Gorman's testimony that 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. He explained that NIPSCO's 2021 IRP did evaluate a scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman. Pet. Ex. 7, Attachment 7-A at 54-55. Mr. Augustine noted that, in the narrative description on p. 54 of the 2021 IRP, it is noted that "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, Figure 9-18 and Figure 9-42 from NIPSCO's 2021 IRP, show NIPSCO's preferred portfolio performed well under such assumptions as can be seen in NIPSCO's cost to customer results across scenarios and NIPSCO's integrated scorecard, respectively. Pet. Ex. 7-R at 17-18.

In response to Ms. Sommer's proposal that battery storage and demand response resources be deployed and her argument that such resources "can be added more quickly than the CT project can be built" (CAC Ex. 1 at 27), Mr. Augustine testified that while development and deployment timelines will vary by resource, he noted that NIPSCO's preferred portfolio from its 2021 IRP and 2023 ~~portfolio analysis~~Portfolio Analysis already contemplates 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 stated that the pending MISO rules changes also appear to offer additional evidence in support of NIPSCO's proposed CT project. He explained that 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~~.~~." Pet. Ex. 7-R at 19-20.

Mr. Augustine disagreed with Ms. Sommer's suggestion that under the proposed D-LOL structure, battery resources will have stronger capacity accreditation than natural gas peaker resources and that 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." CAC Ex. 1 at 23. He testified that future capacity accreditations under D-LOL "remain too uncertain to definitively make such a claim, and the forward-looking information published by MISO is actually supportive of the assumptions used in NIPSCO's 2023 ~~portfolio analysis~~Portfolio Analysis, which included stable accreditation for gas resources and declining accreditations for four-hour battery storage resources over time." Pet. Ex. 7-R at 20-21. Mr. Augustine identifies in his rebuttal MISO's 5- and 10-year capacity accreditation values for natural gas of 84% in the summer and 80% to 82% in the winter, Pet. Ex. 7-R at 21-22, which are lower than the assumption in NIPSCO's analyses that the capacity accreditation of a gas CT would likely remain stable at around 95%. Pet. Ex. 7 at 34-35.~~. Pet. Ex. 7-R at 20-21.~~

In response to Ms. Sommer's 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 (CAC Ex. 1 at 28), Mr. Augustine testified 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~~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~~Portfolio Analysis in Ms. Sommer's analysis. Pet. Ex. 7-R at 23-27.

B. ~~In response to~~CT Project.

Ms. Becker set forth NIPSCO's bases for contending that its CT Project proposal satisfied~~Mr. Hanks' and Ms. Sommer's opposition of NIPSCO's application in part because of the cost of the aeroderivative turbine component (Pub. Ex. 2 at 2 and CAC Ex. 1 at 6-7 and 10), and Mr. Hanks' arguments that "NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units" (Pub. Ex. 2 at 2), Mr. Augustine testified that NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained that in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment (Pet. Ex. 7, Attachment 7-A, 2021 IRP, Sections 9.2.6 and 9.2.7) both highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis (Pet. Ex. 7, Confidential Attachment 7-D at 9–10) identified growing 3-hour and 10-minute ramping requirements by 2030. Pet. Ex. 7-R at 27-28.~~

~~**B. CT Project.** 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 sponsoring supporting testimony related to each element. Pet. Ex. 1 at 4.

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 and identified the NIPSCO witness sponsoring supporting testimony related to each pillar. Pet. Ex. 1 at 6-7. 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 provided by MISO regarding the new generation, including NIPSCO's request to MISO (Exhibit 1 to the Affidavit). Pet. Ex. 1 at 7. In her supplemental testimony, Ms. Becker described NIPSCO's follow-up contact with MISO in light of the shift in the in-service date. Pet. Ex. 1-S at 5.

Ms. Becker testified that 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. Pet. Ex. 1 at 7-8.

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 (Ind. Code § 8-1-8.5-4(2)). 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 this generation. She said that NIPSCO is committed to the development of demand response programs for all customer groups and appreciates the assistance of its stakeholders in finding experts to help with that development 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. Pet. Ex. 1 at 8-19.

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 (5) years. He ~~confirmed~~contended that the CT Project is a clean energy project as that term is defined in Ind. Code § 8-1-8.8-2. He addressed consistency of the proposed construction of the CT Project with the Five Pillars outlined in Ind. Code § 8-1-2-0.6. Pet. Ex. 2 at 22.

Mr. Holcomb testified that the CT Project as a new gas combustion turbine is subject to EPA's final greenhouse gas emissions standards for new fossil fuel-fired power plants ("GHG Rule") as published in the Federal Register on May 9, 2024. Pet. Ex. 9-R at 4. Mr. Holcomb explained that the final GHG Rule established three subcategories based on capacity factor: Low load (less than or equal to 20% capacity factor), Intermediate load (greater than 20% capacity factor but less than or equal to 40% capacity factor), and Base load (greater than 40% capacity factor). *Id.* at 5. Prior to the finalization of the GHG Rules, Mr. Walter testified that NIPSCO projected to maintain capacity factors below 20%, except in the initial months of operation. Pet. Ex. 2 at 29. During those initial months, NIPSCO would either limit capacity factors to 20% or achieve the Intermediate emission limitations. *Id.* After the final GHG Rule was published, NIPSCO reiterated that their position remained the same. NIPSCO-CAC Ex. 8 at 3.

In rebuttal, Mr. Holcomb further explained that both the aeroderivative and frame unit of the CT Project would comply with the Low load category by operating below a 20% capacity factor. Pet.

Ex. 9-R at 5. The CT Project is not designed to operate as a base load turbine and NIPSCO therefore intends to operate the CT Project as peaking units. *Id.* at 6. While Witness Holcomb and Witness Becker (succeeding Sears) note that the GHG Rule imposes operational limitations on the industrial frame units that are not present with the aeroderivative units, Pet. Ex. 9-R at 7 and Pet. Ex. 1-R at 13, NIPSCO projects operating the CT Project at capacity factors below 20%, which would qualify it as a low load plant for purposes of the GHG Rule. NIPSCO-CAC Ex. 2 at 12. NIPSCO has not performed any formal scenario analysis to identify conditions under which any one of the proposed turbines would run at greater than 20% capacity factor, nor has NIPSCO developed capacity factor projections for each individual unit within the proposed CT Project. NIPSCO-CAC Ex. 8 at 4; NIPSCO-CAC Ex. 2 at 3; NIPSCO-CAC Ex. 2-C (spreadsheet labeled as CAC 1-019 Highly Confidential Attachment A-S). NIPSCO has also only developed capacity factor projections for gas peaker projects as a whole. NIPSCO-CAC Ex. 2 at 3.

Mr. Walter testified that the CT Project will be enabled to blend hydrogen, with a 15 to 35% hydrogen blending capability being considered. Pet. Ex. 2 at 29. Mr. Holcomb explains that the potential future combustion of hydrogen and renewable natural gas provide a pathway for the CT Project to help achieve NIPSCO's goal of net zero GHG emissions by 2040, Pet. Ex. ~~4.~~9-R at 8-9. However, NIPSCO did not provide a requirement for hydrogen blending capabilities during the CT OEM bid event. NIPSCO-CAC Ex. 8 at 5-7. Nor does NIPSCO provide any information or analysis related to the costs, availability, or viability of using hydrogen or renewable natural gas as a fuel for this CT Project.NIPSCO-CAC Ex. 2 at 8, 11. CAC witness Sommer noted that NIPSCO does not anticipate needing a hydrogen fuel supply to achieve its 90% reduction in greenhouse gas emissions by 2030 goal, and opined that the hydrogen industry is in an "extremely nascent state" and that, therefore, it would be imprudent to spend tens of millions of dollars merely to preserve the possibility of future hydrogen blending. CAC Ex. 1 at 13-14.

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 new CT Project's contribution to NIPSCO's system reliability. Pet. Ex. 3 at 3.

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. Pet. Ex. 4 at 3.

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). Pet. Ex. 5 at 3-4.

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. Pet. Ex. 6 at 3-4.

Witness Campbell (succeeded by Stanley[6]) testified that NIPSCO intends to support the CT Project's gas usage through options within NIPSCO's currently approved gas tariff. Pet. Ex. 6 at 19.

However, CAC witness Sommer points out that NIPSCO has stated that its plan to supply fuel to the CT project is not yet set. CAC Ex. 1 at 34. While NIPSCO argues that its own gas distribution system has the capacity to serve the gas needs of the project, it continues to explore supply from interstate pipelines in the vicinity of Schahfer. *Id.*; NIPSCO-CAC Ex. 5 at 7, 9. NIPSCO is still formulating the exact fuel strategy it will employ for the CT Project and intends to run a Gas Supply RFP in late 2024 or in 2025 to support the final fueling strategy of the CT project. Pet. Ex. 6 at 19; NIPSCO-CAC Ex. 5 at 3; NIPSCO-CAC Ex. 5 at 9.

Given issues with gas supply during Winter Storm Uri and Winter Storm Elliot, CAC witness Sommer suggests NIPSCO should explore the possibility of multiple pathways to supply the CT Project if approved. CAC Ex. 1 at 34; NIPSCO-CAC Ex. 5 at 11. Further, Ms. Sommer suggests that any material deviations from modeled gas costs, particularly transportation costs, should be vetted thoroughly before recovery from ratepayers. *Id.*

In rebuttal, Witness Stanley concedes that the natural gas procured to fuel the CT Project should be reviewed through the current Fuel Adjustment Clause ("FAC") process. Pet. Ex. 6-R at 4-5.

In his supplemental direct testimony, Mr. Baacke discussed supply chain challenges that led to the anticipated in-service date for the proposed CT Project to be delayed from end of 2026 to end of 2027. Mr. Baacke testified that ongoing conversations with suppliers and NIPSCO's review of bid responses led to material updates with respect to necessary components that impacted the project timeline. Multiple 345 kV breaker suppliers indicated lead times of 26 to over 48 months. Only a single supplier indicated that a delivery of five needed breakers could be potentially achieved by late Quarter 3, 2026. Results of NIPSCO's generator step-up bid event indicated that only a single supplier could deliver generator step-up transformers to support an end of year 2026 in-service date. Due to those external supply chain challenges, NIPSCO was forced to reevaluate an end of year 2026 in-service date, with an in-service date of no-later-than end of year 2027 appearing to be more achievable. Pet. Ex. 5-S at 3-4.

Mr. Baacke stated that NIPSCO's originally estimated in-service date for end of year 2026 was always with the understanding that the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained that 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 that NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Pet. Ex. 5-S at 2-3.

[6] References in this Order to Petitioner's Exhibit 6 will expressly refer to NIPSCO witness Mr. Stanley, who adopted the testimony originally sponsored by witness Campbell.

i. Configuration. 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 that 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. In recent years, 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. Pet. Ex. 5 at 4-5. Despite these comparative benefits of larger industrial frame units, NIPSCO also included three smaller aeroderivative units because of their claimed benefits with regards to efficiency, fast start capability, and flexible operations. Pet. Ex 5 at 5.

Mr. Baacke testified NIPSCO chose the preferred configuration to maximize benefits to NIPSCO and its customers. NIPSCO's preferred configuration was then used to conduct an RFP to seek proposals for an engineering, procurement, and construction ("EPC") contract (the "EPC RFP"). As shown in Appendix 19 of the Simple Cycle Gas Turbine Engineering Study, Report No. SL-016874 (the "Engineering Study") (Highly Confidential Attachment 4-A sponsored by NIPSCO witness Warren), 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 that witness Baacke testified align with the Flexible Resource Analysis (Highly Confidential Attachment 7-D sponsored by NIPSCO witness Augustine), operational factors, costs, environmental, and schedule. Pet. Ex. 5 at 6.

Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated that NIPSCO already owns the property at the Schahfer site. He said constructing the CT Project on the Schahfer site provides cost savings and advantages for NIPSCO, its customers, and the local economy. Pet. Ex. 5 at 7.

As discussed by NIPSCO witness Stanley, NIPSCO also 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. Pet. Ex. 6 at 10-11. As previously discussed, even if the CT Project were approved, NIPSCO would have excess interconnection injection rights left at the Schahfer site that can and should be used for battery storage and other no- or low- carbon resources that NIPSCO should explore building at the Schahfer site. CAC Ex. 1 at 25-26.

OUCC witness Hanks testified that the EPC RFP prevented bidders from proposing a less expensive, all industrial frame configuration. Pub. Ex. 2 at 2. Witness Hanks notes that NIPSCO has not actually committed to installing aeroderivative units in its current proposal. *Id*. Further, as a result of requiring bidders to include the use of aeroderivative units when responding to the EPC RFP, witness Hanks claims the EPC RFP prevented respondents from proposing a more economical, all-industrial frame configuration. *Id.* Witness Hanks also points out that both Mr. Warren and Mr. Baacke testified that smaller industrial frame machines are available and could be used in place of the aeroderivative units. *Id.* at 9; Pet. Ex. 4 at 11; Pet. Ex. 5 at 4.

In response, Mr. Baacke testified that EPC RFP asked bidders to select a combination of industrial frame and aeroderivative CTs that could meet certain defined constraints. Pet. Ex. 5-R at 3. He testified that 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. *Id*. at 4. Despite the RFP request for a "combination" of industrial frame and aeroderivative units, Mr. Baacke opined that "EPC RFP bidders were not prevented from proposing all industrial frame configurations" but, instead, were free to provide bids that would include one larger industrial frame machine and multiple smaller aeroderivative or industrial frame units. Id. at 3-4. Further, Mr. Baacke noted that the project summary included an example of an acceptable combination as one General Electric 7FA industrial frame combustion turbine generator ("CTG") and three General Electric LM6000 aeroderivative CTGs, but claimed that this example was just a clarification of potential combinations and was not a specific requirement. Pet. Ex. 5-R at 2-4; Pet. Ex. 7-C, Highly Confidential Attachment 7-D.

OUCC witness Sanka testified that although NIPSCO claimed it evaluated multiple technologies for the CT Project, NIPSCO failed to evaluate the configuration with one large industrial frame and smaller industrial frame, similarly sized to the aeroderivative turbine, in the decision matrix of S&L's Engineering Study. Pub. Ex. 3 at 7. In response, Mr. Baacke testified that because smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, it was not necessary to perform a separate analysis for a large industrial frame with smaller industrial frame machines. Pet. Ex. 5-R at 16-17.

OUCC witness Sanka further testified that NIPSCO has not justified the need for aeroderivative units, explaining that beyond NIPSCO's desire for "quick start" and "fast ramp" units, NIPSCO has not provided any analysis or support for selecting aeroderivative units in its configuration which industrial frames can also address. Pub. Ex. 3 at 9. While NIPSCO claims that aeroderivative units provide an advantage over industrial frame units in regard to the time to start a unit, Pet. Ex. 4 at 10, NIPSCO provides no support for the purported need for quick start capabilities. Indeed, performance specifications established by the Engineering Study (Highly Confidential Attachment 4-A sponsored by NIPSCO Witness Warren) for NIPSCO's EPC RFP required bids to include a 10-minute cold start capability for 150 MW or more, yet NIPSCO provides no analysis to support such a requirement. Although NIPSCO states it expects to utilize the capability to start quickly, NIPSCO conflates cold-start capability with fast ramp times, pointing to a quantification of 10-minute ramp requirements with no comparable support for the necessity of a 10-minute cold start capability. Pet. Ex. 7-C, Highly Confidential Attachment 7-D.

ii. Competitive Procurement.~~Best Estimate.~~

Mr. Baacke testified 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 sponsored by NIPSCO witness Warren). He stated S&L then supported NIPSCO by drafting technical specifications for the EPC RFP. He said that 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. Pet. Ex. 5 at 10.

CAC witness James testified that common and current best practices to ensure a construction project has a good probability of successful execution involves significant investment in project definition. CAC Ex. 2, Att. RJ-2, § 2.3. Mr. James explains that currently owners for almost every large project involving industrial construction undertake a Front-End Loading ("FEL") process, yet S&L's Engineering Study neglects to mention this process in its entirety. *Id.* While NIPSCO considers S&L's study to be "comparable to a FEED study" [meaning Front-End Engineering Design] – which is part of the final stage of an FEL process, Mr. James noted that S&L admits its engineering and design level of effort does not lend itself to producing mature design drawings for the Project. NIPSCO-CAC Ex. 3 at 5, 7; CAC Ex. 2, Att. RJ-2, § 2.4. Mr. James explained that missing from S&L's conceptual engineering design evaluation are key components that are essential to achieve the detailed design readiness of a FEED study, including but not limited to detailed scopes, heat & material balances, license packages, P&ID's and Electric Single-Line Diagrams issued for design, major equipment specifications, and a take-off based estimate. CAC Ex. 2, Att. RJ-2, § 2.10. Due to these omissions, Mr. James testified that the S&L report is "grossly deficient" and does not currently conform with industry standards. Mr. James suggests that the completion of a FEED study is critical to the success of the CT Project. CAC Ex. 2, Att. RJ-2, § 2.5. To rectify this, Mr. James suggests NIPSCO should authorize S&L to upgrade the Project's design to FEED study quality. CAC Ex. 2, Att. RJ-2, § 4.6.

In response to this suggestion, Mr. Baacke stated that in addition to the services S&L has already completed in detailing the design for the CT Project and in supporting NIPSCO in the procurement of long lead-time equipment and materials, NIPSCO plans to contract with S&L to provide onsite support during construction, start up, and testing to provide quality assurance and control during installation to ensure the units are brought online once they are built. Pet. Ex. 5-R at 15-16.

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 as a result 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. Pet. Ex. 5 at 10-11.

Mr. ~~Baacke described the results of the proposals were received from three bidders.~~Baacke noted that while Mr. Hanks claims that NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness James claims that the quality of NIPSCO's EPC RFP was "wanting insofar as it relies upon a project that needs more definition and planning." Pub. Ex. 2 at 16; CAC Ex. 2, Attachment RJ-2, § 3.4. He 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. Pet. Ex. 5-R at 5. Mr. Baacke testified that NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show that NIPSCO properly vetted the EPC RFP bids.Mr. Baacke described the results of the proposals received from three bidders. One bid did not meet the performance criteria of the technical specifications and provided less than five pages of information, which was not evaluated for further consideration. A second bid provided a proposal that consisted of 10 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~~Mr. Baacke stated was in the best interest of NIPSCO and its customers. Pet. Ex. 5 at 11-12.

OUCC witness Krieger questioned NIPSCO's rejection of the third EPC bid on the grounds that the company improperly increased the cost of that bid by adding unreasonable levels of owner's costs, contingencies, and indirect costs to that bid. Pub. Ex. 4 at 19-20. As witness Krieger explained, owner's costs should be "significantly less" when an EPC contractor is hired because they assume most of the project management responsibilities. *Id*. at 19. As such, most of the project management costs are included in the EPC contract and need not be added on as owner's costs. Yet NIPSCO added significant amounts of owner's costs, along with inflated contingency and indirect costs, to the only EPC bid that met the technical specifications for the project. *Id*. at 19-25. Mr. Krieger opined that by doing so, NIPSCO "unreasonably disqualified an EPC bid that may have improved the probability of an on-time delivery and reduced the project cost risk for consumers." *Id*. at 19. In rebuttal, NIPSCO witness Baacke claimed that Mr. Krieger's critique is only a matter of cost categorization because any reduction in owner's costs resulting from the EPC contractor managing the project would simply be reflected in the EPC contract. Pet. Ex. 5-R at 31-32. But that response does nothing to justify the addition of high levels of owner's costs (and the other costs highlighted by Mr. Krieger) on top of the contract price bid by the EPC contractor.

CAC witness James noted that NIPSCO moved forward with issuing the EPC RFP on August 12, 2022 – eight months before S&L's Engineering Study was finalized for use. CAC Ex. 2, Att. RJ-2, § 3.4. Mr. James stated that this likely contributed to the poor response rate to the RFP and suggested that had the RFP been issued on the basis of a more complete level of definition and planning, it is likely that NIPSCO would have received more EPC bids or at least bids at a potentially lower cost than the single qualifying bid that NIPSCO rejected. *Id.* 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 that with ~~this~~the multi-prime contracting strategy approach, 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. Pet. Ex. 5 at 12-13.

In response to CAC witness James' assertion that a "self-build approach is not in customers' best interests and adds significant risk to the Project costs," Mr. Baacke testified that although EPC has the potential to help firm up the cost of the project earlier in the process than a multi-prime approach, it does not limit the potential of the actual cost of the project to increase prior to completion. Pet. Ex. 5-R at 7. Mr. Baacke further noted that NIPSCO received three EPC bids – with only one meeting the technical specifications. He stated that 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. Pet. Ex. 5-R at 6.

Mr. Baacke testified NIPSCO's multi-prime contracting strategy applies to construction on the CT Project as well. He stated that 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 of 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. Pet. Ex. 5 at 13-14.

iii. Best Estimate.

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 AFUDC. He explained that 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.[7] 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. Pet. Ex. 5 at 17-18.

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 (shown in Attachment 5-A), which includes indirect costs but excludes AFUDC. 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. Pet. Ex. 5-S at 11. In his rebuttal testimony, Mr. Baacke provided an updated cost summary in Attachment 5-R-A in which "Inside the Fence" and interconnection costs were higher than in the initial filing, but those increases were offset by reductions in Owner's Cost, Escalation, and Contingency. As such, the estimated total project cost presented in the rebuttal testimony was exactly the same as in the initial testimony, even though the rebuttal testimony estimate reflected the removal of Selective Catalytic Reduction pollution controls that had been included in the initial estimate. Pet. Ex. 5-R at 19-20.

Witnesses for OUCC and CAC noted that the $641,223,000 cost estimate for the CT Project works out to approximately $1,600 per kW, which is considerably higher than other recent examples. OUCC witness Hanks noted that in October 2022 NIPSCO and Charles River Associates reported that the average cost of thermal resources bid into the 2022 All-Source RFP was $763/kW. Pub. Ex. 2 at 15. Similarly, the U.S. Energy Information Administration reported in its 2023 Annual Energy Outlook $867/kW base overnight costs for industrial frame units and the $1,428/kW for aeroderivative units. Pub. Ex. 2 at 5. The estimated construction cost for the CT Project is also approximately double that of Center Point Energy's 460 MW gas combustion turbine that the IURC approved in 2022. Pub. Ex. 2 at 5-6. CAC witness Sommer testified that the proposed CT Project is the most expensive combustion turbine project currently under development in the U.S. that she is aware of. CAC Ex. 1 at 6. Ms. Sommer explained that the elevated cost for the CT Project is the result not only of increased demand for the equipment, engineering, and skilled labor that would be needed to complete the project, but also, among other things, NIPSCO's decision to include aeroderivative turbines in the

[7] NIPSCO Witness Blissmer testified (Pet. Ex. 8 at 12) that, if NIPSCO's proposed construction work in progress 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.

project, which are more expensive than heavy frame turbines. CAC Ex. 1 at 9-10.

OUCC witness Armstrong stated that the OUCC "does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable." Pub. Ex. 1 at 9. CAC witness Inskeep raised similar affordability concerns, noting that NIPSCO residential customers already have the second-highest electric bills in the state for 1,000 kWh of usage and are facing considerable upward pressure from costs related to additional generation projects, coal combustion residual projects, transmission and distribution investments, and additional cost-shifting from industrial customers to other ratepayers. CAC Ex. 3 at 26-27. Witness Inskeep testified that these affordability pressures would be exacerbated by the proposed CT Project. Id. at 27.

OUCC witnesses contended that NIPSCO's cost estimates for the CT Project are overstated and unreasonably shift increased project cost risks onto ratepayers. Pub. Ex. 1 at 9. In order to reduce such ratepayer impacts, OUCC witness recommended modifications that would reduce the total project cost by approximately $130 million, Pub. Ex. 1 at 10, which would lead to roughly $300 million in savings over the life of the project. Pub. Ex. 4 at 27.

OUCC witness Sanka recommended rejection of the CPCN as filed because NIPSCO had not provided specific justification for why the more expensive aeroderivative turbines would be needed instead of industrial frame turbines. Pub. Ex. 3 at 10. While acknowledging differences in starting time and ramp rates between the two types of turbines, witness Sanka explained that NIPSCO had not quantified the claimed benefits of the aeroderivative turbines nor provided a cost-benefit analysis showing that such benefits would outweigh the increased costs related to such turbines. *Id.* As OUCC witness Hanks explained "NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units," Pub. Ex. 2 at 2, and it would be "unreasonable to require NIPSCO ratepayers to pay for aeroderivative units based on a broad generalization without demonstrating the quantifiable benefits." *Id.* at 7.

CAC witness Sommer also recommended rejection of the CPCN, particularly because of the inclusion of the aeroderivative turbines. CAC Ex. 1 at 10-12, 35. In support, Ms. Sommer explained that the matrix in the Sargent & Lundy study used to select the aeroderivative turbines was subjective and failed to give proper weight to the significant cost difference between aeroderivative and industrial frame turbines. *Id.* at 10-12. Nor were the aeroderivative turbines justified by considerations related to black start needs or hypothetical future interest in burning hydrogen. *Id.* at 12-14.

In rebuttal, NIPSCO witness Becker acknowledged that if the Commission removes the aeroderivative units from the proposed CT Project, "it is not fatal to the proposal" which could proceed with only industrial frame units. Pet. Ex. 1-R at 13.

In response to OUCC and CAC's opposition to NIPSCO's application in part because of the cost of the aeroderivative turbine component (Pub. Ex. 2 at 2 and CAC Ex. 1 at 6-7 and 10), Mr. Augustine testified that NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained that in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment (Pet. Ex. 7, Attachment 7-A, 2021 IRP, Sections 9.2.6 and 9.2.7) both highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis (Pet. Ex. 7, Confidential Attachment 7-D at 9–10) identified growing 3-hour and 10-minute ramping requirements by 2030. Pet. Ex. 7-R at 27-28.

~~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 AFUDC. He explained that 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.[8] 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. Pet. Ex. 5 at 17-18.~~

~~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 (Attachment 5-S-C) and best estimate of costs of construction (Confidential Attachment 5-S-B). Pet. Ex. 5-S at 1-2.~~

~~Mr. Baacke stated that NIPSCO's originally estimated in-service date for end of year 2026 was always with the understanding that the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained that 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 that NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Pet. Ex. 5-S at 2-3. Mr. Baacke testified that NIPSCO's election to self-build with a multi-prime contracting 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 that 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 that NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its strong vendor relationship. Pet. Ex. 5-S at 5-6.~~

~~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 (shown in Attachment 5-A), which includes indirect costs but excludes AFUDC. He explained that 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. Pet. Ex. 5-S at 11.~~

OUCC witness Armstrong recommended that costs associated with certain pollution control technology be removed from the CT Project best estimate. Pub. Ex. 1 at 16-17. In rebuttal, witness Baacke acknowledged that NIPSCO agrees that the Selective Catalytic Reduction ("SCR") pollution controls included in the initial best estimate are not needed. Pet. Ex. 5-R at 20; Pet. Ex. 1-R at 5. As such, the updated best estimate presented in Mr. Baacke's rebuttal reflects removal of the SCRs. Pet. Ex. 5-R at 20. Despite removal of the SCRs, however, the overall cost estimate for the CT Project cited in Mr. Baacke's rebuttal remains the same as in the initial application, Pet. Ex. 5-R at 19, and the "Inside the Fence" costs cited in rebuttal are approximately $27 million higher than in the initial

~~[8] NIPSCO Witness Blissmer testified (Pet. Ex. 8 at 12) that, if NIPSCO's proposed construction work in progress 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.~~

application. Compare Pet. Ex. 5 Attachment 5-A with Pet. Ex. 5-R Attachment 5-R-A. ~~Ms. Armstrong also stated that 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. *Id.* at 19. Ms. Armstrong stated that the OUCC "does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable." *Id.* at 9.~~

OUCC witness Hanks claimed that NIPSCO's best estimate potentially double ~~counts~~counted indirect costs. Pub. Ex. 2 at pp. 10-11. Mr. Hanks stated that NIPSCO did not justify a 5% escalation factor and recommended its proposed escalation be reduced to 3% to match its electric TDSIC Plan. *Id.* at 12-13. Witness Hanks estimated that using a 3% escalation factor would save ratepayers approximately $27 million based on NIPSCO's current best estimate. *Id*. at 13. ~~Mr. Hanks compared the cost of NIPSCO's proposed CT Project to average technology costs from the Energy Information Administration's Annual Energy Outlook of 2023 and to the cost of CEI South's CTs. *Id.* at pp. 5-6.~~

OUCC witness Krieger noted the OUCC's concern with NIPSCO's estimated owner's costs. He believed NIPSCO's application of a "simple" 9% is not supported or justified for a complex project. Mr. Krieger believed the owner's costs would be significantly less ~~when~~if an EPC contractor ~~is~~were hired. Pub. Ex. 4 at pp. 18 -21.

IG witness Gorman stated NIPSCO's cost estimate should be rejected because it is not based on firm pricing as a result of competitive bids received from contractors, but rather on preliminary market analysis of the expected costs. IG Ex. 1 at 8-9.

~~CAC witness Sommer argued for prejudgment of the prudency of certain actions and prospective disallowance of costs. Witness Sommer also argues for a cost cap on project costs.~~CAC witnesses James and Sommer also opined that there was a risk of significant cost increases due to NIPSCO's decision to self-build and self-manage the proposed CT Project despite the company's lack of relevant project experience. CAC Ex. 1 at 10; CAC Ex. 2 at 6. As detailed in a report that witnesses James and Sommer co-sponsored, a potential contracting strategy is known as Engineering, Procurement, Construction or EPC, through which a single firm manages all of those steps of a project, often under a lump sum, fixed fee contract. CAC Ex. 2 Attachment RJ-2 at para. 3.1. EPC contracting is common in the industry in large part because most electric utilities lack staff with the experience of designing and managing the construction of power plants. *Id*. But while NIPSCO initially sought bids for EPC contractors, the company rejected all such bids and decided to proceed with a self-build, multi-prime contract arrangement for the CT Project, *id.* at para. 3.2 and 3.3, which is similar to the approach that Duke Energy Indiana used on the Edwardsport IGCC project. Id. at para. 3.7. NIPSCO's self-build, multi-prime contract approach poses significant risks of cost increases and delays, especially because NIPSCO's lead staff who will exercise oversight of the CT Project construction lack experience constructing power plants. In discovery, NIPSCO identified projects that the NIPSCO CT Project team had previously managed, and all of them were far less costly and complex than the CT Project. *Id*. at para. 3.9 and 3.10, and Confidential Table 1.

OUCC witness Krieger echoed these concerns about NIPSCO's decision to not pursue an EPC contracting approach to the CT Project. As Mr. Krieger explained, EPC contractors bring technology expertise and experience to the project, and typically bear the risks of cost overruns, construction delays, quality assurance, etc. Pub. Ex. 4 at 4-5. By contrast, under the self-build approach, NIPSCO assumes complete responsibility for managing and mitigating financial challenges throughout the project construction lifecycle and takes on a greater share of the risks associated with potential cost increases. *Id*. at 6.

Given NIPSCO's lack of experience managing a project of this size, witness Krieger recommended that any approval of the CT Project be conditioned on ratepayers being of no greater risk than if NIPSCO had hired an EPC contractor. *Id*. at 7. Similarly, witness Sommer proposed a handful of conditions on any approval of the CT Project in light of both the significant costs and risks at issue. CAC Ex. 1 at 36-37. These conditions include a cost cap of $641,223,000 (or a lower amount if the aeroderivative turbines or other components of the best cost estimate are rejected), regular review of the project by a qualified and neutral third party hired at NIPSCO's expense, and disallowance of any costs incurred to accommodate any further delay in the online date of the CT Project

In rebuttal, ~~CAC Ex. 1 at 7, recommendation 3. Ms. Sommer similarly recommended denial of NIPSCO's request based on the cost of the aeroderivative turbines. *Id*. at 6-7, 10. Ms. Sommer recommended that "costs to serve customers in order to accommodate a delay in the online date of the CT Project are disallowed including but not limited to capacity and energy costs." *Id*. at 7.~~

Mr. Baacke disagreed with CAC witness 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~~. Pet. Ex. 5-R at 6-7.

In response to several witnesses claims that entering an EPC contract can mitigate cost risk and that 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, in order 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.[9] Pet. Ex. 5-R at 7-8.

In response to OUCC witness ~~Krieger~~Krieger's and CAC witness ~~James~~James's claim that NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned by their belief that NIPSCO lacks large project management experience, (Pub. Ex. 4 at 15-16; CAC Ex. 2, Attachment RJ-2, § 3.9), Mr. Baacke explained that NIPSCO is leveraging engineering firms (including S&L), construction contractors, and suppliers (including the original equipment manufacturer ("OEM")) who have completed these comparable projects. He testified that NIPSCO's Major Projects team, under his direction, has completed a number of projects of varying complexity, including several projects that are first of their kind or one-of-a-kind projects for NIPSCO and at the time of completion, within the industry. He stated that unlike a CT, which has been executed numerous times across the country, a project that has not been completed before has complexity of the unknown that NIPSCO has shown it can manage effectively. Pet. Ex. 5-R at 9-10.

Mr. Baacke testified that 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

[9] *See* Pet. Ex. 4-R at 8-9. There, NIPSCO witness Warren also responds to the parties' criticisms of NIPSCO's multi-prime contracting strategy.

management experience because it only shows the project variances in absolute dollars, which ignores that 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 to date under his direction and supervision reflect a negative variance of approximately -2.4%. Pet. ~~This~~Ex. 5-R at 14 Table 1. That $1.41 billion overall budget was for 19 separate projects, *id.*, which works out to an average of approximately $74 million per project or approximately 12% of the estimated cost of the CT Project. Witness Baacke opined that 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. Pet. Ex. 5-R at 12-13.

Mr. Baacke testified that NIPSCO's election to self-build with a multi-prime contracting strategy was beneficial in the face of the supply chain challenges that led to the one-year delay of the in-service date for the CT Project because it allowed NIPSCO to pivot without a presently anticipated impact to the best estimate. He noted that 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 that NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its strong vendor relationship. Pet. Ex. 5-S at 5-6.

Mr. Baacke clarified S&L's role and scope of work in the CT Project in responding to CAC witness James that, given their proven experience serving the utility sector, NIPSCO should involve S&L throughout the Project. He stated that S&L has also been contracted by NIPSCO to complete the detailed design for the CT Project. He testified that in addition to these services S&L is already providing, NIPSCO plans to contract with S&L to provide onsite support during construction and start up and testing to provide quality assurance/quality control during installation to ensure the units are brought online once they are built and that the costs associated with these additional services is included in NIPSCO's best estimate. Pet. Ex. 5-R at 15-16.

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 again that 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. Pet. Ex. 5-R at 19-20; Pet. Ex. 8-R, Attachment 8-R-C.

Mr. Baacke emphasized that NIPSCO's best estimate although reasonable, is still an estimate; customers will ~~only~~ pay reflecting the actual costs of the CT Project. He testified that the fact that prices for practically all products and materials in the U.S. (and even globally) are increasing, including the key equipment needed to construct the CT Project, is an undeniable macroeconomic fact that is beyond NIPSCO's control. He testified that NIPSCO ran a competitive RFP, engaged S&L to assist with engineering and cost estimation, chose a multi-prime contracting approach that was $100 million lower in cost than any viable EPC option, and has brought a reasonable, best estimate to the Commission to support a finding of best estimate of costs in this proceeding. Pet. Ex. 5-R at 34-35.

C. ~~Configuration and~~ Ratemaking Treatment of CT Project.

ii.~~**i.**~~ **Petitioner's** ~~**Competitive Procurement.**~~witness 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 would 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. Pet. Ex. 8 at 15-16; Pet. Ex. 8-S at 6.

Commented [CAC1]: ***Comment for the Commission***: The first twelve paragraphs, and the seventeenth, here in this section 6.C are moved up from the "Commission Discussion and Findings" section below in NIPSCO's Proposed Order.

The revenue requirement for capital costs included in the GCT would 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 that NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective WACC. Pet. Ex. 8 at 16. 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. Pet. Ex. 8 at 17.

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. Additionally, NIPSCO would 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. Pet. Ex. 8 at 17. Attachment 8-B to Mr. Blissmer's testimony is an exemplar for the GCT Tracker schedule. He also 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 Tracker filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. Pet. Ex. 8 at 19; Pet. Ex. 8-S at 6. As an additional financial incentive under Section 11, NIPSCO requests that the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the IC 8-1-2-42(d) earnings test. Pet. Ex. 8 at 18.

Mr. Blissmer contended that the proposed GCT Mechanism is authorized by new legislation. He testified that 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 that 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 that 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, as shown in his Attachment 8-S-A. He explained that 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.[10] 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 PISCC under the traditional model. He explained that 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. Pet. Ex. 8 at 8-12; Pet. Ex. 8-S at 3-4.

Mr. Blissmer concluded that 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. Pet. Ex. 8-S, pp. 3-4 and 6.

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. Also, NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained that 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 that CWIP ratemaking improves near term cash flow and mitigates the negative effects of the significant

[10] As set forth in the Verified Petition in this Cause, NIPSCO seeks relief in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT Mechanism or in a general rate case, all as described in the Verified Petition. The request for alternative relief would trigger in the event the proposed GCT is not approved as proposed, which could be either the denial of the GCT or rejection of the forward looking nature of the GCT. Either of these changes to NIPSCO's proposal would result in PISCC and the commencement of depreciation before rate recovery has commenced.

additional debt taken on to construct the project. Pet. Ex. 8 at 12-14.

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."[11] 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. Pet. Ex. 8 at 13.

Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on a number of different factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates that 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. Pet. Ex. 8-S at 8.

OUCC witness Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. Pub. Ex. 5 at 4 She contended that NIPSCO should instead use project-specific financing costs or the cost of short-term debt.

IG witness Gorman testified that simply because there are gross financial savings this does not mean that the CWIP tracker is just and reasonable. IG. Ex. 1 at 15. Both IG witness Gorman and CAC witness Inskeep claimed that the analysis of gross financing savings is inconsistent with the Statute in that it does not include net present value analysis. IG Ex. 1 at 16; CAC Ex. 3 at 7, 24. They both claimed that simply because there may be financing cost savings does not mean that the proposal is just and reasonable.

CAC witness Inskeep testified that the the CT Project will be displacing market purchases and existing natural gas generation, not coal-fired generation as referenced in I.C. § 8-1-37-4, which is the definition of "clean energy project" that NIPSCO is relying on to qualify for CWIP financing. To support this contention, Mr. Inskeep observed that Schahfer Units 17 and 18 are retiring in 2025, regardless of the fate of the CT Project, while the CT Project is not proposed to be placed in service until 2027, assuming no further delays. Mr. Inskeep averred that Schahfer Units 17 and 18 will have already had their electricity generation displaced by other resources, largely renewable technologies, years prior to the CT Project coming online, and also that NIPSCO expressly delayed the retirement of Schahfer Units 17 and 18 from 2023 to 2025 due to delays in the construction of new solar projects. Mr. Inskeep also testified that the proposed CT Project might not displace coal-fired generation from Michigan City, because (i) NIPSCO is under no obligation to retire Michigan City 12 by the stated planned date of 2028, and has previously shown a willingness to delay planned retirement dates; and (ii) the gas-fired CT Project will primarily be displacing electricity generation from the gas-fired, peaking Schahfer Units 16A and 16B that are much more clearly tied together in timing and resource type. Mr. Inskeep argued that based on the above, the CT Project cannot qualify for CWIP financing under I.C. ch. 8-1-8.8. CAC Ex. 3 at 8-9.

[11] *See, e.g.*, *Tucson Elec. Power Co.*, 174 FERC ¶ 61,223 at P 25 (2021) (stating that allowing transmission developers "to include 100% CWIP in rate base would result in greater rate stability for customers by reducing 'rate shock' when certain large-scale transmission projects come on line.") (citing 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 12 (2012) (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229 (2011)); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 43, *reh'g denied*, 124 FERC ¶ 61,229 (2008))).

Mr. Inskeep further testified that NIPSCO is proposing a forward-looking CWIP cost recovery mechanism, which could allow NIPSCO to begin collecting CWIP financing costs before a portion of the financing costs are actually incurred by NIPSCO. He observed that as an illustrative example, NIPSCO is proposing to file its first tracker petition on October 15, 2024, at which time it will include average projected CWIP balances from March 2025 through August 2025 and actual and projected AFUDC through February 2025 -with the resulting rates under the GCT Rider going into effect in March 2025. Mr. Inskeep showed that the projected capital balance as of March 31, 2025, is estimated to be $52,828,766, while the revenue collected via the GCT Rider per month, beginning in March, would be based on a capital balance of $83,505,291 (the weighted average capital balance of March through August 2025). Mr. Inskeep also argued that using projected costs for the GCT rider mechanism is inconsistent with the past-tense word "incurred" used in the CWIP statute. CAC Ex. 3 at 12-13.

Mr. Inskeep opined that CWIP is a violation of the "used and useful" principle because it allows the utility to begin cost recovery prior to the plant being placed in service when CWIP is included in rate base. He noted that the standard helps ensure that the customers who pay for the costs of utility plant, including financing costs, are the same customers who receive the benefit from the utility plant; CWIP, according to Mr. Inskeep, creates a mismatch across time in the ratepayers who pay for, versus the ratepayers who benefit from, the new utility plant. Moreover, if the project is not completed, ratepayers will have financed costs of a project of no ultimate value to them. Mr. Inskeep cited other examples of utility projects, including Edwardsport IGCC, in Indiana, that ultimately went highly over budget or were not completed. Mr. Inskeep recommended that, in light of the risk transfer inherent in CWIP cost recovery, the Commission should ensure CWIP ratemaking proposals meet all statutory requirements and that the interests of consumers are appropriately considered. CAC Ex. 3 at 15-18.

CAC witness Inskeep also submitted that NIPSCO's calculations on cost savings resulting from CWIP financing were erroneous calculations of *nominal* gross financing savings when NIPSCO should have calculated *present value* gross financing savings. Mr. Inskeep averred that NIPSCO failed to consider the time value of money, by applying an appropriate discount rate. Mr. Inskeep stated that ratepayers have alternate uses for their money such that considering the time value of money comports with sound public policy. Mr. Inskeep described CWIP cost recovery as forcing ratepayers to provide interest-free loans upfront to NIPSCO to cover financing costs in return for a stream of lower nominal financing costs in the future (due to AFUDC and PISCC not accruing). Mr. Inskeep testified that under a calculation that compares nominal revenue requirement (without discounting to present value), CWIP financing would always be shown to produce gross financing savings over the life of the project. Mr. Inskeep calculated a present value revenue requirement for each of CWIP financing and traditional cost recovery: using NIPSCO's currently approved weighted average cost of capital of 6.88%, the CT Project capital cost revenue requirement over 2025-2058 would be $685,550,647 under NIPSCO's CWIP proposal compared to a PVRR of $671,616,758 (around $14 million less) under traditional financing mechanisms. Mr. Inskeep also used alternate discount rates of 10% and 15%, which he stated could be more apt for residential customers, citing academic research on time preference. The alternate discount rates increased the $14 million savings figure to $28.4 million and $38.7 million, respectively, of savings using traditional ratemaking. CAC Ex. 3 at 18-23.

In his rebuttal testimony, Mr. Blissmer testified NIPSCO is modifying its GCT proposal to remove WACC, and to apply its then current AFUDC rate. Pet. Ex. 8-R at 3. 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. See Attachment 8-R-A (forward-looking) and Attachment 8-R-B (backward-looking). He testified that (1) as shown in 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 that 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. Pet. Ex. 8-R at 3-4. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Tracker. Pet. Ex. 8-R at 9-12. In response to Mr. Inskeep's claim that the delay of in-service date of the CT Project has caused an increase in total financing costs, Mr. Blissmer asserted that Inskeep had failed to acknowledge Blissmer's supplemental direct testimony that the one-year delay produces $65 million in customer savings through 2028. *Id.* at 12.

D. Ongoing Review of CT Project.

NIPSCO's Petition requested that the Commission, should it grant the requested CPCN for the CT Project, exercise ongoing review of the construction progress pursuant to I.C. § 8-1-8.5-6. Mr. Baacke of NIPSCO elaborated in direct testimony that NIPSCO would provide "periodic" updates on the CT Project including progress reports and cost estimate updates until it goes into service. Pet. Ex. 5 at 19.

OUCC witness Krieger recommended 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. Pub. Ex. 4 at 30-31.

CAC witnesses Sommer and James, after recounting the extensive flaws in NIPSCO's construction management plan as discussed above, testified that the management role of Sargent and Lundy has been and will be insufficient to acceptably mitigate risks in the construction process. In this light, Ms. Sommer recommended that the Commission hire a qualified, neutral third-party expert, at NIPSCO's expense, to review the project at critical points during execution, intended to help inform the record as to whether NIPSCO exercises good judgment and prudent decision making in executing the CT Project and whether a CPCN should be later modified or revoked. CAC Ex. 1 at 7, 36. Mr. James, drawing on his experience in construction management in the utility sector, further recommended that the third party should assist with management of Sargent and Lundy, as well as facilitate performance of joint S&L/NIPSCO project readiness studies, Hazards and Operability studies, post–Front End Loading contractor selection, downstream EPC execution, and development of a comprehensive project risk register program. Mr. James stressed that the third-party oversight program must emphasize interface management and be led by a senior NIPSCO team member as Interface Coordinator. CAC Ex. 2 at 7.

Ms. Becker (the successor to Mr. Sears) testified that Mr. Krieger's recommended quarterly

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reporting requirements go beyond the yearly reporting required by the statute. She stated that 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. Pet. Ex. 1-R at 26-27. Ms. Becker characterized Ms. Sommer's proposal for the external construction consultant (to be paid by NIPSCO) as "forc[ing] NIPSCO […] to expend dollars related to this Project and not be allowed to recover them from its customers." Pet. Ex. 1-R at 24.

~~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 that 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. In recent years, 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. Pet. Ex. 5 at 4-5.~~

~~He explained that NIPSCO is also including three smaller aeroderivative or similarly sized industrial frame turbines in the CT Project. 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. 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. Pet. Ex. 5 at 5.~~

~~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 an engineering, procurement, and construction ("EPC") contract (the "EPC RFP"). As shown in Appendix 19 of the Simple Cycle Gas Turbine Engineering Study, Report No. SL-016874 (the "Engineering Study") (Highly Confidential Attachment 4-A sponsored by NIPSCO witness Warren), 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 (Highly Confidential Attachment 7-D sponsored by NIPSCO witness Augustine), operational factors, costs, environmental, and schedule. Pet. Ex. 5 at 6.~~

~~Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated that NIPSCO already owns the property at the Schahfer site. He said constructing the CT Project on the Schahfer site provides cost savings and advantages for NIPSCO, its customers, and the local economy. Pet. Ex. 5 at 7.~~

~~As discussed by NIPSCO witness Stanley, NIPSCO also 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. Pet. Ex. 6 at 10-11.

In response to OUCC witness Hanks claim that the EPC RFP prevented bidders from proposing less expensive all industrial frame configurations, Mr. Baacke testified that 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 (MECL) less than or equal to approximately 25 MW. He testified that 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. Pet. Ex. 5-R at 2-4; Pet. Ex. 7-C, Highly Confidential Attachment 7-D.

Mr. Baacke noted that while Mr. Hanks claims that NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness James claims that the quality of NIPSCO's EPC RFP was "wanting insofar as it relies upon a project that needs more definition and planning." Pub. Ex. 2 at 16; CAC Ex. 2, Attachment RJ-2, 3.4. He 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. Pet. Ex. 5-R at 5.

Mr. Baacke testified that NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show that NIPSCO properly vetted the EPC RFP bids. He noted that NIPSCO received three EPC bids – one that was $100 million more than the self-build option, a second with a proposed configuration of ten refurbished aeroderivative machines that did not meet technical specifications, and a third with only two larger industrial frame units (also not consistent with technical specifications) that was less than 5 pages of content. He stated that 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. Pet. Ex. 5-R at 6.

In response to OUCC witness Sanka's claims that 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 that criticism is misplaced. He explained that 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. Pet. Ex. 5-R at 16-17.

In addition, NIPSCO witnesses Augustine and 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, that lay out best system of emission reduction standards for new natural gas-fired facilities based on their capacity factor. Pet. Ex. 7-R 28-29; Pet. Ex. 9-R. He 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.~~

~~In arguing against NIPSCO's proposed project configuration of the CT Project, OUCC witness Sanka claims that, "[b]ase load plants come at a lower initial cost and have lower operations and maintenance ("O&M") costs compared to a peaker plant containing aeroderivative units, making them more financially viable. Therefore, in the context of 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." Pub. Ex. 3 at 10, lines 4-9. Mr. Augustine explained that Ms. Sanka's framing of the cost-effectiveness evaluation is incomplete, particularly as resource planning questions become more complex. Pet. Ex. 7-R at 30.~~

~~5.~~6. Commission Discussion and Findings. In its 2021 IRP, NIPSCO identified the need for up to 300 MW of dispatchable gas combustion turbine capacity. 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 an additional approximately 100 MW of flexible dispatchable capacity, and the utility now proposes a gas-fired combustion turbine resource between 400 MW and 442 MW~~. Based on the needs associated with~~ to meet that need. This resource, known as the proposed CT Project, would replace NIPSCO's retiring gas peaker units at the Schahfer site and support system reliability and resiliency, while NIPSCO deploys several types of clean energy resources to facilitate the planned retirement of the majority of NIPSCO's coal-fired generation by the end of 2025 and the ~~addition of more renewable resources,~~complete retirement of coal generation by 2028. 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 key part of NIPSCO's electric generating fleet, as it will~~is proposed to provide key reliability attributes and additional capacity (especially in the winter season) and help mitigate customers' price exposure on the hottest and coldest days of the year. NIPSCO's evidence supports that reliability and resource adequacy concerns have been voiced by many important organizations, including NERC, MISO, MISO's Independent Market Monitor ("IMM"), OMS, and others. Pet. Ex. 3 at 8-11, 17; Pet Ex. 6 at 17.

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 that 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 more expensive storage additions.~~. In addition, the Flexible Resource Analysis identified energy market exposure 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. It then ~~evaluates~~evaluated the change in 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. Pet. Ex. 7, Conf. Att. 7-D at 3-4, 10, 62. ~~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 MW/minute ramp rate for at least 150 MW~~However, the Commission notes that the Flexible Resource Analysis was limited in that it did not identify gas peaker generation as a preferred solution (NIPSCO-CAC Ex. 6 at 15-16, 31); did not simulate the dispatch of resources (CAC Ex. 1 at 20); did not quantify the cost of potential energy market exposure (*id.*); and did not compare the cost of different resource options (*id.*). Moreover, the portion of the Flexible Resource Analysis that included the remainder of MISO Zone 6 and the PJM regions of Indiana and Illinois in a "system"-level analysis was limited in that the PJM load forecasts used were from 2020, prior to new distributed generation and EE requirements enacted in Illinois' Public Act 102-0662 of 2021, also known as the Climate and Equitable Jobs Act. NIPSCO-CAC Ex. 6 at 30, 35. Additionally, as discussed below in our discussion of the statutory Five Pillars at section 6.D, the Flexible Resource Analysis did not meet the legal requirements for new IRP analysis to justify a change from the 2021 IRP's preferred portfolio, and lacked the transparency and opportunity for meaningful stakeholder engagement that are important elements of resource planning~~. Pet. Ex. 5-R at 3. The OUCC agrees that NIPSCO needs load following generation. Pub. Ex. 1 at 3. Through the detailed analysis below, we conclude that moving forward on the CT Project is the best economic and most reliable decision for NIPSCO's customers and grant the requested CPCN for the CT Project~~.

As further discussed above and below, NIPSCO has proposed an extremely expensive project with three aeroderivative gas turbines (in addition to one frame turbine), which will more than double the construction cost (per installed megawatt) compared to that modeled in NIPSCO's 2021 IRP. NIPSCO did not justify why aeroderivatives are needed, relying on a scoring rubric for ranking options that was created based on nontransparent reasons and then applied nontransparently to create scores. Worryingly, NIPSCO proposes to manage the entire CT Project's construction without an EPC contractor, although NIPSCO's lead personnel slated to oversee the construction project have never worked on construction of a power plant in their careers, and NIPSCO has declined to follow best practices in construction planning to mitigate risks on the front end, before construction begins.

Through the detailed analysis below, we conclude that moving forward on the CT Project would not be the best economic and most reliable decision for NIPSCO's customers. We will explain through our review of statutory requirements why NIPSCO did not meet its burden to justify its request.

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[.]"

As discussed above, Mr. Baacke ~~explained~~of NIPSCO described the CT Project, including key specifications and characteristics, as well as NIPSCO's approach to configuration selection and contracting strategy. Pet. Ex. 5 at 4-5. He also provided the project schedule, ~~the best~~an estimate of costs of construction, and NIPSCO's request for ongoing review pursuant to Ind. Code § 8-1-8.5-6. *Id*. at 14-19. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit of about 200 MW with three smaller aeroderivative turbine units (around 56 MW each) or similarly sized industrial frame units (dependent on the results of the CT original equipment manufacturer ("OEM") bid event). *Id.* at 3. Mr. Walter ~~explained~~stated that 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. Pet. Ex. 2 at 31.

NIPSCO witness Mr. Walter testified that, in terms of project development, NIPSCO began with a competitive RFP and engaged the assistance of Sargent and Lundy~~. Based~~ to design the project and develop the scope of the RFP. According to Mr. Walter, based on available information in the market~~,~~ (that is, after receiving bids from potential RFP contractors), NIPSCO determined the best path forward is to self-build the CT Project~~, leveraging~~. Pet Ex. 2 at 30-31. NIPSCO intends to leverage the available MISO interconnection rights from the retiring ~~generation at~~ Schahfer~~.~~ Units 17 and 18 by building the CT Project at the Schahfer site. Pet. Ex. 2 at ~~30-31~~12. NIPSCO issued its Turbine Equipment RFP in June 2023 and executed an agreement with its selected turbine manufacturer on March 29, 2024, to reserve its selected equipment. ~~Jt.~~NIPSCO-CAC Ex. 3 at 8~~, Confidential Attachment A. Mr.~~; NIPSCO-CAC Ex. 8 at 5-7; NIPSCO-CAC Ex. 3-C at 55. However, NIPSCO still had not finalized a Limited Notice to Proceed ("LNTP") by June 2024, shortly before the evidentiary hearing in this matter. NIPSCO-CAC Ex. 3 at 18, CAC 25-001(a).

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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, as a result, NIPSCO shifted the expected in-service date for the CT Project from year-end 2026 to year-end 2027. Pet. Ex. 5-S at 2-5. Even with this update to the project schedule, the best estimate of the total cost of construction did not change from NIPSCO's direct testimony. *Id.* at 11-12.

Mr. Blissmer testified that 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. Pet. Ex. 8 at 21. 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. Pet. Ex. 5-R, Attachment 5-R-A and Confidential Attachment 5-R-B. ~~NIPSCO did not simply file its estimate in its case-in-chief and rely on this evidence. Instead,~~ NIPSCO through due diligence confirmed its cost estimate in its supplemental testimony based on updated supply chain information, which NIPSCO witness Baacke further testified to in rebuttal, confirming that NIPSCO's best estimate of the total cost of construction was updated with information received from bid events for the CT original equipment manufacturer, generator step-up transformers, unit auxiliary transformers, and diesel generator, which resulted in increases and decreases to certain line items. *Id.* at 19-20. He also explained that NIPSCO removed escalation and reduced the amount of contingency associated with owner's costs and certain equipment. *Id.* at 20. As of its rebuttal filing, the total estimated cost of the CT Project, including estimated AFUDC of $2,680,234, is $643,903,234. Pet. Ex. 8-R, Attachment 8-R-C. This AFUDC estimate assumes NIPSCO's proposed forward looking GCT Mechanism is approved.

Challenges to NIPSCO's best estimate can be summarized as follows:

- NIPSCO's preferred configuration for the CT Project should be rejected because its front-end design process was inadequate, and the preferred configuration's three aeroderivative turbines are too expensive and not cost justified;

- Out of concern with NIPSCO's project management experience, NIPSCO should not self-build the CT Project and should contract with an EPC instead;

- NIPSCO's best estimate contains duplicative or unreasonably high cost components, including contingency, owner's costs, escalation, and indirect costs; and

- NIPSCO's best estimate includes unnecessary pollution control technology, which can be sought in a subsequent federally mandated cost tracker proceeding, as necessary.

(a) Configuration of CT Project. As discussed in more detail above, CAC witness Mr. James opined (CAC Ex. 2, Attachment RJ-2, §§ 4.1 and 4.2) that 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 final investment decision remains questionable. ~~The record offers ample evidence by which to conclude that, in partnership, NIPSCO and S&L's design and engineering process was thorough, consistent with industry standards, including AACE cost classification, and rigorous in evaluating three different configurations for the design of the CT Project. *See*~~ d Mr. Warren averred~~Pet. Ex. 4 at 5-13 and Confidential Attachment 4-A, Pet. Ex. 5 at 6-14, Pet. Ex. 4-R at 9-21, and Pet. Ex. 5-R at 7-35. Mr. Warren explained~~ on rebuttal that FEED studies evaluate whether a project should move forward at each step or stage and is rendered unnecessary by the IRP process and S&L's Engineering Study. Pet. Ex. 4-R at 4, 10. ~~The process~~We are concerned, however, that NIPSCO's lack of experience in managing power construction projects, both organizationally and in the persons of its individual leaders, makes it all the more crucial that NIPSCO ~~used to develop its CT Project is similar to processes we have seen used by other utilities for which we have approved CPCNs. *See*~~carry out prudent front-end design.~~ *CEI South*, Cause No. 45564 (IURC 6/28/2022), *Indianapolis Power & Light Company*, Cause No. 44339 (IURC 5/14/2014). While~~ FEED studies have been used for other projects in Indiana, ~~we have only seen them~~often in connection with novel technologies, such as coal gasification or carbon capture. *Duke Energy Indiana, Inc.*, Consolidated Cause Nos. 43114 and 43114-S1, at 6, (IURC 11/20/2007); *Indiana Michigan Power Co.*, Cause No. 44075 (IURC 2/13/2013). ~~As described in more detail below, in designing and engineering~~NIPSCO's plans to self-build the CT Project~~,~~ and use aeroderivative turbines are, while perhaps not novel in the utility industry, new to NIPSCO~~ leveraged S&L's extensive~~. NIPSCO has not used a multi-prime approach for building a gas power ~~industry expertise.~~ plant. Pub.~~Pet.~~ Ex. 4 at ~~7.~~13. S&L's Engineering Study, Confidential Attachment 4-A, ~~provided~~purported to provide NIPSCO with the level of information needed to determine the technology and configuration that best met the simple cycle gas turbine requirements. ~~Based on the record evidence, we find that NIPSCO's CT Project was properly scoped, designed, and engineered and that NIPSCO and, although not specifically required, S&L's up-front design activities reasonably align with the intended purpose of CAC witness James' recommended design process. As such, NIPSCO is not required to complete any further front-end engineering and design diligence.~~However, the specific configuration chosen by NIPSCO around June-July 2022 (Pet. Ex. 4-R, Att. 4-R-A at 2) was arrived at based on an opaque, subjective system that cannot be replicated by observers working with the same data, as discussed more below in section 6.D.i. Additionally, the Engineering Study included only Piping and Instrumentation Diagrams ("P&IDs") marked with words other than "issued for design," which is a grave omission according to industry experts. The Engineering Study also contained no heat or material balances, another critical failure. CAC Ex. 2, Att. RJ-2, §§ 2.3, 2.5; Pet. Ex. 4, Conf. Att. 4-

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A at Appx. 11. Based on the record evidence, we find that NIPSCO's CT Project was not properly scoped, designed, and engineered. This alone makes it difficult for the Commission to deem any cost estimate a best estimate of costs..

The OUCC and CAC also took issue with NIPSCO's EPC RFP. By arguing that NIPSCO "self-selected" a configuration with aeroderivative turbines (Pub. Ex. 2 at 16) and that NIPSCO did not evaluate other configurations, including an all-industrial frame configuration (Pub. Ex. 3 at 7-8), the OUCC asserts that NIPSCO's EPC RFP was too narrow. At the same time, CAC witness James (CAC Ex. 2, § Attachment RJ-2, 3.4) alleged that a lack of detail contributed to the poor response rate to the RFP. Although they take opposite positions regarding the RFP, the OUCC and CAC ~~appear to~~ both challenge the aeroderivative turbines because of their cost. OUCC witnesses Sanka and Hanks asserted that, from a cost-effectiveness perspective, the operational characteristics of the aeroderivative units ~~do~~have not been shown to justify the higher overall expenditure when compared to a configuration comprised of only industrial frame turbines. CAC witness Sommer recommended denial of the CT Project particularly because of the three aeroderivative turbines and suggested reducing the cost of the Project by replacing the aeroderivative turbines with a second industrial frame machine.

~~As we will note later, three of the Five Pillars we are charged with evaluating in the context of a CPCN for new generation are reliability, resiliency, and stability.[12] We make this point because we must 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 including: desired machine sizing, cold start timing, ramp rates, minimum emission compliant loads, emission limits, remote start and operational capabilities, and other reliability capabilities. Importantly, this analysis further refined the need by noting that there is a significant growth in the need for faster ramping/quicker starting resources. That analysis shows that 150 MW of growth in the need for capacity with a ramp rate of 10 minute by 2030~~The ~~. Pet. Ex. 7, Conf. Att. 7-D, at 9-10, 61. 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. Pet. Ex. 5-R at 3-4 and Confidential Attachment 5-R-C. NIPSCO witness Mr. Baacke pointed out that the Engineering Study recognized that smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, rendering~~

~~[12] The evidence offered against the aeroderivative units did not come from the witnesses possessing the qualifications we would have expected to raise such challenges to design. From the OUCC, it was not Mr. Krieger, an engineer with over 20 years of working experience, who raised issues about the design. *See* Public's Ex. 4 at 29. Instead, the main witness was a person whose education background is in economics and who has no technical experience in generation. He was supported by a witness who does have a very recent engineering degree, but who likewise has no technical experience. Pet. Ex. 11, at 8-11; Pet. Ex. CX-1, pp. 18-19. From the CAC, the witness on configuration was not Mr. James, again another engineer with years of working experience, but their IRP witness. This is significant because considerations of reliability, resiliency, and stability require us to consider the relative impacts of other parties' proposals. The qualifications of the witnesses who presented alternatives is a factor for the Commission to consider when thoroughly examining these three highly technical pillars.~~

~~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, which is discussed in detail below. Finally, the cost of the CT Project here is below the $1,440 in direct cost that was assumed in the Portfolio Analysis, which was based on NIPSCO's responses to the 2022 RFP. Pet. Ex. 7 at 39-40; Pet. Ex. 7-R at 9-12.~~

~~Further, the~~ amount by which the OUCC seeks to reduce the best estimate ~~allegedly~~ to remove the aeroderivative configuration ~~does not follow~~follows from ~~its own testimony.~~data presented by NIPSCO, and is consistent with the amount identified by CAC witness Sommer. Witness Krieger provides the reduction in cost as a range of $30-40 million, ~~but he does not provide the methodology to arrive at this amount. Instead, he cites~~citing to witness Sanka. Pub. Ex. 4 at 26. Relying on bid data produced by NIPSCO in discovery, Witness Sanka ~~does not provide the range cited by witness Krieger or even provide an estimate of the cost differential. She does, however, compare~~compared the cost of three aeroderivative units to the cost of a single larger frame unit using data pulled from her Confidential Attachment RS-3, ~~and the math from her comparison produces a difference of~~ which showed that the latter was $37.6 million~~.~~ lower in cost than the former. Pub. Ex. 3C at 9. ~~The problem with this comparison is that~~ CAC witness Sommer, relying on a similar comparison in S&L's Engineering Study, identified a very similar reduction in cost if the three aeroderivative units were replaced by a single larger frame unit. CAC Ex. 1C at 6-7, citing Pet. Conf. Att. ~~does not possess the 10 minute cold start and ramp rates from smaller industrial units or~~ 4-A at 1-3. While NIPSCO criticizes this cost estimate because it does not compare three aeroderivative units~~. Ms. Sanka stated that her objection was that NIPSCO allegedly did not evaluate a configuration with three smaller~~ to three similarly sized industrial frame units~~sized to match the aeroderivative units.~~, the decision matrix in Appendix 19 of the S&L Study shows that it is NIPSCO itself that failed to make such a comparison. As such, we credit the approximately $37.6 million savings identified by witnesses Sanka and Sommer. ~~Pub. Ex. 3 at 6. Thus, the OUCC's proposed reduction is based upon a peaker that would not possess the start time and ramping rates that NIPSCO requires. The OUCC is comparing costs of smaller, more nimble units to a single larger industrial frame unit that would not address the 10 minute ramp requirements identified in the Flexibility Analysis.~~

~~As to the costs and benefits of smaller units, the OUCC's and CAC's evidence fails to counter the important fact~~We acknowledge that aeroderivative turbines provide ~~several key attributes that complement NIPSCO's largely renewable portfolio, including faster start capability than larger industrial frame units~~some important operational advantages in comparison to industrial frame turbines, such as faster ramp times, the ability to start and stop multiple times per day without impacting maintenance cycles, and higher efficiency~~as compared to industrial frame gas turbines.~~. Pet. Ex. 4-R at 20-21, and ~~Jt. Pet.~~NIPSCO-CAC Ex. 3 at 3–4. ~~The fast ramping capability of the~~ NIPSCO, however, has failed to provide any assessment showing that those advantages outweigh the significantly higher cost of aeroderivative units. And while NIPSCO references a 10-minute startup time for aeroderivative ~~turbines provides functionality that is essential to satisfying reliability needs within NIPSCO's service territory and the MISO footprint. This is not a matter of gold plating; an all-large industrial frame configuration simply would not satisfy these reliability needs. Importantly, while the OUCC claims that a specific cost-benefit analysis on the aeroderivative turbines is critical, they can cite to no other example where an electric utility has done the analysis they claim should have been done.~~units, the company's analyses did not actually find that fast startup time was a necessary characteristic of the CT Project. Additionally~~Pet. Ex. 11 at 12.~~

~~The stability of the aeroderivative turbines' fast-ramping capability mitigates risk posed to customers from inadequate capacity. This is critical as CAC witness Ms. Sommer testifies (p. 21 and Figure 1, p. 24) that, if certain MISO market reforms are implemented, NIPSCO will likely need more capacity starting in 2028, even when assuming that 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, Pet. Ex. 9-R at 5-6 establishes that, under the newly final GHG Rule, 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, in order 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 Stanley at p. 6 of his supplemental testimony.~~

~~OUCC witness Mr. Hanks' testimony raises general arguments about the cost of the CT Project, intimating that its cost/kW should not exceed that of CEI South's CTs in Cause No. 45564 or the average cost/kW located in the Energy Information Administration's ("EIA") 2023 Energy Outlook. We reject any 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 predictions or point estimates." Pet. Ex. 5-R at 27. Further, Mr. Hanks~~ did not ~~attempt to reconcile the many factors that could impact – positively and negatively – the installed cost per kW of various technologies. As to Cause No. 45564, we note at the outset that NIPSCO and CEI South operate under very different generation constraints and customer composition. Further, CEI South's~~ provide evidence that other new gas generation projects in the MISO or Indiana footprint are unable to use only frame turbines. For example, the 460 MW gas combustion turbine project ~~was designed over 3 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. Having been approved in 2022, CEI South's CTs were designed before the escalation in demand for CTs occurred, which has created a more competitive construction market. Most critical is the fact that, by its own admission, 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. *See* Pet.~~ that we approved in Cause No. 45564 a little over two years ago involved two F-class frame turbines.~~Ex. 5-R at 29-30 and Attachment 5-R-D, OUCC response to NIPSCO Request 2-1. This oversight further invalidates Mr. Hanks' attempted comparison. The estimated cost of NIPSCO's gas interconnection (which is under $1.5 million) was discussed by NIPSCO witness Austin in his direct testimony and was included within the best estimate for the CT Project. The interconnection is approximately 1,500 feet, supplied by an existing onsite 20" gas line. Pet. Ex. 3 at 4; Pet. Ex. 5-R at 30.~~

The substantial cost of the proposed CT Project also gives us pause; the record clearly establishes that the approximately $1,600/kW cost far exceeds average costs for gas combustion turbines reported by the U.S. Energy Information Administration, the cost of CEI South's CTs in Cause No. 45564, the bids for thermal resources received in response to NIPSCO's 2022 All-Source RFP, the cost for the gas CT included in NIPSCO's 2021 IRP portfolio, and the cost of gas CT projects that CAC witness Sommer has seen. While NIPSCO quibbles with some of those comparisons, the substantial cost of the CT Project calls for careful scrutiny especially given the increasing rates and affordability challenges confronting NIPSCO's ratepayers.

The technical specifications for the combustion turbine equipment ~~were~~as expressed in the EPC RFP released in August 2022 were not sufficiently defined, ~~appropriately developed to address~~

~~the needs of NIPSCO's renewable portfolio without limiting~~ however, as discussed by CAC witness James. We also note inconsistencies in NIPSCO's representations of whether EPC bidders ~~to a specific kind of technology, and consistent with industry standard. We find~~were expected to conform to a "technical specification for the 2022 EPC RFP using the preferred configuration of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame unit" (Pet. Ex. 4-R, Att. 4-R-A at 2) or whether the bids were required to include "a combination of industrial-frame and aeroderivative CTs (and optionally, RICE units)" as the RFP stated (OUCC Ex. 2, Att. JWH-1 at 12). It appears that an EPC bid's inclusion of only one type of turbines was viewed by NIPSCO as a reason to reject it. NIPSCO-CAC Ex. 4 at 17-18. We also find that NIPSCO's preferred configuration of one industrial frame turbine and three aeroderivative turbines ~~was appropriately informed by the results of the bid event and will provide critical, stable, load-following generation.~~, as determined through the Engineering Study's Appendix 19, was (as discussed below in section 6.D.i) the result of an arbitrary decision process that the Commission is unable to evaluate as sound or not. We ~~find no reason to modify this preferred approach. Finally, given the substantial~~ appreciate the record evidence on the important, load-following attributes ~~the~~that aeroderivative turbines can provide, but we cannot find that the aeroderivative turbines are cost-justified ~~and~~or 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 Krieger testified (pp. 5-6) 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 James testified (Attachment RJ-2, 3.7 and 3.9) that NIPSCO lacks experience constructing power plants and that 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 ("IGCC") project. Both OUCC and CAC witnesses raised the complete lack of experience of NIPSCO's lead individual construction managers in overseeing power plant construction projects.

The record contains substantial evidence regarding the results of NIPSCO's EPC RFP bid event. 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: one with a proposed configuration of ten refurbished aeroderivative machines and another with only two larger industrial frame units that was less than five pages of content. Pet. Ex. 5 at 11; Pet. Ex. 10. ~~Even with~~Having received suboptimal responses from its bidders, NIPSCO summarily rejected two bids as nonresponsive and then conducted ~~extensive~~ due diligence, discussed further below, to evaluate ~~each~~the remaining 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 above 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. Pet. Ex. 10 at 2. While an EPC contract is a valid way to execute a generation project, it is not a requirement to receive a CPCN in the State of Indiana nor is it a guarantee against project cost overruns. While our responsibility under Section 8-1-8.5-5(b)(1) is not to accept or reject an overall construction management approach – it is simply to make a finding of a best estimate of costs – we cannot help but note that the self-build approach opens the potential range of cost outcomes more widely. It is true that a fixed price under an EPC contract may nonetheless increase due to change orders, as Mr. Baacke noted (Pet. Ex. 5-R at 8) but under the proposed self-build, multi-prime approach, NIPSCO has not even entered into contracts yet with construction companies, nor a final contract with a turbine supplier. The Commission has serious concern about the potential for costs to increase above the estimate that NIPSCO has provided, should construction move forward.

OUCC witness Krieger and CAC witnesses Sommer and James ~~claim~~inform us that NIPSCO does not have experience building gas-fired generation projects of this scale, and they are concerned by ~~their belief~~the fact that NIPSCO ~~lacks~~, and its individual lead construction managers, lack large project management experience.~~[13]~~ Pub. Ex. 4 at 15-16; CAC Ex. 2 at Attachment RJ-2, 3.9; CAC Ex. 1 at 14. ~~As we have already discussed, the evidence of record in this Cause establishes that NIPSCO conducted rigorous diligence in both resource planning decisions~~This would not necessarily be a devastating concern were NIPSCO going to engage an EPC contractor with responsibility for cost control and project ~~design, engineering, and contracting. There is also substantial evidence in~~completion. But, although we appreciate the ~~record with an unusual amount of detail on the project management experience of NIPSCO's team.~~ intended role of Sargent and Lundy in helping to manage and monitor construction progress (Pet. Ex. ~~5~~4-R at ~~9-15. Forced to "prove a negative," it is clear~~18-19) we note that ~~NIPSCO's Major Projects team~~S&L has not served as a mechanical contractor, civil construction contractor, or electrical contractor on a thermal power plant project within the past 5 years. NIPSCO-CAC Ex. 3 at 17. We would be more comfortable if the proverbial buck stopped with a more experienced ~~intense (and abnormal) scrutiny throughout this Cause~~responsible party.

Mr. Krieger also suggested that the supply chain challenges with 345 kV breakers and generator step-up transformers that initiated NIPSCO's decision to shift the CT Project's in-service date from end-of-year 2026 to end-of-year 2027 were well known when NIPSCO originally filed its case and that NIPSCO engineering and project management should have been well aware of these challenges when NIPSCO's September 2023 Petition was filed. ~~This is the kind of "Monday Morning Quarterbacking" – or hindsight review – that puts utilities in a bind when facing the varied and complex factors at play in resource planning and major generation construction.~~We take this point, but NIPSCO's proposal before us is now for a project going online at the end of 2027. When challenges arise, we encourage and expect our regulated utilities to pivot as needed to reasonably respond, particularly when doing so would result in a savings to its customers. Rather than sitting on its hands, NIPSCO proactively notified the parties and the Commission that its in-service date had changed due to supply chain constraints, which was proved out in its rebuttal testimony showing a 70% cost increase to 345 kV breakers in three months. Pet. Ex. 5-R at 26. ~~This is not a sign of incompetence as the OUCC implies, but rather the kind of well-considered, deliberative decision-making we encourage our regulated utilities to engage in.~~

~~We acknowledge that this will be NIPSCO's first time overseeing construction of a new gas-fired generation project. However, the CT Project has undergone extensive upfront design and engineering, will be built on an existing NIPSCO site with no additional land acquisition needed and only a 1,500 lateral in order to access NIPSCO's natural gas system, which is stable and supported by seven interstate pipelines. Pet. Ex. 5 at 7-9; Pet. Ex. 3 at 4; Pet. Ex. 5-R at 30. NIPSCO's preferred~~

~~[13] We pause to note the lack of OUCC experience to level objections about Mr. Baacke's experience. None of the OUCC's witnesses have overseen or worked on construction of electric generation. Pet. Ex. 11 at 9-10.~~

~~configuration is intended to support its largely renewable and therefore, intermittent, portfolio, which the NIPSCO Major Projects team has been actively supporting through the construction of cutting edge generating projects, including the 345kV Synchronous Condenser and a confidential Unit 16A/B Addition. Pet. Ex. 5-R at 10-12. Unlike the CT Project, which represents a more "standard" generation project, albeit in a dynamic economic and market environment, NIPSCO executed these first of their kind projects concurrent with a global pandemic and experienced only minimal cost increases. NIPSCO has already prudently extended its runway to complete the CT Project through year-end 2027 and given that it has made a substantial reservation payment with its turbine equipment manufacturer, the evidence supports that NIPSCO has a project plan in place to ensure the CT Project will be constructed on time and on budget within reasonable constraints. The multi-prime strategy selected by NIPSCO produces a best estimate of costs that saves $100 million from the cost that would be produced under the only responsive EPC bid NIPSCO received. If NIPSCO had not pursued the multi-prime strategy in the face of such possible savings, we would have been concerned. Any sense of "bumps in the road" to this point is indicative not of mismanagement, but of NIPSCO's thorough and deliberative process.~~

Put simply, CAC and NIPSCO both agree demand for EPC contractors in the power industry is high. CAC Ex. 1 at 9, Pet. Ex. 4-R at 7-8. NIPSCO witness Warren testified that this high level of demand has shifted interest from EPC contractors to larger projects that maximize their potential profits. Pet. Ex. 4-R at 7-8. ~~Rather than reward NIPSCO for making the cost-effective decision to self-build the CT Project, the OUCC and CAC call for additional expense in order to "improve" the management of the CT Project – without a shred of real evidence to support the notion that the Project is not being managed effectively right now. We do not believe it would be prudent to require NIPSCO to pursue an EPC contract that, based on current market conditions,~~The utility sector in this State cannot simply close down shop under these economic circumstances, in light of the imperative to continue building out new resources to meet customer needs, Nonetheless, the Commission would be more comfortable with NIPSCO's proposed project if it either had more experienced hands sitting in-house leading the project, or else if it had constructed an EPC RFP that was better designed to attract capable, responsive bidders. We do not believe it would be prudent to move forward with construction based on the factors we have identified ~~Pet. Ex. 10 at 2, could exceed the cost of NIPSCO's multi prime contracting strategy by $100 million~~.

Unquestionably, S&L and witness Warren have a great deal of experience ~~executing~~ advising on the execution of gas-fired generation projects. Pet. Ex. 4 at 7. ~~The parties appear to minimize the role~~ S&L has ~~played in~~led the design and engineering of the CT Project thus far, through creating the technical specifications for the ECP RFP bid event, and by consulting with NIPSCO as it decided not to pursue an EPC contract ~~at excessive cost~~ in favor of self-building the CT Project using a multi prime contracting strategy. CAC witness James recommends (Attachment RJ-2, 4.10) NIPSCO involve S&L through the CT Project as S&L has proven experience serving the utility sector. We have substantial evidence upon which to base the conclusion that NIPSCO has selected a competent partner in S&L, and that this collaboration ~~will continue throughout~~ can enhance NIPSCO's construction ~~and start-up/commissioning of the CTs. To the extent we had any~~oversight. Yet our doubts about NIPSCO's internal expertise to successfully complete the CT Project~~, its ongoing engagement with S&L eliminates those lingering concerns.~~ are difficult to overcome,.

As discussed below, 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 in excess of 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. *Southern Ind. Gas & Elec. Co.,* Cause No. 45836 (IURC 6/6/2023), at 28. The CAC and OUCC's fears over risk and escalation ~~are all appropriately~~can be mitigated somewhat through ongoing review~~. It is~~, although the ~~ongoing review process which protects ratepayers from unnecessary costs and~~Commission still has the responsibility to act as gatekeeper in approving a CPCN request to begin with based on the proposed project ~~mismanagement that the OUCC fears. Pub Ex. 1 at 9~~structure.

This case was originally filed in September 2023 and was extended by NIPSCO as a proactive response to major shifts in critical supply chains that occurred at the same time that MISO unveiled significant changes to its resource adequacy construct and seasonal accreditation factors. ~~That~~We acknowledge that this decision ~~alone~~by NIPSCO points to prudent decision-making in the face of varied challenges and constraints~~. We conclude that NIPSCO's Major Projects team has~~, although we wish NIPSCO had, for example, updated its modeling to include the ~~requisite skillset, experience, and project management process necessary to complete~~new long-range capacity accreditation rates announced by MISO around the ~~CT Project within the project schedule and budget and decline to order NIPSCO to revise its contracting strategy or secure an EPC. If we were inclined to order that NIPSCO secure an EPC, we acknowledge that doing so would require additional expense that would be reasonably recovered~~time NIPSCO filed its supplemental testimony, as ~~a project cost from customers~~discussed below in section 6.A.ii.

(c) Best Estimate Cost Components. OUCC witnesses recommended changes to NIPSCO's $641,233,000 cost estimate that would reduce the total cost by approximately $130 million. Pub. Ex. 1 at 10. One major cost reduction would be from the denial of the aeroderivative turbines, as recommended by OUCC and CAC. Pub. Ex. 3 at 10; CAC Ex. 1 at 10-12, 35. As discussed above, we agree that the added cost of the aeroderivative turbines has not been justified and, therefore, would remove $37.6 million from NIPSCO's cost estimate to reflect disapproval of those turbines.

OUCC witnesses Hanks and Krieger challenged NIPSCO's indirect costs, alleging that they lacked support and were potentially double counted in S&L's cost estimate. Based on our review~~Mr. Baacke's rebuttal testimony explained that the confidential version~~ of the ~~best estimate (Confidential Attachment 5-R-B),[14] 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~~record, it appears that no double counting actually occurred. While it is understandable that ~~NIPSCO explained each~~witnesses Hanks and Krieger would suspect double counting given the inconsistent cost ~~category~~categorization and ~~how they were estimated~~ labelling used by NIPSCO versus S&L, NIPSCO explained in response to CAC discovery ~~(included in Mr. Baacke's Highly Confidential Attachment 5-R-C) 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. Pet. Ex. 5-R at 21-22. ~~We agree. NIPSCO's internal indirect costs are capital overhead and stores, freight, and handling (Pet. Ex. 5-R at 5) 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~~As such, NIPSCO's evidence supports concluding no indirect costs were double counted.

~~[14] Also Confidential Attachment 5-B and Confidential Attachment 5-S-B.~~

OUCC witness Hanks also challenged NIPSCO's proposed 5% escalation factor and recommended that it be reduced to 3%, as was approved in NIPSCO's electric TDSIC Plan. ~~We are convinced by NIPSCO's evidence~~NIPSCO contends that a 5% escalation factor is appropriate~~. In particular, NIPSCO's supplemental testimony, which was filed before the OUCC's prefiling date, describes the global supply chain uncertainty that prompted the shift in the CT Project's in-service date to end of year 2027. Mr. Baacke's rebuttal testimony (at p. 26) provides specific detail on the 70% cost increase for 345kV breakers NIPSCO has witnessed in just a matter of a few months in late 2023. Given that NIPSCO's~~ because the electric TDSIC Plan ~~was approved~~case reflected cost from before the ~~COVID-19~~ pandemic and~~ its~~, therefore, did not account for the resulting supply chain and inflation issues. Pet. Ex. 5-R at 25. We note, however, that even since the pandemic began, we ~~conclude that reducing NIPSCO's~~ have approved escalation ~~factor to that which was requested and~~ rates even lower than 3%, such as the 2.4% rate that CEI North proposed in its most recent TDSIC Plan, which we approved in ~~that proceeding is not appropriate. Accordingly, we find NIPSCO's 5%~~ April 2022. *See CEI North*, Cause No. 45611 (April 20, 2022) at p. 4. As such, we believe a reduction of NIPSCO's escalation ~~factor is reasonable and approved.~~rate to 3% is justified, which would reduce the best estimate by approximately $27 million. Pub. Ex. 2 at 13.

OUCC witness Krieger also opposed NIPSCO's 9% estimate for owner's costs, arguing that 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. Pet. Ex. 5-R at 30-32 and Attachment 5-R-A. ~~We have addressed the parties' concern with NIPSCO's contracting strategy above and found that NIPSCO's self-build, multi-prime approach reduced the cost of the CT Project to the benefit of its customers.~~ Based on Mr. Baacke's rebuttal testimony, we conclude that NIPSCO's estimated owner's costs for its self-build project are informed by executed contracts and are ~~approved~~reasonable.

(d) **Pollution Control Technology.** A final element of cost reduction stems from OUCC witness ~~Armstrong testified~~Armstrong's testimony that the Selective Catalytic Reduction ~~units~~("SCR") controls 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 FMCA statute. Pub. Ex 1 at 19. Mr. ~~Holcomb's~~Baacke's rebuttal testimony confirmed that the ~~CT Project will~~ SCRs are not needed to comply with ~~the final GHG Rule~~existing regulatory standards (Pet. Ex. ~~9~~5-R at ~~5-6~~20); therefore, NIPSCO updated the best estimate to reflect the removal of the ~~Selective Catalytic Reduction units.~~SCR controls. 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~~, though question why, given the removal of the SCRs, the overall cost estimate for ~~recovering compliance costs, including the FMCA statute.~~ the CT Project cited in Mr. Baacke's rebuttal remains the same as in the initial application, Pet. Ex. 5-R at 19.

(e) **Conclusion on Best Estimate.** After reviewing the evidence of record, ~~we find that NIPSCO has submitted extensive~~ including NIPSCO's evidence ~~supporting~~in support of its best estimate on the cost to construct the CT Project, which is driven by its preferred configuration and contracting strategy~~.~~, we find that NIPSCO's best estimate of $641,223,000 is based on a detailed engineering analysis, as well as information from turbine manufacturers and contractor bid events from which capital costs, operating costs, performance characteristics, and construction schedules were determined. The best estimate may not, however, reasonably reflect the potential cost impact of project risk due to factors both within and without NIPSCO's control, which will be magnified by NIPSCO's multi-prime construction management strategy undertaken without adequate experience in the thermal power plant construction space. We also conclude, as discussed above, that the extra costs stemming from inclusion of the aeroderivative turbines and the use of an inflated 5% escalation rate should be removed from the best estimate. Removing the aeroderivative turbines and lowering the escalation rate to 3% would reduce the best estimate by $37.6 million and $27 million, respectively, for a total savings of $64.6 million. Therefore, we find that based on the evidence of record, the best estimate of the cost of construction of the CT Project should be $576,633,000. We remind NIPSCO and all litigants and stakeholders that pursuant to I.C. §§ 8-1-8.5-6 and -6.5, if the CPCN were approved, only $576,633,000 would (as a result of this finding) be pre-approved for inclusion in rate base in a future general electric rate case after project completion, unless an increased cost amount is approved through our review of the project progress following this order, which we would exercise with the utmost scrutiny that ratepayers of this State deserve. The standard would be whether the public convenience and necessity continue to require the project at the increased cost estimate. See, e.g., *CEI South*, Cause No. ~~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. Thus, based on the evidence of record, we find that $641,223,000 (excluding AFUDC) is the best estimate of the cost of construction of the CT Project.~~45836, at 28 (June 6, 2023); *N. Indiana Pub. Serv. Co. LLC*, Cause No. 45529, at 26 (July 28, 2021). The previous three sentences about Sections 6 and 6.5 are, of course, conditional on whether we determine to approve the CPCN request, which we will address in the coming pages.

ii. **Consistency with Petitioner's 2021 IRP 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~~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). However, as discussed below in section 6.D.i where we address the statutory Five Pillars, changes in the inputs, data, assumptions, methods, models, judgment factors, and rationales embodied in a utility's most recent IRP must be fully explained and justified with supporting evidence, including an updated IRP analysis. 170 IAC 4-7-2.5(b). The Portfolio Analysis and Flexible Resource Analysis sponsored by Mr. Augustine do not suffice to explain why NIPSCO now proposes a 400 MW project with one industrial frame turbine and three aeroderivative turbines, 33% larger and over twice the cost per kW compared to what NIPSCO contemplated in the Short

Term Action Plan identified in Petitioner's 2021 IRP.

~~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 All-Source 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) at 19. 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 that earlier retirement of coal capacity resulted in lower costs for customers. The 2021 IRP also concluded that 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 ("DER"), 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 also conducted an additional technical reliability assessment to ensure that the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and 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 that 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.[15]

~~Although it was not required to do so~~As part of its petition in the instant matter, NIPSCO ~~voluntarily~~ performed the 2023 ~~portfolio analysis~~Portfolio Analysis (presented in Pet. Ex. 7, Att. 7-C), sponsored by witness Augustine, to consider changes that have occurred since its 2021 IRP and thereby ~~determined~~determine whether its preferred portfolio and the Short-Term Action Plan are still reasonable. ~~The record demonstrates~~Unfortunately, the Portfolio Analysis was not structured to arrive at an optimized portfolio after allowing generation expansion parameters to vary across technologies; instead, the Portfolio Analysis started with a cramped set of three portfolios to analyze, none of which were based on the 2021 IRP's Short-Term Action Plan of installing 300 MW of new gas peaking generation.

What's more, the Portfolio Analysis assumed that ~~the 2023 portfolio analysis accounted for~~ under MISO capacity accreditation methodologies, the accreditation rate of four-hour duration storage will decline to 70% by 2040, while a gas peaker will have an accreditation rate around 95%. Pet. Ex. 7 at 35. Yet Ms. Sommer showed that based on MISO's latest accreditation methodology proposal (currently under consideration by FERC in the pending Docket No. ER24-1638), NIPSCO's ~~ongoing resource planning~~accreditation assumptions for storage were over 11 percentage points too low in summer and ~~other market conditions~~over 8 percentage points too low in winter; and ~~developments that have occurred since the 2021 IRP was completed, including, among other things, updated pricing from~~ NIPSCO's ~~2022 All-Source RFP~~accreditation assumptions for gas were 9 percentage points too high in summer and 31 percentage points too high in winter. Stated differently, under MISO's latest plans, storage would have a higher accreditation rate than gas (94 percent against 88 percent) in summer, and a higher accreditation rate than gas (91 percent against 66 percent) in winter. CAC Ex. 1 at 22. NIPSCO's rebuttal testimony was filed in May, following MISO's submission of its capacity accreditation reform proposal to FERC in March, but witness Augustine (while acknowledging the new FERC case) declined to update the Portfolio Analysis accordingly to account for pending, changes to the MISO resource adequacy construct~~, commodity pricing updates, and changes to federal law.~~ . Pet. Ex. 7-R at 19.

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 evidence demonstrates, and the Commission has previously found, that NIPSCO "utilized an array of best practices, including basing model inputs on its All-Source RFP, which allowed for an informed forecast at that time." *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021).~~ We are sympathetic to a utility's position when it sets certain plans based on one modeling exercise and then relevant conditions in the world change. However, with hundreds of millions of dollars of ratepayer money at stake, it is imperative that the utility update its view of the world accordingly before taking a resource action, if not too late. Here, NIPSCO failed to do so.

IG witness 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

15 Section 9.2.7.6 of NIPSCO's 2021 IRP for the detailed summary of reliability scoring, as well as the technical reliability assessment addendum in IRP Confidential Appendix E (included in Confidential Attachment 7-B).

constraints, tariff uncertainty and inflationary cost pressure; and (4) additional RFPs with Charles River Associates to assess the latest market data for new resources. ~~However, his claims are contradicted by clear evidence in the record. As Mr. Augustine explained in his rebuttal testimony, Mr. Gorman's testimony does not acknowledge or reference NIPSCO's 2023 portfolio analysis.~~ IG Ex. 1 at 5-6. While we believe NIPSCO did update its modeling in the 2023 Portfolio Analysis to incorporate certain favorable and unfavorable national developments impacting development cost and timing, Mr. Gorman's critique about MISO's resource adequacy construct is certainly salient, as discussed above.~~ Pet. Ex. 7-R at 5. 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. *Id.* at 6. Mr. Augustine's direct testimony (at 26) 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 in order 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 Indeed, we have relied upon NIPSCO's 2023 portfolio analysis to support approval of other generation projects.[16] As such, we find that 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 also testified that 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~~posited three reasons why this criticism is invalid: (1) the Rate 831/531 Modification Agreement approved in Cause No. 45772 recognizes that 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 witness 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 scenario with the exact reduction in Tier 1 demand commitments suggested by witness Gorman, and NIPSCO's preferred portfolio was found to perform well under such assumptions. Pet. Ex 7-R at 17-18. We find Mr. Augustine's explanation convincing. 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. As witness Becker pointed out, the 531 customers *may* reduce their load, but they have not done so yet and NIPSCO cannot assume that they necessarily will. Pet. Ex. 1-R at 14. Furthermore, and as noted by CAC witness Sommer, NIPSCO likely will need *an additional* 400+ MW of capacity beginning in 2028, which could be partially addressed by

~~[16] 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.~~

further reductions of 531 Tier 1 load. *Id.;* CAC Ex. 1 at 22. ~~This is no reason to reject NIPSCO's CT Project.~~ This issue by itself is not a reason to reject NIPSCO's CT Project. (Elsewhere in this Order, we discuss separate concerns with the load forecast used in the Flexible Resource Analysis.)

~~The~~Overall, the evidence of record demonstrates that the CT Project is not consistent with ~~and~~or supported by the 2021 IRP and 2023 ~~portfolio analysis~~Portfolio Analysis. The 2021 IRP concluded that 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 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.~~The 2023 Portfolio Analysis suffers from serious flaws: first, the 2021 IRP's preferred portfolio (which called for up to 300 MW of new gas peaking capacity) was "adjusted" to increase the gas peaker from 300 MW to 400 MW based, apparently, on "results from the 2022 RFPs" – which, in turn, were based (as discussed above) on a request to bidders for 370-450 MW of new gas at the Schahfer site. Pet. Ex. 7 at 30-32. And in turn, the expanded gas request in the 2022 RFP was based on "key conclusions identified in the Flexible Resource Analysis" – which, as we show above in section 6, was insufficient to draw conclusions about expanding the gas peaker size.

~~Far from a "fatal flaw", we conclude that not incorporating the potential reduction in Rate 531 Tier 1 firm demand in NIPSCO's resource planning process is appropriate given the amount of uncertainty around timing and actual amounts of load reduction. As witness Becker pointed out, the 531 customers *may* reduce their load, but they have not done so yet and NIPSCO cannot assume that the necessarily will. Pet. Ex. 1-R at 14. Furthermore, and as noted by CAC witness Sommer, NIPSCO likely will need *an additional* 400+ MW of capacity beginning in 2028, which could be partially addressed by further reductions of 531 Tier 1 load. *Id.;* CAC Ex. 1 at 22. We are further convinced by NIPSCO's evidence on the need for the CT Project – and even more capacity purchases or additions – in order to meet future demand growth in its service territory. Thus, based on the evidence of record and for the reasons explained above, we find that 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. Pet. Ex. 2 at 14. The record in this Cause contains findings by MISO, MISO's IMM, and the NERC (Pet. Ex. 3 at 16-19) supporting 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 that 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 particular fast-ramping, load-following needs. Based on the evidence of record, we ~~agree~~disagree, 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 that the Commission must, in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity, consider the following:

(1) The applicant's current and potential arrangement with other electric utilities for:
- (A) The interchange of power;
- (B) The pooling of facilities;
- (C) The purchase of power; and
- (D) Joint ownership of facilities.

(2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

We address these considerations below.

(a) Ind. Code § 8-1-8.5-4(b)(1). Mr. Stanley described NIPSCO's involvement in MISO, an independent transmission system operator, and testified that this portion of the statutory language predates the formation of MISO. He stated that 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 also 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 that 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. Pet. Ex. 6 at 20-24. NIPSCO witness Augustine testified that NIPSCO's all-source RFPs, its IRP, and the 2023 ~~portfolio analysis~~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. Pet. Ex. 7 at 7-8.

The evidence of record shows that 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).** We now analyze "[o]ther methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources."

Notably, while some of the parties directly and implicitly challenge 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 that 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, lines 17-18; 10, lines 17-19. The CAC points out that if recent proposed MISO market reforms are implemented, "NIPSCO likely needs more capacity starting in 2028" even when assuming that the proposed CT Project enters into service. CAC Ex. 1 at 21, 24. These statements affirm NIPSCO's requirement for incremental capacity~~, and~~. However, the ~~evidence of record supports NIPSCO's~~question before us is whether the CT Project ~~as~~ has been demonstrated to be a ~~required addition~~reasonable and prudent way to meet that ~~will help fill this~~ need. We conclude that the CT Project, as proposed, has not.

We address each aspect of Subsection 4(b)(2) below.

(1) **Reliability.** There is substantial record evidence on the need for reliability within NIPSCO's service territory and across the MISO footprint to maintain dispatchable generation for grid reliability. Specifically, MISO's Response to the Reliability Imperative dated January 2023 (p. 13) states that:

> To compliment the expected growth of solar generation, the system's need for controllable upramp capability could triple by 2031 and quadruple by 2041 compared to current levels. As the solar generation capacity grows, so does the challenge of steeper ramping needs for the non-solar generation fleet. At sunset, MISO will increasingly need controllable resources that can rapidly turn on and ramp up their output when generation from solar becomes unavailable. The need for fast-ramping resources is expected to vary by season and be most prominent in the winter months.

Pet. Ex. 3 at 16-17.

In regard to future market needs, the IMM, in its 2022 State of the Market Report for the MISO Electricity Markets (Executive Summary, p. v), reaffirmed that:

> Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This will lead to significant changes in the system's ramping needs. For example, conventional resources will increasingly have to ramp up quickly in the evenings as the sun sets, particularly in the winter season since load

peaks in the evening.

Id. at 18.

Regarding maintaining essential reliability services, NERC, in its 2022 Long-Term Reliability Assessment, states (Executive Summary, p. 7): "[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 Augustine testified NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP and found that conversion was higher cost than the alternatives. Pet. Ex. 7 at 32-33. Section 4.10.5 of NIPSCO's 2018 IRP noted that the analysis "showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more." Mr. Augustine also explained that 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~~Portfolio Analysis called for. Pet. Ex. 7 at 33. No party challenged any of this evidence.

As to cogeneration, NIPSCO witness Stanley testified that 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 that NIPSCO has added and continues to add. He explained that cogeneration, if available, would have been responsive to the all-source RFPs. Pet. Ex. 6 at 23.

NIPSCO witness 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, and commercial and industrial customers. She explained that 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.~~Market Potential Study ("MPS") to determine the achievable amount of savings. Ms. Becker stated that NIPSCO remains committed to offering income-qualified savings opportunities to its customers and will leverage both future MPS estimates and historical program performance to establish future savings goals and spending levels. Ms. Becker also reiterated that NIPSCO will continue to work with the NIPSCO Oversight Board on updates to the MPS to inform future IRP iterations. NIPSCO-CAC Ex. 1 at 2; NIPSCO-CAC Ex. 1 at 5. Ms. Becker further explained that NIPSCO's 2021 IRP modeling demonstrates that 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, according to Ms. Becker, 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 that, based on her experience with NIPSCO's ~~energy efficiency~~EE initiatives, NIPSCO could not derive sufficient energy savings to replace this generation. Pet. Ex. 1 at 8-19.

Ms. Sommer, on behalf of CAC, offered an important counterpoint, however. Based on a report prepared by the consultancy Cadeo Group for this proceeding, Ms. Sommer found that NIPSCO has the potential to develop up to 90 MW of new demand response capacity in summer and up to 46 MW of demand response in winter by 2027; and looking out to 2030, NIPSCO has the potential to develop up to 132 MW of new demand response capacity in summer and up to 63 MW in winter. This new capacity would have a cost of $75 per megawatt-day, under 25% the cost of NIPSCO's proposed combustion turbine generation ($367 per megawatt-day). CAC Ex. 1 at 25, 27. Cadeo Group, a consultancy that focuses on demand-side energy management programs across the nation, used both NIPSCO and national data to develop estimates of new potential for residential smart thermostat direct load control; residential behavioral demand response; and non-residential interruptible rates. The Commission believes NIPSCO has been remiss not to build the adoption of similar programs into its resource modeling, and NIPSCO should make a filing by the end of 2024 to add additional, cost-effective demand response resources to its portfolio.

In CEI South's Cause No. 45564 Order at 13, we found that "[t]he flexible and controllable nature of [CEI South's] gas CTs will support the intermittent nature of the renewable generation in the Preferred Portfolio to ensure system reliability." NIPSCO's record evidence supports~~ the same~~, at a high level, a conclusion ~~here. Integrating~~that integrating flexible and dispatchable resources that quick start will be vital as renewable resource penetration increases across the grid. ~~After~~However, after considering the evidence of record, we cannot find that the CT Project as proposed is ~~needed,~~ consistent with the 2021 IRP, ~~and shown to be~~or a reasonable, cost-effective solution to address ~~reliability~~the flexibility needs that have been identified. The reasons for this are discussed further below in sections 6.A.iv.b.3 and 6.A.v and, in the Five Pillars portion of our discussion, section 6.D.iv.

(2) **Efficiency.** The CT Project is configured to be an efficient and cost-effective solution that provides critical fast ramping capability to follow NIPSCO's largely renewable, and therefore intermittent, load. Mr. Augustine described how NIPSCO's Flexible Resource Analysis evaluated the frequency and duration of events where net load was simulated to be greater than available dispatchable capacity and identified potential future risks associated with energy adequacy and resource flexibility the CT Project is designed to meet. Pet. Ex. 7 at 20. The evidence of record demonstrates that the CT Project, and the aeroderivative turbines in particular, is designed to start and ramp up or down quickly and therefore can be dispatched for short periods several times a day or for prolonged periods, whichever is necessary, to cover shortfalls. Mr. Warren explained that the aeroderivative turbines possess several key attributes, including: fast start capability that can achieve full power in as few as five minutes, multiple starts and stops per day without impacting maintenance cycles, higher efficiency compared to industrial frame gas turbines, and lower power needs for blackstart implementation. Pet. Ex. 5-R at 20-21. In addition, Mr. Holcomb testified that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the GHG Rule and be allowed to operate at capacity factors up to 40%, as needed. Pet. Ex. 9-R at 7. ~~We~~As discussed further above in section 5.B and below in section 6.D.v, the industrial frame turbine (which comprises around half of the overall CT Project's maximum generating capacity) will have its annual capacity factor legally limited by the GHG Rule to 20%, however. Additionally, as also discussed below, NIPSCO was unable to articulate a plan for mitigating the risks of severe winter weather limiting its gas supply or gas generating equipment. Putting aside our deep concerns about cost, discussed below, we find that the CT Project ~~is~~as proposed to be configured is not optimally designed to efficiently meet the needs of NIPSCO's unique generation portfolio and ~~will~~customer needs such that it could provide reliable, resilient, stable power to its customers while satisfying federal environmental regulations.

(3) Economical Electric Service. We note at the outset that, as NIPSCO began its generation transition following its 2018 IRP, the move away from coal-fired to renewable generation was driven primarily by the estimated monetary savings for customers over the life of the generating assets NIPSCO would be investing in. NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. Although the difference in costs between various retirement options was narrower in the 2021 IRP relative to the 2018 IRP due to different portfolio concepts under study, updated commodity price inputs, and updated new resource costs from the 2021 RFP, the IRP continued to affirm that earlier retirement of coal capacity resulted in lower costs for customers. ~~NIPSCO's 2023 Portfolio Analysis shows that, consistent with its 2021 IRP, the Preferred Portfolio results in a lower net present value than any Portfolio that does not include any thermal peaking capacity and includes only storage additions.~~

As previously noted, issues with various aspects of NIPSCO's modeling were raised in this Cause. We addressed the IG's load forecast arguments (including Rate 531 implications) above. OUCC witness Hanks's testimony focuses on aspects of NIPSCO's 2023 ~~portfolio analysis~~Portfolio Analysis, which Mr. Gorman ignored, while CAC witness Sommer's testimony criticized aspects of NIPSCO's Flexible Resource Analysis~~.~~ and Portfolio Analysis. We address each below.

Mr. Hanks claimed NIPSCO's 2023 ~~portfolio analysis~~Portfolio Analysis included artificially inflated costs for new peaking capacity and that the results of the All-Source RFP and EPC RFP were both inappropriately combined and restricted in terms of technology and configuration. ~~However, NIPSCO's evidence demonstrated that (1)~~We find that the All-Source RFP and EPC RFP were separate and distinct events utilizing different criteria~~ such~~. Additionally, we take well Mr. Hanks' point that~~ any comparison of the resulting costs from bidders is inappropriate, (2)~~, as discussed at length above, the EPC RFP ~~did not restrict~~unduly restricted the technology and configurations that could be proposed by bidders~~, and required a dispatchable, blackstart-capable resource at the Schahfer site with several other performance criteria, and (3) thermal resources were offered in response to NIPSCO's separate All-Source RFP but those resources did not provide the local capacity, dispatchability, and blackstart requirements of the EPC RFP~~.

Mr. Hanks also suggested NIPSCO's 2023 ~~portfolio analysis~~Portfolio Analysis understated the costs of the CT Project by excluding indirect costs. Mr. Augustine explained that the purpose of the portfolio and revenue requirement modeling done in the 2023 ~~portfolio analysis~~Portfolio Analysis is primarily to compare costs of resource options such that excluding indirect costs provides a direct cost comparison. Pet. Ex. 7-R at 11-12~~.~~; Pet. Ex. 7 at 39-40. In response to CAC discovery that was stipulated into the record, NIPSCO ~~explained~~asserted that, 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 that included only direct costs. ~~Jt. Ex. 6. Indirect costs are company-specific, and we agree that their inclusion would skew the results of any project cost comparison; therefore, excluding them is~~NIPSCO-CAC Ex. 6 at 38. While that may be, the practice of excluding indirect costs from a comparison among resource options strikes us as moving the analysis further away from an apples-to-apples comparison. For NIPSCO's self-build proposal, indirect costs amount to around 13% of the total construction cost. Pet. Ex. 5, Att. 5-A. Indirect costs may be a smaller share of other resource acquisition models. Where the self-build option is directly at issue, excluding the company-specific indirect costs associated with NIPSCO's self-build option and with other resource options would skew the results of any project cost comparison; therefore, we agree with Mr. Hanks that excluding indirect costs, as NIPSCO did in the Portfolio Analysis, is not a reasonable approach to weighing resource options.

Ms. Sommer did not deny that NIPSCO's Flexible Resource Analysis evaluated potential market exposure, but she ~~alleged~~observed (p. 20) that 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 its load exposure. Mr. Augustine conceded that the Flexible Resource Analysis (Attachment 7-R-A) was not an economic assessment, but that the Analysis evaluated the magnitude, frequency, and duration of the expected timing of market exposure events of longer than four hours, which is a key metric supporting the need for dispatchable capacity with duration longer than 4-hour lithium ion battery storage resources can provide. NIPSCO's Flexible Resource Analysis illustrated that market exposure events were projected to be concentrated in the late evening, overnight, and early morning hours, particularly in the fall months that align with MISO's own expectations of when tight hours and system-wide loss of load events are likely to occur. ~~These~~NIPSCO advanced the bare assertion that such periods of time coincide with high market prices and high economic costs for NIPSCO – and potentially, its customers – ~~if NIPSCO's portfolio lacks available resources. The key outcomes of NIPSCO's Flexible Resource Analysis support the fact that additions of long-duration dispatchable capacity like the CT Project will improve reliability and reduce market exposure cost risk for customers – something~~ but NIPSCO never quantified the economic risk of such exposure, to allow stakeholders or this Commission to understand how serious that problem is ~~Ms. Sommer did not challenge. Dispatchable thermal generation is currently the only resource that provides the kind of long-duration capacity NIPSCO's largely renewable portfolio requires; we do not require a specific analysis to prove out, by exactly how much, thermal generation will meet this need at a lower cost than alternatives~~.

Ms. Sommer also observed that the sub-hourly energy and ancillary services market value of battery storage resources, which NIPSCO's 2021 IRP analysis projected to be the highest such value of any resource type, was properly integrated in the 2021 IRP's portfolio modeling. However, for the 2023 Portfolio Analysis, NIPSCO ignored such ancillary services value of battery storage. Pet. Ex. 7, Conf. Att. 7-C; NIPSCO-CAC Conf. Ex. 6-C (Excel file labeled CAC 3-015 Conf. Att. A). NIPSCO witness Augustine acknowledged Ms. Sommer's point on this score as "reasonable" and also acknowledged that ancillary services value could influence the conclusions of the Portfolio Analysis. Pet. Ex. 7-R at 26-27; Pet. Ex. 7 at 34. The Commission is concerned that this analytical omission could further send NIPSCO's proposed project technology and configuration in the direction of uneconomic cost to ratepayers.

~~Ms. Sommer also claimed (p. 20) 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. We conclude this testimony ignores the resource attribute needs identified in the Flexible Resource Analysis as well as NIPSCO's 2023 portfolio analysis, which specifically evaluated a portfolio with additional battery storage resources and no new thermal peaking capacity. Pet. Ex. 7-R at 16-17. This updated portfolio analysis determined that the portfolio with new peaking capacity was lower cost for customers – as did NIPSCO's 2021 IRP. CAC's recommendation also ignores NIPSCO witness Becker's direct testimony, which states, based on her experience with NIPSCO's energy efficiency initiatives, NIPSCO could not derive sufficient energy~~

~~savings to replace this generation. NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project. Given the extensive testimony on the record regarding the challenges battery storage poses to reliability, resiliency, and stability of the power grid, we decline to mandate additional iteration that would serve only to hinder and delay the active bidding process already occurring related to high demand CTs – the aeroderivative turbines in particular.~~

CAC witness Sommer also argued (pp. 25–26) that NIPSCO should quickly develop its excess injection rights at the Schahfer site to fully utilize them, ~~including through demand response and battery storage resources.~~potentially through battery storage resources. Ms. Sommer highlighted that MISO recently changed its rules (with FERC approval) to require full re-use of surplus interconnection rights by the time of signing a new interconnection agreement at an existing controlled site – or else any unused portion of the interconnection rights will be extinguished. CAC Ex. 1 at 26-27; FERC Docket No. ER24-1055. NIPSCO witness Stanley explained that NIPSCO is already investigating the best use for its remaining injection rights at the Schahfer site and RFPs have been issued as part of NIPSCO's 2024 IRP development process for various technology solutions to address NIPSCO's future capacity and energy needs.[17] ~~These RFP responses will~~The Technical Specifications provided to bidders ("Appendix G") as part of this 2024 RFP for battery storage at the Schahfer site were entered into evidence as part of the confidential NIPSCO-CAC Ex. 5-C (labeled as CAC 22-005 Highly Conf. Att. A). We are deeply concerned that almost no technical details about the Schahfer site were provided to bidders, except for two low-resolution overhead images. Engineering and design of installing complex battery equipment will entail understanding the existing roads, geology, electrical configuration, and other technical details at the site – all of which were not provided. We are doubtful that this request for proposals will prompt a strong response from battery storage developers in the manner that Ms. Sommer recommended, to best inform NIPSCO's investigation of how best to utilize the excess injection rights at the Schafer site. We ~~also~~ agree with Ms. Sommer and Mr. Stanley that~~, while~~ batteries can offer an important alternative technology to meet peak load~~, as NIPSCO witness Stanley observed, they are typically smaller in size, closer to 45 – 75 MW, while the CT Project will be able to provide 402 MW of energy when MISO calls for it~~.

NIPSCO's failure to develop a plan for fully utilizing the entire interconnection rights associated with the retiring Schahfer Units 16A, 16B, 17, and 18 (CAC Ex. 1 at 26) has the potential to significantly increase cost if NIPSCO loses the remaining partial rights and must look elsewhere to fill the looming capacity gap that both witness Sommer and witness Augustine identified. NIPSCO is hereby put on notice that in future IRPs or CPCN applications, the Commission will expect to see that NIPSCO has robustly considered options (including through RFPs that offer adequate disclosure to developers) to fully replace the Schahfer interconnection rights. The Commission further directs NIPSCO to file by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so.

While we have indicated in previous CPCN cases that least-cost planning is an essential component of our CPCN law, we have also recognized that least-cost planning does not require selection of the absolute lowest cost alternative. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No. 44339, at 20 (May 14, 2014) (quoting *Southern Indiana Gas & Elec. Co.*, Cause No. 38738, at 5 (Oct. 25, 1989)). We have defined least-cost planning as a planning approach that will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels

[17] https://www.nipsco-rfp.com/.

are determined. We also consider the risk created by future uncertainty. Ind. Code ch. 8-1-8.5 does not require a utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment on how best to meet its obligation to serve. If a utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting options to implement which minimize the cost of providing such services. *Id.*

~~As noted above, while various parties' raised concerns with~~ Having said that, we note that NIPSCO's ~~evaluation process of its~~ preferred configuration for the CT Project~~, no party proposed an alternative~~ is both poorly supported – based on a vaguely defined scoring rubric that pointed to that configuration~~.[18] We do not believe the parties' criticisms merit~~ – and vastly more expensive than previously modeled in NIPSCO's 2021 IRP, While NIPSCO warns that denial of the requested CPCN would risk delay in building needed replacement resources, we note that NIPSCO's 12-month delay of the requested in-service date for its replacement resource at the Schahfer site offers the Commission and NIPSCO some flexibility in conducting further study ~~or redoing~~to develop the ~~work already~~concepts first performed as part of the 2021 IRP process~~ and 2023 portfolio analysis and risking delay in so doing. This is particularly true because none of the parties' testimony addresses the concerns raised by the NERC and MISO to encourage~~. Indeed, the Commission cannot use the fear of delay in resource development ~~of flexible, controllable resources, such~~ as ~~the proposed CT Project, to complement~~a reflexive reason to grant CPCN requests, lest the ~~transition to intermittent, renewable resources.~~General Assembly's grant of decisional authority to the Commission become an empty rubber stamp. In the event of a denial of the CPCN, NIPSCO would still need to secure ~~the~~replacement capacity ~~offered by the CT Project. In addition, other variables, such as the cost and availability of long lead time equipment, as described in Mr. Baacke's rebuttal testimony,~~proposed to be filled by the CT Project, but NIPSCO could ~~result in increased cost if~~take the ~~requested CPCN is denied.~~opportunity offered by its 2024 IRP process and contemporaneous RFPs to more robustly evaluate alternative options.

In light of the evidence of record, we find that NIPSCO has ~~exercised~~failed to exercise reasonable judgment in selecting an option that ~~both~~ minimizes the risks of future cost~~ uncertainty and will allow it to meet its obligation to provide reliable service to its customers~~.

(c) **Conclusion.** NIPSCO conducted an All-Source RFP and Schahfer RFP in 2022 to meet its capacity needs, and the RFP responses ~~enabled~~helped NIPSCO to consider a variety of alternatives, described above. However, the RFPs were unduly limited in their specifications, as discussed below in section 6.A.v, and furthermore, we are puzzled at how the results of the RFP translated to the request in this case for three aeroderivative gas turbines and one industrial frame turbine. NIPSCO did not adequately consider the potential for using excess interconnection rights at the Schahfer site for battery storage, nor the sizable potential for demand response capacity, as outlined by witness Sommer. CAC Ex. 1 at 25-27. Given the foregoing evidence, the Commission finds that Petitioner has not satisfied the requirement under Ind. Code § 8-1-8.5-4 that it consider

~~[18] On alternatives, NIPSCO's 2018 IRP concluded that converting its existing coal units to gas is not a viable option, as converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections while replacing both units would cost customers at least $540 million more. Moreover, Mr. Augustine confirmed that a refueled Unit 17 and 18 would not possess the fast-start/quick-ramping and reliability characteristics of a peaking facility that either the 2021 IRP or the 2023 portfolio analysis called for.~~

alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. ~~Ultimately, 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.~~

Therefore, based on the evidence of record, the Commission finds that Petitioner has not shown ~~a~~adequate need for the proposed CT Project~~ and~~, nor 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.

As we have previously explained, these are two different requirements. 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 that actual costs that are incurred are, to the extent commercially practicable, based on competitive procurement. *Northern Ind. Pub. Serv. Co.*, Cause 45194 (IURC 8/7/2019), at 56.

NIPSCO conducted multiple RFPs during 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 some actionable resource cost data that incorporated the latest policy, technology, and macroeconomic information. ~~The~~Ideally, the RFPs should have provided information related to the latest costs of storage resources and the viability of alternative ~~natural gas peaker~~dispatchable resource options. However, the 2022 All-Source RFP and Schahfer RFP were unduly restrictive in how they defined the location and technology type of resources allowed, as discussed further below.

The statute ~~does not require that the cost estimate be based on competitive bids~~ at ~~firm prices received from contractors, as Mr. Gorman complains. Mr. Gorman is confusing the two requirements in subsection~~ Ind. Code § 8-1-8.5-5(e)(1~~). Instead, the statute~~)(A) requires the estimate to be the result, to the extent commercially practicable, ~~a~~of competitively bid engineering, procurement or construction contracts. Petitioner conducted the EPC RFP bid event in 2022 and ~~leveraged~~purported to leverage the information gained through that process to develop its best estimate for the cost to construct the CT Project through a multi~~-~~-prime contracting strategy. However, according to NIPSCO witness Baacke, two bids from the EPC RFP were rejected as non-responsive to the performance criteria of the technical specifications, and a third bid was rejected as more expensive than a self-build option. Pet. Ex. 5 at 11; NIPSCO-CAC Ex. 4 at 17-18. The Commission was able to review the bids as part of NIPSCO-CAC Conf. Ex. 4-C (labeled as CAC 1-004 Highly Conf. Att. A) and was disappointed at the poor responses. As ~~such, we reject~~CAC witness James (who previously testified to the Commission about the construction of Duke's Edwardsport project) raised, NIPSCO had failed to furnish adequate information to potential EPC bidders to elicit a robust set of bids. CAC Ex. 2, Att. RJ-2, § 3.4. For example, NIPSCO issued the EPC RFP before its Engineering Study defining the scope of the project was finished. *Id.* Even if the Engineering Study *had* been available for EPC bidders, that study failed to include detailed scopes, heat & material balances, license packages, P&ID's and Electric Single-Line Diagrams issued for design, major equipment specifications, and a take-off-based estimate. *Id.* at § 2.10. The Commission was able to review the technical specifications given to bidders, which were provided as evidence under NIPSCO-CAC Conf. Ex. 4-C (labeled as CAC 1-004 Att. C), and found them wanting.

Additionally, as NIPSCO witness Mr. ~~Gorman's assertion.~~Warren stated, "currently, there is not significant interest by power industry EPC contractors for this size and type of project." Pet. Ex. 4-R at 7. Both Mr. Warren and CAC witness Sommer are in agreement that with the large number of large gas power projects under development across the country, many EPC contractors may be otherwise engaged. *Id.* at 7-8; CAC Ex. 1 at 9. While this market dynamic may be out of NIPSCO's ~~best estimate of construction reflects information received from~~ control, the Commission notes that NIPSCO did not take every effort to encourage EPC bidders. With this confluence of circumstances, it is difficult for us to label the EPC bidding process as competitive, as required by the statute. As to equipment bid events ~~for the CT original equipment manufacturer,~~, the Commission notes that only a single supplier is able to deliver generator step-up transformers~~,~~ by the needed date, and only a single supplier is able to deliver 345 kV breakers by the needed date. Pet. Ex. 5-S at 4. unit auxiliary transformers, and diesel generator. ~~*See* Baacke Attachment 5-R-A and Confidential Attachment 5-R-B.~~While not necessarily uncompetitive *per se* under the statute, multiple bid events with only one qualifying bidder do not enhance the competitive profile of the overall project bidding. Accordingly, we find that Ind. Code § 8-1-8.5-5(e)(1)(A) has not been satisfied ~~and~~: that the cost estimates of the proposed facility are not, 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. Pet. Ex. 5 at 13. He testified that under the planned construction and bid process, NIPSCO will have allowed 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. *Id.* at 14. ~~This satisfies Ind. Code § 8-1-8.5-5(e)(1)(B~~Even if this aspect of the proposed multi-prime approach satisfied the statutory requirements of Ind. Code § 8-1-8.5-5(e)(1)(B), it would not vindicate NIPSCO's overall failure to satisfy Section 8-1-8.5-5(e)(1).

Regarding Ind. Code § 8-1-8.5-5(e)(2), we ~~have found herein,~~find (as discussed in the Five Pillars section below), based on the evidence of record, that the proposed CT Project ~~is reliable~~may not meet the statutory standard of reliability. The record has also established that Petitioner engaged in an All-Source RFP process to inform its overall generation transition plan~~. Thus, we have considered~~, although that did not allow for use of existing interconnection rights and site control at NIPSCO's Schahfer site, while the contemporaneous "Schahfer RFP" (also called the EPC RFP) was discriminatory in that it purported to be for general dispatchable resources yet also established gas turbines as the technology of choice. NIPSCO-CAC Conf. Ex. 4-C; CAC Ex. 1 at 33.[19] Thus, in light of the issues of reliability and solicitation by NIPSCO of competitive bids to obtain purchase power capacity and energy from alternative suppliers, ~~and~~ we find that the requirements of Ind. Code § 8-1-8.5-5(e~~) are~~)(2) have not been satisfied.

vi. Conclusion on CPCN for CT Project. Ind. Code § 8-1-8.5-5(d) requires us to "consider and approve, in whole or in part, or disapprove a utility specific proposal . . . jointly with an application for a certificate under this chapter [but] solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity." Based upon the evidence of record, the Commission finds that NIPSCO has not met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity does not require construction of the CT Project. Without determining whether we would have legal authority to approve a different configuration of combustion turbines as suggested by witness Becker (succeeding Sears), we note that that a configuration with only industrial frame turbines would also fail to satisfy the statutory standards under Chapter 8.5, considering our grave concerns with NIPSCO's procurement practices and construction management plan. Therefore, we ~~grant~~deny NIPSCO's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

Additionally, we note our serious concern that NIPSCO's resource planning software vendor, Energy Exemplar (which offers the widely used Aurora modeling tool) refuses to make any edits to its standard license agreement, which features terms reading that the license may only be used for "reviewing or analyzing" a forecast already developed. In other words, an intervenor party in a CPCN proceeding like this one, or a stakeholder in an IRP process, may not license the Aurora software to develop its own modeling simulation. What's more, acquiring a full license to get around this barrier costs up to six figures. CAC Ex. 1 at 32. Mr. Augustine noted in rebuttal that Energy Exemplar attempted to offer clarifying concessions to CAC's consultant during the early months of this case, but Mr. Augustine did not report that Energy Exemplar agreed to change its license terms. Pet. Ex. 7-R at 31-32. The Commission wishes to encourage fulsome, good-faith exploration around important and costly resource action decisions in Indiana, and discourages utilities from blocking participants who wish in good faith to model alternative resource portfolios under appropriate confidentiality

[19] NIPSCO's All-Source RFP and Schahfer RFP (also called EPC RFP) from 2022 can be found at Pub. Ex. 2, Att. JWH-1; and the same may be found at https://www.nipsco-rfp.com/Portals/0/Documents/RFPDocuments/NIPSCO_2022_All-Source_Request_for_Proposal_FINAL.pdf.

provisions.

Finally, we reiterate our directives above, pursuant to our authority under I.C. §§ 8-1-2-68 and -69, that (i) NIPSCO file, by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so; and (ii) NIPSCO make a filing by the end of 2024 to add additional, cost-effective demand response resources to its portfolio.

B. Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a).

Having determined to deny the requested CPCN, the issue of ongoing review of the CT Project is moot.

[*Citizens Action Coalition of Indiana above proposes that the Commission deny the request for a Certificate of Public Convenience and Necessity. However, in the alternative that the Commission determines to grant the requested CPCN, CAC offers the proposed language below regarding ongoing review*.]

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 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 that Mr. Krieger's recommended quarterly reporting requirements go beyond the yearly reporting required by the statute. She stated that 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. Pet. Ex. 10-R at 26-27.~~ We find Ms. Becker's proposal reporting acceptable given that it is more than contemplated by the statute; however, these reports should be submitted independent of any GCT (construction work in progress) rate-related filings. The Commission has already above noted grave concerns with NIPSCO's intended approach to managing the construction process for the proposed CT Project. To protect ratepayers and ensure the integrity of the final generating units, the Commission takes seriously its responsibility to exercise oversight over construction and intends to engage a construction monitor with expertise in power projects.

In the proceeding authorizing Duke Energy Indiana's construction of the Edwardsport Integrated Gasification Combined Cycle plant, the Commission required Duke Energy Indiana to contract with and pay the reviewing consultant, which had been requested by Duke, that ultimately reported to the Commission under I.C. § 8-1-8.7-7. Cause No. 43114 IGCC 1, Docket Entry dated June 3, 2008. While Chapter 8.7 is not implicated in this proceeding, Section 8-1-8.7-7, which creates a structure for CPCN approval for a "clean coal technology system," has nearly identical language in subsection (b) to the ongoing review provisions of Chapter 8.5, Section 5(b) of the Code. The Commission concludes that Chapter 5 gives the Commission flexibility to direct a utility to retain and pay a consultant for ongoing review just as in the Edwardsport proceeding. The Commission finds it useful to quote its pertinent directives in the Edwardsport docket entry:

> In order to facilitate the Commission's continuing oversight of the Edwardsport Project that falls outside the parameters IGCC Rider proceedings, the Presiding Officer's find that Duke Energy Indiana shall retain the services of Black & Veatch Corporation ("Commission Contractor" or "Black & Veatch") a professional engineering firm that has been selected by the Commission to oversee the Edwardsport Project at the direction of the Commission. While it will be Duke Energy Indiana's obligation to enter into a contract and pay all fees associated with the responsibilities undertaken by the Commission Contractor, the Commission Contractor will act independently of Duke Energy Indiana and report directly to the Commission.
>
> In order for Black & Veatch to effectively undertake its oversight role on behalf of the Commission, the Petitioner must ensure that it has the ability to undertake construction surveillance and A&E Services as may be necessary to fully report to the Commission. Therefore, Duke Energy Indiana must ensure that the Commission Contractor has the ability to enter into confidentiality agreements with various parties involved in the design and construction of the project; attend project construction management meetings as necessary; and generally review pertinent information with respect to the Edwardsport Project.

For this matter involving NIPSCO, the Commission will select a qualified consultant to provide construction oversight at a time in the near future and will issue a docket entry when that consultant has been identified. The Commission hereby directs that, as in the Edwardsport matter, NIPSCO enter into a contract with the identified consultant based on terms that the Commission will publish in the future docket entry. As the Commission will detail in the future docket entry, the selected consultant must have similar responsibilities to those of the Edwardsport construction monitor as described in the second excerpted paragraph above.

We find that NIPSCO shall report to the construction monitor and 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, achievement of construction milestones, and the best estimate of costs, as well as the: (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~~filings stylized as 45947 ~~GCT~~CT-XX. 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.

We caution NIPSCO that costs to serve customers in order to accommodate a delay in the proposed online date of the CT Project stand a nontrivial chance of disallowance including but not limited to capacity and energy costs. As part of the ongoing review under Section 8-1-8.5-6(a), we will examine the financial impact of any delay and whether any delay in the scheduled in-service date (and incremental capital costs associated with that delay) evince imprudence by NIPSCO. *See CAC v. Duke Energy Indiana, Inc.*, 16 N.E.3d 449, 458 (Ind. Ct. App. 2014) (utility not entitled to recover financing charges incurred during a three-month delay and remanding to the Commission for findings as to whether the delay was chargeable to the utility, and if so, what impact that delay had on customers' rates). Capacity and energy costs incurred to procure replacement power during the pendency of the delay could be determined to be imprudent in separate rate-related proceedings, consistent with the Commission's obligation to ensure just and reasonable rates as well as reliability and affordability under I.C. § 8-1-2-0.6. We will also consider disallowance as imprudent in future rate-related cases of any costs incurred after the commercial online date related to bringing the Project to its modeled forced and planned outage rates, which Ms. Sommer provided confidentially based on NIPSCO's modeling information.

Commented [CAC6]: ***Comment for the Commission regarding confidential information***:
[redacted]

C. Clean Energy Project and Financial Incentives Under Ind. Code § 8-1-8.8-11.

Having determined to deny the requested CPCN, the issue of cost recovery or other financial incentives for the CT Project is moot. To be completely clear, the Commission is hereby denying any cost recovery related to development of the CT Project.

[***Citizens Action Coalition of Indiana above proposes denial of the CPCN and of cost recovery related to the CT Project. However, in the alternative that the Commission determines to grant the requested CPCN, CAC offers the language below regarding ratemaking treatment***.]

In addition to the CPCN under Ind. Code §8-1-8.5-5, 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 (among other options) "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~~A 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."

As discussed above, NIPSCO witness Walter testified that the CT Project will displace electricity generated from the coal-fired generating plants at Schahfer ~~Unites~~Units 17 and 18 (when they retire at the end of 2025) and Michigan City Unit 12 (when it retires by the end of 2028). ~~Pet. Ex.~~ Pet. Ex. 2 at 15. But as also discussed above, CAC witness Mr. Inskeep asserted that Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project" (CAC Ex. 3 at 8) – two years before the CT Project is proposed to come online – and that NIPSCO did not demonstrate the CT Project will displace electricity generated from the coal-fired Schahfer Units 17 and 18 and Michigan City Unit 12. NIPSCO states that it plans to use its several new solar and wind generating units (including both owned and contracted projects) coming online over the next few years for baseload power to replace the lost generation from Schahfer – and, as Mr. Inskeep observed, NIPSCO has staged the timing of the Schahfer coal retirements based on when new solar and storage units will be available. Moreover, the CT Project is expected to provide peaking capacity and run at less than 20% annual capacity factors across the future time horizon, according to NIPSCO's witness Mr. Walter. Notably, NIPSCO is also planning to retire its Schahfer 16A/B gas peaking units, totaling 155 MW in the near future, according to Mr. Walter, but is staging those retirements in connection with the proposed CT Project. Mr. Walter's initial testimony in this case proposed to retire Schahfer 16A/B at the end of 2026 (the initially named online date for the CT Project) but then – after the CT Project had to be delayed by one year – Mr. Walter pivoted in supplemental testimony to characterizing the Schahfer 16A/B retirement goal as "until the CT Project reaches commercial operation." The CT Project is a peaker that will simply provide a different function for NIPSCO's load needs than do Schahfer or Michigan City 12, which is slated to retire by late 2028. ~~2 at 15.~~

~~CAC witness Mr. Inskeep asserted that Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project." (Inskeep at 8) and~~We note that NIPSCO ~~did not demonstrate the CT Project will displace electricity generated from the coal-fired Schahfer Units 17 and 18 and Michigan City Unit 12. We disagree. NIPSCO~~ witness Stanley's rebuttal testimony ~~clearly~~ states that NIPSCO will be using the injection rights from the retiring Schahfer coal units for purposes of MISO interconnection~~.~~ for the CT Project (Pet. Ex. 6-R at 5-6~~. We further observe that the 2021 IRP's Short Term Action Plan plainly shows that~~). However, that does not mean the function of the new CT Project within 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 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. Pet. Ex. 9-R at 8.~~portfolio

~~CAC~~ is ~~an active participant in Indiana investor owner utility IRP processes, and~~the same as ~~part~~that of ~~NIPSCO's IRP process and through~~ the ~~various CPCN and CPCN modification proceedings NIPSCO has filed in the last three years in effect, CAC has had access to this public information and withheld challenge until this case.[20] Some displacement~~retiring Schahfer or Michigan City coal units.

Displacement of retiring coal-fired energy generation with ~~a gas peaking resource~~clean energy resources and upgrades at Sugar Creek has been a transparent component of NIPSCO's IRP modeling and related CPCN regulatory filings since 2021~~.~~, while the same modeling calls for new gas peaking capacity to replace the Schahfer gas peakers.[21] As such, we find the CT Project is not being

~~[20] June 5, 2019 Order in Cause No. 45195 (Jordan Creek PPA); September 1, 2021 Order in Cause No. 45541 (Indiana Crossroads Wind II PPA); May 5, 2021 Order in Cause No. 45472 (Green River Solar PPA); September 13, 2023 Order in Cause No. 45887 (Appleseed Solar and Templeton Wind Energy Center; October 18, 2023 Order in Cause No. 45908 (Carpenter Wind); August 7, 2019 Order in Cause No. 45194 (Rosewater Wind); February 19, 2020 Order in Cause No. 45310, as modified in March 29, 2021 Order in Cause No. 45463 (Indiana Crossroads Wind); July 28, 2021 Order in Cause No. 45524 (Indiana Crossroads Solar); May 5, 2021 Order in Cause No. 45462 (Dunn's Bridge Solar), and Cavalry Solar and Dunn's Bridge II Solar (as modified in January 17, 2024 Order in Cause No. 45936) January 17, 2024 Order in Cause No. 45511 (Fairbanks Solar); and November 22, 2023 Order in Cause No. 45926 (Gibson Solar).~~

[21] NIPSCO 2021 Integrated Resource Plan, Summary, at 13 ("To replace the retiring resources, NIPSCO has identified a preferred pathway that balances all of NIPSCO's major planning objectives, while preserving flexibility in an environment

constructed to displace energy from an existing coal-fired generation facility as required in Ind. Code § 8-1-37-4(a)(21) and is therefore not eligible for the relief provided in Ind. Code § 8-1-8.8-11.

i. The Clean Energy Project is Just and Reasonable. 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 include the application of 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) The Cost of the CT Project. ~~The~~As discussed above, the evidence in this Cause supports a finding that the ~~energy to be generated by the~~ CT Project is ~~reasonably~~excessively priced compared to other alternatives ~~and provides material benefits. We have already found~~ , particularly due to the ~~best estimate~~inclusion of ~~the costs is \$100 million below the price for an EPC contract for a comparable facility and that the cost is consistent with the costs assumed in the 2023 Portfolio Analysis.~~aeroderivative units.

(b) Consistency of the CT Project to NIPSCO's IRP. As we noted above, the CT Project is not consistent with NIPSCO's 2021 IRP ~~(as updated in~~, nor does the 2023 ~~portfolio analysis).~~Portfolio Analysis form an adequate basis to update the conclusions of the 2021 IRP.

(c) The Need for the CT Project. As ~~noted~~discussed above, ~~the CT Project fills the~~NIPSCO will have a significant capacity need in coming years, including a need for fast-start, quick-ramping ~~generation~~resources that will complement NIPSCO's overall generation transition and follow the load. This evidence reinforces our prior finding in CEI South's Cause No. 45564 that MISO, NIPSCO's grid operator, has "indicated a system-wide need for controllable resources … to ensure system reliability as more intermittent resources are added to the system." ~~The CT Project is necessary to assure reliability, resiliency, and stability of NIPSCO's supply of electricity.~~

(d) The Competitive Solicitation of the CT Project. We have previously found ~~and reiterate~~ that NIPSCO's procurement of the CT Project has been and will continue to be through competitive solicitation. However, we reiterate our concern that NIPSCO's competitive solicitation for both the turbine components and the EPC role failed to provide adequate information to potential bidders to kindle a healthy competition.

Based on the foregoing, we find the CT Project ~~is~~ cannot qualify as a clean energy project under Ind. Code § 8-1-8.8-11 ~~and is~~ ; we thus find it unnecessary to determine for purposes of Section 8-1-8.8-11 whether the CT Project is just and reasonable. ~~The record shows that the addition of the~~

of market, technology, and policy uncertainty. In the near-term, replacement options include a diverse, flexible, and scalable mix of incremental resources, including DSM resources, distributed energy resources, solar, stand-alone energy storage, and upgrades to existing facilities at the Sugar Creek Generating Station. The plan also calls for a natural gas peaking unit to replace existing vintage gas peaking units at Schahfer and support system reliability and resiliency, as well as upgrades to the transmission system to enhance the electric generation transition.").

~~CT Project to NIPSCO's resource mix will provide needed energy and capacity. We also find that 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 not a clean energy project and ~~is~~not eligible for the financial incentives pursuant to Ind. Code § 8-1-8.8-11 ("Section 11"), ~~we turn now to~~it is unnecessary for us to further examine NIPSCO's proposal to recover its costs during construction through a semi-annual forecasted capital tracker (the "GCT Mechanism") until such time as the project is included in base rates subsequent to being placed in service. ~~Petitioner's witness 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~~However, we will offer additional analysis of the GCT Mechanism to offer guidance 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. Pet. Ex. 8 at 15-16; Pet. Ex. 8-S at 6.~~

~~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 that NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective WACC. Pet. Ex. 8 at 16. 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. Pet. Ex. 8 at 17.~~

~~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. Additionally, 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. Pet. Ex. 8 at 17. Attachment 8-B to Mr. Blissmer's testimony is an exemplar for the GCT Tracker schedule. He also 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 Tracker filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. Pet. Ex. 8 at 19; Pet. Ex. 8-S at 6. As an additional financial incentive under Section 11, NIPSCO~~

~~requests that the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the IC 8-1-2-42(d) earnings test. Pet. Ex. 8 at 18.~~

~~Mr. Blissmer explained how this proposed GCT Mechanism is authorized by new legislation. He testified that 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 that 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 that 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, as shown in his Attachment 8-S-A. He explained that 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.[22] 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 PISCC under the traditional model. He explained that 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. Pet. Ex. 8 at 8-12; Pet. Ex. 8-S at 3-4.~~

~~Mr. Blissmer concluded that 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~~

~~[22] As set forth in the Verified Petition in this Cause, NIPSCO seeks relief in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT Mechanism or in a general rate case, all as described in the Verified Petition. The request for alternative relief would trigger in the event the proposed GCT is not approved as proposed, which could be either the denial of the GCT or rejection of the forward looking nature of the GCT. Either of these changes to NIPSCO's proposal would result in PISCC and the commencement of depreciation before rate recovery has commenced.~~

~~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. Pet. Ex. 8-S, pp. 3-4 and 6.~~

~~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. Also, NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained that 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 that CWIP ratemaking improves near term cash flow and mitigates the negative effects of the significant additional debt taken on to construct the project. Pet. Ex. 8 at 12-14.~~

~~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."[23] 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. Pet. Ex. 8 at 13.~~

~~Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on a number of different factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates that 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. Pet. Ex. 8-S at 8.~~

~~OUCC witness Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. Pub. Ex. 5 at 4 She contended that NIPSCO should instead use project-specific financing costs or the cost of short-term debt.~~

~~IG witness Gorman testified that simply because there are gross financial savings this does not mean that the CWIP tracker is just and reasonable. IG. Ex. 1 at 15. Both IG witness Gorman and CAC witness Inskeep claimed that the analysis of gross financing savings is inconsistent with the Statute in that it does not include net present value analysis. IG Ex. 1 at 16; CAC Ex. 3 at 7, 24. They both claimed that simply because there may be financing cost savings does not mean that the proposal is just and reasonable. Finally, Mr. Inskeep objected to the forward looking version of the GCT Tracker, alleging it was inconsistent with the verb tense of the statute and also 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. Pet. Ex. 8-R at 3. 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. See Attachment 8-R-A (forward-looking) and Attachment 8-R-B~~

~~[23] *See, e.g., Tucson Elec. Power Co.*, 174 FERC ¶ 61,223 at P 25 (2021) (stating that allowing transmission developers "to include 100% CWIP in rate base would result in greater rate stability for customers by reducing 'rate shock' when certain large-scale transmission projects come on line.") (citing 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 12 (2012) (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229 (2011)); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 43, *reh'g denied*, 124 FERC ¶ 61,229 (2008))).~~

~~(backward-looking). He testified that (1) as shown in 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 my 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 that 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. Pet. Ex. 8-R at 3-4. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Tracker. Pet. Ex. 8-R at 9-12. Mr. Inskeep claimed that 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. *Id.* at 12.~~

~~Having found that the CT Project is "clean energy project" under Ind. Code § 8-1-8.8-2(5) and also having found that 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 that we approve its proposed GCT Mechanism, which~~utilities in future proceedings.

NIPSCO's proposed GCT Mechanism would provide for construction work in progress ratemaking as allowed by Ind. Code § 8-1-8.8-11(a)(1). Subsection 11(a)(1) allows that we may provide for "[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 that 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."

We will take these two findings in reverse order and begin with the determination of gross financing cost savings. Mr. Blissmer presented the calculation of his gross financing savings in his direct and supplemental direct testimony. Using the forward looking GCT, Mr. Blissmer calculated the gross financing savings in direct testimony at $81,986,410 over the life of the CT Project. Pet. Ex. 8-S at 4. Using the more traditional backward looking GCT tracker, there would be reduced savings of $48,019,573. Pet. Ex. 8-S at 6. In rebuttal, Mr. Blissmer changed the financing cost rate to the AFUDC rate rather than the WACC in response to OUCC witness 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. Pet. Ex. 8-R at 3.

IG witness Gorman and CAC witness Inskeep objected to Mr. Blissmer's calculations on the grounds that they were not done on a present value basis~~. However,~~; their calculations showed that it is *traditional* ratemaking that would be less expensive on a present value basis. It is true that the statute, by its terms, does not expressly require the calculation to be done based upon net present value. By its terms, the statute requires the demonstration of "gross financing cost savings over the life of the project." ~~The~~Mr. Blissmer claimed that calculating a present value of cost savings cannot be reconciled with the term "gross" in the statute (Pet. Ex. 8-R at 9). To resolve this legal dispute, we must be mindful that 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~~ 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 Blissmer, both~~; in cases of ambiguity, the ~~forward looking and backward looking versions of~~Commission has several interpretive tools, starting with consulting a dictionary. *Rainbow Realty Group, Inc. v. Carter*, 131 N.E.3d 168, 174 (Ind. 2019) ("when a statutory term is undefined, the ~~proposed GCT Mechanism will generate~~legislature directs us to interpret the term using its plain, or ordinary and usual, sense. … We generally avoid legal or other specialized dictionaries for such purposes and turn instead to general-language dictionaries" (internal citation omitted)). Merriam-Webster defines "gross" as "consisting of an overall total exclusive of deductions." The Commission thus interprets "gross financing ~~cost~~costs savings~~"~~ over the life of the ~~CT Project~~project" to mean adding up all annual savings without subtracting any other factors from the calculation. There is no reason why this calculation cannot make appropriate discounting based on the time value of money, and the Commission finds that such discounting is appropriate to better capture the savings experienced by customers who fund revenue requirement. Furthermore, were the Commission to *not* discount the future annual savings to present value, the "gross savings" calculation would always find that CWIP financing results in savings compared to traditional ratemaking, as CAC witness Inskeep noted without refutation. A test that cannot be failed violates the interpretive canon requiring us to avoid construing legislative text as mere surplusage, devoid of meaning. *See, e.g.*, *Loughrin v. United States*, 573 U.S. 351, 358 (2014) ("the 'cardinal principle' of interpretation [is] that courts 'must give effect, if possible, to every clause and word of a statute.'"); *Witzke v. Female*, 376 F.3d 744, 753 (7th Cir. 2004) ("We must read a statute to give effect to each word so as to avoid rendering any words meaningless, redundant, or superfluous."). As gross financing costs savings is another statutory requirement under section 8-1-8.8-11(a)(1)(B) and the GCT proposal does not clear this bar (as demonstrated by witnesses Inskeep and Gorman), the Commission has another independent reason to deny the GCT request. The Commission believes that the calculations advanced by Mr. Gorman and Mr. Inskeep represent a better application of the statutory "gross financing costs savings" concept than do Mr. Blissmer's calculations.

We are ~~likewise unpersuaded~~also persuaded by Messrs. Gorman and Inskeep's assertion that NIPSCO did not demonstrate the proposed GCT is just and reasonable~~, particularly because neither witness responded substantively to Mr. Blissmer's direct testimony describing~~. Conclusory statements that CWIP ratemaking can "benefit … financial health" and "provide … cash flow during a potentially lengthy construction period," as Mr. Blissmer stated (Pet. Ex. 8 at 13), are not enough to justify the requested relief. NIPSCO provided no evidence as to its specific capital needs as a company, nor any illustration of its recent financial experience developing various renewable power plants. Next, we will address Mr. Blissmer's direct testimony alleging how, through the avoidance of so-called "rate shock" when a large construction project is reflected in rates in a single step, the GCT benefits customers. ~~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 Commission takes this concern seriously but notes that in NIPSCO's particular case, it is planning to retire certain coal and gas-fired generating units around the time it puts the proposed CT Project into service, allowing the removal of, at a minimum, the fuel and operating expenses of the retiring units from customer rates.~~ Pet. Ex. 8-R at 11-12.~~

The General Assembly has specifically directed that affordability is one of the attributes to be considered in the context of generation transition. Ind. ~~IC~~Code § 8-1-2-0.6. 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~~ ; however, we must evaluate whether the ~~benefits of lower rates and smaller rate increases. We cannot simply ignore the benefits a CWIP tracker~~ use of CWIP ratemaking will ~~contribute to affordability by lowering rates and smoothing and mitigating rate increases during generation transition. NIPSCO's~~ in fact reduce customers' rate burden. NIPSCO offered testimony (citing a credit rating agency's comments from July 2008, prior to multiple upheaval cycles in financial markets) on the ~~overall~~generic benefits of CWIP ratemaking on utilities' credit quality, ~~which ultimately informs the carrying charge applied~~but offered no specific information on how CWIP ratemaking might be expected now to reduce NIPSCO's ~~investment and, therefore, customer rates, was effectively unrebutted.~~cost of debt or equity. 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~~, and while these are not objections to whether this particular proposal meets the requirements of the statute, ~~and they ignore the fact that the legislative decision has already been made~~we are mindful of our responsibility to enforce the threshold tests set out by our legislature to allow CWIP ratemaking. ~~We~~In light of the discussion above, we find that, under Section 11, both the forward and backward looking versions of NIPSCO's proposed GCT Mechanism are not just and reasonable.

~~We now move to~~For completeness, we will evaluate the ~~question of which method we should approve~~two CWIP cost recovery methods proposed by NIPSCO: 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. Pet. Ex. 8-R at 7-8.[24] 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~~.~~." Pet. Ex. 8 at 12. 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 very limited AFUDC that has already been accrued and expected to be accrued until rates take effect in March 2025 under the GCT ~~Tracker.~~Mechanism." Pet. Ex. 8-S at 5. In addition, there would be no depreciation to defer. Pet. Ex. 8~~-S~~ at ~~5, 7~~16. 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 of CAC had two objections to the forward looking version of the GCT. First, he claimed that the statute uses past tense ("incurred") and that this ~~somehow~~ 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~~ Having decided that CWIP

[24] If we were to approve the backward looking version of the GCT, we would need to address NIPSCO's request in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT or in a general rate case. Pet. Ex. 8, p. 9, n. 1.

financing is not applicable, the Commission is not required to address Mr. Inskeep's argument about forecasted costs, but wishes to pause here to caution NIPSCO and any other electric utility that the plain language of Section 8-1-8.8-11 contemplates "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~~no provision for forecasting costs in advance. While a seemingly trivial or tautological point, it is nonetheless of real moment in ratemaking to note that until costs ~~and expense that~~ are actually ~~"~~incurred~~," and this recovery begins during the same six month period during which those~~, no 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 tracker 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,~~ While Section 11's neighbor in the ~~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~~, Section 12, contains specific authorization for the use of forecasted data for retail charges plus a reconciliation mechanism for actual costs, Section 11 has no such authorization. The interpretive canon against surplusage counsels us to take this distinction seriously: 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." IC 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 that NIPSCO's proposed forward-looking GCT Mechanism using the AFUDC rate as reflected on rebuttal should be approved~~may not use forecasted costs under the CWIP rider mechanism. *See, e.g.*, *Loughrin v. United States*, 573 U.S. at 358. .[25]

~~We further approve~~Having determined that the CT Project is not eligible for CWIP financing under Section 8-1-8.8-11, we next turn to NIPSCO's alternative request for approval to accrue [as a regulatory asset] post-in service carrying costs and to "defer [as a regulatory asset] the accrual of depreciation and amortization expense on the CT Project from its in-service date until the implementation of rates including recovery of a return thereon and including recovery of depreciation and amortization expense thereon in Petitioner's recoverable operating expenses." Pet. at 17. The Commission returns to Ind. Code. § 8-1-8.8-11, which is the authority NIPSCO cites for its request. Section 11 allows the Commission to grant "[o]ther financial incentives the [C]ommission considers appropriate" to clean energy projects. However, as discussed above, the CT Project does not qualify as a clean energy project within the meaning of Chapter 8.8 as the supposed authority for this request. Even if the CT Project qualified as a "clean energy project," the Commission is left with no basis to decide if the requested alternative financing mechanism is "appropriate" as contemplated in Section 11, other than a single footnote in Mr. Blissmer's direct testimony (Pet. Ex. 8 at 9) cursorily recounting the requested relief. The alternative financing relief is denied.

Finally, we fail to see evidence in the record establishing why Petitioner's request that the operating income associated with the CT Project through the GCT Mechanism be included in the total

[25] As a result of our ~~approval of~~ determination that the ~~forward-looking GCT as proposed~~CT Project cannot qualify for any CWIP financing, NIPSCO's GCT Mechanism request in the alternative (namely, for use of backward-looking actual costs for rider recovery) is moot.

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 as such~~ is an appropriate additional financial incentive under Section 11. Mr. Blissmer stated that such treatment is consistent with the treatment of earnings associated with Rider 588 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Rider 587 – Adjustment of Charges for Federally Mandated Costs, but did not explain how this treatment would be appropriate for the new GCT Mechanism. Although this issue is moot because we have above denied the proposed GCT Mechanism, we emphasize that petitioners must establish the required prima facie elements of a statutory test in order to obtain the requested relief.

D. Five Pillars Under Ind. Code § 8-1-2-0.6. 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. Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service: as reliability, affordability, resiliency, stability, and environmental sustainability, (collectively, the "Five Pillars"). NIPSCO witness Becker's Attachment 1-C identifies the seven different NIPSCO witnesses who sponsored testimony supporting each of the Pillars.

While the specific construct of Indiana's Five Pillars is relatively new, these attributes have been long-standing aspects of our statutorily driven process for deliberating on requests to construct new electric generation in the State. For instance, in determining whether to issue a CPCN, we are required to consider alternative means of providing "reliable, efficient and economical electric service." Ind. Code § 8-1-8.5-4(b)(2). Consistency with integrated resource planning has long played a role in our analysis (Ind. Code § 8-1-8.5-5(b)(2)), and integrated resource planning includes analysis of "how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty." 170 IAC 4-7-8(c)(7). Indeed, NIPSCO's 2021 IRP integrated scorecard approach included objectives associated with "Reliable, Flexible, and Resilient Supply," "Rate Stability," "Affordability," and "Environmental Sustainability." Therefore, while the particular analytical framework under Ind. Code § 8-1-2-0.6 may be a recent addition to our regulatory considerations, we note that the Five Pillars themselves are bedrock principles long applied to the complex issues at play when examining a proposal to construct new generation in the State. NIPSCO's CT CPCN is no different. We have discussed, throughout this Order to this point, how our findings are guided by and ultimately support the Five Pillars.

Having concluded that NIPSCO has ~~satisfied~~failed to satisfy the statutory elements and interrelated findings we are required to make under Sections 8.5 and 8.8 in approving a CPCN for new generation and a just and reasonable clean energy project respectively, we will nonetheless additionally review each of the Five Pillars below and address the statutory elements and policy considerations related thereto. 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.

i. Reliability. 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), pp. 18-19. NIPSCO witness Austin's testimony informs us that this need is increasing even since our findings in Cause No. 45564. Record evidence supports findings that ~~the proposed CT Project addresses~~a fast-start resource could, at a generic level, address needs identified by key stakeholders, including MISO, NERC, the MISO IMM, and others, and ~~addresses~~address 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. Pet. Ex. 3 at 11, 17-19. Mr. Austin cited numerous publications from NERC, MISO, and MISO's IMM discussing the need to install fast-starting, quick ramping ~~generation~~resources to support the growing portfolio of renewable resources and maintain reliable service. Pet. Ex. 3 at 8-11, 17 citing Electric Reliability Organization ("ERO") Priorities Report 2023, NERC 2021 Long-Term Reliability Assessment (December 2021), NERC 2022 Long-Term Reliability Assessment (December 2022), MISO's Response to the Reliability Imperative dated January 2023, and IMM 2022 State of the Market Report for the Miso Electricity Markets (June 15, 2023). NERC even 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 ERO Priorities Report. Pet. Ex. 3 at 8-10. Mr. Austin, quoting from the ERO Priorities report explained: "[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." *Id*. at 10. The 2022 Long-Term Reliability Assessment issued December 2022 (pp. 17-18) 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.

Pet. Ex. 3 at 11. ~~This is precisely why NIPSCO is proposing the addition of the CT Project.~~

~~Further,~~ NIPSCO witness Austin ~~explained~~asserted that the proposed CT Project will help meet MISO's Resource Adequacy Requirements. Pet. Ex. 3 at 12-16. The 2023 OMS-MISO Survey Results (published July 14, 2023) reflect that delayed retirements and capacity additions have resulted in a capacity surplus of 1,500 MW for the 2024/25 planning year. However, 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. *Id*. at 15. This demonstrates a growing need for dispatchable resources to support system reliability within the MISO region, including Indiana.

NIPSCO witness Austin ~~also explained why~~argued that batteries, inverter based resources ("IBRs"), and energy storage resources ("ESR") do not meet system reliability needs. *Id.* 19-23.

NERC and MISO's IMM reach similar conclusions, as the NERC highlights in its 2022 Long-Term Reliability Assessment (Executive Summary, p. 7) 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.

Id. at 20. ~~The IMM, in its 2022 State of the Market Report for the MISO Electricity Markets, concurs (p. 22), stating that:~~As NIPSCO, like many utilities in Indiana and around the country, is planning to transition to a portfolio mostly composed of wind, solar, and storage resources, the Commission trusts that NIPSCO, working with MISO, will be able to manage and mitigate any risks in the transmission and distribution grids resulting from the use of inverter-based resources.

> ~~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.~~

~~*Id.*~~

NIPSCO witness Stanley also 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.

Pet. Ex. 6 at 17 (citing the MTEP Report).[26] The Executive Summary in this Report goes on to outline different attributes or characteristics provided by different generation resource types and reflects that gas resources ~~have a significant~~are at the same relative advantage ~~over renewable~~as are battery resources, compared to other resource types, in providing: (1) ~~long duration energy at high output~~fuel assurance; (2) ~~voltage stability; (3)~~ ramp up capability; ~~(4~~and (3) rapid start-up~~; and (5) blackstart capability. It is precisely these attributes~~. NIPSCO clarified in discovery that the ~~CT Project will offer to NIPSCO's~~Stanley testimony was not trying to contend that battery resources are inferior to gas generation ~~portfolio, for the benefit of all of its customers~~when it comes to ramp-up and rapid start-up capability. NIPSCO-CAC Ex. 5 at 5-6. As to voltage stability, gas resources are only marginally better equipped than battery storage resources, and batteries may improve in this dimension in the ~~broader MISO region.~~future as technology advances. Pet. Ex. 6 at 18. In addition, while still in

[26] MTEP Report Executive Summary at 4. This executive summary of this report is available at: https://cdn.misoenergy.org/MTEP22%20Executive%20Summary626707.pdf.

development and under review, NIPSCO witness Mr. Augustine cited ~~from (Direct~~(Pet. Ex. 7, p. 15) from MISO's Resource Adequacy Subcommittee ("RASC") 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. As to blackstart capability, the MISO chart cited by Mr. Stanley showed that gas resources more fully fulfill the needed attribute than do battery resources, but that battery resources' strength may increase in the future.

~~Furthermore,~~ NIPSCO conducted extensive diligence on the reliability of the potential resource portfolios in its 2021 IRP. The Non-Economic Reliability Assessment (2021 IRP, Confidential Appendix E) 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 ~~also~~, through its consultant Charles River Associates, 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~~. The Flexible Resource Analysis 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 2021 IRP's preferred portfolio of approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and 3-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~~.~~, although the Flexible Resource Analysis did not attempt to quantify the cost of relying on energy market purposes. Pet. Ex. 7, Conf. Att. 7-D at 9-10, 61. NIPSCO offered that its proposed CT Project in its preferred configuration is designed to fill this capacity gap ensuring that service on NIPSCO's entire system is reliable. NIPSCO's preferred configuration, including three aeroderivative combustion turbines and one frame turbine totaling around 400 MW, represented a departure from the judgment factors and rationales embodied in the 2021 IRP, which called for up to ***300*** MW of new gas peaking capacity and did not mention aeroderivative turbines. The change from the 2021 IRP was required to be fully explained and justified with supporting evidence, including an updated IRP analysis. 170 IAC 4-7-2.5(b). The Flexible Resource Analysis and Portfolio Analysis together did not satisfy the requirements of an Integrated Resource Plan as defined in our rules. Notably, the Flexible Resource Analysis failed to take account of resource costs (170 IAC 4-7-2(c)(2)(B)) or cost-benefit or cost-effectiveness analysis (170 IAC 4-7-4(5), (24)). It also did not undertake any capacity planning modeling (170 IAC 4-7-2(c)(2)(C)) or generation expansion planning criteria (170 IAC 4-7-4(22)) except to predict the market exposure effects of adding varying levels of "*any* flexible, dispatchable capacity." NIPSCO-CAC Ex. 6 at 31-32. Regarding the 2023 Portfolio Analysis, Mr. Augustine in rebuttal testimony confirmed Ms. Sommer's observation that the Portfolio Analysis did not include re-optimization of capacity expansion plans to determine a lowest cost portfolio. CAC Ex. 1 at 17; Pet. Ex. 7-R at 6. And as discussed above in section 6.A.ii, the Portfolio Analysis considered only a static, narrow set of portfolios based on unsupported assumptions. Thus, NIPSCO has violated the regulatory requirement that a utility's resource action must be consistent with its most recent IRP, unless differences are fully explained and justified with supporting evidence, including an updated IRP analysis. ~~Pet. Ex. 7, Conf. Att. 7-D at 9-10, 61. NIPSCO's CT Project in its preferred configuration is designed to fill this capacity gap ensuring that service on NIPSCO's entire system is~~

~~reliable.~~

Our review of the substantial evidence of record regarding the attributes of the aeroderivative turbines leads us to conclude that ~~their~~NIPSCO has not justified how aeroderivatives' operational characteristics are a ~~vital~~necessary part of ~~the CT Project's expected reliability~~NIPSCO's future resource portfolio, further buttressing our findings above that support ~~approval~~denial of NIPSCO's chosen configuration. It appears that NIPSCO and its consultant developed a "decision matrix" to score and rank different combustion turbine configurations, based on a pre-made set of weightings across 23 factors that was not explained in testimony, and based on scoring within each factor for each of the three configuration options. NIPSCO explained that the assignment of scores across factors was apparently not based on a specific mathematical rubric (although quantitative values within each factor were considered), but rather, was "completed during working sessions held between [S&L] and NIPSCO where the factors [] were discussed and evaluated and the overall score was collaboratively determined." Pet. Ex. 4 at 12; Pet. Conf. Ex. 4-A, Appx. 19; NIPSCO-CAC Conf. Ex. 4-C at 574-576. We are concerned that this crucial step in the process of choosing a turbine configuration was apparently done based on semi-arbitrary, nontransparent judgments that were "completely subjective" as CAC witness Ms. Sommer phrased it (CAC Ex. 1 at 12) NIPSCO admitted in discovery that, for example, it did not did not quantify the benefits or perform a cost-benefit analysis for the difference in starting time/ramp rate between the industrial frame and the aeroderivative (Pub. Ex. 3 at 7). What's more, the assignment of scores to the configuration options appears illogical in some places, calling into question the reliability of the entire scoring scheme.

Commented [CAC7]: ***Comment for the Commission regarding highly confidential information***:

[redacted]

NIPSCO witness Baacke ~~explained~~averred (Direct, p. 5) that 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~~Whether this is true or not, we are unable to conclude that ~~it is these~~the aeroderivative turbine's features ~~that will~~are necessary to 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 also note that 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. As simple as this fact may be, it illustrates the balancing and tension between and among the Five Pillars that naturally occurs as a utility invests to ensure the availability and delivery of reliable energy to its customers. The OUCC, NIPSCO IG, and CAC's 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 that the Pillars of reliability, resiliency, and stability should not supplant meaningful consideration of the customer affordability of NIPSCO's request. ~~In considering the affordability of a very recent utility rate request, we set forth that:~~Moreover, it is important for us to define a tractable standard for affordability so that we may recognize affordability (or the lack thereof) when we see it.

> ~~Affordability is always an important consideration for the Commission when establishing just and reasonable rates. Affordability is an ongoing concern for all consumers in the State of Indiana. However, our role in addressing this concern is not to reach a conclusion as to whether the rates approved herein are "affordable" for each and every customer, particularly given the difficulty in defining affordability in general and for the many diverse customers and communities Indiana American serves.~~

~~*Indiana American Water Co.*, Cause No. 45870 (IURC 2/14/2024), p. 105.~~

Although we are not approving exact customer rates as part of this proceeding, ~~we are authorizing~~ NIPSCO is seeking approval to construct a generation facility that will operate for many years and approving a recovery mechanism for costs associated with construction of the facility. ~~The approach we discussed in *Indiana American Water Co.* thus applies in many respects as we~~We evaluate the affordability of the generation CPCN request in the context of a large electric utility's generation transition, which stands to impact its customers in significant ways. ~~Because a utility has limited control over nearly all of the external factors that could impact its customers' ability to pay for utility service, the~~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~~The evidence here fails to supports that ~~its~~NIPSCO's proposal in this case does ~~just~~ 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. ~~From there, NIPSCO utilized a competitively bid EPC contract event and determined that a multi-prime contracting strategy could save $100 million over the only viable EPC bid it received. When NIPSCO determined supply chain constraints were so impactful that reaching the originally contemplated in-service date was no longer 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.~~However, as CAC witness Sommer pointed out, NIPSCO took a stark detour from its 2021 IRP, when crafting its proposal for this CPCN proceeding. NIPSCO's proposal with aeroderivative turbines amounts to a massive cost increase per megawatt of installed capacity compared to that in the 2021 IRP. The cost of nearly $1,600 per kW is the most expensive of any combustion project currently under development in the United States in the awareness of CAC witness Ms. Sommer. CAC Ex. 1 at 6. Comparing the cost estimate of NIPSCO's proposal to the market and to NIPSCO's prior estimate of what its portfolio needs, we cannot conclude that NIPSCO

Commented [CAC8]: ***Comment for the Commission regarding confidential information***: [redacted] has prioritized affordability.~~ Pet. Ex. 8-S at 4. 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.~~

~~NIPSCO witness Mr. Stanley testifies (p 26) that "[o]verall, NIPSCO is confident that, through its own resource planning efforts and its participation in the MISO market, it will be able to serve all its customers reliably and affordably during and upon completion of its generation transition." 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 discussing Reliability is applicable here. But resiliency also represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. For example, fast starting capabilities, including potential for blackstart capabilities, are the ability of the system to restore service when one or more areas of the bulk electric system shuts down for whatever reason. The fast start capabilities of the CT Project, especially given the configuration with aeroderivative units~~ are~~, could meet a key component of resiliency. NIPSCO witness Mr. Walter testified that 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 also offered extensive confidential testimony that directly addressed how the CT Project will support resiliency. On the other hand, the Commission notes that NIPSCO confidentially divulged certain challenges with the interstate supply and the on-site equipment at its existing Sugar Creek gas generating station during Winter Storm Elliott in December 2022, and when asked how it will mitigate these issues in future winter conditions, did not offer any new strategies beyond citing its gas distribution system's existing interstate pipeline connections and on-system storage facilities. NIPSCO-CAC Conf. Ex. 5-C at 3-4. Moreover, NIPSCO's Flexible Resource Analysis did not consider any seasonal variation in the performance of a hypothetical new flexible, dispatchable resource, even though the Engineering Study did explore performance variation for a new gas combustion turbine based on ambient temperature and humidity. NIPSCO-CAC Ex. 6 at 32; Pet. Ex. 4, Conf. Att. 4-A at 5-6. This raises serious concerns about how seriously NIPSCO is taking the statutory goal of 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 Augustine, the 2023 ~~portfolio analysis~~Portfolio Analysis incorporated market shifts and changes that have occurred since the 2021 IRP, including the MISO seasonal resource adequacy construct. We agree that these changes point to the increased need for capacity-advantaged resources in NIPSCO's generation portfolio, a need which ~~the CT Project directly fulfills.~~ both the CT Project and battery storage could directly fulfill. We note, further, that NIPSCO overestimated the future capacity accreditation of gas generation and underestimated the future capacity accreditation of battery storage, under MISO's new accreditation methodology currently pending before FERC in Docket No. ER24-1638. CAC Ex. 1 at 22-23.

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 transition portfolio transition since its 2018, 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. Pet. Ex. 3 at 21. As gas turbines can operate continuously for extended durations, the CT Project ~~clearly supports~~has the potential to support system stability. NIPSCO witness Mr. Stanley testified that gas resources have a significant advantage relative to inverter-based (*e.g.*, renewable) resources~~, as gas~~ (Pet. Ex. 6 at 18). However, if we focus on battery storage resources ~~can provide (1) long duration energy at high output; (2)~~in the MISO chart referenced by Mr. Stanley, it appears that gas and battery resources are on equal footing when it comes to ramp-up capability and rapid start-up, while gas is a small degree stronger than batteries when it comes to voltage stability~~; (3) ramp-up capability; (4) rapid start-up; and (5) blackstart capability. Pet. Ex. 6 at 18~~ (although MISO notes that batteries' strength in that attribute has the potential to improve). *Id.* 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. ~~Undisputed record~~Record evidence supports a finding that ~~the CT Project offers~~both a new gas peaker generator and battery storage could offer these types of needed attributes and supports system stability for NIPSCO, the State of Indiana, and the broader MISO region.

v. Environmental Sustainability. Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources~~. The~~, under I.C. § 8-1-2-0.6(5). NIPSCO asserts that its proposed 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. ~~Pet. Ex. 2 at 20. As described above,~~Pet. Ex. 2 at 20. However, as discussed above, it appears that the CT Project is not needed to support the substitution of coal generation with wind and solar generation; rather, it will be used to replace the retiring gas peaker generating units at the Schahfer site. As further discussed above, it appears that NIPSCO did not correctly model alternative resource options including battery storage that would not emit ambient pollution and greenhouse gases.

NIPSCO claimed, as described above, that the CT Project will have the flexibility to run beyond its currently anticipated capacity factors and still maintain compliance with the newly adopted GHG Rule. ~~Finally, 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 an expansive 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 Armstrong states (pp. 12-13) 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. Furthermore, the potential future combustion of hydrogen and~~

~~renewable natural gas (RNG) provide pathways for the CT Project to help achieve NIPSCO's goal of net zero Scope 1 and 2 GHG emissions by 2040 and, to the extent necessary, comply with changes in environmental regulations. The efficiency of the aeroderivative turbines in particular serves the environmental sustainability pillar.~~ NIPSCO witness Mr. Holcomb explained (p. 7) that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the GHG Rule (40 C.F.R. Part 60, Subpart TTTTa) and be allowed to operate at capacity factors up to 40%, as needed. By comparison, 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~~However, the Commission is concerned that, as discussed above, NIPSCO did not model the projected capacity factor of individual generating units within its proposed CT Project (as individual units are the object of regulatory interest under the new federal greenhouse gas rule). Furthermore, the evidence showed that the upgrades needed to run the turbines on hydrogen such that a unit could comply with the federal standards have not been fully investigated or costed, nor have hydrogen fuel supply options been identified. Moreover, using exclusively aeroderivative turbines (which was not NIPSCO's proposal in this matter) to better comply with environmental regulations would further worsen the proposed project's affordability, given the excessive cost of aeroderivatives that we recounted above. Overall, the proposed CT Project's configuration ~~balances environmental sustainability while~~appears unable to fully meet environmental requirements, and the cost of full compliance would be intolerably high, given that cleaner, less expensive resource options to meet NIPSCO's portfolio needs were not chosen.

Few parties presented evidence on the demand from consumers for environmentally sustainable sources of electric generation. We note that at the field hearing in this proceeding conducted March 14, 2024 in LaPorte, several public commenters who are customers of NIPSCO expressed their desire for zero-pollution energy resources, including Libré Booker, a Portage resident, speaking on behalf of an organization called Just Transition Northwest Indiana. Ms. Booker expressed that NIPSCO, through runoff from coal ash sites, has already damaged the water supply of 38 homes in the area that rely on groundwater for drinking. Ms. Booker also ~~supporting reliability, resiliency, and stability.~~ expressed that other options exist besides a new gas power plant, and that NIPSCO should move to renewable energy to consider the planet's future. Next, Chris Chyung of Indiana Conservation Voters spoke. Born in Merrillville, he encouraged NIPSCO to make a transition to renewable resources, which would support renewable jobs. He encouraged NIPSCO to tap into trillions of dollars of federal incentives for a clean energy transition. In light of these comments, we are compelled to note that approving the CT Project would run directly counter to these ratepayers' expressed demand and thus would be at odds with the sustainability attribute lifted up by our legislature.

Above, we have evaluated and discussed each of the Five Pillars. The record evidence demonstrates the CT Project ~~directly and substantially addresses concerns related to~~, though it has the potential to address reliability, resiliency, and stability~~, as it will serve as a dispatchable generation resources that offers key attributes needed as part of NIPSCO's generation~~ in the NIPSCO portfolio and ~~by~~ the state of Indiana's broader ~~market.~~electric grid, fails to satisfy key attributes set out in state law including affordability and sustainability, particularly compared to alternative options that NIPSCO could have proposed to meet the same purposes for its load-serving needs. We have also ~~approved NIPSCO's "best estimate" for the CT Project and discussed~~concluded that the proposed GCT Mechanism through which costs ~~will~~would be recovered from customers~~. We likewise discussed how a gas-fired generation facility with the potential to burn hydrogen and other forms of fuel with the configuration proposed by NIPSCO relates to environmental sustainability.~~ fails to produce gross financing costs savings for customers as required by law (in addition to its non-applicability to NIPSCO's proposal, in any event). Having considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6 in reaching our decision in this proceeding, the Commission finds that NIPSCO's proposed CT Project and related proposals are described herein are not consistent with ~~and appropriately balance~~ the legislative directive in this state policy statement.

~~6.~~7. **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. All of 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~~NIPSCO's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct an approximately 400 megawatt ("MW") natural gas combustion turbine peaking plant to be located at NIPSCO's existing R.M. Schahfer site~~. This Order constitutes the certificate.~~ and all associated relief requested is denied.

~~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.~~2. 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.~~denied as moot.

~~4.~~3. The CT Project is not 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~~denied.

~~5.~~4. ~~NIPSCO is hereby granted~~NIPSCO's request for authority to recover costs incurred in connection with the CT Project through its Generation Cost Tracker ("GCT") Mechanism, as proposed, including ~~approval of the specific ratemaking and accounting treatment approved in and consistent with the findings within Paragraph 5.C. NIPSCO's~~ proposed changes to its Electric Service Tariff relating to the GCT Mechanism~~ are approved~~, is denied.

5. NIPSCO's request in paragraph 25 of its Petition for certain ratemaking treatment related to post-in service carrying costs is denied as moot.

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.

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Dana Kosco
Secretary of the Commission

CLEAN VERSION (REDACTED)

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**

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]

Also on September 12, 2023, Petitioner filed the testimony and attachments of the following

[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. Pet. Ex. 1, Attachment 1-E.

(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 (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 of Procedural Schedule, which was granted by docket entry dated January 25, 2024.

On January 16, 2024, Petitioner filed 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 in the in-service date of the proposed generation project.

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 and Primary Energy did not file 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

[2] Petitioner originally prefiled the Verified Direct Testimony of Andrew S. Campbell as Pet. Ex. 6. NIPSCO filed a Notice of Substitution of Witness on January 16, 2024 whereby witness Mr. Stanley adopted Mr. Campbell's direct testimony.

[3] Petitioner originally prefiled the Verified Rebuttal Testimony of Robert C. Sears. NIPSCO filed a Notice of Substitution of Witness on May 29, 2024 whereby witness Ms. Becker adopted Mr. Sears's rebuttal testimony.

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.** Notice of the evidentiary hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of that term as used in Ind. Code § 8-1-2-1 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. NIPSCO is also an "eligible business" as that term is defined in Ind. Code § 8-1-8.8-6. NIPSCO is also an "energy utility" within the meaning of Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO also is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** NIPSCO is a limited liability company organized and existing under the laws of the State of Indiana with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is authorized by the Commission to provide 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. Pursuant to the Commission's Order dated September 24, 2003, in Cause No. 42349, NIPSCO has transferred functional control of its transmission facilities to the Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under the authority of FERC, which administers the use of NIPSCO's transmission system and the economic dispatching of NIPSCO's generating units pursuant to MISO's FERC approved tariff provisions. NIPSCO also engages in power purchase transactions through MISO as necessary to meet the demands of its customers. Pet. Ex. 1, Attachment 1-A, at 3-5.

3. **Relief Requested.** In this Cause, NIPSCO has petitioned the Commission for (1) issuance of a CPCN pursuant to Ind. Code ch. 8-1-8.5 to construct the 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 ("CWIP") 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 ("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.

4. The Proposed CT Project. The CT Project for which NIPSCO seeks approval would be an approximately 400 MW gas combustion turbine that, as proposed, would consist of one F-class frame turbine and three aeroderivative turbines. Pet. Ex. 5 at 3-5. While NIPSCO's initial application identified an in-service date by the end of 2026 for the CT Project, due to supply chain challenges, the in-service date has been delayed to the end of 2027. NIPSCO cites an estimated cost for the project of $641,223,000 not including Allowance for Funds Used During Construction ("AFUDC"), which is approximately $1,600 per kW. CAC Ex. 3 at 25. Under NIPSCO's proposal, the cost of the CT Project to a residential customer using 1,000 kWh per month would be $8.94 per month when the project would be rolled into rate base. Pub. Ex. 5 at 7.

5. 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 NIPSCO's resource planning analyses over the last several years, particularly the Integrated Resource Plan submitted November 15, 2021 (the "2021 IRP"). He also reviewed major market developments since NIPSCO's submission of 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 contended that the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by the additional analyses NIPSCO has performed since the submission of the 2021 IRP. Pet. Ex. 7 at 5-6.

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 that NIPSCO's Flexible Resource Analysis ("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 projected that pivoting towards a larger-sized, cost-effective thermal resource would lead to a total portfolio cost of $11.4 billion on a 30-year NPVRR basis, as compared to $11.643 billion if 650 MW of storage were pursued instead. Pet. Ex. 7 at 40. Mr. Augustine noted that the cost difference between the gas CT and battery storage portfolios was largely due to the assumption that the capacity accreditation of storage would decline

[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.

to 70% by 2040, while the capacity accreditation of a gas CT would remain stable around 95%. Pet. Ex. 7 at 34-35.

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 NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP. Pet. Ex. 7 at 42.

In his supplemental testimony, Mr. Augustine presented updated information from MISO related to planning reserve margin requirements ("PRMR"), capacity accreditation, and NIPSCO's supply/demand balance. Pet. Ex. 7-S at 2. 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 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." Pet. Ex. 7-S at 3. 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." Pet. Ex. 7-S at 14. 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 that "overall, 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." Pet. Ex. 7-S at 14-15.

IG witness Gorman recommended rejection of the CPCN, in part because, "[i]nstead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study." IG Ex. 1 at 4. As Mr. Gorman noted, the 2021 IRP had included up to 300 MW of new gas peaking capacity, NIPSCO is seeking approval for an approximately 400 MW gas peaker. *Id*. at 4-5. IG witness Gorman explained that the Flexible Resource Analysis failed to take into account a "several material developments" since the 2021 IRP, including MISO's seasonal resource construct, the Inflation Reduction Act, issues like supply constraints, tariff uncertainty, and inflation, and the latest market data from additional Requests for Proposals ("RFPs"). *Id.* at 5. IG witness Gorman testified that NIPSCO has failed to account for the expected changes in Rate 531 Tier 1 demand, which could lead to a reduction in 100 MW of contracted load that NIPSCO would need to serve, and has therefore failed to "right size" the CT Project. *Id*. at 7-8.

CAC witness Anna Sommer identified additional shortcomings in the Flexible Resource Analysis. That analysis found that NIPSCO's 2021 resource plan would result in periods of market exposure, the majority of which would last less than an hour but a few dozen of which were projected to last longer than four hours in duration. CAC Ex. 1 at 19. However, while the Flexible Resource Analysis found that an additional 100-200 MW of flexible capacity (beyond up to 300 MW gas peaker included in the 2021 IRP) could reduce such market exposure, it did not quantify the cost of the potential market exposure or of the resources that could reduce that exposure. CAC Ex. 1 at 19-20. Nor did the Analysis provide any evaluation of the costs or effectiveness of alternative options for reducing the market exposure, such as battery storage combined with demand response, or different turbine configurations for the CT Project. CAC Ex. 1 at 20.

With regards to NIPSCO's 2023 Portfolio Analysis, witness Sommer explained that such analysis did not include re-optimization of capacity expansion plans to determine a lowest cost portfolio. CAC Ex. 1 at 17. Instead, NIPSCO merely used portfolios from its 2021 IRP, which the company then updated to reflect changes in project costs and PPA prices, MISO seasonal planning reserve margins and capacity accreditation, commodity price inputs, tax credits for solar, wind, and storage under the Inflation Reduction Act. CAC Ex. 1 at 16-17. CAC witness Sommer also contended that under MISO's proposed direct loss of load ("D-LOL") capacity accreditation structure, NIPSCO's capacity calculations likely "overstate both summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources." *Id*. at 23. In particular, while NIPSCO had assumed accreditation of 97% for the gas peakers and 82.63% for storage, MISO's D-LOL proposal had gas at 88% in summer and 66% in winter, while storage was at 94% in summer and 91% in winter.

In light of MISO's proposed D-LOL capacity accreditation values, Ms. Sommer testified that NIPSCO would likely need additional capacity in 2028 when the Michigan City plant is scheduled to retire even if the CT Project is approved and comes online. *Id.* at 23-24. Ms. Sommer urged NIPSCO to pursue two types of resources – demand response and battery storage – both of which could be brought online in a shorter timeframe than a combustion turbine project. *Id*. at 25-28. With regards to demand response, witness Sommer included with her testimony an analysis from the Cadeo Group that found NIPSCO could add 90 MW of summer and 46 MW of winter capacity from demand response by 2027, with additional amounts in the years thereafter. CAC Ex. 1 at 27 and Attachment AS-3. Ms. Sommer testified that the levelized cost of capacity from such demand response programs would be $27,480/MW-yr or $75/MW-day, while the CT Project has a levelized capacity cost of $133,721/MW-yr or $367/MW-day. CAC Ex. 1 at 25, Table 4. Ms. Sommer recommended that the Commission direct NIPSCO to make a filing by the end of 2024 for additional cost-effective demand response resources to add to its portfolio. *Id.* at 37.

As for battery storage, CAC witness Sommer detailed that even if the CT Project were approved, NIPSCO would have excess interconnection injections rights left at the Schahfer site from the retirement of Units 17 and 18. Those rights, along with additional rights that will become available when Schahfer Units 16A and 16B retire, could be transferred to battery storage and other no- or low-carbon resources that NIPSCO should explore building at the Schahfer site. CAC Ex. 1 at 25-26. Those injection rights are extremely valuable assets that should be reutilized given that they enable the avoidance of the current delays in MISO's injection queue. Reutilizing the excess injection rights that will be available at the Schahfer site for battery storage makes sense given that storage has a shorter development timeframe than the CT Project and would benefit from the energy community bonus adder under the Inflation Reduction Act. *Id.* at 26-28. Especially given the potential for changes to MISO rules regarding the reutilization of injection rights, witness Sommer opined that it is important that NIPSCO quickly develop a plan for how it can fully utilize the Schahfer injection point. *Id.* at 27. As such, Ms. Sommer recommended that the Commission direct NIPSCO to file by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so. *Id.* at 37.

CAC witness Sommer testified that NIPSCO did not provide any opportunity for stakeholder involvement or input in conducting the Flexible Resource Analysis or the 2023 Portfolio Analysis.

CAC Ex. 1 at 18-19. Ms. Sommer further expressed serious concerns over the continued use of the Aurora resource planning model absent resolution of recent transparency and access concerns for the model. Due to an inability to secure a license for the Aurora modeling software, CAC was unable to recreate or modify the modeling NIPSCO performed in its 2023 Portfolio Analysis. *Id.* at 18. Ms. Sommer explained that Aurora's vendor, Energy Exemplar, only allowed short-term, project-based licenses by going through an existing licensee. *Id.* at 32. While not ideal, Ms. Sommer stated that she had successfully navigated such a process with utilities in the past. However, the language of the licensing agreement here prevented CAC from executing any of its own simulations in the Aurora model. To conduct their own modeling with Aurora, CAC would be required to purchase a full license that would be entirely cost-prohibitive for intervenor clients and non-utility stakeholders. *Id.* Ms. Sommer explained that a continued inability to recreate or modify the modeling that NIPSCO performs in Aurora will substantially hinder the engagement of intervenors and other non-utility stakeholders.

Ms. Sommer raised similar concerns about the lack of transparency and stakeholder engagement in NIPSCO's RFP process. Ms. Sommer stated that the Schahfer development RFP issued in 2022 was singularly focused on gas-fired technologies, as evidenced by S&L's development of technical specifications for only gas turbines specifically for that RFP. CAC Ex. 1 at 33. Because CAC was not invited to provide feedback on NIPSCO's resource procurement RFP, CAC was unable to flag concerns about the RFP until after the fact. Ms. Sommer testified that NIPSCO has acknowledged its failure to give intervenors the opportunity to review the Schahfer RFP. *Id.*

In rebuttal, Mr. Augustine testified that "overall, while the parties directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, no party has testified that 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." Pet. Ex. 7-R at 2. Mr. Augustine addressed the parties' 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.

In response to Mr. Gorman's testimony 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 testified that Mr. Gorman has 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. Pet. Ex. 7-R at 5.

In responding to Mr. Gorman's suggestion that NIPSCO failed to take into account 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 testified 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 in order to develop portfolios based on capacity requirements for both the summer and winter seasons. Pet. Ex. 7-R at 7, citing Pet. Ex. 7 at 13-15, 26 and Pet. Ex. Attachment 7-A (2021 IRP), Section 4.5, Section 8.2.4, Section 9.2, and Section 9.3. He also stated that NIPSCO's 2023 Portfolio Analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after FERC approved MISO's seasonal construct. *Id.* at 10, citing Pet. Ex. 7 at 26. He testified that 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. Pet. Ex. 7-R at 7-8, citing Pet. Ex. 7 at 31-32.

In responding to Ms. Sommer's testimony that she did not perform independent modeling, Mr. Augustine highlights Ms. Sommer's reference to "concerns about the portfolios that were examined since they include projects that NIPSCO has canceled" (CAC Ex. 1 at 18), which he suggests provides an inaccurate assessment of the portfolios that were evaluated in the 2023 Portfolio Analysis. Pet. Ex. 7-R at 8-9. Mr. Augustine explains that preferred Portfolio 3 was explicitly developed to incorporate the risk of such project cancellations, Pet. Ex. 7-R at 8-9, citing Pet. Ex. 7 at 30, and that consistent with these assumptions, NIPSCO has since filed termination notices for these four projects and used the 2023 Portfolio Analysis to support replacement of these projects with incremental wind and solar capacity, as explicitly modeled in preferred Portfolio 3. Contrary to Mr. Augustine's critique, however, Ms. Sommer did not dispute that project cancellations had occurred; instead, her concerns were that it would be challenging to assess the impact of those cancellations without re-optimization of the portfolios, which is something that NIPSCO's input database was not set up to do. CAC Ex. 1 at 18. Ms. Sommer's testimony was also clear that she did not perform independent modeling "due to an inability to secure a license" for the Aurora modeling software. *Id*.

In response to Ms. Sommer's concerns about the ability for intervenors to use Aurora in this proceeding, Mr. Augustine acknowledged that the language of clauses within the proposed limited license agreement with Energy Exemplar may be interpreted differently by different parties. Pet. Ex. 7-R at 31. However, Mr. Augustine reiterated that NIPSCO and CRA are committed to continuing to work with Energy Exemplar in the 2024 IRP process to provide the opportunity for stakeholders to license the model with the purpose of running independent simulations. *Id.* at 32.

In responding to Ms. Sommer that 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 testified 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." Pet. Ex. 7-R at 14-15. Mr. Augustine testified that "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—something Ms. Sommer did not challenge. Pet. Ex. 7-R at 16.

With regards to Ms. Sommer's argument that the Flexible Resource Analysis did not evaluate different resource options for mitigating the potential risks identified therein, CAC Ex. 1 at 20, Mr. Augustine notes that 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, which concluded that the portfolio with new peaking capacity was lower cost for customers. Pet. Ex. 7-R at 16-17. He noted that NIPSCO's 2021 IRP did the same and concluded that the portfolio with new peaker capacity performed similarly or better on the cost-based metrics than a portfolio relying only on storage and best on the reliability metrics (2021 IRP, Figure 9-42 and Section 9.2.7). Mr. Augustine testified that NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project. Pet. Ex. 7-R at 16-17.

Mr. Augustine responded to Mr. Gorman's testimony that 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. He explained that NIPSCO's 2021 IRP did evaluate a scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman. Pet. Ex. 7, Attachment 7-A at 54-55. Mr. Augustine noted that, in the narrative description on p. 54 of the 2021 IRP, it is noted that "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, Figure 9-18 and Figure 9-42 from NIPSCO's 2021 IRP, show NIPSCO's preferred portfolio performed well under such assumptions as can be seen in NIPSCO's cost to customer results across scenarios and NIPSCO's integrated scorecard, respectively. Pet. Ex. 7-R at 17-18.

In response to Ms. Sommer's proposal that battery storage and demand response resources be deployed and her argument that such resources "can be added more quickly than the CT project can be built" (CAC Ex. 1 at 27), Mr. Augustine testified that while development and deployment timelines will vary by resource, he noted that NIPSCO's preferred portfolio from its 2021 IRP and 2023 Portfolio Analysis already contemplates 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 stated that the pending MISO rules changes also appear to offer additional evidence in support of NIPSCO's proposed CT project. He explained that 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." Pet. Ex. 7-R at 19-20.

Mr. Augustine disagreed with Ms. Sommer's suggestion that under the proposed D-LOL structure, battery resources will have stronger capacity accreditation than natural gas peaker resources and that 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." CAC Ex. 1 at 23. He testified that future capacity accreditations under D-LOL "remain too uncertain to definitively make such a claim, and the forward-looking information published by MISO is actually 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." Pet. Ex. 7-R at 20-21. Mr. Augustine identifies in his rebuttal MISO's 5- and 10-year capacity accreditation values for natural gas of 84% in the summer and 80% to 82% in the winter, Pet. Ex. 7-R at 21-22, which are lower than the assumption in NIPSCO's analyses that the capacity accreditation of a gas CT would likely remain stable at around 95%. Pet. Ex. 7 at 34-35.

In response to Ms. Sommer's 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 (CAC Ex. 1 at 28), Mr. Augustine testified 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. Pet. Ex. 7-R at 23-27.

B. CT Project.

Ms. Becker set forth NIPSCO's bases for contending that its CT Project proposal satisfied 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 sponsoring supporting testimony related to each element. Pet. Ex. 1 at 4.

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 and identified the NIPSCO witness sponsoring supporting testimony related to each pillar. Pet. Ex. 1 at 6-7. 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 provided by MISO regarding the new generation, including NIPSCO's request to MISO (Exhibit 1 to the Affidavit). Pet. Ex. 1 at 7. In her supplemental testimony, Ms. Becker described NIPSCO's follow-up contact with MISO in light of the shift in the in-service date. Pet. Ex. 1-S at 5.

Ms. Becker testified that 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. Pet. Ex. 1 at 7-8.

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 (Ind. Code § 8-1-8.5-4(2)). 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 this generation. She said that NIPSCO is committed to the development of demand response programs for all customer groups and appreciates the assistance of its stakeholders in finding experts to help with that development 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. Pet. Ex. 1 at 8-19.

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 (5) years. He contended that the CT Project is a clean energy project as that term is defined in Ind. Code § 8-1-8.8-2. He addressed consistency of the proposed construction of the CT Project with the Five Pillars outlined in Ind. Code § 8-1-2-0.6. Pet. Ex. 2 at 22.

Mr. Holcomb testified that the CT Project as a new gas combustion turbine is subject to EPA's final greenhouse gas emissions standards for new fossil fuel-fired power plants ("GHG Rule") as published in the Federal Register on May 9, 2024. Pet. Ex. 9-R at 4. Mr. Holcomb explained that the final GHG Rule established three subcategories based on capacity factor: Low load (less than or equal to 20% capacity factor), Intermediate load (greater than 20% capacity factor but less than or equal to 40% capacity factor), and Base load (greater than 40% capacity factor). *Id.* at 5. Prior to the finalization of the GHG Rules, Mr. Walter testified that NIPSCO projected to maintain capacity factors below 20%, except in the initial months of operation. Pet. Ex. 2 at 29. During those initial months, NIPSCO would either limit capacity factors to 20% or achieve the Intermediate emission limitations. *Id.* After the final GHG Rule was published, NIPSCO reiterated that their position remained the same. NIPSCO-CAC Ex. 8 at 3.

In rebuttal, Mr. Holcomb further explained that both the aeroderivative and frame unit of the CT Project would comply with the Low load category by operating below a 20% capacity factor. Pet. Ex. 9-R at 5. The CT Project is not designed to operate as a base load turbine and NIPSCO therefore intends to operate the CT Project as peaking units. *Id.* at 6. While Witness Holcomb and Witness Becker (succeeding Sears) note that the GHG Rule imposes operational limitations on the industrial frame units that are not present with the aeroderivative units, Pet. Ex. 9-R at 7 and Pet. Ex. 1-R at 13, NIPSCO projects operating the CT Project at capacity factors below 20%, which would qualify it as a low load plant for purposes of the GHG Rule. NIPSCO-CAC Ex. 2 at 12. NIPSCO has not performed any formal scenario analysis to identify conditions under which any one of the proposed turbines would run at greater than 20% capacity factor, nor has NIPSCO developed capacity factor projections for each individual unit within the proposed CT Project. NIPSCO-CAC Ex. 8 at 4; NIPSCO-CAC Ex. 2 at 3; NIPSCO-CAC Ex. 2-C (spreadsheet labeled as CAC 1-019 Highly Confidential Attachment A-S). NIPSCO has also only developed capacity factor projections for gas peaker projects as a whole. NIPSCO-CAC Ex. 2 at 3.

Mr. Walter testified that the CT Project will be enabled to blend hydrogen, with a 15 to 35% hydrogen blending capability being considered. Pet. Ex. 2 at 29. Mr. Holcomb explains that the potential future combustion of hydrogen and renewable natural gas provide a pathway for the CT Project to help achieve NIPSCO's goal of net zero GHG emissions by 2040, Pet. Ex. 9-R at 8-9. However, NIPSCO did not provide a requirement for hydrogen blending capabilities during the CT OEM bid event. NIPSCO-CAC Ex. 8 at 5-7. Nor does NIPSCO provide any information or analysis related to the costs, availability, or viability of using hydrogen or renewable natural gas as a fuel for this CT Project.NIPSCO-CAC Ex. 2 at 8, 11. CAC witness Sommer noted that NIPSCO does not anticipate needing a hydrogen fuel supply to achieve its 90% reduction in greenhouse gas emissions by 2030 goal, and opined that the hydrogen industry is in an "extremely nascent state" and that, therefore, it would be imprudent to spend tens of millions of dollars merely to preserve the possibility of future hydrogen blending. CAC Ex. 1 at 13-14.

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 new CT Project's contribution to NIPSCO's system reliability. Pet. Ex. 3 at 3.

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. Pet. Ex. 4 at 3.

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). Pet. Ex. 5 at 3-4.

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. Pet. Ex. 6 at 3-4.

Witness Campbell (succeeded by Stanley[5]) testified that NIPSCO intends to support the CT Project's gas usage through options within NIPSCO's currently approved gas tariff. Pet. Ex. 6 at 19.

However, CAC witness Sommer points out that NIPSCO has stated that its plan to supply fuel to the CT project is not yet set. CAC Ex. 1 at 34. While NIPSCO argues that its own gas distribution system has the capacity to serve the gas needs of the project, it continues to explore supply from interstate pipelines in the vicinity of Schahfer. *Id.*; NIPSCO-CAC Ex. 5 at 7, 9. NIPSCO is still formulating the exact fuel strategy it will employ for the CT Project and intends to run a Gas Supply RFP in late 2024 or in 2025 to support the final fueling strategy of the CT project. Pet. Ex. 6 at 19; NIPSCO-CAC Ex. 5 at 3; NIPSCO-CAC Ex. 5 at 9.

Given issues with gas supply during Winter Storm Uri and Winter Storm Elliot, CAC witness Sommer suggests NIPSCO should explore the possibility of multiple pathways to supply the CT Project if approved. CAC Ex. 1 at 34; NIPSCO-CAC Ex. 5 at 11. Further, Ms. Sommer suggests that any material deviations from modeled gas costs, particularly transportation costs, should be vetted thoroughly before recovery from ratepayers. *Id.*

In rebuttal, Witness Stanley concedes that the natural gas procured to fuel the CT Project should be reviewed through the current Fuel Adjustment Clause ("FAC") process. Pet. Ex. 6-R at 4-5.

In his supplemental direct testimony, Mr. Baacke discussed supply chain challenges that led to the anticipated in-service date for the proposed CT Project to be delayed from end of 2026 to end of 2027. Mr. Baacke testified that ongoing conversations with suppliers and NIPSCO's review of bid responses led to material updates with respect to necessary components that impacted the project timeline. Multiple 345 kV breaker suppliers indicated lead times of 26 to over 48 months. Only a single supplier indicated that a delivery of five needed breakers could be potentially achieved by late Quarter 3, 2026. Results of NIPSCO's generator step-up bid event indicated that only a single supplier could deliver generator step-up transformers to support an end of year 2026 in-service date. Due to

[5] References in this Order to Petitioner's Exhibit 6 will expressly refer to NIPSCO witness Mr. Stanley, who adopted the testimony originally sponsored by witness Campbell.

those external supply chain challenges, NIPSCO was forced to reevaluate an end of year 2026 in-service date, with an in-service date of no-later-than end of year 2027 appearing to be more achievable. Pet. Ex. 5-S at 3-4.

Mr. Baacke stated that NIPSCO's originally estimated in-service date for end of year 2026 was always with the understanding that the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained that 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 that NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Pet. Ex. 5-S at 2-3.

i. **<u>Configuration.</u>** 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 that 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. In recent years, 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. Pet. Ex. 5 at 4-5. Despite these comparative benefits of larger industrial frame units, NIPSCO also included three smaller aeroderivative units because of their claimed benefits with regards to efficiency, fast start capability, and flexible operations. Pet. Ex 5 at 5.

Mr. Baacke testified NIPSCO chose the preferred configuration to maximize benefits to NIPSCO and its customers. NIPSCO's preferred configuration was then used to conduct an RFP to seek proposals for an engineering, procurement, and construction ("EPC") contract (the "EPC RFP"). As shown in Appendix 19 of the Simple Cycle Gas Turbine Engineering Study, Report No. SL-016874 (the "Engineering Study") (Highly Confidential Attachment 4-A sponsored by NIPSCO witness Warren), 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 that witness Baacke testified align with the Flexible Resource Analysis (Highly Confidential Attachment 7-D sponsored by NIPSCO witness Augustine), operational factors, costs, environmental, and schedule. Pet. Ex. 5 at 6.

Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated that NIPSCO already owns the property at the Schahfer site. He said constructing the CT Project on the Schahfer site provides cost savings and advantages for NIPSCO, its customers, and the local economy. Pet. Ex. 5 at 7.

As discussed by NIPSCO witness Stanley, NIPSCO also 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. Pet. Ex. 6 at 10-11. As previously discussed, even if the CT Project were approved, NIPSCO would have excess interconnection injection rights left at the Schahfer site that can and should be used for battery storage and other no- or low- carbon resources that NIPSCO should explore building at the Schahfer site. CAC Ex. 1 at 25-26.

OUCC witness Hanks testified that the EPC RFP prevented bidders from proposing a less expensive, all industrial frame configuration. Pub. Ex. 2 at 2. Witness Hanks notes that NIPSCO has not actually committed to installing aeroderivative units in its current proposal. *Id*. Further, as a result of requiring bidders to include the use of aeroderivative units when responding to the EPC RFP, witness Hanks claims the EPC RFP prevented respondents from proposing a more economical, all-industrial frame configuration. *Id.* Witness Hanks also points out that both Mr. Warren and Mr. Baacke testified that smaller industrial frame machines are available and could be used in place of the aeroderivative units. *Id.* at 9; Pet. Ex. 4 at 11; Pet. Ex. 5 at 4.

In response, Mr. Baacke testified that EPC RFP asked bidders to select a combination of industrial frame and aeroderivative CTs that could meet certain defined constraints. Pet. Ex. 5-R at 3. He testified that 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. *Id*. at 4. Despite the RFP request for a "combination" of industrial frame and aeroderivative units, Mr. Baacke opined that "EPC RFP bidders were not prevented from proposing all industrial frame configurations" but, instead, were free to provide bids that would include one larger industrial frame machine and multiple smaller aeroderivative or industrial frame units. Id. at 3-4. Further, Mr. Baacke noted that the project summary included an example of an acceptable combination as one General Electric 7FA industrial frame combustion turbine generator ("CTG") and three General Electric LM6000 aeroderivative CTGs, but claimed that this example was just a clarification of potential combinations and was not a specific requirement. Pet. Ex. 5-R at 2-4; Pet. Ex. 7-C, Highly Confidential Attachment 7-D.

OUCC witness Sanka testified that although NIPSCO claimed it evaluated multiple technologies for the CT Project, NIPSCO failed to evaluate the configuration with one large industrial frame and smaller industrial frame, similarly sized to the aeroderivative turbine, in the decision matrix of S&L's Engineering Study. Pub. Ex. 3 at 7. In response, Mr. Baacke testified that because smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, it was not necessary to perform a separate analysis for a large industrial frame with smaller industrial frame machines. Pet. Ex. 5-R at 16-17.

OUCC witness Sanka further testified that NIPSCO has not justified the need for aeroderivative units, explaining that beyond NIPSCO's desire for "quick start" and "fast ramp" units, NIPSCO has not provided any analysis or support for selecting aeroderivative units in its configuration which industrial frames can also address. Pub. Ex. 3 at 9. While NIPSCO claims that aeroderivative units provide an advantage over industrial frame units in regard to the time to start a unit, Pet. Ex. 4 at 10, NIPSCO provides no support for the purported need for quick start capabilities. Indeed, performance specifications established by the Engineering Study (Highly Confidential Attachment 4-A sponsored by NIPSCO Witness Warren) for NIPSCO's EPC RFP required bids to include a 10-minute cold start capability for 150 MW or more, yet NIPSCO provides no analysis to support such a requirement. Although NIPSCO states it expects to utilize the capability to start quickly, NIPSCO conflates cold-start capability with fast ramp times, pointing to a quantification of 10-minute ramp requirements with no comparable support for the necessity of a 10-minute cold start capability. Pet. Ex. 7-C, Highly Confidential Attachment 7-D.

ii. **Competitive Procurement.** Mr. Baacke testified 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 sponsored by NIPSCO witness Warren). He stated S&L then supported NIPSCO by drafting technical specifications for the EPC RFP. He said that 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. Pet. Ex. 5 at 10.

CAC witness James testified that common and current best practices to ensure a construction project has a good probability of successful execution involves significant investment in project definition. CAC Ex. 2, Att. RJ-2, § 2.3. Mr. James explains that currently owners for almost every large project involving industrial construction undertake a Front-End Loading ("FEL") process, yet S&L's Engineering Study neglects to mention this process in its entirety. *Id.* While NIPSCO considers S&L's study to be "comparable to a FEED study" [meaning Front-End Engineering Design] – which is part of the final stage of an FEL process, Mr. James noted that S&L admits its engineering and design level of effort does not lend itself to producing mature design drawings for the Project. NIPSCO-CAC Ex. 3 at 5, 7; CAC Ex. 2, Att. RJ-2, § 2.4. Mr. James explained that missing from S&L's conceptual engineering design evaluation are key components that are essential to achieve the detailed design readiness of a FEED study, including but not limited to detailed scopes, heat & material balances, license packages, P&ID's and Electric Single-Line Diagrams issued for design, major equipment specifications, and a take-off based estimate. CAC Ex. 2, Att. RJ-2, § 2.10. Due to these omissions, Mr. James testified that the S&L report is "grossly deficient" and does not currently conform with industry standards. Mr. James suggests that the completion of a FEED study is critical to the success of the CT Project. CAC Ex. 2, Att. RJ-2, § 2.5. To rectify this, Mr. James suggests NIPSCO should authorize S&L to upgrade the Project's design to FEED study quality. CAC Ex. 2, Att. RJ-2, § 4.6.

In response to this suggestion, Mr. Baacke stated that in addition to the services S&L has already completed in detailing the design for the CT Project and in supporting NIPSCO in the procurement of long lead-time equipment and materials, NIPSCO plans to contract with S&L to provide onsite support during construction, start up, and testing to provide quality assurance and control during installation to ensure the units are brought online once they are built. Pet. Ex. 5-R at 15-16.

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 as a result 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. Pet. Ex. 5 at 10-11.

Mr. Baacke noted that while Mr. Hanks claims that NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness James claims that the quality of NIPSCO's EPC RFP was "wanting insofar as it relies upon a project that needs more definition and planning." Pub. Ex. 2 at 16; CAC Ex. 2, Attachment RJ-2, § 3.4. He 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. Pet. Ex. 5-R at 5. Mr. Baacke testified that NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show that NIPSCO properly vetted the EPC RFP bids.Mr. Baacke described the results of the proposals received from three bidders. One bid did not meet the performance criteria of the technical specifications and provided less than five pages of information, which was not evaluated for further consideration. A second bid provided a proposal that consisted of 10 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. NIPSCO ultimately chose the self-build option, which Mr. Baacke stated was in the best interest of NIPSCO and its customers. Pet. Ex. 5 at 11-12.

OUCC witness Krieger questioned NIPSCO's rejection of the third EPC bid on the grounds that the company improperly increased the cost of that bid by adding unreasonable levels of owner's costs, contingencies, and indirect costs to that bid. Pub. Ex. 4 at 19-20. As witness Krieger explained, owner's costs should be "significantly less" when an EPC contractor is hired because they assume most of the project management responsibilities. *Id*. at 19. As such, most of the project management costs are included in the EPC contract and need not be added on as owner's costs. Yet NIPSCO added significant amounts of owner's costs, along with inflated contingency and indirect costs, to the only EPC bid that met the technical specifications for the project. *Id*. at 19-25. Mr. Krieger opined that by doing so, NIPSCO "unreasonably disqualified an EPC bid that may have improved the probability of an on-time delivery and reduced the project cost risk for consumers." *Id*. at 19. In rebuttal, NIPSCO witness Baacke claimed that Mr. Krieger's critique is only a matter of cost categorization because any reduction in owner's costs resulting from the EPC contractor managing the project would simply be reflected in the EPC contract. Pet. Ex. 5-R at 31-32. But that response does nothing to justify the addition of high levels of owner's costs (and the other costs highlighted by Mr. Krieger) on top of the contract price bid by the EPC contractor.

CAC witness James noted that NIPSCO moved forward with issuing the EPC RFP on August 12, 2022 – eight months before S&L's Engineering Study was finalized for use. CAC Ex. 2, Att. RJ-2, § 3.4. Mr. James stated that this likely contributed to the poor response rate to the RFP and suggested that had the RFP been issued on the basis of a more complete level of definition and planning, it is likely that NIPSCO would have received more EPC bids or at least bids at a potentially lower cost than the single qualifying bid that NIPSCO rejected. *Id.* 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 that with the multi-prime contracting strategy approach, 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. Pet. Ex. 5 at 12-13.

In response to CAC witness James' assertion that a "self-build approach is not in customers' best interests and adds significant risk to the Project costs," Mr. Baacke testified that although EPC has the potential to help firm up the cost of the project earlier in the process than a multi-prime approach, it does not limit the potential of the actual cost of the project to increase prior to completion. Pet. Ex. 5-R at 7. Mr. Baacke further noted that NIPSCO received three EPC bids – with only one meeting the technical specifications. He stated that 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. Pet. Ex. 5-R at 6.

Mr. Baacke testified NIPSCO's multi-prime contracting strategy applies to construction on the CT Project as well. He stated that 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 of 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. Pet. Ex. 5 at 13-14.

iii. <u>Best Estimate.</u>

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 AFUDC. He explained that 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. Pet. Ex. 5 at 17-18.

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 (shown in Attachment 5-A), which includes indirect costs but excludes AFUDC. 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. Pet. Ex. 5-S at 11. In his rebuttal testimony, Mr. Baacke provided an updated cost summary in Attachment 5-R-A in which "Inside the Fence" and interconnection costs were higher than in the initial filing, but those increases were offset by reductions in Owner's Cost, Escalation, and Contingency. As such, the estimated total project cost presented in the rebuttal testimony was exactly the same as in the initial testimony, even though the rebuttal testimony estimate reflected the removal of Selective Catalytic Reduction pollution controls that had been included in the initial estimate. Pet. Ex. 5-R at 19-20.

Witnesses for OUCC and CAC noted that the $641,223,000 cost estimate for the CT Project works out to approximately $1,600 per kW, which is considerably higher than other recent examples. OUCC witness Hanks noted that in October 2022 NIPSCO and Charles River Associates reported that

[6] NIPSCO Witness Blissmer testified (Pet. Ex. 8 at 12) that, if NIPSCO's proposed construction work in progress 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.

the average cost of thermal resources bid into the 2022 All-Source RFP was $763/kW. Pub. Ex. 2 at 15. Similarly, the U.S. Energy Information Administration reported in its 2023 Annual Energy Outlook $867/kW base overnight costs for industrial frame units and the $1,428/kW for aeroderivative units. Pub. Ex. 2 at 5. The estimated construction cost for the CT Project is also approximately double that of Center Point Energy's 460 MW gas combustion turbine that the IURC approved in 2022. Pub. Ex. 2 at 5-6. CAC witness Sommer testified that the proposed CT Project is the most expensive combustion turbine project currently under development in the U.S. that she is aware of. CAC Ex. 1 at 6. Ms. Sommer explained that the elevated cost for the CT Project is the result not only of increased demand for the equipment, engineering, and skilled labor that would be needed to complete the project, but also, among other things, NIPSCO's decision to include aeroderivative turbines in the project, which are more expensive than heavy frame turbines. CAC Ex. 1 at 9-10.

OUCC witness Armstrong stated that the OUCC "does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable." Pub. Ex. 1 at 9. CAC witness Inskeep raised similar affordability concerns, noting that NIPSCO residential customers already have the second-highest electric bills in the state for 1,000 kWh of usage and are facing considerable upward pressure from costs related to additional generation projects, coal combustion residual projects, transmission and distribution investments, and additional cost-shifting from industrial customers to other ratepayers. CAC Ex. 3 at 26-27. Witness Inskeep testified that these affordability pressures would be exacerbated by the proposed CT Project. Id. at 27.

OUCC witnesses contended that NIPSCO's cost estimates for the CT Project are overstated and unreasonably shift increased project cost risks onto ratepayers. Pub. Ex. 1 at 9. In order to reduce such ratepayer impacts, OUCC witness recommended modifications that would reduce the total project cost by approximately $130 million, Pub. Ex. 1 at 10, which would lead to roughly $300 million in savings over the life of the project. Pub. Ex. 4 at 27.

OUCC witness Sanka recommended rejection of the CPCN as filed because NIPSCO had not provided specific justification for why the more expensive aeroderivative turbines would be needed instead of industrial frame turbines. Pub. Ex. 3 at 10. While acknowledging differences in starting time and ramp rates between the two types of turbines, witness Sanka explained that NIPSCO had not quantified the claimed benefits of the aeroderivative turbines nor provided a cost-benefit analysis showing that such benefits would outweigh the increased costs related to such turbines. *Id.* As OUCC witness Hanks explained "NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units," Pub. Ex. 2 at 2, and it would be "unreasonable to require NIPSCO ratepayers to pay for aeroderivative units based on a broad generalization without demonstrating the quantifiable benefits." *Id.* at 7.

CAC witness Sommer also recommended rejection of the CPCN, particularly because of the inclusion of the aeroderivative turbines. CAC Ex. 1 at 10-12, 35. In support, Ms. Sommer explained that the matrix in the Sargent & Lundy study used to select the aeroderivative turbines was subjective and failed to give proper weight to the significant cost difference between aeroderivative and industrial frame turbines. *Id*. at 10-12. Nor were the aeroderivative turbines justified by considerations related to black start needs or hypothetical future interest in burning hydrogen. *Id*. at 12-14.

In rebuttal, NIPSCO witness Becker acknowledged that if the Commission removes the aeroderivative units from the proposed CT Project, "it is not fatal to the proposal" which could proceed with only industrial frame units. Pet. Ex. 1-R at 13.

In response to OUCC and CAC's opposition to NIPSCO's application in part because of the cost of the aeroderivative turbine component (Pub. Ex. 2 at 2 and CAC Ex. 1 at 6-7 and 10), Mr. Augustine testified that NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained that in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment (Pet. Ex. 7, Attachment 7-A, 2021 IRP, Sections 9.2.6 and 9.2.7) both highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis (Pet. Ex. 7, Confidential Attachment 7-D at 9–10) identified growing 3-hour and 10-minute ramping requirements by 2030. Pet. Ex. 7-R at 27-28.

OUCC witness Armstrong recommended that costs associated with certain pollution control technology be removed from the CT Project best estimate. Pub. Ex. 1 at 16-17. In rebuttal, witness Baacke acknowledged that NIPSCO agrees that the Selective Catalytic Reduction ("SCR") pollution controls included in the initial best estimate are not needed. Pet. Ex. 5-R at 20; Pet. Ex. 1-R at 5. As such, the updated best estimate presented in Mr. Baacke's rebuttal reflects removal of the SCRs. Pet. Ex. 5-R at 20. Despite removal of the SCRs, however, the overall cost estimate for the CT Project cited in Mr. Baacke's rebuttal remains the same as in the initial application, Pet. Ex. 5-R at 19, and the "Inside the Fence" costs cited in rebuttal are approximately $27 million higher than in the initial application. Compare Pet. Ex. 5 Attachment 5-A with Pet. Ex. 5-R Attachment 5-R-A.

OUCC witness Hanks claimed that NIPSCO's best estimate potentially double counted indirect costs. Pub. Ex. 2 at pp. 10-11. Mr. Hanks stated that NIPSCO did not justify a 5% escalation factor and recommended its proposed escalation be reduced to 3% to match its electric TDSIC Plan. *Id.* at 12-13. Witness Hanks estimated that using a 3% escalation factor would save ratepayers approximately $27 million based on NIPSCO's current best estimate. *Id*. at 13.

OUCC witness Krieger noted the OUCC's concern with NIPSCO's estimated owner's costs. He believed NIPSCO's application of a "simple" 9% is not supported or justified for a complex project. Mr. Krieger believed the owner's costs would be significantly less if an EPC contractor were hired. Pub. Ex. 4 at pp. 18 -21.

IG witness Gorman stated NIPSCO's cost estimate should be rejected because it is not based on firm pricing as a result of competitive bids received from contractors, but rather on preliminary market analysis of the expected costs. IG Ex. 1 at 8-9.

CAC witnesses James and Sommer also opined that there was a risk of significant cost increases due to NIPSCO's decision to self-build and self-manage the proposed CT Project despite the company's lack of relevant project experience. CAC Ex. 1 at 10; CAC Ex. 2 at 6. As detailed in a report that witnesses James and Sommer co-sponsored, a potential contracting strategy is known as Engineering, Procurement, Construction or EPC, through which a single firm manages all of those steps of a project, often under a lump sum, fixed fee contract. CAC Ex. 2 Attachment RJ-2 at para. 3.1. EPC contracting is common in the industry in large part because most electric utilities lack staff with the experience of designing and managing the construction of power plants. *Id*. But while NIPSCO initially sought bids for EPC contractors, the company rejected all such bids and decided to proceed with a self-build, multi-prime contract arrangement for the CT Project, *id.* at para. 3.2 and 3.3, which is similar to the approach that Duke Energy Indiana used on the Edwardsport IGCC project. Id. at para. 3.7. NIPSCO's self-build, multi-prime contract approach poses significant risks of cost increases and delays, especially because NIPSCO's lead staff who will exercise oversight of the CT

Project construction lack experience constructing power plants. In discovery, NIPSCO identified projects that the NIPSCO CT Project team had previously managed, and all of them were far less costly and complex than the CT Project. *Id*. at para. 3.9 and 3.10, and Confidential Table 1.

OUCC witness Krieger echoed these concerns about NIPSCO's decision to not pursue an EPC contracting approach to the CT Project. As Mr. Krieger explained, EPC contractors bring technology expertise and experience to the project, and typically bear the risks of cost overruns, construction delays, quality assurance, etc. Pub. Ex. 4 at 4-5. By contrast, under the self-build approach, NIPSCO assumes complete responsibility for managing and mitigating financial challenges throughout the project construction lifecycle and takes on a greater share of the risks associated with potential cost increases. *Id*. at 6.

Given NIPSCO's lack of experience managing a project of this size, witness Krieger recommended that any approval of the CT Project be conditioned on ratepayers being of no greater risk than if NIPSCO had hired an EPC contractor. *Id*. at 7. Similarly, witness Sommer proposed a handful of conditions on any approval of the CT Project in light of both the significant costs and risks at issue. CAC Ex. 1 at 36-37. These conditions include a cost cap of $641,223,000 (or a lower amount if the aeroderivative turbines or other components of the best cost estimate are rejected), regular review of the project by a qualified and neutral third party hired at NIPSCO's expense, and disallowance of any costs incurred to accommodate any further delay in the online date of the CT Project

In rebuttal, Mr. Baacke disagreed with CAC witness 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. Pet. Ex. 5-R at 6-7.

In response to several witnesses claims that entering an EPC contract can mitigate cost risk and that 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, in order 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.[7] Pet. Ex. 5-R at 7-8.

In response to OUCC witness Krieger's and CAC witness James's claim that NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned by their belief that NIPSCO lacks large project management experience, (Pub. Ex. 4 at 15-16; CAC Ex. 2, Attachment RJ-2, § 3.9), Mr. Baacke explained that NIPSCO is leveraging engineering firms (including S&L), construction contractors, and suppliers (including the original equipment manufacturer ("OEM")) who have completed these comparable projects. He testified that NIPSCO's Major Projects team, under his direction, has completed a number of projects of varying complexity, including several projects that are first of their kind or one-of-a-kind projects for NIPSCO and at the time of completion, within the industry. He stated that unlike a CT, which has been executed numerous

[7] *See* Pet. Ex. 4-R at 8-9. There, NIPSCO witness Warren also responds to the parties' criticisms of NIPSCO's multi-prime contracting strategy.

times across the country, a project that has not been completed before has complexity of the unknown that NIPSCO has shown it can manage effectively. Pet. Ex. 5-R at 9-10.

Mr. Baacke testified that 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 because it only shows the project variances in absolute dollars, which ignores that 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 to date under his direction and supervision reflect a negative variance of approximately -2.4%. Pet. Ex. 5-R at 14 Table 1. That $1.41 billion overall budget was for 19 separate projects, *id.*, which works out to an average of approximately $74 million per project or approximately 12% of the estimated cost of the CT Project. Witness Baacke opined that 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. Pet. Ex. 5-R at 12-13.

Mr. Baacke testified that NIPSCO's election to self-build with a multi-prime contracting strategy was beneficial in the face of the supply chain challenges that led to the one-year delay of the in-service date for the CT Project because it allowed NIPSCO to pivot without a presently anticipated impact to the best estimate. He noted that 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 that NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its strong vendor relationship. Pet. Ex. 5-S at 5-6.

Mr. Baacke clarified S&L's role and scope of work in the CT Project in responding to CAC witness James that, given their proven experience serving the utility sector, NIPSCO should involve S&L throughout the Project. He stated that S&L has also been contracted by NIPSCO to complete the detailed design for the CT Project. He testified that in addition to these services S&L is already providing, NIPSCO plans to contract with S&L to provide onsite support during construction and start up and testing to provide quality assurance/quality control during installation to ensure the units are brought online once they are built and that the costs associated with these additional services is included in NIPSCO's best estimate. Pet. Ex. 5-R at 15-16.

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 again that 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. Pet. Ex. 5-R at 19-20; Pet. Ex. 8-R, Attachment 8-R-C.

Mr. Baacke emphasized that NIPSCO's best estimate although reasonable, is still an estimate; customers will pay reflecting the actual costs of the CT Project. He testified that the fact that prices for practically all products and materials in the U.S. (and even globally) are increasing, including the key equipment needed to construct the CT Project, is an undeniable macroeconomic fact that is beyond NIPSCO's control. He testified that NIPSCO ran a competitive RFP, engaged S&L to assist with engineering and cost estimation, chose a multi-prime contracting approach that was $100 million lower in cost than any viable EPC option, and has brought a reasonable, best estimate to the Commission to support a finding of best estimate of costs in this proceeding. Pet. Ex. 5-R at 34-35.

C. Ratemaking Treatment of CT Project.

Petitioner's witness 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 would 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. Pet. Ex. 8 at 15-16; Pet. Ex. 8-S at 6.

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The revenue requirement for capital costs included in the GCT would 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 that NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective WACC. Pet. Ex. 8 at 16. 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. Pet. Ex. 8 at 17.

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. Additionally, NIPSCO would 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. Pet. Ex. 8 at 17. Attachment 8-B to Mr. Blissmer's testimony is an exemplar for the GCT Tracker schedule. He also 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 Tracker filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. Pet. Ex. 8 at 19; Pet. Ex. 8-S at 6. As an additional financial incentive under Section 11, NIPSCO requests that the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the IC 8-1-2-42(d) earnings test. Pet. Ex. 8 at 18.

Mr. Blissmer contended that the proposed GCT Mechanism is authorized by new legislation. He testified that 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 that 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 that 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, as shown in his Attachment 8-S-A. He explained that 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.[8] 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 PISCC under the traditional model. He explained that 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. Pet. Ex. 8 at 8-12; Pet. Ex. 8-S at 3-4.

Mr. Blissmer concluded that 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. Pet. Ex. 8-S, pp. 3-4 and 6.

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. Also, NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained that the primary

[8] As set forth in the Verified Petition in this Cause, NIPSCO seeks relief in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT Mechanism or in a general rate case, all as described in the Verified Petition. The request for alternative relief would trigger in the event the proposed GCT is not approved as proposed, which could be either the denial of the GCT or rejection of the forward looking nature of the GCT. Either of these changes to NIPSCO's proposal would result in PISCC and the commencement of depreciation before rate recovery has commenced.

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 that CWIP ratemaking improves near term cash flow and mitigates the negative effects of the significant additional debt taken on to construct the project. Pet. Ex. 8 at 12-14.

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."[9] 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. Pet. Ex. 8 at 13.

Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on a number of different factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates that 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. Pet. Ex. 8-S at 8.

OUCC witness Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. Pub. Ex. 5 at 4 She contended that NIPSCO should instead use project-specific financing costs or the cost of short-term debt.

IG witness Gorman testified that simply because there are gross financial savings this does not mean that the CWIP tracker is just and reasonable. IG. Ex. 1 at 15. Both IG witness Gorman and CAC witness Inskeep claimed that the analysis of gross financing savings is inconsistent with the Statute in that it does not include net present value analysis. IG Ex. 1 at 16; CAC Ex. 3 at 7, 24. They both claimed that simply because there may be financing cost savings does not mean that the proposal is just and reasonable.

CAC witness Inskeep testified that the the CT Project will be displacing market purchases and existing natural gas generation, not coal-fired generation as referenced in I.C. § 8-1-37-4, which is the definition of "clean energy project" that NIPSCO is relying on to qualify for CWIP financing. To support this contention, Mr. Inskeep observed that Schahfer Units 17 and 18 are retiring in 2025, regardless of the fate of the CT Project, while the CT Project is not proposed to be placed in service until 2027, assuming no further delays. Mr. Inskeep averred that Schahfer Units 17 and 18 will have already had their electricity generation displaced by other resources, largely renewable technologies, years prior to the CT Project coming online, and also that NIPSCO expressly delayed the retirement of Schahfer Units 17 and 18 from 2023 to 2025 due to delays in the construction of new solar projects. Mr. Inskeep also testified that the proposed CT Project might not displace coal-fired generation from Michigan City, because (i) NIPSCO is under no obligation to retire Michigan City 12 by the stated planned date of 2028, and has previously shown a willingness to delay planned retirement dates; and (ii) the gas-fired CT Project will primarily be displacing electricity generation

[9] *See*, *e.g.*, *Tucson Elec. Power Co.*, 174 FERC ¶ 61,223 at P 25 (2021) (stating that allowing transmission developers "to include 100% CWIP in rate base would result in greater rate stability for customers by reducing 'rate shock' when certain large-scale transmission projects come on line.") (citing 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 12 (2012) (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229 (2011)); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 43, *reh'g denied*, 124 FERC ¶ 61,229 (2008))).

from the gas-fired, peaking Schahfer Units 16A and 16B that are much more clearly tied together in timing and resource type. Mr. Inskeep argued that based on the above, the CT Project cannot qualify for CWIP financing under I.C. ch. 8-1-8.8. CAC Ex. 3 at 8-9.

Mr. Inskeep further testified that NIPSCO is proposing a forward-looking CWIP cost recovery mechanism, which could allow NIPSCO to begin collecting CWIP financing costs before a portion of the financing costs are actually incurred by NIPSCO. He observed that as an illustrative example, NIPSCO is proposing to file its first tracker petition on October 15, 2024, at which time it will include average projected CWIP balances from March 2025 through August 2025 and actual and projected AFUDC through February 2025 -with the resulting rates under the GCT Rider going into effect in March 2025. Mr. Inskeep showed that the projected capital balance as of March 31, 2025, is estimated to be $52,828,766, while the revenue collected via the GCT Rider per month, beginning in March, would be based on a capital balance of $83,505,291 (the weighted average capital balance of March through August 2025). Mr. Inskeep also argued that using projected costs for the GCT rider mechanism is inconsistent with the past-tense word "incurred" used in the CWIP statute. CAC Ex. 3 at 12-13.

Mr. Inskeep opined that CWIP is a violation of the "used and useful" principle because it allows the utility to begin cost recovery prior to the plant being placed in service when CWIP is included in rate base. He noted that the standard helps ensure that the customers who pay for the costs of utility plant, including financing costs, are the same customers who receive the benefit from the utility plant; CWIP, according to Mr. Inskeep, creates a mismatch across time in the ratepayers who pay for, versus the ratepayers who benefit from, the new utility plant. Moreover, if the project is not completed, ratepayers will have financed costs of a project of no ultimate value to them. Mr. Inskeep cited other examples of utility projects, including Edwardsport IGCC, in Indiana, that ultimately went highly over budget or were not completed. Mr. Inskeep recommended that, in light of the risk transfer inherent in CWIP cost recovery, the Commission should ensure CWIP ratemaking proposals meet all statutory requirements and that the interests of consumers are appropriately considered. CAC Ex. 3 at 15-18.

CAC witness Inskeep also submitted that NIPSCO's calculations on cost savings resulting from CWIP financing were erroneous calculations of *nominal* gross financing savings when NIPSCO should have calculated *present value* gross financing savings. Mr. Inskeep averred that NIPSCO failed to consider the time value of money, by applying an appropriate discount rate. Mr. Inskeep stated that ratepayers have alternate uses for their money such that considering the time value of money comports with sound public policy. Mr. Inskeep described CWIP cost recovery as forcing ratepayers to provide interest-free loans upfront to NIPSCO to cover financing costs in return for a stream of lower nominal financing costs in the future (due to AFUDC and PISCC not accruing). Mr. Inskeep testified that under a calculation that compares nominal revenue requirement (without discounting to present value), CWIP financing would always be shown to produce gross financing savings over the life of the project. Mr. Inskeep calculated a present value revenue requirement for each of CWIP financing and traditional cost recovery: using NIPSCO's currently approved weighted average cost of capital of 6.88%, the CT Project capital cost revenue requirement over 2025-2058 would be $685,550,647 under NIPSCO's CWIP proposal compared to a PVRR of $671,616,758 (around $14 million less) under traditional financing mechanisms. Mr. Inskeep also used alternate discount rates of 10% and 15%, which he stated could be more apt for residential customers, citing academic research on time preference. The alternate discount rates increased the $14 million savings figure to $28.4 million and $38.7 million, respectively, of savings using traditional ratemaking. CAC Ex. 3 at 18-23.

In his rebuttal testimony, Mr. Blissmer testified NIPSCO is modifying its GCT proposal to remove WACC, and to apply its then current AFUDC rate. Pet. Ex. 8-R at 3. 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. See Attachment 8-R-A (forward-looking) and Attachment 8-R-B (backward-looking). He testified that (1) as shown in 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 that 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. Pet. Ex. 8-R at 3-4. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Tracker. Pet. Ex. 8-R at 9-12. In response to Mr. Inskeep's claim that the delay of in-service date of the CT Project has caused an increase in total financing costs, Mr. Blissmer asserted that Inskeep had failed to acknowledge Blissmer's supplemental direct testimony that the one-year delay produces $65 million in customer savings through 2028. *Id*. at 12.

D. <u>Ongoing Review of CT Project.</u>

NIPSCO's Petition requested that the Commission, should it grant the requested CPCN for the CT Project, exercise ongoing review of the construction progress pursuant to I.C. § 8-1-8.5-6. Mr. Baacke of NIPSCO elaborated in direct testimony that NIPSCO would provide "periodic" updates on the CT Project including progress reports and cost estimate updates until it goes into service. Pet. Ex. 5 at 19.

OUCC witness Krieger recommended 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. Pub. Ex. 4 at 30-31.

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CAC witnesses Sommer and James, after recounting the extensive flaws in NIPSCO's construction management plan as discussed above, testified that the management role of Sargent and Lundy has been and will be insufficient to acceptably mitigate risks in the construction process. In this light, Ms. Sommer recommended that the Commission hire a qualified, neutral third-party expert, at NIPSCO's expense, to review the project at critical points during execution, intended to help inform the record as to whether NIPSCO exercises good judgment and prudent decision making in executing the CT Project and whether a CPCN should be later modified or revoked. CAC Ex. 1 at 7, 36. Mr. James, drawing on his experience in construction management in the utility sector, further recommended that the third party should assist with management of Sargent and Lundy, as well as facilitate performance of joint S&L/NIPSCO project readiness studies, Hazards and Operability studies, post–Front End Loading contractor selection, downstream EPC execution, and development of a comprehensive project risk register program. Mr. James stressed that the third-party oversight program must emphasize interface management and be led by a senior NIPSCO team member as

Interface Coordinator. CAC Ex. 2 at 7.

Ms. Becker (the successor to Mr. Sears) testified that Mr. Krieger's recommended quarterly reporting requirements go beyond the yearly reporting required by the statute. She stated that 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. Pet. Ex. 1-R at 26-27. Ms. Becker characterized Ms. Sommer's proposal for the external construction consultant (to be paid by NIPSCO) as "forc[ing] NIPSCO […] to expend dollars related to this Project and not be allowed to recover them from its customers." Pet. Ex. 1-R at 24.

Commented [CAC3]: ***Comment for the Commission***: The first three sentences here are moved up from the Commission Discussion and Findings section in NIPSCO's Proposed Order.

6. <u>Commission Discussion and Findings.</u> In its 2021 IRP, NIPSCO identified the need for up to 300 MW of dispatchable gas combustion turbine capacity. 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 an additional approximately 100 MW of flexible dispatchable capacity, and the utility now proposes a gas-fired combustion turbine resource between 400 MW and 442 MW to meet that need. This resource, known as the proposed CT Project, would replace NIPSCO's retiring gas peaker units at the Schahfer site and support system reliability and resiliency, while NIPSCO deploys several types of clean energy resources to facilitate the planned retirement of the majority of NIPSCO's coal-fired generation by the end of 2025 and the complete retirement of coal generation by 2028. NIPSCO seeks to construct and operate the CT Project as a part of its overall, diverse portfolio of generation assets. Once operational, the facility is proposed to provide key reliability attributes and additional capacity (especially in the winter season) and help mitigate customers' price exposure on the hottest and coldest days of the year. NIPSCO's evidence supports that reliability and resource adequacy concerns have been voiced by many important organizations, including NERC, MISO, MISO's Independent Market Monitor ("IMM"), OMS, and others. Pet. Ex. 3 at 8-11, 17; Pet Ex. 6 at 17.

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. In addition, the Flexible Resource Analysis identified energy market exposure 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. It then evaluated the change in 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. Pet. Ex. 7, Conf. Att. 7-D at 3-4, 10, 62. However, the Commission notes that the Flexible Resource Analysis was limited in that it did not identify gas peaker generation as a preferred solution (NIPSCO-CAC Ex. 6 at 15-16, 31); did not simulate the dispatch of resources (CAC Ex. 1 at 20); did not quantify the cost of potential energy market exposure (*id.*); and did not compare the cost of different resource options (*id.*). Moreover, the portion of the Flexible Resource Analysis that included the remainder of MISO Zone 6 and the PJM regions of Indiana and Illinois in a "system"-level analysis was limited in that the PJM load forecasts used were from 2020, prior to new distributed generation and EE requirements enacted in Illinois' Public Act 102-0662 of 2021, also known as the Climate and Equitable Jobs Act. NIPSCO-CAC Ex. 6 at 30, 35. Additionally, as discussed below in our discussion of the statutory Five Pillars at section 6.D, the Flexible Resource Analysis did not meet the legal requirements for new IRP analysis to justify a change from the 2021 IRP's preferred portfolio, and lacked the transparency and opportunity for meaningful stakeholder engagement that are important elements of resource planning.

As further discussed above and below, NIPSCO has proposed an extremely expensive project with three aeroderivative gas turbines (in addition to one frame turbine), which will more than double the construction cost (per installed megawatt) compared to that modeled in NIPSCO's 2021 IRP. NIPSCO did not justify why aeroderivatives are needed, relying on a scoring rubric for ranking options that was created based on nontransparent reasons and then applied nontransparently to create scores. Worryingly, NIPSCO proposes to manage the entire CT Project's construction without an EPC contractor, although NIPSCO's lead personnel slated to oversee the construction project have never worked on construction of a power plant in their careers, and NIPSCO has declined to follow best practices in construction planning to mitigate risks on the front end, before construction begins.

Through the detailed analysis below, we conclude that moving forward on the CT Project would not be the best economic and most reliable decision for NIPSCO's customers. We will explain through our review of statutory requirements why NIPSCO did not meet its burden to justify its request.

A. **<u>CPCN for CT Project Under Ind. Code § 8-1-8.5-5.</u>** 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. **<u>Best Estimate of Costs.</u>** 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[.]"

As discussed above, Mr. Baacke of NIPSCO described the CT Project, including key specifications and characteristics, as well as NIPSCO's approach to configuration selection and contracting strategy. Pet. Ex. 5 at 4-5. He also provided the project schedule, an estimate of costs of construction, and NIPSCO's request for ongoing review pursuant to Ind. Code § 8-1-8.5-6. *Id*. at 14-19. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit of about 200 MW with three smaller aeroderivative turbine units (around 56 MW each) or similarly sized industrial frame units (dependent on the results of the CT original equipment manufacturer ("OEM") bid event). *Id.* at 3. Mr. Walter stated that 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. Pet. Ex. 2 at 31.

NIPSCO witness Mr. Walter testified that, in terms of project development, NIPSCO began with a competitive RFP and engaged the assistance of Sargent and Lundy to design the project and develop the scope of the RFP. According to Mr. Walter, based on available information in the market (that is, after receiving bids from potential RFP contractors), NIPSCO determined the best path forward is to self-build the CT Project. Pet Ex. 2 at 30-31. NIPSCO intends to leverage the available

MISO interconnection rights from the retiring Schahfer Units 17 and 18 by building the CT Project at the Schahfer site. Pet. Ex. 2 at 12. NIPSCO issued its Turbine Equipment RFP in June 2023 and executed an agreement with its selected turbine manufacturer on March 29, 2024, to reserve its selected equipment. NIPSCO-CAC Ex. 3 at 8; NIPSCO-CAC Ex. 8 at 5-7; NIPSCO-CAC Ex. 3-C at 55. However, NIPSCO still had not finalized a Limited Notice to Proceed ("LNTP") by June 2024, shortly before the evidentiary hearing in this matter. NIPSCO-CAC Ex. 3 at 18, CAC 25-001(a).

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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, as a result, NIPSCO shifted the expected in-service date for the CT Project from year-end 2026 to year-end 2027. Pet. Ex. 5-S at 2-5. Even with this update to the project schedule, the best estimate of the total cost of construction did not change from NIPSCO's direct testimony. *Id.* at 11-12.

Mr. Blissmer testified that 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. Pet. Ex. 8 at 21. 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. Pet. Ex. 5-R, Attachment 5-R-A and Confidential Attachment 5-R-B. NIPSCO through due diligence confirmed its cost estimate in its supplemental testimony based on updated supply chain information, which NIPSCO witness Baacke further testified to in rebuttal, confirming that NIPSCO's best estimate of the total cost of construction was updated with information received from bid events for the CT original equipment manufacturer, generator step-up transformers, unit auxiliary transformers, and diesel generator, which resulted in increases and decreases to certain line items. *Id.* at 19-20. He also explained that NIPSCO removed escalation and reduced the amount of contingency associated with owner's costs and certain equipment. *Id.* at 20. As of its rebuttal filing, the total estimated cost of the CT Project, including estimated AFUDC of $2,680,234, is $643,903,234. Pet. Ex. 8-R, Attachment 8-R-C. This AFUDC estimate assumes NIPSCO's proposed forward looking GCT Mechanism is approved.

Challenges to NIPSCO's best estimate can be summarized as follows:

- NIPSCO's preferred configuration for the CT Project should be rejected because its front-end design process was inadequate, and the preferred configuration's three aeroderivative turbines are too expensive and not cost justified;
- Out of concern with NIPSCO's project management experience, NIPSCO should not self-build the CT Project and should contract with an EPC instead;
- NIPSCO's best estimate contains duplicative or unreasonably high cost components, including contingency, owner's costs, escalation, and indirect costs; and
- NIPSCO's best estimate includes unnecessary pollution control technology, which can be sought in a subsequent federally mandated cost tracker proceeding, as necessary.

(a) <u>Configuration of CT Project.</u> As discussed in more detail above, CAC witness Mr. James opined (CAC Ex. 2, Attachment RJ-2, §§ 4.1 and 4.2) that 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 final investment decision remains questionable. d Mr. Warren averred on rebuttal that FEED studies evaluate whether a project should move forward at each step or stage and is rendered unnecessary by the IRP process and S&L's Engineering Study. Pet. Ex. 4-R at 4, 10. We are concerned, however, that NIPSCO's lack of experience in managing power construction projects, both organizationally and in the persons of its individual leaders, makes it all the more crucial that NIPSCO carry out prudent front-end design. FEED studies have been used for other projects in Indiana, often in connection with novel technologies, such as coal gasification or carbon capture. *Duke Energy Indiana, Inc.*, Consolidated Cause Nos. 43114 and 43114-S1, at 6, (IURC 11/20/2007); *Indiana Michigan Power Co.,* Cause No. 44075 (IURC 2/13/2013). NIPSCO's plans to self-build the CT Project and use aeroderivative turbines are, while perhaps not novel in the utility industry, new to NIPSCO. NIPSCO has not used a multi-prime approach for building a gas power plant. Pub. Ex. 4 at 13. S&L's Engineering Study, Confidential Attachment 4-A, purported to provide NIPSCO with the level of information needed to determine the technology and configuration that best met the simple cycle gas turbine requirements. However, the specific configuration chosen by NIPSCO around June-July 2022 (Pet. Ex. 4-R, Att. 4-R-A at 2) was arrived at based on an opaque, subjective system that cannot be replicated by observers working with the same data, as discussed more below in section 6.D.i. Additionally, the Engineering Study included only Piping and Instrumentation Diagrams ("P&IDs") marked with words other than "issued for design," which is a grave omission according to industry experts. The Engineering Study also contained no heat or material balances, another critical failure. CAC Ex. 2, Att. RJ-2, §§ 2.3, 2.5; Pet. Ex. 4, Conf. Att. 4-A at Appx. 11. Based on the record evidence, we find that NIPSCO's CT Project was not properly scoped, designed, and engineered. This alone makes it difficult for the Commission to deem any cost estimate a best estimate of costs..

Commented [CAC5]: ***Comment for the Commission regarding confidential information***: [redacted]

The OUCC and CAC also took issue with NIPSCO's EPC RFP. By arguing that NIPSCO "self-selected" a configuration with aeroderivative turbines (Pub. Ex. 2 at 16) and that NIPSCO did not evaluate other configurations, including an all-industrial frame configuration (Pub. Ex. 3 at 7-8), the OUCC asserts that NIPSCO's EPC RFP was too narrow. At the same time, CAC witness James (CAC Ex. 2, § Attachment RJ-2, 3.4) alleged that a lack of detail contributed to the poor response rate to the RFP. Although they take opposite positions regarding the RFP, the OUCC and CAC both challenge the aeroderivative turbines because of their cost. OUCC witnesses Sanka and Hanks asserted that, from a cost-effectiveness perspective, the operational characteristics of the aeroderivative units have not been shown to justify the higher overall expenditure when compared to a configuration comprised of only industrial frame turbines. CAC witness Sommer recommended denial of the CT Project particularly because of the three aeroderivative turbines and suggested reducing the cost of the Project by replacing the aeroderivative turbines with a second industrial frame machine.

The amount by which the OUCC seeks to reduce the best estimate to remove the aeroderivative configuration follows from data presented by NIPSCO, and is consistent with the amount identified by CAC witness Sommer. Witness Krieger provides the reduction in cost as a range of $30-40 million, citing to witness Sanka. Pub. Ex. 4 at 26. Relying on bid data produced by NIPSCO in discovery, Witness Sanka compared the cost of three aeroderivative units to the cost of a single larger frame unit using data pulled from her Confidential Attachment RS-3, which showed that the latter was $37.6

million lower in cost than the former. Pub. Ex. 3C at 9. CAC witness Sommer, relying on a similar comparison in S&L's Engineering Study, identified a very similar reduction in cost if the three aeroderivative units were replaced by a single larger frame unit. CAC Ex. 1C at 6-7, citing Pet. Conf. Att. 4-A at 1-3. While NIPSCO criticizes this cost estimate because it does not compare three aeroderivative units to three similarly sized industrial frame units, the decision matrix in Appendix 19 of the S&L Study shows that it is NIPSCO itself that failed to make such a comparison. As such, we credit the approximately $37.6 million savings identified by witnesses Sanka and Sommer.

We acknowledge that aeroderivative turbines provide some important operational advantages in comparison to industrial frame turbines, such as faster ramp times, the ability to start and stop multiple times per day without impacting maintenance cycles, and higher efficiency. Pet. Ex. 4-R at 20-21, and NIPSCO-CAC Ex. 3 at 3–4. NIPSCO, however, has failed to provide any assessment showing that those advantages outweigh the significantly higher cost of aeroderivative units. And while NIPSCO references a 10-minute startup time for aeroderivative units, the company's analyses did not actually find that fast startup time was a necessary characteristic of the CT Project. Additionally, NIPSCO did not provide evidence that other new gas generation projects in the MISO or Indiana footprint are unable to use only frame turbines. For example, the 460 MW gas combustion turbine project that we approved in Cause No. 45564 a little over two years ago involved two F-class frame turbines.

The substantial cost of the proposed CT Project also gives us pause; the record clearly establishes that the approximately $1,600/kW cost far exceeds average costs for gas combustion turbines reported by the U.S. Energy Information Administration, the cost of CEI South's CTs in Cause No. 45564, the bids for thermal resources received in response to NIPSCO's 2022 All-Source RFP, the cost for the gas CT included in NIPSCO's 2021 IRP portfolio, and the cost of gas CT projects that CAC witness Sommer has seen. While NIPSCO quibbles with some of those comparisons, the substantial cost of the CT Project calls for careful scrutiny especially given the increasing rates and affordability challenges confronting NIPSCO's ratepayers.

The technical specifications for the combustion turbine equipment as expressed in the EPC RFP released in August 2022 were not sufficiently defined, however, as discussed by CAC witness James. We also note inconsistencies in NIPSCO's representations of whether EPC bidders were expected to conform to a "technical specification for the 2022 EPC RFP using the preferred configuration of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame unit" (Pet. Ex. 4-R, Att. 4-R-A at 2) or whether the bids were required to include "a combination of industrial-frame and aeroderivative CTs (and optionally, RICE units)" as the RFP stated (OUCC Ex. 2, Att. JWH-1 at 12). It appears that an EPC bid's inclusion of only one type of turbines was viewed by NIPSCO as a reason to reject it. NIPSCO-CAC Ex. 4 at 17-18. We also find that NIPSCO's preferred configuration of one industrial frame turbine and three aeroderivative turbines, as determined through the Engineering Study's Appendix 19, was (as discussed below in section 6.D.i) the result of an arbitrary decision process that the Commission is unable to evaluate as sound or not. We appreciate the record evidence on the important, load-following attributes that aeroderivative turbines can provide, but we cannot find that the aeroderivative turbines are cost-justified or 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 Krieger testified (pp. 5-6) 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 James testified (Attachment RJ-2, 3.7 and 3.9) that NIPSCO lacks experience constructing power plants and that 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 ("IGCC") project. Both OUCC and CAC witnesses raised the complete lack of experience of NIPSCO's lead individual construction managers in overseeing power plant construction projects.

The record contains substantial evidence regarding the results of NIPSCO's EPC RFP bid event. 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: one with a proposed configuration of ten refurbished aeroderivative machines and another with only two larger industrial frame units that was less than five pages of content. Pet. Ex. 5 at 11; Pet. Ex. 10. Having received suboptimal responses from its bidders, NIPSCO summarily rejected two bids as nonresponsive and then conducted due diligence, discussed further below, to evaluate the remaining 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 concerns that, without an EPC contractor, the risk of ratepayer-borne cost overruns from the construction of the CT Project has increased. NIPSCO solicited bids from the EPC market and received only one bid that would have met its technical requirements, at a price that is $100 million more than NIPSCO's best estimate of construction in this Cause. Pet. Ex. 10 at 2. While an EPC contract is a valid way to execute a generation project, it is not a requirement to receive a CPCN in the State of Indiana nor is it a guarantee against project cost overruns. While our responsibility under Section 8-1-8.5-5(b)(1) is not to accept or reject an overall construction management approach – it is simply to make a finding of a best estimate of costs – we cannot help but note that the self-build approach opens the potential range of cost outcomes more widely. It is true that a fixed price under an EPC contract may nonetheless increase due to change orders, as Mr. Baacke noted (Pet. Ex. 5-R at 8) but under the proposed self-build, multi-prime approach, NIPSCO has not even entered into contracts yet with construction companies, nor a final contract with a turbine supplier. The Commission has serious concern about the potential for costs to increase above the estimate that NIPSCO has provided, should construction move forward.

OUCC witness Krieger and CAC witnesses Sommer and James inform us that NIPSCO does not have experience building gas-fired generation projects of this scale, and they are concerned by the fact that NIPSCO, and its individual lead construction managers, lack large project management experience. Pub. Ex. 4 at 15-16; CAC Ex. 2 at Attachment RJ-2, 3.9; CAC Ex. 1 at 14. This would not necessarily be a devastating concern were NIPSCO going to engage an EPC contractor with responsibility for cost control and project completion. But, although we appreciate the intended role of Sargent and Lundy in helping to manage and monitor construction progress (Pet. Ex. 4-R at 18-19) we note that S&L has not served as a mechanical contractor, civil construction contractor, or electrical contractor on a thermal power plant project within the past 5 years. NIPSCO-CAC Ex. 3 at 17. We would be more comfortable if the proverbial buck stopped with a more experienced responsible party.

Mr. Krieger also suggested that the supply chain challenges with 345 kV breakers and generator step-up transformers that initiated NIPSCO's decision to shift the CT Project's in-service date from end-of-year 2026 to end-of-year 2027 were well known when NIPSCO originally filed its case and that NIPSCO engineering and project management should have been well aware of these challenges when NIPSCO's September 2023 Petition was filed. We take this point, but NIPSCO's proposal before us is now for a project going online at the end of 2027. When challenges arise, we encourage and expect our regulated utilities to pivot as needed to reasonably respond, particularly when doing so would result in a savings to its customers. Rather than sitting on its hands, NIPSCO proactively notified the parties and the Commission that its in-service date had changed due to supply chain constraints, which was proved out in its rebuttal testimony showing a 70% cost increase to 345 kV breakers in three months. Pet. Ex. 5-R at 26.

Put simply, CAC and NIPSCO both agree demand for EPC contractors in the power industry is high. CAC Ex. 1 at 9, Pet. Ex. 4-R at 7-8. NIPSCO witness Warren testified that this high level of demand has shifted interest from EPC contractors to larger projects that maximize their potential profits. Pet. Ex. 4-R at 7-8. The utility sector in this State cannot simply close down shop under these economic circumstances, in light of the imperative to continue building out new resources to meet customer needs, Nonetheless, the Commission would be more comfortable with NIPSCO's proposed project if it either had more experienced hands sitting in-house leading the project, or else if it had constructed an EPC RFP that was better designed to attract capable, responsive bidders. We do not believe it would be prudent to move forward with construction based on the factors we have identified.

Unquestionably, S&L and witness Warren have a great deal of experience advising on the execution of gas-fired generation projects. Pet. Ex. 4 at 7. S&L has led the design and engineering of the CT Project thus far, through creating the technical specifications for the ECP RFP bid event, and by consulting with NIPSCO as it decided not to pursue an EPC contract in favor of self-building the CT Project using a multi prime contracting strategy. CAC witness James recommends (Attachment RJ-2, 4.10) NIPSCO involve S&L through the CT Project as S&L has proven experience serving the utility sector. We have substantial evidence upon which to base the conclusion that NIPSCO has selected a competent partner in S&L, and that this collaboration can enhance NIPSCO's construction oversight. Yet our doubts about NIPSCO's internal expertise to successfully complete the CT Project are difficult to overcome,.

As discussed below, 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 in excess of 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. *Southern Ind. Gas & Elec. Co.,* Cause No. 45836 (IURC 6/6/2023), at 28. The CAC and OUCC's fears over risk and escalation can be mitigated somewhat through ongoing review, although the Commission still has the responsibility to act as gatekeeper in approving a CPCN request to begin with based on the proposed project structure.

This case was originally filed in September 2023 and was extended by NIPSCO as a proactive response to major shifts in critical supply chains that occurred at the same time that MISO unveiled significant changes to its resource adequacy construct and seasonal accreditation factors. We acknowledge that this decision by NIPSCO points to prudent decision-making in the face of varied challenges and constraints, although we wish NIPSCO had, for example, updated its modeling to include the new long-range capacity accreditation rates announced by MISO around the time NIPSCO filed its supplemental testimony, as discussed below in section 6.A.ii.

(c) **Best Estimate Cost Components.** OUCC witnesses recommended changes to NIPSCO's $641,233,000 cost estimate that would reduce the total cost by approximately $130 million. Pub. Ex. 1 at 10. One major cost reduction would be from the denial of the aeroderivative turbines, as recommended by OUCC and CAC. Pub. Ex. 3 at 10; CAC Ex. 1 at 10-12, 35. As discussed above, we agree that the added cost of the aeroderivative turbines has not been justified and, therefore, would remove $37.6 million from NIPSCO's cost estimate to reflect disapproval of those turbines.

OUCC witnesses Hanks and Krieger challenged NIPSCO's indirect costs, alleging that they lacked support and were potentially double counted in S&L's cost estimate. Based on our review of the record, it appears that no double counting actually occurred. While it is understandable that witnesses Hanks and Krieger would suspect double counting given the inconsistent cost categorization and labelling used by NIPSCO versus S&L, NIPSCO explained in response to CAC discovery that the itemization of S&L's indirect costs in Section 10.2.3 of the Engineering Study do not duplicate NIPSCO's indirect costs. Pet. Ex. 5-R at 21-22. As such, NIPSCO's evidence supports concluding no indirect costs were double counted.

OUCC witness Hanks also challenged NIPSCO's proposed 5% escalation factor and recommended that it be reduced to 3%, as was approved in NIPSCO's electric TDSIC Plan. NIPSCO contends that a 5% escalation factor is appropriate because the electric TDSIC Plan case reflected cost from before the pandemic and, therefore, did not account for the resulting supply chain and inflation issues. Pet. Ex. 5-R at 25. We note, however, that even since the pandemic began, we have approved escalation rates even lower than 3%, such as the 2.4% rate that CEI North proposed in its most recent TDSIC Plan, which we approved in April 2022. *See CEI North*, Cause No. 45611 (April 20, 2022) at p. 4. As such, we believe a reduction of NIPSCO's escalation rate to 3% is justified, which would reduce the best estimate by approximately $27 million. Pub. Ex. 2 at 13.

OUCC witness Krieger also opposed NIPSCO's 9% estimate for owner's costs, arguing that it is too simple for a high cost capital project. 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. Pet. Ex. 5-R at 30-32 and Attachment 5-R-A. Based on Mr. Baacke's rebuttal testimony, we conclude that NIPSCO's estimated owner's costs for its self-build project are informed by executed contracts and are reasonable.

(d) **Pollution Control Technology.** A final element of cost reduction stems from OUCC witness Armstrong's testimony that the Selective Catalytic Reduction ("SCR") controls 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 FMCA statute. Pub. Ex 1 at 19. Mr. Baacke's rebuttal testimony confirmed that the SCRs are not needed to comply with existing regulatory standards (Pet. Ex. 5-R at 20); therefore, NIPSCO updated the best estimate to reflect the removal of the SCR controls. We approve this revision to the scope of the CT Project, though question why, given the removal of the SCRs, the overall cost estimate for the CT Project cited in Mr. Baacke's rebuttal remains the same as in the initial application, Pet. Ex. 5-R at 19.

(e) **Conclusion on Best Estimate.** After reviewing the evidence of record, including NIPSCO's evidence in support of its best estimate on the cost to construct the CT Project, which is driven by its preferred configuration and contracting strategy, we find that NIPSCO's best estimate of $641,223,000 is based on a detailed engineering analysis, as well as information from turbine manufacturers and contractor bid events from which capital costs, operating costs, performance characteristics, and construction schedules were determined. The best estimate may not, however, reasonably reflect the potential cost impact of project risk due to factors both within and without NIPSCO's control, which will be magnified by NIPSCO's multi-prime construction management strategy undertaken without adequate experience in the thermal power plant construction space. We also conclude, as discussed above, that the extra costs stemming from inclusion of the aeroderivative turbines and the use of an inflated 5% escalation rate should be removed from the best estimate. Removing the aeroderivative turbines and lowering the escalation rate to 3% would reduce the best estimate by $37.6 million and $27 million, respectively, for a total savings of $64.6 million. Therefore, we find that based on the evidence of record, the best estimate of the cost of construction of the CT Project should be $576,633,000. We remind NIPSCO and all litigants and stakeholders that pursuant to I.C. §§ 8-1-8.5-6 and -6.5, if the CPCN were approved, only $576,633,000 would (as a result of this finding) be pre-approved for inclusion in rate base in a future general electric rate case after project completion, unless an increased cost amount is approved through our review of the project progress following this order, which we would exercise with the utmost scrutiny that ratepayers of this State deserve. The standard would be whether the public convenience and necessity continue to require the project at the increased cost estimate. See, e.g., *CEI South*, Cause No. 45836, at 28 (June 6, 2023); *N. Indiana Pub. Serv. Co. LLC*, Cause No. 45529, at 26 (July 28, 2021). The previous three sentences about Sections 6 and 6.5 are, of course, conditional on whether we determine to approve the CPCN request, which we will address in the coming pages.

ii. <u>Consistency with Petitioner's 2021 IRP and 2023 Portfolio Analysis.</u> 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). However, as discussed below in section 6.D.i where we address the statutory Five Pillars, changes in the inputs, data, assumptions, methods, models, judgment factors, and rationales embodied in a utility's most recent IRP must be fully explained and justified with supporting evidence, including an updated IRP analysis. 170 IAC 4-7-2.5(b). The Portfolio Analysis and Flexible Resource Analysis sponsored by Mr. Augustine do not suffice to explain why NIPSCO now proposes a 400 MW project with one industrial frame turbine and three aeroderivative turbines, 33% larger and over twice the cost per kW compared to what NIPSCO contemplated in 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 All-Source 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) at 19. 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'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 that earlier retirement of coal capacity resulted in lower costs for customers. The 2021 IRP also concluded that 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 ("DER"), 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 also conducted an additional technical reliability assessment to ensure that the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and 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 that 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.[10]

As part of its petition in the instant matter, NIPSCO performed the 2023 Portfolio Analysis (presented in Pet. Ex. 7, Att. 7-C), sponsored by witness Augustine, to consider changes that have occurred since its 2021 IRP and thereby determine whether its preferred portfolio and the Short-Term Action Plan are still reasonable. Unfortunately, the Portfolio Analysis was not structured to arrive at an optimized portfolio after allowing generation expansion parameters to vary across technologies; instead, the Portfolio Analysis started with a cramped set of three portfolios to analyze, none of which were based on the 2021 IRP's Short-Term Action Plan of installing 300 MW of new gas peaking generation.

What's more, the Portfolio Analysis assumed that under MISO capacity accreditation methodologies, the accreditation rate of four-hour duration storage will decline to 70% by 2040, while

[10] Section 9.2.7.6 of NIPSCO's 2021 IRP for the detailed summary of reliability scoring, as well as the technical reliability assessment addendum in IRP Confidential Appendix E (included in Confidential Attachment 7-B).

a gas peaker will have an accreditation rate around 95%. Pet. Ex. 7 at 35. Yet Ms. Sommer showed that based on MISO's latest accreditation methodology proposal (currently under consideration by FERC in the pending Docket No. ER24-1638), NIPSCO's accreditation assumptions for storage were over 11 percentage points too low in summer and over 8 percentage points too low in winter; and NIPSCO's accreditation assumptions for gas were 9 percentage points too high in summer and 31 percentage points too high in winter. Stated differently, under MISO's latest plans, storage would have a higher accreditation rate than gas (94 percent against 88 percent) in summer, and a higher accreditation rate than gas (91 percent against 66 percent) in winter. CAC Ex. 1 at 22. NIPSCO's rebuttal testimony was filed in May, following MISO's submission of its capacity accreditation reform proposal to FERC in March, but witness Augustine (while acknowledging the new FERC case) declined to update the Portfolio Analysis accordingly to account for pending, changes to the MISO resource adequacy construct. Pet. Ex. 7-R at 19.

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). We are sympathetic to a utility's position when it sets certain plans based on one modeling exercise and then relevant conditions in the world change. However, with hundreds of millions of dollars of ratepayer money at stake, it is imperative that the utility update its view of the world accordingly before taking a resource action, if not too late. Here, NIPSCO failed to do so.

IG witness 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. IG Ex. 1 at 5-6. While we believe NIPSCO did update its modeling in the 2023 Portfolio Analysis to incorporate certain favorable and unfavorable national developments impacting development cost and timing, Mr. Gorman's critique about MISO's resource adequacy construct is certainly salient, as discussed above.

Mr. Gorman also testified that 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 posited three reasons why this criticism is invalid: (1) the Rate 831/531 Modification Agreement approved in Cause No. 45772 recognizes that 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 witness 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 scenario with the exact reduction in Tier 1 demand commitments suggested by witness Gorman, and NIPSCO's preferred portfolio was found to perform well under such assumptions. Pet. Ex 7-R at 17-18. We find Mr. Augustine's explanation convincing. 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. As witness Becker pointed out, the 531 customers *may* reduce their load, but they have not done so yet and NIPSCO cannot assume that they necessarily will. Pet. Ex. 1-R at 14. Furthermore, and as noted by CAC witness Sommer, NIPSCO likely will need *an additional* 400+ MW of capacity beginning in 2028, which could be partially addressed by further reductions of 531 Tier 1 load. *Id.;* CAC Ex. 1 at 22. This issue by itself is not a reason to reject NIPSCO’s CT Project. (Elsewhere in this Order, we discuss separate concerns with the load forecast used in the Flexible Resource Analysis.)

Overall, the evidence of record demonstrates that the CT Project is not consistent with or supported by the 2021 IRP and 2023 Portfolio Analysis. The 2021 IRP concluded that 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 to meet current and future load and reserve margin requirements. The 2023 Portfolio Analysis suffers from serious flaws: first, the 2021 IRP’s preferred portfolio (which called for up to 300 MW of new gas peaking capacity) was “adjusted” to increase the gas peaker from 300 MW to 400 MW based, apparently, on “results from the 2022 RFPs” – which, in turn, were based (as discussed above) on a request to bidders for 370-450 MW of new gas at the Schahfer site. Pet. Ex. 7 at 30-32. And in turn, the expanded gas request in the 2022 RFP was based on “key conclusions identified in the Flexible Resource Analysis” – which, as we show above in section 6, was insufficient to draw conclusions about expanding the gas peaker size.

iii. <u>Consistency with Commission’s Energy Analysis.</u> 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. Pet. Ex. 2 at 14. The record in this Cause contains findings by MISO, MISO’s IMM, and the NERC (Pet. Ex. 3 at 16-19) supporting 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 that NIPSCO’s proposal to build 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. <u>Public Convenience and Necessity.</u> 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 particular fast-ramping, load-following needs. Based on the evidence of record, we disagree, 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 that the Commission must, in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity, consider the following:

(1) The applicant's current and potential arrangement with other electric utilities for:
- (A) The interchange of power;
- (B) The pooling of facilities;
- (C) The purchase of power; and
- (D) Joint ownership of facilities.

(2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

We address these considerations below.

(a) <u>Ind. Code § 8-1-8.5-4(b)(1).</u> Mr. Stanley described NIPSCO's involvement in MISO, an independent transmission system operator, and testified that this portion of the statutory language predates the formation of MISO. He stated that 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 also 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 that 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. Pet. Ex. 6 at 20-24. NIPSCO witness Augustine testified that 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. Pet. Ex. 7 at 7-8.

The evidence of record shows that 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). We now analyze "[o]ther methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources."

Notably, while some of the parties directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, which we addressed above, no party stated that 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, lines 17-18; 10, lines 17-19. The CAC points out that if recent proposed MISO market reforms are implemented, "NIPSCO likely needs more capacity starting in 2028" even when assuming that the proposed CT Project enters into service. CAC Ex. 1 at 21, 24. These statements affirm NIPSCO's requirement for incremental capacity. However, the question before us is whether the CT Project has been demonstrated to be a reasonable and prudent way to meet that need. We conclude that the CT Project, as proposed, has not.

We address each aspect of Subsection 4(b)(2) below.

(1) Reliability. There is substantial record evidence on the need for reliability within NIPSCO's service territory and across the MISO footprint to maintain dispatchable generation for grid reliability. Specifically, MISO's Response to the Reliability Imperative dated January 2023 (p. 13) states that:

> To compliment the expected growth of solar generation, the system's need for controllable upramp capability could triple by 2031 and quadruple by 2041 compared to current levels. As the solar generation capacity grows, so does the challenge of steeper ramping needs for the non-solar generation fleet. At sunset, MISO will increasingly need controllable resources that can rapidly turn on and ramp up their output when generation from solar becomes unavailable. The need for fast-ramping resources is expected to vary by season and be most prominent in the winter months.

Pet. Ex. 3 at 16-17.

In regard to future market needs, the IMM, in its 2022 State of the Market Report for the MISO Electricity Markets (Executive Summary, p. v), reaffirmed that:

> Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This will lead to significant changes in the system's ramping needs. For example, conventional resources will increasingly have to ramp up quickly in the evenings as the sun sets, particularly in the winter season since load peaks in the evening.

Id. at 18.

Regarding maintaining essential reliability services, NERC, in its 2022 Long-Term Reliability

Assessment, states (Executive Summary, p. 7): "[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 Augustine testified NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP and found that conversion was higher cost than the alternatives. Pet. Ex. 7 at 32-33. Section 4.10.5 of NIPSCO's 2018 IRP noted that the analysis "showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more." Mr. Augustine also explained that 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. Pet. Ex. 7 at 33. No party challenged any of this evidence.

As to cogeneration, NIPSCO witness Stanley testified that 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 that NIPSCO has added and continues to add. He explained that cogeneration, if available, would have been responsive to the all-source RFPs. Pet. Ex. 6 at 23.

NIPSCO witness 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, and commercial and industrial customers. She explained that NIPSCO carried out a lengthy analysis of demand side management/energy efficiency resources included in its IRP process, including completing a Market Potential Study ("MPS") to determine the achievable amount of savings. Ms. Becker stated that NIPSCO remains committed to offering income-qualified savings opportunities to its customers and will leverage both future MPS estimates and historical program performance to establish future savings goals and spending levels. Ms. Becker also reiterated that NIPSCO will continue to work with the NIPSCO Oversight Board on updates to the MPS to inform future IRP iterations. NIPSCO-CAC Ex. 1 at 2; NIPSCO-CAC Ex. 1 at 5. Ms. Becker further explained that NIPSCO's 2021 IRP modeling demonstrates that 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, according to Ms. Becker, 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 that, based on her experience with NIPSCO's EE initiatives, NIPSCO could not derive sufficient energy savings to replace this generation. Pet. Ex. 1 at 8-19.

Ms. Sommer, on behalf of CAC, offered an important counterpoint, however. Based on a report prepared by the consultancy Cadeo Group for this proceeding, Ms. Sommer found that NIPSCO has the potential to develop up to 90 MW of new demand response capacity in summer and up to 46 MW of demand response in winter by 2027; and looking out to 2030, NIPSCO has the potential to develop up to 132 MW of new demand response capacity in summer and up to 63 MW in winter. This new capacity would have a cost of $75 per megawatt-day, under 25% the cost of NIPSCO's proposed combustion turbine generation ($367 per megawatt-day). CAC Ex. 1 at 25, 27. Cadeo Group, a consultancy that focuses on demand-side energy management programs across the nation, used both NIPSCO and national data to develop estimates of new potential for residential smart thermostat direct load control; residential behavioral demand response; and non-residential interruptible rates. The Commission believes NIPSCO has been remiss not to build the adoption of similar programs into its resource modeling, and NIPSCO should make a filing by the end of 2024 to add additional, cost-effective demand response resources to its portfolio.

In CEI South's Cause No. 45564 Order at 13, we found that "[t]he flexible and controllable nature of [CEI South's] gas CTs will support the intermittent nature of the renewable generation in the Preferred Portfolio to ensure system reliability." NIPSCO's record evidence supports, at a high level, a conclusion that integrating flexible and dispatchable resources that quick start will be vital as renewable resource penetration increases across the grid. However, after considering the evidence of record, we cannot find that the CT Project as proposed is consistent with the 2021 IRP, or a reasonable, cost-effective solution to address the flexibility needs that have been identified. The reasons for this are discussed further below in sections 6.A.iv.b.3 and 6.A.v and, in the Five Pillars portion of our discussion, section 6.D.iv.

(2) **Efficiency.** The CT Project is configured to be an efficient and cost-effective solution that provides critical fast ramping capability to follow NIPSCO's largely renewable, and therefore intermittent, load. Mr. Augustine described how NIPSCO's Flexible Resource Analysis evaluated the frequency and duration of events where net load was simulated to be greater than available dispatchable capacity and identified potential future risks associated with energy adequacy and resource flexibility the CT Project is designed to meet. Pet. Ex. 7 at 20. The evidence of record demonstrates that the CT Project, and the aeroderivative turbines in particular, is designed to start and ramp up or down quickly and therefore can be dispatched for short periods several times a day or for prolonged periods, whichever is necessary, to cover shortfalls. Mr. Warren explained that the aeroderivative turbines possess several key attributes, including: fast start capability that can achieve full power in as few as five minutes, multiple starts and stops per day without impacting maintenance cycles, higher efficiency compared to industrial frame gas turbines, and lower power needs for blackstart implementation. Pet. Ex. 5-R at 20-21. In addition, Mr. Holcomb testified that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the GHG Rule and be allowed to operate at capacity factors up to 40%, as needed. Pet. Ex. 9-R at 7. As discussed further above in section 5.B and below in section 6.D.v, the industrial frame turbine (which comprises around half of the overall CT Project's maximum generating capacity) will have its annual capacity factor legally limited by the GHG Rule to 20%, however. Additionally, as also discussed below, NIPSCO was unable to articulate a plan for mitigating the risks of severe winter weather limiting its gas supply or gas generating equipment. Putting aside our deep concerns about cost, discussed below, we find that the CT Project as proposed to be configured is not optimally designed to efficiently meet the needs of NIPSCO's unique generation portfolio and customer needs such that it could provide reliable, resilient, stable power to its customers while satisfying federal environmental regulations.

(3) **Economical Electric Service.** We note at the outset that, as NIPSCO began its generation transition following its 2018 IRP, the move away from coal-fired to renewable generation was driven primarily by the estimated monetary savings for customers over the life of the generating assets NIPSCO would be investing in. NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. Although the difference in costs between various retirement options was narrower in the 2021 IRP relative to the 2018 IRP due to different portfolio concepts under study, updated commodity price inputs, and updated new resource costs from the 2021 RFP, the IRP continued to affirm that earlier retirement of coal capacity resulted in lower costs for customers.

As previously noted, issues with various aspects of NIPSCO's modeling were raised in this Cause. We addressed the IG's load forecast arguments (including Rate 531 implications) above. OUCC witness Hanks's testimony focuses on aspects of NIPSCO's 2023 Portfolio Analysis, which Mr. Gorman ignored, while CAC witness Sommer's testimony criticized aspects of NIPSCO's Flexible Resource Analysis and Portfolio Analysis. We address each below.

Mr. Hanks claimed NIPSCO's 2023 Portfolio Analysis included artificially inflated costs for new peaking capacity and that the results of the All-Source RFP and EPC RFP were both inappropriately combined and restricted in terms of technology and configuration. We find that the All-Source RFP and EPC RFP were separate and distinct events utilizing different criteria. Additionally, we take well Mr. Hanks' point that, as discussed at length above, the EPC RFP unduly restricted the technology and configurations that could be proposed by bidders.

Mr. Hanks also suggested NIPSCO's 2023 Portfolio Analysis understated the costs of the CT Project by excluding indirect costs. Mr. Augustine explained that the purpose of the portfolio and revenue requirement modeling done in the 2023 Portfolio Analysis is primarily to compare costs of resource options such that excluding indirect costs provides a direct cost comparison. Pet. Ex. 7-R at 11-12; Pet. Ex. 7 at 39-40. In response to CAC discovery that was stipulated into the record, NIPSCO asserted that, 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 that included only direct costs. NIPSCO-CAC Ex. 6 at 38. While that may be, the practice of excluding indirect costs from a comparison among resource options strikes us as moving the analysis further away from an apples-to-apples comparison. For NIPSCO's self-build proposal, indirect costs amount to around 13% of the total construction cost. Pet. Ex. 5, Att. 5-A. Indirect costs may be a smaller share of other resource acquisition models. Where the self-build option is directly at issue, excluding the company-specific indirect costs associated with NIPSCO's self-build option and with other resource options would skew the results of any project cost comparison; therefore, we agree with Mr. Hanks that excluding indirect costs, as NIPSCO did in the Portfolio Analysis, is not a reasonable approach to weighing resource options.

Ms. Sommer did not deny that NIPSCO's Flexible Resource Analysis evaluated potential market exposure, but she observed (p. 20) that 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 its load exposure. Mr. Augustine conceded that the Flexible Resource Analysis (Attachment 7-R-A) was not an economic assessment, but that the Analysis evaluated the magnitude, frequency, and duration of the expected timing of market exposure events of longer than four hours, which is a key metric supporting the need for dispatchable capacity with duration longer than 4-hour lithium ion battery storage resources can provide. NIPSCO's Flexible Resource Analysis illustrated that market exposure events were projected to be concentrated in the late evening, overnight, and early morning hours, particularly in the fall months that align with MISO's own expectations of when tight hours and system-wide loss of load events are likely to occur. NIPSCO advanced the bare assertion that such periods of time coincide with high market prices and high economic costs for NIPSCO – and potentially, its customers – but NIPSCO never quantified the economic risk of such exposure, to allow stakeholders or this Commission to understand how serious that problem is .

Ms. Sommer also observed that the sub-hourly energy and ancillary services market value of battery storage resources, which NIPSCO's 2021 IRP analysis projected to be the highest such value of any resource type, was properly integrated in the 2021 IRP's portfolio modeling. However, for the 2023 Portfolio Analysis, NIPSCO ignored such ancillary services value of battery storage. Pet. Ex. 7, Conf. Att. 7-C; NIPSCO-CAC Conf. Ex. 6-C (Excel file labeled CAC 3-015 Conf. Att. A). NIPSCO witness Augustine acknowledged Ms. Sommer's point on this score as "reasonable" and also acknowledged that ancillary services value could influence the conclusions of the Portfolio Analysis. Pet. Ex. 7-R at 26-27; Pet. Ex. 7 at 34. The Commission is concerned that this analytical omission could further send NIPSCO's proposed project technology and configuration in the direction of uneconomic cost to ratepayers.

CAC witness Sommer also argued (pp. 25–26) that NIPSCO should quickly develop its excess injection rights at the Schahfer site to fully utilize them, potentially through battery storage resources. Ms. Sommer highlighted that MISO recently changed its rules (with FERC approval) to require full re-use of surplus interconnection rights by the time of signing a new interconnection agreement at an existing controlled site – or else any unused portion of the interconnection rights will be extinguished. CAC Ex. 1 at 26-27; FERC Docket No. ER24-1055. NIPSCO witness Stanley explained that NIPSCO is already investigating the best use for its remaining injection rights at the Schahfer site and RFPs have been issued as part of NIPSCO's 2024 IRP development process for various technology solutions to address NIPSCO's future capacity and energy needs.[11] The Technical Specifications provided to bidders ("Appendix G") as part of this 2024 RFP for battery storage at the Schahfer site were entered into evidence as part of the confidential NIPSCO-CAC Ex. 5-C (labeled as CAC 22-005 Highly Conf. Att. A). We are deeply concerned that almost no technical details about the Schahfer site were provided to bidders, except for two low-resolution overhead images. Engineering and design of installing complex battery equipment will entail understanding the existing roads, geology, electrical configuration, and other technical details at the site – all of which were not provided. We are doubtful that this request for proposals will prompt a strong response from battery storage developers in the manner that Ms. Sommer recommended, to best inform NIPSCO's investigation of how best to utilize the excess injection rights at the Schafer site. We agree with Ms. Sommer and Mr. Stanley that batteries can offer an important alternative technology to meet peak load.

NIPSCO's failure to develop a plan for fully utilizing the entire interconnection rights associated with the retiring Schahfer Units 16A, 16B, 17, and 18 (CAC Ex. 1 at 26) has the potential to significantly increase cost if NIPSCO loses the remaining partial rights and must look elsewhere to fill the looming capacity gap that both witness Sommer and witness Augustine identified. NIPSCO is hereby put on notice that in future IRPs or CPCN applications, the Commission will expect to see that NIPSCO has robustly considered options (including through RFPs that offer adequate disclosure to developers) to fully replace the Schahfer interconnection rights. The Commission further directs NIPSCO to file by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so.

While we have indicated in previous CPCN cases that least-cost planning is an essential component of our CPCN law, we have also recognized that least-cost planning does not require selection of the absolute lowest cost alternative. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No.

[11] https://www.nipsco-rfp.com/.

44339, at 20 (May 14, 2014) (quoting *Southern Indiana Gas & Elec. Co.*, Cause No. 38738, at 5 (Oct. 25, 1989)). We have defined least-cost planning as a planning approach that will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined. We also consider the risk created by future uncertainty. Ind. Code ch. 8-1-8.5 does not require a utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment on how best to meet its obligation to serve. If a utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting options to implement which minimize the cost of providing such services. *Id.*

Having said that, we note that NIPSCO's preferred configuration for the CT Project is both poorly supported – based on a vaguely defined scoring rubric that pointed to that configuration – and vastly more expensive than previously modeled in NIPSCO's 2021 IRP, While NIPSCO warns that denial of the requested CPCN would risk delay in building needed replacement resources, we note that NIPSCO's 12-month delay of the requested in-service date for its replacement resource at the Schahfer site offers the Commission and NIPSCO some flexibility in conducting further study to develop the concepts first performed as part of the 2021 IRP process. Indeed, the Commission cannot use the fear of delay in resource development as a reflexive reason to grant CPCN requests, lest the General Assembly's grant of decisional authority to the Commission become an empty rubber stamp. In the event of a denial of the CPCN, NIPSCO would still need to secure replacement capacity proposed to be filled by the CT Project, but NIPSCO could take the opportunity offered by its 2024 IRP process and contemporaneous RFPs to more robustly evaluate alternative options.

In light of the evidence of record, we find that NIPSCO has failed to exercise reasonable judgment in selecting an option that minimizes the risks of future cost.

(c) **<u>Conclusion.</u>** NIPSCO conducted an All-Source RFP and Schahfer RFP in 2022 to meet its capacity needs, and the RFP responses helped NIPSCO to consider a variety of alternatives, described above. However, the RFPs were unduly limited in their specifications, as discussed below in section 6.A.v, and furthermore, we are puzzled at how the results of the RFP translated to the request in this case for three aeroderivative gas turbines and one industrial frame turbine. NIPSCO did not adequately consider the potential for using excess interconnection rights at the Schahfer site for battery storage, nor the sizable potential for demand response capacity, as outlined by witness Sommer. CAC Ex. 1 at 25-27. Given the foregoing evidence, the Commission finds that Petitioner has not satisfied the requirement under Ind. Code § 8-1-8.5-4 that it consider alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources.

Therefore, based on the evidence of record, the Commission finds that Petitioner has not shown adequate need for the proposed CT Project, nor that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. <u>Competitive Procurement.</u> 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.

As we have previously explained, these are two different requirements. 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 that actual costs that are incurred are, to the extent commercially practicable, based on competitive procurement. *Northern Ind. Pub. Serv. Co.,* Cause 45194 (IURC 8/7/2019), at 56.

NIPSCO conducted multiple RFPs during 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 some actionable resource cost data that incorporated the latest policy, technology, and macroeconomic information. Ideally, the RFPs should have provided information related to the latest costs of storage resources and the viability of alternative dispatchable resource options. However, the 2022 All-Source RFP and Schahfer RFP were unduly restrictive in how they defined the location and technology type of resources allowed, as discussed further below.

The statute at Ind. Code § 8-1-8.5-5(e)(1)(A) requires the estimate to be the result, to the extent commercially practicable, of competitively bid engineering, procurement or construction contracts. Petitioner conducted the EPC RFP bid event in 2022 and purported to leverage the information gained through that process to develop its best estimate for the cost to construct the CT Project through a multi-prime contracting strategy. However, according to NIPSCO witness Baacke, two bids from the EPC RFP were rejected as non-responsive to the performance criteria of the technical specifications, and a third bid was rejected as more expensive than a self-build option. Pet. Ex. 5 at 11; NIPSCO-CAC Ex. 4 at 17-18. The Commission was able to review the bids as part of NIPSCO-CAC Conf. Ex. 4-C (labeled as CAC 1-004 Highly Conf. Att. A) and was disappointed at the poor responses. As CAC witness James (who previously testified to the Commission about the construction of Duke's

Edwardsport project) raised, NIPSCO had failed to furnish adequate information to potential EPC bidders to elicit a robust set of bids. CAC Ex. 2, Att. RJ-2, § 3.4. For example, NIPSCO issued the EPC RFP before its Engineering Study defining the scope of the project was finished. *Id.* Even if the Engineering Study *had* been available for EPC bidders, that study failed to include detailed scopes, heat & material balances, license packages, P&ID's and Electric Single-Line Diagrams issued for design, major equipment specifications, and a take-off-based estimate. *Id.* at § 2.10. The Commission was able to review the technical specifications given to bidders, which were provided as evidence under NIPSCO-CAC Conf. Ex. 4-C (labeled as CAC 1-004 Att. C), and found them wanting.

Additionally, as NIPSCO witness Mr. Warren stated, "currently, there is not significant interest by power industry EPC contractors for this size and type of project." Pet. Ex. 4-R at 7. Both Mr. Warren and CAC witness Sommer are in agreement that with the large number of large gas power projects under development across the country, many EPC contractors may be otherwise engaged. *Id.* at 7-8; CAC Ex. 1 at 9. While this market dynamic may be out of NIPSCO's control, the Commission notes that NIPSCO did not take every effort to encourage EPC bidders. With this confluence of circumstances, it is difficult for us to label the EPC bidding process as competitive, as required by the statute. As to equipment bid events, the Commission notes that only a single supplier is able to deliver generator step-up transformers by the needed date, and only a single supplier is able to deliver 345 kV breakers by the needed date. Pet. Ex. 5-S at 4. unit auxiliary transformers, and diesel generator. While not necessarily uncompetitive *per se* under the statute, multiple bid events with only one qualifying bidder do not enhance the competitive profile of the overall project bidding. Accordingly, we find that Ind. Code § 8-1-8.5-5(e)(1)(A) has not been satisfied: that the cost estimates of the proposed facility are not, 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. Pet. Ex. 5 at 13. He testified that under the planned construction and bid process, NIPSCO will have allowed 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. *Id.* at 14. Even if this aspect of the proposed multi-prime approach satisfied the statutory requirements of Ind. Code § 8-1-8.5-5(e)(1)(B), it would not vindicate NIPSCO's overall failure to satisfy Section 8-1-8.5-5(e)(1).

Regarding Ind. Code § 8-1-8.5-5(e)(2), we find (as discussed in the Five Pillars section below), based on the evidence of record, that the proposed CT Project may not meet the statutory standard of reliability. The record has also established that Petitioner engaged in an All-Source RFP process to inform its overall generation transition plan, although that did not allow for use of existing interconnection rights and site control at NIPSCO's Schahfer site, while the contemporaneous "Schahfer RFP" (also called the EPC RFP) was discriminatory in that it purported to be for general dispatchable resources yet also established gas turbines as the technology of choice. NIPSCO-CAC Conf. Ex. 4-C; CAC Ex. 1 at 33.[12] Thus, in light of the issues of reliability and solicitation by NIPSCO of competitive bids to obtain purchase power capacity and energy from alternative suppliers, we find

[12] NIPSCO's All-Source RFP and Schahfer RFP (also called EPC RFP) from 2022 can be found at Pub. Ex. 2, Att. JWH-1; and the same may be found at https://www.nipsco-rfp.com/Portals/0/Documents/RFPDocuments/NIPSCO_2022_All-Source_Request_for_Proposal_FINAL.pdf.

that the requirements of Ind. Code § 8-1-8.5-5(e)(2) have not been satisfied.

vi. <u>Conclusion on CPCN for CT Project.</u> Ind. Code § 8-1-8.5-5(d) requires us to "consider and approve, in whole or in part, or disapprove a utility specific proposal . . . jointly with an application for a certificate under this chapter [but] solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity." Based upon the evidence of record, the Commission finds that NIPSCO has not met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity does not require construction of the CT Project. Without determining whether we would have legal authority to approve a different configuration of combustion turbines as suggested by witness Becker (succeeding Sears), we note that that a configuration with only industrial frame turbines would also fail to satisfy the statutory standards under Chapter 8.5, considering our grave concerns with NIPSCO's procurement practices and construction management plan. Therefore, we deny NIPSCO's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

Additionally, we note our serious concern that NIPSCO's resource planning software vendor, Energy Exemplar (which offers the widely used Aurora modeling tool) refuses to make any edits to its standard license agreement, which features terms reading that the license may only be used for "reviewing or analyzing" a forecast already developed. In other words, an intervenor party in a CPCN proceeding like this one, or a stakeholder in an IRP process, may not license the Aurora software to develop its own modeling simulation. What's more, acquiring a full license to get around this barrier costs up to six figures. CAC Ex. 1 at 32. Mr. Augustine noted in rebuttal that Energy Exemplar attempted to offer clarifying concessions to CAC's consultant during the early months of this case, but Mr. Augustine did not report that Energy Exemplar agreed to change its license terms. Pet. Ex. 7-R at 31-32. The Commission wishes to encourage fulsome, good-faith exploration around important and costly resource action decisions in Indiana, and discourages utilities from blocking participants who wish in good faith to model alternative resource portfolios under appropriate confidentiality provisions.

Finally, we reiterate our directives above, pursuant to our authority under I.C. §§ 8-1-2-68 and -69, that (i) NIPSCO file, by October 31, 2024, a plan to cost-effectively reuse the additional injection rights at the Schahfer site before they expire or explain why it is not cost-effective to do so; and (ii) NIPSCO make a filing by the end of 2024 to add additional, cost-effective demand response resources to its portfolio.

B. <u>Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a).</u>

Having determined to deny the requested CPCN, the issue of ongoing review of the CT Project is moot.

[*Citizens Action Coalition of Indiana above proposes that the Commission deny the request for a Certificate of Public Convenience and Necessity. However, in the alternative that the Commission determines to grant the requested CPCN, CAC offers the proposed language below regarding ongoing review*.]

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. We find Ms. Becker's proposal reporting acceptable given that it is more than contemplated by the statute; however, these reports should be submitted independent of any GCT (construction work in progress) rate-related filings. The Commission has already above noted grave concerns with NIPSCO's intended approach to managing the construction process for the proposed CT Project. To protect ratepayers and ensure the integrity of the final generating units, the Commission takes seriously its responsibility to exercise oversight over construction and intends to engage a construction monitor with expertise in power projects.

In the proceeding authorizing Duke Energy Indiana's construction of the Edwardsport Integrated Gasification Combined Cycle plant, the Commission required Duke Energy Indiana to contract with and pay the reviewing consultant, which had been requested by Duke, that ultimately reported to the Commission under I.C. § 8-1-8.7-7. Cause No. 43114 IGCC 1, Docket Entry dated June 3, 2008. While Chapter 8.7 is not implicated in this proceeding, Section 8-1-8.7-7, which creates a structure for CPCN approval for a "clean coal technology system," has nearly identical language in subsection (b) to the ongoing review provisions of Chapter 8.5, Section 5(b) of the Code. The Commission concludes that Chapter 5 gives the Commission flexibility to direct a utility to retain and pay a consultant for ongoing review just as in the Edwardsport proceeding. The Commission finds it useful to quote its pertinent directives in the Edwardsport docket entry:

> In order to facilitate the Commission's continuing oversight of the Edwardsport Project that falls outside the parameters IGCC Rider proceedings, the Presiding Officer's find that Duke Energy Indiana shall retain the services of Black & Veatch Corporation ("Commission Contractor" or "Black & Veatch") a professional engineering firm that has been selected by the Commission to oversee the Edwardsport Project at the direction of the Commission. While it will be Duke Energy Indiana's obligation to enter into a contract and pay all fees associated with the responsibilities undertaken by the Commission Contractor, the Commission Contractor will act independently of Duke Energy Indiana and report directly to the Commission.
>
> In order for Black & Veatch to effectively undertake its oversight role on behalf of the Commission, the Petitioner must ensure that it has the ability to undertake construction surveillance and A&E Services as may be necessary to fully report to the Commission. Therefore, Duke Energy Indiana must ensure that the Commission Contractor has the ability to enter into confidentiality agreements with various parties involved in the design and construction of the project; attend project construction management meetings as necessary; and generally review pertinent information with respect to the Edwardsport Project.

For this matter involving NIPSCO, the Commission will select a qualified consultant to provide construction oversight at a time in the near future and will issue a docket entry when that consultant has been identified. The Commission hereby directs that, as in the Edwardsport matter, NIPSCO enter into a contract with the identified consultant based on terms that the Commission will publish in the future docket entry. As the Commission will detail in the future docket entry, the selected consultant must have similar responsibilities to those of the Edwardsport construction monitor as described in the second excerpted paragraph above.

We find that NIPSCO shall report to the construction monitor and 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, achievement of construction milestones, and the best estimate of costs, as well as the: (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 semi-annual filings stylized as 45947 CT-XX. 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.

We caution NIPSCO that costs to serve customers in order to accommodate a delay in the proposed online date of the CT Project stand a nontrivial chance of disallowance including but not limited to capacity and energy costs. As part of the ongoing review under Section 8-1-8.5-6(a), we will examine the financial impact of any delay and whether any delay in the scheduled in-service date (and incremental capital costs associated with that delay) evince imprudence by NIPSCO. *See CAC v. Duke Energy Indiana, Inc.*, 16 N.E.3d 449, 458 (Ind. Ct. App. 2014) (utility not entitled to recover financing charges incurred during a three-month delay and remanding to the Commission for findings as to whether the delay was chargeable to the utility, and if so, what impact that delay had on customers' rates). Capacity and energy costs incurred to procure replacement power during the pendency of the delay could be determined to be imprudent in separate rate-related proceedings, consistent with the Commission's obligation to ensure just and reasonable rates as well as reliability and affordability under I.C. § 8-1-2-0.6. We will also consider disallowance as imprudent in future rate-related cases of any costs incurred after the commercial online date related to bringing the Project to its modeled forced and planned outage rates, which Ms. Sommer provided confidentially based on NIPSCO's modeling information.

Commented [CAC6]: ***Comment for the Commission regarding confidential information***: [redacted]

C. Clean Energy Project and Financial Incentives Under Ind. Code § 8-1-8.8-11.

Having determined to deny the requested CPCN, the issue of cost recovery or other financial incentives for the CT Project is moot. To be completely clear, the Commission is hereby denying any cost recovery related to development of the CT Project.

[***Citizens Action Coalition of Indiana above proposes denial of the CPCN and of cost recovery related to the CT Project. However, in the alternative that the Commission determines to grant the requested CPCN, CAC offers the language below regarding ratemaking treatment***.]

In addition to the CPCN under Ind. Code §8-1-8.5-5, 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 (among other options) "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." A 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."

As discussed above, NIPSCO witness Walter testified that the CT Project will displace electricity generated from the coal-fired generating plants at Schahfer Units 17 and 18 (when they retire at the end of 2025) and Michigan City Unit 12 (when it retires by the end of 2028). Pet. Ex. 2 at 15. But as also discussed above, CAC witness Mr. Inskeep asserted that Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project" (CAC Ex. 3 at 8) – two years before the CT Project is proposed to come online – and that NIPSCO did not demonstrate the CT Project will displace electricity generated from the coal-fired Schahfer Units 17 and 18 and Michigan City Unit 12. NIPSCO states that it plans to use its several new solar and wind generating units (including both owned and contracted projects) coming online over the next few years for baseload power to replace the lost generation from Schahfer – and, as Mr. Inskeep observed, NIPSCO has staged the timing of the Schahfer coal retirements based on when new solar and storage units will be available. Moreover, the CT Project is expected to provide peaking capacity and run at less than 20% annual capacity factors across the future time horizon, according to NIPSCO's witness Mr. Walter. Notably, NIPSCO is also planning to retire its Schahfer 16A/B gas peaking units, totaling 155 MW in the near future, according to Mr. Walter, but is staging those retirements in connection with the proposed CT Project. Mr. Walter's initial testimony in this case proposed to retire Schahfer 16A/B at the end of 2026 (the initially named online date for the CT Project) but then – after the CT Project had to be delayed by one year – Mr. Walter pivoted in supplemental testimony to characterizing the Schahfer 16A/B retirement goal as "until the CT Project reaches commercial operation." The CT Project is a peaker that will simply provide a different function for NIPSCO's load needs than do Schahfer or Michigan City 12, which is slated to retire by late 2028.

We note that NIPSCO witness Stanley's rebuttal testimony states that NIPSCO will be using the injection rights from the retiring Schahfer coal units for purposes of MISO interconnection for the CT Project (Pet. Ex. 6-R at 5-6). However, that does not mean the function of the new CT Project within NIPSCO's portfolio is the same as that of the retiring Schahfer or Michigan City coal units.

Displacement of retiring coal-fired energy generation with clean energy resources and upgrades at Sugar Creek has been a transparent component of NIPSCO's IRP modeling and related CPCN regulatory filings since 2021, while the same modeling calls for new gas peaking capacity to replace the Schahfer gas peakers.[13] As such, we find the CT Project is not being constructed to displace

[13] NIPSCO 2021 Integrated Resource Plan, Summary, at 13 ("To replace the retiring resources, NIPSCO has identified a preferred pathway that balances all of NIPSCO's major planning objectives, while preserving flexibility in an environment of market, technology, and policy uncertainty. In the near-term, replacement options include a diverse, flexible, and scalable mix of incremental resources, including DSM resources, distributed energy resources, solar, stand-alone energy storage, and upgrades to existing facilities at the Sugar Creek Generating Station. The plan also calls for a natural gas

energy from an existing coal-fired generation facility as required in Ind. Code § 8-1-37-4(a)(21) and is therefore not eligible for the relief provided in Ind. Code § 8-1-8.8-11.

i. The Clean Energy Project is Just and Reasonable. 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 include the application of 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) The Cost of the CT Project. As discussed above, the evidence in this Cause supports a finding that the CT Project is excessively priced compared to other alternatives, particularly due to the inclusion of aeroderivative units.

(b) Consistency of the CT Project to NIPSCO's IRP. As we noted above, the CT Project is not consistent with NIPSCO's 2021 IRP, nor does the 2023 Portfolio Analysis form an adequate basis to update the conclusions of the 2021 IRP.

(c) The Need for the CT Project. As discussed above, NIPSCO will have a significant capacity need in coming years, including a need for fast-start, quick-ramping resources that will complement NIPSCO's overall generation transition and follow the load. This evidence reinforces our prior finding in CEI South's Cause No. 45564 that MISO, NIPSCO's grid operator, has "indicated a system-wide need for controllable resources … to ensure system reliability as more intermittent resources are added to the system."

(d) The Competitive Solicitation of the CT Project. We have previously found that NIPSCO's procurement of the CT Project has been and will continue to be through competitive solicitation. However, we reiterate our concern that NIPSCO's competitive solicitation for both the turbine components and the EPC role failed to provide adequate information to potential bidders to kindle a healthy competition.

Based on the foregoing, we find the CT Project cannot qualify as a clean energy project under Ind. Code § 8-1-8.8-11; we thus find it unnecessary to determine for purposes of Section 8-1-8.8-11 whether the CT Project is just and reasonable.

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peaking unit to replace existing vintage gas peaking units at Schahfer and support system reliability and resiliency, as well as upgrades to the transmission system to enhance the electric generation transition.").

ii. <u>Cost Recovery.</u> Having found the CT Project is not a clean energy project and not eligible for the financial incentives pursuant to Ind. Code § 8-1-8.8-11 ("Section 11"), it is unnecessary for us to further examine NIPSCO's proposal to recover its costs during construction through a semi-annual forecasted capital tracker (the "GCT Mechanism") until such time as the project is included in base rates subsequent to being placed in service. However, we will offer additional analysis of the GCT Mechanism to offer guidance to utilities in future proceedings.

NIPSCO's proposed GCT Mechanism would provide for construction work in progress ratemaking as allowed by Ind. Code § 8-1-8.8-11(a)(1). Subsection 11(a)(1) allows that we may provide for "[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 that 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."

We will take these two findings in reverse order and begin with the determination of gross financing cost savings. Mr. Blissmer presented the calculation of his gross financing savings in his direct and supplemental direct testimony. Using the forward looking GCT, Mr. Blissmer calculated the gross financing savings in direct testimony at $81,986,410 over the life of the CT Project. Pet. Ex. 8-S at 4. Using the more traditional backward looking GCT tracker, there would be reduced savings of $48,019,573. Pet. Ex. 8-S at 6. In rebuttal, Mr. Blissmer changed the financing cost rate to the AFUDC rate rather than the WACC in response to OUCC witness 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. Pet. Ex. 8-R at 3.

IG witness Gorman and CAC witness Inskeep objected to Mr. Blissmer's calculations on the grounds that they were not done on a present value basis; their calculations showed that it is *traditional* ratemaking that would be less expensive on a present value basis. It is true that the statute, by its terms, does not expressly require the calculation to be done based upon net present value. By its terms, the statute requires the demonstration of "gross financing cost savings over the life of the project." Mr. Blissmer claimed that calculating a present value of cost savings cannot be reconciled with the term "gross" in the statute (Pet. Ex. 8-R at 9). To resolve this legal dispute, we must be mindful that the Commission is a creature of statute with delegated authority from the Indiana General Assembly. When a statute does not require interpretation, the Commission shall follow the law as written; in cases of ambiguity, the Commission has several interpretive tools, starting with consulting a dictionary. *Rainbow Realty Group, Inc. v. Carter*, 131 N.E.3d 168, 174 (Ind. 2019) ("when a statutory term is undefined, the legislature directs us to interpret the term using its plain, or ordinary and usual, sense. … We generally avoid legal or other specialized dictionaries for such purposes and turn instead to general-language dictionaries" (internal citation omitted)). Merriam-Webster defines "gross" as "consisting of an overall total exclusive of deductions." The Commission thus interprets "gross financing costs savings over the life of the project" to mean adding up all annual savings without subtracting any other factors from the calculation. There is no reason why this calculation cannot make appropriate discounting based on the time value of money, and the Commission finds that such discounting is appropriate to better capture the savings experienced by customers who fund revenue requirement. Furthermore, were the Commission to *not* discount the future annual savings to present value, the "gross savings" calculation would always find that CWIP financing results in savings compared to traditional ratemaking, as CAC witness Inskeep noted without refutation. A test that cannot be failed violates the interpretive canon requiring us to avoid construing legislative text as mere surplusage, devoid of meaning. *See, e.g., Loughrin v. United States*, 573 U.S. 351, 358 (2014) ("the 'cardinal principle' of interpretation [is] that courts 'must give effect, if possible, to every clause and word of a statute.'"); *Witzke v. Female*, 376 F.3d 744, 753 (7th Cir. 2004) ("We must read a statute to give effect to each word so as to avoid rendering any words meaningless, redundant, or superfluous."). As gross financing costs savings is another statutory requirement under section 8-1-8.8-11(a)(1)(B) and the GCT proposal does not clear this bar (as demonstrated by witnesses Inskeep and Gorman), the Commission has another independent reason to deny the GCT request. The Commission believes that the calculations advanced by Mr. Gorman and Mr. Inskeep represent a better application of the statutory "gross financing costs savings" concept than do Mr. Blissmer's calculations.

We are also persuaded by Messrs. Gorman and Inskeep's assertion that NIPSCO did not demonstrate the proposed GCT is just and reasonable. Conclusory statements that CWIP ratemaking can "benefit … financial health" and "provide … cash flow during a potentially lengthy construction period," as Mr. Blissmer stated (Pet. Ex. 8 at 13), are not enough to justify the requested relief. NIPSCO provided no evidence as to its specific capital needs as a company, nor any illustration of its recent financial experience developing various renewable power plants. Next, we will address Mr. Blissmer's direct testimony alleging how, through the avoidance of so-called "rate shock" when a large construction project is reflected in rates in a single step, the GCT benefits customers. The Commission takes this concern seriously but notes that in NIPSCO's particular case, it is planning to retire certain coal and gas-fired generating units around the time it puts the proposed CT Project into service, allowing the removal of, at a minimum, the fuel and operating expenses of the retiring units from customer rates.

The General Assembly has specifically directed that affordability is one of the attributes to be considered in the context of generation transition. Ind. Code § 8-1-2-0.6. One of the tools provided by the General Assembly in the case of transition to clean energy projects is a CWIP tracker; however, we must evaluate whether the use of CWIP ratemaking will in fact reduce customers' rate burden. NIPSCO offered testimony (citing a credit rating agency's comments from July 2008, prior to multiple upheaval cycles in financial markets) on the generic benefits of CWIP ratemaking on utilities' credit quality, but offered no specific information on how CWIP ratemaking might be expected now to reduce NIPSCO's cost of debt or equity. 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, and while these are not objections to whether this particular proposal meets the requirements of the statute, we are mindful of our responsibility to enforce the threshold tests set out by our legislature to allow CWIP ratemaking. In light of the discussion above, we find that, under Section 11, both the forward and backward looking versions of NIPSCO's proposed GCT Mechanism are not just and reasonable.

For completeness, we will evaluate the two CWIP cost recovery methods proposed by NIPSCO: 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. Pet. Ex. 8-R at 7-8.[14] With the forward looking GCT, NIPSCO

[14] If we were to approve the backward looking version of the GCT, we would need to address NIPSCO's request in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service

would "reflect CWIP financing costs projected to occur over the next six-month billing period in each tracker filing." Pet. Ex. 8 at 12. 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 very limited AFUDC that has already been accrued and expected to be accrued until rates take effect in March 2025 under the GCT Mechanism." Pet. Ex. 8-S at 5. In addition, there would be no depreciation to defer. Pet. Ex. 8 at 16. 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 of CAC had two objections to the forward looking version of the GCT. First, he claimed that the statute uses past tense ("incurred") 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. Having decided that CWIP financing is not applicable, the Commission is not required to address Mr. Inskeep's argument about forecasted costs, but wishes to pause here to caution NIPSCO and any other electric utility that the plain language of Section 8-1-8.8-11 contemplates "timely recovery of costs and expenses incurred during construction" with no provision for forecasting costs in advance. While a seemingly trivial or tautological point, it is nonetheless of real moment in ratemaking to note that until costs are actually incurred, no costs are incurred. While Section 11's neighbor in the Code, Section 12, contains specific authorization for the use of forecasted data for retail charges plus a reconciliation mechanism for actual costs, Section 11 has no such authorization. The interpretive canon against surplusage counsels us to take this distinction seriously: utilities may not use forecasted costs under the CWIP rider mechanism. *See, e.g., Loughrin v. United States*, 573 U.S. at 358. .[15]

Having determined that the CT Project is not eligible for CWIP financing under Section 8-1-8.8-11, we next turn to NIPSCO's alternative request for approval to accrue [as a regulatory asset] post-in service carrying costs and to "defer [as a regulatory asset] the accrual of depreciation and amortization expense on the CT Project from its in-service date until the implementation of rates including recovery of a return thereon and including recovery of depreciation and amortization expense thereon in Petitioner's recoverable operating expenses." Pet. at 17. The Commission returns to Ind. Code. § 8-1-8.8-11, which is the authority NIPSCO cites for its request. Section 11 allows the Commission to grant "[o]ther financial incentives the [C]ommission considers appropriate" to clean energy projects. However, as discussed above, the CT Project does not qualify as a clean energy project within the meaning of Chapter 8.8 as the supposed authority for this request. Even if the CT Project qualified as a "clean energy project," the Commission is left with no basis to decide if the requested alternative financing mechanism is "appropriate" as contemplated in Section 11, other than a single footnote in Mr. Blissmer's direct testimony (Pet. Ex. 8 at 9) cursorily recounting the requested relief. The alternative financing relief is denied.

until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT or in a general rate case. Pet. Ex. 8, p. 9, n. 1.

[15] As a result of our determination that the CT Project cannot qualify for any CWIP financing, NIPSCO's GCT Mechanism request in the alternative (namely, for use of backward-looking actual costs for rider recovery) is moot.

Finally, we fail to see evidence in the record establishing why Petitioner's request that the operating income associated with the CT Project 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 is an appropriate additional financial incentive under Section 11. Mr. Blissmer stated that such treatment is consistent with the treatment of earnings associated with Rider 588 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Rider 587 – Adjustment of Charges for Federally Mandated Costs, but did not explain how this treatment would be appropriate for the new GCT Mechanism. Although this issue is moot because we have above denied the proposed GCT Mechanism, we emphasize that petitioners must establish the required prima facie elements of a statutory test in order to obtain the requested relief.

D. <u>Five Pillars Under Ind. Code § 8-1-2-0.6.</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. Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service: as reliability, affordability, resiliency, stability, and environmental sustainability, (collectively, the "Five Pillars"). NIPSCO witness Becker's Attachment 1-C identifies the seven different NIPSCO witnesses who sponsored testimony supporting each of the Pillars.

While the specific construct of Indiana's Five Pillars is relatively new, these attributes have been long-standing aspects of our statutorily driven process for deliberating on requests to construct new electric generation in the State. For instance, in determining whether to issue a CPCN, we are required to consider alternative means of providing "reliable, efficient and economical electric service." Ind. Code § 8-1-8.5-4(b)(2). Consistency with integrated resource planning has long played a role in our analysis (Ind. Code § 8-1-8.5-5(b)(2)), and integrated resource planning includes analysis of "how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty." 170 IAC 4-7-8(c)(7). Indeed, NIPSCO's 2021 IRP integrated scorecard approach included objectives associated with "Reliable, Flexible, and Resilient Supply," "Rate Stability," "Affordability," and "Environmental Sustainability." Therefore, while the particular analytical framework under Ind. Code § 8-1-2-0.6 may be a recent addition to our regulatory considerations, we note that the Five Pillars themselves are bedrock principles long applied to the complex issues at play when examining a proposal to construct new generation in the State. NIPSCO's CT CPCN is no different. We have discussed, throughout this Order to this point, how our findings are guided by and ultimately support the Five Pillars.

Having concluded that NIPSCO has failed to satisfy the statutory elements and interrelated findings we are required to make under Sections 8.5 and 8.8 in approving a CPCN for new generation and a just and reasonable clean energy project respectively, we will nonetheless additionally review each of the Five Pillars below and address the statutory elements and policy considerations related thereto. 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.

i. Reliability. 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), pp. 18-19. NIPSCO witness Austin's testimony informs us that this need is increasing even since our findings in Cause No. 45564. Record evidence supports findings that a fast-start resource could, at a generic level, address needs identified by key stakeholders, including MISO, NERC, the MISO IMM, and others, and address 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. Pet. Ex. 3 at 11, 17-19. Mr. Austin cited numerous publications from NERC, MISO, and MISO's IMM discussing the need to install fast-starting, quick ramping resources to support the growing portfolio of renewable resources and maintain reliable service. Pet. Ex. 3 at 8-11, 17 citing Electric Reliability Organization ("ERO") Priorities Report 2023, NERC 2021 Long-Term Reliability Assessment (December 2021), NERC 2022 Long-Term Reliability Assessment (December 2022), MISO's Response to the Reliability Imperative dated January 2023, and IMM 2022 State of the Market Report for the Miso Electricity Markets (June 15, 2023). NERC even 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 ERO Priorities Report. Pet. Ex. 3 at 8-10. Mr. Austin, quoting from the ERO Priorities report explained: "[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." *Id*. at 10. The 2022 Long-Term Reliability Assessment issued December 2022 (pp. 17-18) 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.

Pet. Ex. 3 at 11.

NIPSCO witness Austin asserted that the proposed CT Project will help meet MISO's Resource Adequacy Requirements. Pet. Ex. 3 at 12-16. The 2023 OMS-MISO Survey Results (published July 14, 2023) reflect that delayed retirements and capacity additions have resulted in a capacity surplus of 1,500 MW for the 2024/25 planning year. However, 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. *Id*. at 15. This demonstrates a growing need for dispatchable resources to support system reliability within the MISO region, including Indiana.

NIPSCO witness Austin argued that batteries, inverter based resources ("IBRs"), and energy storage resources ("ESR") do not meet system reliability needs. *Id.* 19-23. NERC and MISO's IMM reach similar conclusions, as the NERC highlights in its 2022 Long-Term Reliability Assessment (Executive Summary, p. 7) 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.

Id. at 20. As NIPSCO, like many utilities in Indiana and around the country, is planning to transition to a portfolio mostly composed of wind, solar, and storage resources, the Commission trusts that NIPSCO, working with MISO, will be able to manage and mitigate any risks in the transmission and distribution grids resulting from the use of inverter-based resources.

NIPSCO witness Stanley also 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.

Pet. Ex. 6 at 17 (citing the MTEP Report).[16] The Executive Summary in this Report goes on to outline different attributes or characteristics provided by different generation resource types and reflects that gas resources are at the same relative advantage as are battery resources, compared to other resource types, in providing: (1) fuel assurance; (2) ramp up capability; and (3) rapid start-up. NIPSCO clarified in discovery that the Stanley testimony was not trying to contend that battery resources are inferior to gas generation when it comes to ramp-up and rapid start-up capability. NIPSCO-CAC Ex. 5 at 5-6. As to voltage stability, gas resources are only marginally better equipped than battery storage resources, and batteries may improve in this dimension in the future as technology advances. Pet. Ex. 6 at 18. In addition, while still in development and under review, NIPSCO witness Mr. Augustine cited (Pet. Ex. 7, p. 15) from MISO's Resource Adequacy Subcommittee ("RASC") 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. As to blackstart capability, the MISO chart cited by Mr. Stanley showed that gas resources more fully fulfill the needed attribute than do battery resources, but that battery resources' strength may increase in the future.

NIPSCO conducted extensive diligence on the reliability of the potential resource portfolios

16 MTEP Report Executive Summary at 4. This executive summary of this report is available at: https://cdn.misoenergy.org/MTEP22%20Executive%20Summary626707.pdf.

in its 2021 IRP. The Non-Economic Reliability Assessment (2021 IRP, Confidential Appendix E) 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, through its consultant Charles River Associates, 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. The Flexible Resource Analysis 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 2021 IRP’s preferred portfolio of approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and 3-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, although the Flexible Resource Analysis did not attempt to quantify the cost of relying on energy market purposes. Pet. Ex. 7, Conf. Att. 7-D at 9-10, 61. NIPSCO offered that its proposed CT Project in its preferred configuration is designed to fill this capacity gap ensuring that service on NIPSCO’s entire system is reliable. NIPSCO’s preferred configuration, including three aeroderivative combustion turbines and one frame turbine totaling around 400 MW, represented a departure from the judgment factors and rationales embodied in the 2021 IRP, which called for up to ***300*** MW of new gas peaking capacity and did not mention aeroderivative turbines. The change from the 2021 IRP was required to be fully explained and justified with supporting evidence, including an updated IRP analysis. 170 IAC 4-7-2.5(b). The Flexible Resource Analysis and Portfolio Analysis together did not satisfy the requirements of an Integrated Resource Plan as defined in our rules. Notably, the Flexible Resource Analysis failed to take account of resource costs (170 IAC 4-7-2(c)(2)(B)) or cost-benefit or cost-effectiveness analysis (170 IAC 4-7-4(5), (24)). It also did not undertake any capacity planning modeling (170 IAC 4-7-2(c)(2)(C)) or generation expansion planning criteria (170 IAC 4-7-4(22)) except to predict the market exposure effects of adding varying levels of “*any* flexible, dispatchable capacity.” NIPSCO-CAC Ex. 6 at 31-32. Regarding the 2023 Portfolio Analysis, Mr. Augustine in rebuttal testimony confirmed Ms. Sommer’s observation that the Portfolio Analysis did not include re-optimization of capacity expansion plans to determine a lowest cost portfolio. CAC Ex. 1 at 17; Pet. Ex. 7-R at 6. And as discussed above in section 6.A.ii, the Portfolio Analysis considered only a static, narrow set of portfolios based on unsupported assumptions. Thus, NIPSCO has violated the regulatory requirement that a utility’s resource action must be consistent with its most recent IRP, unless differences are fully explained and justified with supporting evidence, including an updated IRP analysis.

Our review of the substantial evidence of record regarding the attributes of the aeroderivative turbines leads us to conclude that NIPSCO has not justified how aeroderivatives’ operational characteristics are a necessary part of NIPSCO’s future resource portfolio, further buttressing our findings above that support denial of NIPSCO’s chosen configuration. It appears that NIPSCO and its consultant developed a “decision matrix” to score and rank different combustion turbine configurations, based on a pre-made set of weightings across 23 factors that was not explained in testimony, and based on scoring within each factor for each of the three configuration options. NIPSCO explained that the assignment of scores across factors was apparently not based on a specific mathematical rubric (although quantitative values within each factor were considered), but rather, was “completed during working sessions held between [S&L] and NIPSCO where the factors [] were discussed and evaluated and the overall score was collaboratively determined.” Pet. Ex. 4 at 12; Pet. Conf. Ex. 4-A, Appx. 19; NIPSCO-CAC Conf. Ex. 4-C at 574-576. We are concerned that this crucial step in the process of choosing a turbine configuration was apparently done based on semi-arbitrary, nontransparent judgments that were "completely subjective" as CAC witness Ms. Sommer phrased it (CAC Ex. 1 at 12) NIPSCO admitted in discovery that, for example, it did not did not quantify the benefits or perform a cost-benefit analysis for the difference in starting time/ramp rate between the industrial frame and the aeroderivative (Pub. Ex. 3 at 7). What's more, the assignment of scores to the configuration options appears illogical in some places, calling into question the reliability of the entire scoring scheme.

Commented [CAC7]: ***Comment for the Commission regarding highly confidential information***: [redacted]

NIPSCO witness Baacke averred (Direct, p. 5) that 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. Whether this is true or not, we are unable to conclude that the aeroderivative turbine's features are necessary to 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 also note that 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. As simple as this fact may be, it illustrates the balancing and tension between and among the Five Pillars that naturally occurs as a utility invests to ensure the availability and delivery of reliable energy to its customers. The OUCC, NIPSCO IG, and CAC's 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 that the Pillars of reliability, resiliency, and stability should not supplant meaningful consideration of the customer affordability of NIPSCO's request. Moreover, it is important for us to define a tractable standard for affordability so that we may recognize affordability (or the lack thereof) when we see it.

Although we are not approving exact customer rates as part of this proceeding, NIPSCO is seeking approval to construct a generation facility that will operate for many years and approving a recovery mechanism for costs associated with construction of the facility. We evaluate the affordability of the generation CPCN request in the context of a large electric utility's generation transition, which stands to impact its customers in significant ways. 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. The evidence here fails to supports that NIPSCO's proposal in this case 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. However, as CAC witness Sommer pointed out, NIPSCO took a stark detour from its 2021 IRP, when crafting its proposal for this CPCN proceeding. NIPSCO's proposal with aeroderivative turbines amounts to a massive cost increase per

Commented [CAC8]: ***Comment for the Commission regarding confidential information***: [redacted] CAC Ex. 1 at 16-17.

megawatt of installed capacity compared to that in the 2021 IRP. The cost of nearly $1,600 per kW is the most expensive of any combustion project currently under development in the United States in the awareness of CAC witness Ms. Sommer. CAC Ex. 1 at 6. Comparing the cost estimate of NIPSCO's proposal to the market and to NIPSCO's prior estimate of what its portfolio needs, we cannot conclude that NIPSCO has prioritized affordability.

iii. **Resiliency.** Resiliency is similar to reliability, and much of our discussion above discussing Reliability is applicable here. But resiliency also represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. For example, fast starting capabilities, including potential for blackstart capabilities, are the ability of the system to restore service when one or more areas of the bulk electric system shuts down for whatever reason. The fast start capabilities of the CT Project, especially given the configuration with aeroderivative units, could meet a key component of resiliency. NIPSCO witness Mr. Walter testified that 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 also offered extensive confidential testimony that directly addressed how the CT Project will support resiliency. On the other hand, the Commission notes that NIPSCO confidentially divulged certain challenges with the interstate supply and the on-site equipment at its existing Sugar Creek gas generating station during Winter Storm Elliott in December 2022, and when asked how it will mitigate these issues in future winter conditions, did not offer any new strategies beyond citing its gas distribution system's existing interstate pipeline connections and on-system storage facilities. NIPSCO-CAC Conf. Ex. 5-C at 3-4. Moreover, NIPSCO's Flexible Resource Analysis did not consider any seasonal variation in the performance of a hypothetical new flexible, dispatchable resource, even though the Engineering Study did explore performance variation for a new gas combustion turbine based on ambient temperature and humidity. NIPSCO-CAC Ex. 6 at 32; Pet. Ex. 4, Conf. Att. 4-A at 5-6. This raises serious concerns about how seriously NIPSCO is taking the statutory goal of 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 Augustine, the 2023 Portfolio Analysis incorporated market shifts and changes that have occurred since the 2021 IRP, including the MISO seasonal resource adequacy construct. We agree that these changes point to the increased need for capacity-advantaged resources in NIPSCO's generation portfolio, a need which both the CT Project and battery storage could directly fulfill. We note, further, that NIPSCO overestimated the future capacity accreditation of gas generation and underestimated the future capacity accreditation of battery storage, under MISO's new accreditation methodology currently pending before FERC in Docket No. ER24-1638. CAC Ex. 1 at 22-23.

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 transition portfolio transition since its 2018, 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. Pet. Ex. 3 at 21. As gas turbines can operate continuously for extended durations, the CT Project has the potential to support system stability. NIPSCO witness Mr. Stanley testified that gas resources have a significant advantage relative to inverter-based (*e.g.*, renewable) resources (Pet. Ex. 6 at 18). However, if we focus on battery storage resources in the MISO chart referenced by Mr. Stanley, it appears that gas and battery resources are on equal footing when it comes to ramp-up capability and rapid start-up, while gas is a small degree stronger than batteries when it comes to voltage stability (although MISO notes that batteries' strength in that attribute has the potential to improve). *Id.* 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. Record evidence supports a finding that both a new gas peaker generator and battery storage could offer these types of needed attributes and supports system stability for NIPSCO, the State of Indiana, and the broader MISO region.

v. **<u>Environmental Sustainability</u>**. Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources, under I.C. § 8-1-2-0.6(5). NIPSCO asserts that its proposed 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. Pet. Ex. 2 at 20. However, as discussed above, it appears that the CT Project is not needed to support the substitution of coal generation with wind and solar generation; rather, it will be used to replace the retiring gas peaker generating units at the Schahfer site. As further discussed above, it appears that NIPSCO did not correctly model alternative resource options including battery storage that would not emit ambient pollution and greenhouse gases.

NIPSCO claimed, as described above, that the CT Project will have the flexibility to run beyond its currently anticipated capacity factors and still maintain compliance with the newly adopted GHG Rule.

NIPSCO witness Mr. Holcomb explained (p. 7) that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the GHG Rule (40 C.F.R. Part 60, Subpart TTTTa) and be allowed to operate at capacity factors up to 40%, as needed. By comparison, the frame unit is not expected to meet the intermediate load emission standard and would, therefore, be limited to a 20% capacity factor. However, the Commission is concerned that, as discussed above, NIPSCO did not model the projected capacity factor of individual generating units within its proposed CT Project (as individual units are the object of regulatory interest under the new federal greenhouse gas rule). Furthermore, the evidence showed that the upgrades needed to run the turbines on hydrogen such that a unit could comply with the federal standards have not been fully investigated or costed, nor have hydrogen fuel supply options been identified. Moreover, using exclusively aeroderivative turbines (which was not NIPSCO's proposal in this matter) to better comply with environmental regulations would further worsen the proposed project's affordability, given the excessive cost of aeroderivatives that we recounted above. Overall, the proposed CT Project's configuration appears unable to fully meet environmental requirements, and the cost of full compliance would be intolerably high, given that cleaner, less expensive resource options to meet NIPSCO's portfolio needs were not chosen.

Few parties presented evidence on the demand from consumers for environmentally sustainable sources of electric generation. We note that at the field hearing in this proceeding conducted March 14, 2024 in LaPorte, several public commenters who are customers of NIPSCO expressed their desire for zero-pollution energy resources, including Libré Booker, a Portage resident, speaking on behalf of an organization called Just Transition Northwest Indiana. Ms. Booker expressed that NIPSCO, through runoff from coal ash sites, has already damaged the water supply of 38 homes in the area that rely on groundwater for drinking. Ms. Booker also expressed that other options exist besides a new gas power plant, and that NIPSCO should move to renewable energy to consider the planet's future. Next, Chris Chyung of Indiana Conservation Voters spoke. Born in Merrillville, he encouraged NIPSCO to make a transition to renewable resources, which would support renewable jobs. He encouraged NIPSCO to tap into trillions of dollars of federal incentives for a clean energy transition. In light of these comments, we are compelled to note that approving the CT Project would run directly counter to these ratepayers' expressed demand and thus would be at odds with the sustainability attribute lifted up by our legislature.

Above, we have evaluated and discussed each of the Five Pillars. The record evidence demonstrates the CT Project, though it has the potential to address reliability, resiliency, and stability in the NIPSCO portfolio and the state of Indiana's broader electric grid, fails to satisfy key attributes set out in state law including affordability and sustainability, particularly compared to alternative options that NIPSCO could have proposed to meet the same purposes for its load-serving needs. We have also concluded that the proposed GCT Mechanism through which costs would be recovered from customers fails to produce gross financing costs savings for customers as required by law (in addition to its non-applicability to NIPSCO's proposal, in any event). Having considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6 in reaching our decision in this proceeding, the Commission finds that NIPSCO's proposed CT Project and related proposals are described herein are not consistent with the legislative directive in this state policy statement.

7. <u>Confidentiality.</u> NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information on September 12, 2023, January 16, 2024, and April 25, 2024. All of 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's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct an approximately 400 megawatt ("MW") natural gas combustion turbine peaking plant to be located at NIPSCO's existing R.M. Schahfer site and all associated relief requested is denied.

2. NIPSCO's request for ongoing review of the CT Project is denied as moot.

3. The CT Project is not approved as a clean energy project. 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 denied.

4. NIPSCO's request for authority to recover costs incurred in connection with the CT

Project through its Generation Cost Tracker ("GCT") Mechanism, as proposed, including proposed changes to its Electric Service Tariff relating to the GCT Mechanism, is denied.

5. NIPSCO's request in paragraph 25 of its Petition for certain ratemaking treatment related to post-in service carrying costs is denied as moot.

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.

<u>HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR</u>:

APPROVED:

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

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Dana Kosco
Secretary of the Commission