STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF PETITIONER'S 7-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE 8-1-39-10(a) INCLUDING TARGETED ECONOMIC DEVELOPMENT PROJECTS PURSUANT TO IND. CODE 8-1-39-10(c) AND EXTENSIONS TO RURAL AREAS PURSUANT TO IND. CODE 8-1-39-11.	)	Cause No. 44403

SUBMISSION OF THE INDUSTRIAL GROUP'S PROPOSED ORDER

The NIPSCO Industrial Group hereby submits a proposed order for this proceeding. A copy will be sent to the Administrative Law Judge in word processing format.

Respectfully submitted,

LEWIS & KAPPES, P.C.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing document have been served upon the following via electronic mail, this 28th day of February, 2014:

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ORDER OF THE COMMISSION

Presiding Officers:
James D. Atterholt, Chairman
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its Verified Petition commencing this proceeding on October 3, 2013, seeking relief pursuant to Ind. Code §§8-1-39-10 and 8-1-39-11 with respect to a 7-year plan for certain improvements to its natural gas transmission, distribution and storage system assets, including targeted economic development projects and extensions to rural areas ("7-Year Gas Plan"). NIPSCO concurrently submitted its prefiled case-in-chief evidence, and moved for protection and nondisclosure of certain confidential and proprietary information. By Docket Entry dated October 16, 2013, the Presiding Officers granted the request for confidential treatment on a preliminary basis.

The Indiana Office of Utility Consumer Counselor ("OUCC") was served with the Verified Petition and participated as a party throughout the proceeding. By unopposed petitions to intervene, duly granted by the Commission, the following additional parties participated as intervenors: the NIPSCO Industrial Group ("Industrial Group"), Citizens Action Coalition of Indiana, Inc. ("CAC") and United States Steel Corporation ("U. S. Steel").

A duly noticed Technical Conference was conducted before the Commission on December 13, 2013. Pursuant to a procedural schedule established by the Commission, the OUCC, the Industrial Group and U. S. Steel submitted their prefiled case-in-chief evidence on January 13, 2014. On the same date, the Industrial Group also filed a Motion for Administrative Notice , which was granted by Docket Entry on January 27, 2014. NIPSCO submitted its prefiled rebuttal evidence on January 27, 2014, and concurrently filed a Motion to Strike portions of the prefiled testimony submitted by the Industrial Group and U. S. Steel. Following briefing by the parties, the Motion to Strike was denied by Docket Entry dated February 17, 2014.

On February 18, 2014, a duly noticed evidentiary hearing was held before the Commission in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, the Industrial Group, U. S. Steel and CAC appeared and were represented by counsel. No members of the general public appeared or participated in the hearing. The prefiled evidence and administratively noticed materials were admitted into the record, two additional Commission orders were administratively noticed at the request of NIPSCO, and certain witnesses presented live testimony and responded to cross-examination and questions from the Presiding Officers. The parties subsequently submitted post-hearing filings.

Having considered the evidence and being duly advised, the Commission now finds:

1. Notice and Jurisdiction. Notice of the hearings in this Cause was given and published by the Commission as required by law. NIPSCO is a "public utility" within the meaning and scope of Ind. Code §§8-1-2-1(a) and 8-1-39-4, rendering retail natural gas service to about 786,000 residential, commercial and industrial consumers in all or parts of 32 counties in northern Indiana. In that capacity, NIPSCO is subject to regulation by the Commission in the manner and to the extent provided by the public utility laws of Indiana. Under Ind. Code §8-1-39-10, a public utility may petition the Commission for approval of a 7-year plan for eligible transmission, distribution and storage system improvements, and may include in such petition a request for approval of targeted economic development projects and rural extensions as provided in Ind. Code §8-1-39-11. The Commission, accordingly, has jurisdiction over Petitioner and over the subject matter of this proceeding.

2. Petitioner's Characteristics. NIPSCO is a public utility organized and existing pursuant to the laws of the State of Indiana, having its principal office at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO is in the business of providing retail electric and natural gas utility service to members of the public in portions of northern Indiana, and owns, operates, manages and controls plant and equipment within the State of Indiana that is used for the transmission, distribution and furnishing of such service to the public. NIPSCO is a wholly-owned subsidiary of NiSource Inc., an energy holding company whose stock is listed on the New York Stock Exchange.

3. Requested Relief. This proceeding is governed by Ind. Code §8-1-39-1 et seq. (the "TDSIC Statute"), which provides a process by which energy utilities may recover defined investments in certain infrastructure projects through a tracking mechanism.

Under the TDSIC Statute, "eligible transmission, distribution and storage system improvements" are defined as new or replacement projects that: (1) are undertaken for purposes of safety, reliability, system modernization or economic development; (2) were not included in the utility's rate base as of its most recent rate case; and (3) either were designated in an approved 7-year plan under Section 10 or approved as a targeted economic development project under Section 11. See Ind. Code §8-1-39-2. A "TDSIC" is a charge by which investments in such projects are substantially recovered through a rate tracker. Id. Sections 6, 9. Section 10 provides a framework for a utility to seek approval of a 7-year plan identifying projects eligible for TDSIC treatment. Section 11 provides for targeted economic development projects and extensions into rural areas, with associated investments also being recoverable through a TDSIC. Pursuant to Section 9, a utility's basic rates and charges may be automatically adjusted periodically to recover 80% of approved capital expenditures and TDSIC costs, with the remaining 20% being deferred for recovery in the utility's next general rate case.

NIPSCO's Verified Petition in this cause sought approval of a 7-Year Gas Plan pursuant to Section 10 of the TDSIC Statute, including targeted economic development projects and rural extensions within the scope of Section 11. NIPSCO requested the Commission find that the projects set forth in the 7-Year Gas Plan constitute "eligible transmission, distribution and storage system improvements," that the best estimate of costs were provided, that the public convenience and necessity require or will require the projects, and that the estimated costs are justified by incremental benefits attributable to the plan. NIPSCO further requested inclusion of targeted economic development projects and rural extensions in the approved plan. If the Commission finds the 7-Year Gas Plan is reasonable, NIPSCO requested that the Commission designate the improvements in the plan as eligible for TDSIC treatment and include the improvements in NIPSCO's rate base for purposes of future rate proceedings.

NIPSCO's Verified Petition in this cause did not seek the establishment of a TDSIC by which eligible costs would be recovered through a rate tracker, as provided for in Sections 9 and 12 of the TDSIC Statute. This proceeding concerns the request for approval of the 7-Year Gas Plan pursuant to Section 10, including targeted economic development projects and rural extensions within the scope of Section 11. If and to the extent the requested approval is granted, NIPSCO will commence a separate proceeding under Sections 9 and 12 to establish the tracker by which eligible costs would be recovered through rates.

4. Evidence Presented.

A. NIPSCO's case-in-chief. In support of its Verified Petition, NIPSCO offered the prefiled testimony and exhibits of three witnesses: Steven M. Auld, NIPSCO's Director of Gas System Operations; Mark G. Small, NIPSCO's Director of Engineering; and Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for NIPSCO.

Mr. Auld described the design and operation of NIPSCO's gas system, in order to provide context for the projects set forth in the 7-Year Gas Plan. See NIPSCO Ex. SMA at 2-3. He presented, as exhibits, maps of NIPSCO's gas system and in greater detail its 483 lb. transmission system. Exs. SMA-1, SMA-2. He explained how system design is determined based on Design Day conditions, reflecting expected usage at peak demand, and noted that the last time NIPSCO reached system peak was on January 18, 1994. Ex. SMA at 3-6.

Mr. Auld described NIPSCO's transmission system, which consists of three distinct components identified by their respective operating pressures: the "483 lb. system," "600 lb. system" and "275 lb. system." See Ex. SMA at 6-14. He explained the 600 lb. system is a loop extending from the Illinois state line to Fort Wayne, branching north near South Bend and south through Royal Center, interconnecting with all seven interstate pipelines that connect to

NIPSCO's system. Id. at 10-11. The 275 lb. system interconnects with the 600 lb. loop. The 483 lb. system is fed from a single point of delivery at the Highland Junction hub and is used to serve very high demand, very high load factor customers in the northwest corner of the NIPSCO system. Id. at 11-12. Any condition adversely impacting that single feed could potentially interrupt service to some of NIPSCO's biggest customers. Id. The 483 lb. system currently is not interconnected with the 600 lb. loop. Id. at 12.

Mr. Auld further described NIPSCO's distribution system, which consists of 16,837 miles of distribution main and 848,811 service pipes. See Ex. SMA at 14-17. He noted NIPSCO had a very low percentage of priority pipe, which is main that is not plastic or cathodically protected steel. Id. at 15-16. He explained the distribution system in the Kokomo area was designed to operate as a low pressure system, presenting operational challenges. Id. at 16.

Mr. Auld also described NIPSCO's three on-system storage operations: an underground facility at Royal Center with a working capacity of 4 bcf of gas; liquefied natural gas or "LNG" facilities near LaPorte at which gas is stored in liquid form; and "line pack" capability by which gas can be stored on the transmission system with an increase in pressure for short-term availability. See Ex. SMA at 17-25. He described customer benefits relating to the storage assets. Id.

On cross-examination, Mr. Auld noted the current winter has been challenging due to sustained cold temperatures and might have resulted in a new Design Day had heavy snow not led to closures that reduced gas usage. See Tr. at A21-22, A40. He testified there had been hard winters and interruptions in service in the past. Id. at A22-23, A33. He agreed as usage approaches peak design capacity the customers farthest from the supply source are at risk of interruption, and with the 483 lb. system there is only a single point of delivery and several of NIPSCO's largest customers are located near the end of that system. Id. at A23-25. He testified the 483 lb. system has been a single feed since it was installed, and the risk of interruptions from any conditions impacting that feed had been the case as long as he could remember. Id. at A26. He agreed NIPSCO had been aware of that risk for many years, but had not previously undertaken the projects included in the 7-Year Gas Plan to address it, such as interconnecting the 483 lb. and 600 lb. systems. Id. at A27-29. While NIPSCO has invested heavily in its distribution system over the years, Mr. Auld admitted NIPSCO had not invested as much in the transmission system. Id. at A31-32.

Mr. Small presented the 7-Year Gas Plan, including the summary of the planned project categories and costs, the infrastructure study prepared by a third party consultant, the cost estimates and the proposed records improvements. See NIPSCO Ex. MGS at 2; Exs. MGS-1 through MGS-4. He explained EN Engineering was engaged to assist with the preparation of the 7-Year Gas Plan, and in conjunction with NIPSCO conducted risk assessment of system infrastructure to identify and prioritize projects to support reliability and integrity improvements. See Ex. MGS at 3-4, 12-15. EN Engineering also assisted in preparing and reviewing cost estimates. Id. at 8, 14, 47-48.

NIPSCO's 7-Year Gas Plan was presented in Ex. MGS-1. Mr. Small categorized the 7-Year Gas Plan as comprised of four segments: (1) system reliability improvements through enhanced deliverability; (2) replacement of certain assets to ensure integrity and safe operations; (3) data and technology investments; and (4) extension of facilities into rural areas. See Ex. MGS at 4-7. He stated the total estimated capital cost of the 7-Year Gas Plan is $713 million, including indirect capital and allowance for funds used during construction ("AFUDC"), and the total estimated operations and maintenance ("O&M") cost is $8.5 million. Id. at 11. He provided individual project detail and total spend for Year 1 of the plan ($53.3 million capital and $2.5 million O&M), and expected spend by project category for Years 1 through 7. Id. He indicated the 7-Year Gas Plan is meant to be dynamic, not static, and will be updated in future filings as additional information becomes available. Id. at 9-10. He stated NIPSCO considered a plan detailing every individual project by year, but concluded it would not be practical. Id. at 10.

Mr. Small described the manner in which NIPSCO identified investments for each of the four segments of the 7-Year Gas Plan. See Ex. MGS at 15-23. He indicated deliverability projects were, and would be in the future, determined through a planning process conducted annually by NIPSCO. Id. at 15-17. Integrity investments were identified through assessment of safety risks, with the assistance of EN Engineering. Id. at 17-21. Data integration investments relate to legacy paper records and the benefits of conversion to electronic format. Id. at 21-22. Finally, NIPSCO analyzed rural extensions based on specified considerations. Id. at 22-23.

With regard to deliverability investments, Mr. Small identified a number of projects under review to meet demand and enhance reliability. See Ex. MGS at 24-27. He explained one project included in the plan for 2014, and stated after 2014 other projects will be identified through the annual system planning process. Id. at 24-25. For each successive year, there is a funding forecast based on study areas. Id. at 25. In addition, the 7-Year Gas Plan includes near term and potentially longer term investment in the LNG storage facility. Id. at 26-27.

With regard to integrity investments, Mr. Small stated that projects included in the 7-Year Gas Plan include replacement of certain transmission mains, installation of automated valves, implementation of in-line inspection capabilities, upgrade of the low pressure system near Kokomo, replacement of bare steel distribution pipe, and replacement of assets as identified through the inspection and assessment processes. See Ex. MGS at 27-38. By replacing 75 miles of transmission main installed between 1944 and 1960, an additional 40 miles of transmission main installed between 1951 and 1956 can be either retired or reduced in operating pressure. Id. at 27-28. Additional transmission investments would reduce operational risk in the northwest portion of NIPSCO's system, including an interconnection between the 600 lb. system and the 483 lb. system, thereby reducing dependence on the Highland Junction hub as sole source of gas on the 483 lb. network. Id. at 28. The planned transmission replacements also include segments with shallow depth of cover. Id. at 30-31. Mr. Small explained the benefits of automated valves in mitigating the consequences of a pipeline failure more promptly, and described the enhanced inspection benefits through in-line use of "smart pigs." Id. at 31-33. He explained the planned upgrade of the low-pressure Kokomo system to a medium pressure system, the replacement of the 59 remaining miles of bare steel distribution pipe in the NIPSCO system that date back to the late 1920s, and the cycle of inspections and assessments that would identify specific projects on an ongoing basis. Id. at 33-38.

Mr. Small described the data integration portion of the 7-Year Gas Plan, which involves the integration of data currently in legacy paper records into NIPSCO's GIS system for enhanced access and utilization. See Ex. MGS at 38-39. The cost estimate is $8.5 million. Id.

Mr. Small testified that the 7-Year Gas Plan includes $98.8 million for rural extensions. See Ex. MGS at 39. The estimate was a forecast based on historical demand and expected economics under a 20-year margin test. Id. NIPSCO proposes a process to balance customer needs with operational considerations, involving an annual "open season" for requested extensions followed by determinations by NIPSCO as to orderly and cost effective construction within the extension budget for the year. Id. at 40-41. Mr. Small summarized the assumptions utilized by NIPSCO in setting the budget for extensions. Id. at 42-43.

As described by Mr. Small, the first year of the plan involves a more modest investment of $53.3 million but as the plan matures the annual investments will grow to about $115 million. See Ex. MGS at 44. He noted the investments in the 7-Year Gas Plan are "at levels beyond past experience," but involve the type of work NIPSCO does routinely, and for portions "in areas NIPSCO has not seen in the recent past" an industry expert was engaged to develop cost estimates. Id. He broke down the $731.1 million total capital costs as $593.2 million in direct cost, $98.3 million of indirect capital and $21.6 million of AFUDC. Id. at 45-46. He offered the opinion that the cost estimates were reasonable and satisfied the statutory criteria. Id. at 47-48.

On cross-examination, Mr. Small agreed that the projects identified in the 7-Year Gas Plan are important to safety and reliability. See Tr. at A47-48. He noted the goals of the plan differed from NIPSCO's goals prior to developing the plan only with respect to rural extensions. Id. at A48-49. He testified the plan involves a significant increase in transmission expenditures beyond past experience, on the order of a $30 to $40 million increase per year. Id. at A50-51. He stated a Major Projects team at NIPSCO that would assist in implementing the plan was created to handle recent environmental upgrades, the costs of which, he agreed, were also recovered through a rate tracker. Id. at A51-52.

Mr. Small testified EN Engineering was engaged about a year earlier to assist with the 7-Year Gas Plan, though they had handled other projects for NIPSCO previously. See Tr. at A52. NIPSCO already had a process in place to identify projects needed for safety and reliability, but EN was brought in because NIPSCO lacked experience with large transmission projects. Id. at A52-53. NIPSCO's planning process the prior year identified projects now included in the 7-Year Gas Plan, but generally not transmission projects. Id. at A53-55. EN Engineering identified and prioritized transmission projects and prepared the cost estimates for those projects, though Mr. Small admitted the transmission system was owned and operated by NIPSCO and was an important part of the system to provide safe, reliable service. Id. at A55-56. He stated federal guidelines to identify integrity issues had been more aggressively developed since the San Bruno incident in September 2010, though he agreed there was always risk associated with operating a pressurized gas transmission system. Id. at A56-57. He did not know what process was in place prior to 2002, but in that year transmission integrity rules went into effect and led to increased attention, then there was significantly more attention starting in 2010, and at the time EN Engineering was engaged NIPSCO still felt outside expertise was needed. Id. at A57-59.

With regard to the 115 miles of transmission main installed between 1944 and 1960 that would be replaced, retired or operated under reduced pressure as a result of the 7-Year Gas Plan, Mr. Small testified those segments are the highest rated risk areas of the transmission system. See Tr. at A61-62. The integrity risks were previously rated by NIPSCO using a less developed model, and NIPSCO was aware that the 115 miles of transmission pipe had been installed 50 to 75 years ago. Id. at A62-64.

Mr. Small further testified the 7-Year Gas Plan identifies transmission and certain other projects, but for the distribution system the plan identifies Year 1 projects with specificity and for Years 2 through 7 includes projected spend levels by categories but not specific projects. See Tr. at A64-66. He agreed the planned investments start at a lower level and ramp up in Years 3 to 7. Id. at A66-67. He testified that distribution deliverability projects are under review for potential inclusion at some point, and specific projects will be identified as inspections occur and experience is gained. Id. at A68-69. He agreed specific projects could not be predicted in advance, nor could the number of projects in a given year, nor the magnitude beyond historical levels. Id. at A69-70. He further agreed the level of expense required for projects in a given year could not be predicted, as "it's very hard to tell what it will take." Id. at A70-71.

In response to questions from the Presiding Officers, Mr. Small testified the 7-Year Gas Plan was developed prior to or about the same time the TDSIC legislation was being enacted. See Tr. at A83. The plan mirrored the 7-year span under the legislation because it started with a 10-year plan and evolved to match the TDSIC legislation. Id. at A83-84. Of the $713 million in the plan, minor components such as in-line inspection projects are federally mandated, the majority of the large transmission projects are not mandated but are in line with federal guidance, and rural extensions are neither mandated nor suggested best practices. Id. at A84-85. Mr. Small expected more of the best practice guidance to become mandated in time, though implementation of integrity standards would still involve interpretation. Id. at A85-87. To explain what is excessive and what is appropriate and proper, he noted pipe installed in the 1940s to 1960s was not subject to welding regulations, pressure testing requirements or documentation standards, and it is time to start replacing those components in order to address safety risks. Id. at A87-89.

Mr. Shambo summarized the relief sought by NIPSCO, addressed the statutory authority, defined certain terms, and discussed rural extensions, the proposed approach for updating the plan, the impact on retail revenue, the capital allocation process, treatment of indirect capital and the stakeholder process. See NIPSCO Ex. FAS at 3.

Mr. Shambo described the relief sought in this proceeding and provided an overview of the TDSIC Statute, which was enacted as part of Senate Bill 560 with an effective date of April 30, 2013. See Ex. FAS at 4-7. He proposed definitions for certain terms that were not defined in the statute: Safety; Reliability; System Modernization; Economic Development; Transmission, Distribution and Storage; Under Construction; and Rural Area. Id. at 7-8. He also provided an overview of the 7-Year Gas Plan, noting the plan identifies projects with considerable detail for the first twelve months and otherwise NIPSCO is requesting approval for total annual projected spends. Id. at 8-10. He offered the opinions that the improvements included in the plan satisfied the public convenience and necessity standard, that the best estimate of costs had been provided, that those costs were justified by incremental benefits, and that the O&M amounts were properly included. Id. at 10-14. He noted the O&M component was not included in NIPSCO's overall revenue requirement as set in its last rate case, and none of the investments in the 7-Year Gas Plan were included in NIPSCO's rate base as of its most recent rate case. Id. at 14-15.

Addressing rural extensions, Mr. Shambo identified NIPSCO's objectives and described the planned "open season" approach for determining what construction to undertake in a given year. See Ex. FAS at 15-20. He estimated NIPSCO would connect roughly 2,600 new rural customers per year under the TDSIC program. Id. at 18. He proposed that Rural Area be defined as including communities with a population of less than 2,000 as of the 2010 census. Id. at 8, 20.

Mr. Shambo testified that NIPSCO intends to update its 7-Year Gas Plan with adjustment filings submitted every six months starting September 1, 2014. See Ex. FAS at 21. At least once a year, NIPSCO proposes to provide project detail for the upcoming year similar to that provided in this proceeding for Year 1, and will also update the required annual spends. Id. He stated that the plan will change as new information becomes available, costs will be need to be adjusted due to changes over time, and it would be too rigid to detail projects in advance for all seven years. Id. at 22-24.

With regard to the impact on retail revenue, Mr. Shambo calculated the average increase attributable to the 7-Year Gas Plan as 1.4% annually (or about 10% over the 7-year period), with current total retail revenue of $653.4 million and estimated total revenue as of 2020 at $718.6 million. See Ex. FAS at 24-25. He noted NIPSCO must file its next general rate case prior to the end of the 7-Year Gas Plan in 2020, and though NIPSCO has not determined when that filing will be made, the balance of deferred TDSIC costs at the end of 2020 will be about $104.5 million. Id. at 24-25.

Mr. Shambo further discussed NIPSCO's capital allocation process, as one of three business units of its parent NiSource. See Ex. FAS at 27-29. NIPSCO competes for capital dollars with other business units, through a planning process reflecting financial assumptions, business results and investor expectations on performance. Id. As capital is a scarce resource, Mr. Shambo explained NIPSCO is proposing a flexible approach to the TDSIC program to avoid overcommitting to an unknown future. Id. at 29. He also described indirect capital costs for overhead, stores, freight and handling, and AFUDC. Id. at 30-31. He testified that NIPSCO used the same indirect capital cost methodology as it did in the test year of its last rate case, and stated that although the last rate case provided for recovery of labor expenses and pension costs the proposed inclusion of indirect capital costs in the TDSIC adjustment would not result in a double recovery of expenditures. Id. at 31-32.

On cross-examination, Mr. Shambo agreed that the projected total capital spend of $713.1 million in the 7-Year Gas Plan is roughly equivalent to the fair value rate base of $725 million as presented in NIPSCO's most recent rate case. See Tr. at B5-6. He stated that, where the TDSIC Statute provides for a 90-day period to complete the anticipated tracker proceeding, NIPSCO intended to allow for a 150-day period for its first tracker filing. Id. at B7-9. He described the methodology used in projecting the impact on retail revenues, which assumed a

9.9% rate of return as approved in the last rate case. Id. at B9. He agreed the last rate case was filed in May 2010 and settled a few months later, and before that there was a period of over twenty years since the prior rate case in 1988. Id. at B10-11. He stated NIPSCO's debt rate is lower than its allowed return on equity. Id. at B12.

On further cross-examination, Mr. Shambo did not agree that the recently issued electric TDSIC order was the largest rate increase ever authorized by the Commission for NIPSCO or that the 7-Year Gas Plan would result in the largest revenue increase for NIPSCO's gas business, noting that the increases would be implemented over a 7-year period. See Tr. at B13-15. He was not aware, however, of any prior authorized increase of $713 million in gas rate base, and he agreed the amount would double the fair value rate base and triple the original cost rate base as determined in the last rate case. Id. at B15. He testified the planned investments for safety and reliability would be made by NIPSCO with or without the availability of tracker treatment, although the rural extensions would not be part of the plan absent the TDSIC Statute. Id. at B16-17. He agreed NIPSCO could file a rate case to recover costs instead of filing a tracker. Id.

Mr. Shambo admitted a significant capital expenditure program benefits NiSource by growing earnings, and NiSource had committed to the financial community to grow earnings by 5 to 7% annually. See Tr. at B18. He stated NIPSCO earnings had been higher than authorized in the last rate case in recent quarters, but over a longer period of time that may not be the case. Id. at B18-19. With reference to an exhibit presenting an internal Capital Allocation Request for both the electric and gas TDSIC programs (IG CX-1), Mr. Shambo agreed NiSource had already authorized NIPSCO to spend the capital for both the gas and electric TDSIC programs. See Tr. at B22-23. He reiterated NIPSCO will make the investments for safety and reliability regardless of the outcome of this proceeding, though an adverse outcome could trigger a rate case and affect rural extensions. Id. at B23-25.

Addressing NIPSCO's proposal to update its 7-Year Gas Plan annually, Mr. Shambo stated the plan provides project level detail for the first year and dollar amounts for all seven years, with further specific project level detail to be provided once a year. See Tr. at B25-26. He provided an example of a line built in the 1940s that serves U. S. Steel, and admitted the risk has been increasing every year as it gets older. Id. at B28-30. He stated NIPSCO is seeking approval of the 7-Year Gas Plan, not dollar amounts for individual years. Id. at B30-31. He expected expenditures to shift year to year from the projections, and stated the $713.1 million total could change, though major changes would require Commission approval. Id. at B31-33. He had not thought about whether increases could be sought through the semi-annual update process. Id. at B33-34. He had not thought of, for example, the $377 million estimate for transmission projects as a cap, and declined to state there would be no other transmission projects beyond those listed. Id. at B35-37. He indicated there would be flexibility especially in rural extensions and distribution projects. Id. at B37-39. He had not thought about whether, if the budget for a given category is exhausted NIPSCO could spend more for that project within the total $713 million budget, though he stated major changes would require Commission approval. Id. at B41-42.

On questions from the Presiding Officers, Mr. Shambo testified the largest project in the 7-Year Gas Plan is not a federal mandate but is in accordance with federal guidance. See Tr. at

B46-47. He discussed NIPSCO's decision to file under the TDSIC Statute rather than the process for tracking federal mandate expenditures, as simplifying the regulatory process. Id. at B47-48. He characterized the $713 million figure as a hard estimate, noting as an example that NIPSCO may increase the budget for rural extensions and that increase would not reduce the budget for other projects NIPSCO is committed to completing. Id. at B49-50. He had not thought about how such an increase would be presented for Commission approval. Id. at B50-51. He testified the $713 million could go higher or lower, based primarily on rural extensions and distribution projects. Id. at B51-52. He also stated the 7-Year Gas Plan would necessitate hiring additional NIPSCO employees and some contractors. Id. at B52-53. He also clarified that projects including both rural and non-rural applicants would be submitted to the Indiana Economic Development Corporation but rural-only projects would not. Id. at B53-54.

Before closing, NIPSCO requested that the Commission take administrative notice of its February 17, 2014 final orders in Cause Nos. 44370 and 44371, concerning NIPSCO's electric 7-year plan. That request was granted without objection. See Tr. at B56-57.

B. OUCC's case-in-chief. The OUCC offered the prefiled testimony and exhibits of three witnesses: Barbara A. Smith, Director of the OUCC's Resource Planning and Communications Division; Maclean O. Eke, a Utility Analyst with the Resource Planning and Communications Division; and Mark H. Grosskopf, a Utility Analyst with the OUCC's Natural Gas Division.

Ms. Smith's testimony recommended that the 7-Year Gas Plan be approved with specified conditions, subject to on-going reporting requirements and submission of work order level detail for approved projects. See Public Ex. 1 at 3. She explained that proposed expenditures in 7-year TDSIC plans should be prioritized through appropriate risk-based assessments, and that NIPSCO did so sufficiently in this case. Id. at 4-7. She further noted that critical data must support such assessments in order to protect ratepayers, and that NIPSCO provided the necessary data with the exception of sufficient cost estimates. Id. at 7-10.

With regard to the major distribution system projects in NIPSCO's 7-Year Gas Plan, Ms. Smith agreed that the proposals to replace remaining segments of bare steel pipe, to upgrade the low pressure Kokomo system to medium pressure, and to upgrade certain master meter systems were reasonable, subject to provision of appropriate information by NIPSCO. See Public Ex. 1 at 10-12. Ms. Smith further agreed that the transmission projects included in the 7-Year Gas Plan, as well as the LNG projects, were reasonable. Id. at 12-16. With respect to NIPSCO's proposal to update the 7-Year Gas Plan, she proposed annual reporting requirements. Id. at 16-18. She noted that targeted economic development projects and the proposed data integrity integration projects were properly included, subject to reporting requirements and collaboration with the OUCC and intervenors. Id. at 18-23.

Addressing the statutory criteria for approval of the 7-Year Gas Plan, Ms. Smith concluded that the identified projects would provide incremental benefits and that project cost estimates provided by NIPSCO were reasonable, but she did not agree that NIPSCO had presented the best cost estimates for all projects. See Public Ex. 1 at 23-26. She noted that

NIPSCO provided work order level cost estimates only for certain projects, and proposed that NIPSCO be required to provide sufficiently detailed estimates in future tracker filings. Id.

Mr. Eke addressed NIPSCO's risk model study, and concluded that the risk analysis was satisfactory but could be improved with increased use of probabilistic models to enhance its predictive ability as opposed to present condition assessment. See Public Ex. 2 at 3-5.

Mr. Grosskopf compared proposed annual average investment in transmission, distribution and storage projects under NIPSCO's 7-Year Gas Plan with its historic levels. See Public Ex. 3 at 2-3. He calculated NIPSCO's historic annual investment over the past five years as about $48.5 million, while the annual average under the 7-Year Gas Plan would be some $84.9 million, or an increase from historic levels of 75%. Id. He further concluded NIPSCO's proposed rural extensions would be beneficial to rural customers currently utilizing propane as a fuel source, but proposed detailed accounting of associated revenues in future TDSIC filings and noted rural extensions may result in monthly increases to residential rates averaging about $0.43 over the 7-Year Gas Plan. Id. at 4-5. He also pointed out that NIPSCO expects an overall rate increase of 1.4% per year over the course of the 7-Year Gas Plan, but that NIPSCO had not analyzed potential savings in infrastructure-related O&M expenses. Id. at 5-6.

C. Industrial Group's case-in-chief. The Industrial Group offered the prefiled testimony and exhibits of Nicholas Phillips, Jr., and also presented a Motion for Administrative Notice. The materials included in the Motion for Administrative Notice consisted of documents relating to NIPSCO's most recent gas rate case, Cause No. 43894, specifically: (1) the settlement testimony and exhibits of three NIPSCO witnesses as submitted in September 2010; (2) the Commission's final order dated November 4, 2010; (3) the testimony and exhibits of two NIPSCO witnesses supporting an extension of the rate case settlement as submitted in June 2013; and (4) the August 28, 2013 Commission order approving the extension. The Motion for Administrative Notice was granted without opposition by Docket Entry dated January 27, 2014.

On February 11, 2014, NIPSCO moved to strike portions of Mr. Phillips' testimony relating to NIPSCO's current rate structure and the potential rate impact, alleging the challenged testimony was irrelevant and outside the scope of this proceeding. The motion to strike was denied by Docket Entry dated February 17, 2014, which concluded the challenged testimony was relevant to the statutory criteria of reasonableness, public convenience and necessity and justification, and was responsive to the testimony of NIPSCO witnesses. When Mr. Phillips' testimony and exhibits were offered into evidence at the hearing, NIPSCO objected and expressed disagreement with the Docket Entry. The evidence was admitted over objection.

Mr. Phillips put into context NIPSCO's proposal for approval of over $700 million in capital expenditures over seven years, by noting NIPSCO's entire original cost rate base was only $318 million as of its last rate case. See IG Ex. NP at 3. The plan would add twice that amount and basically triple NIPSCO's original cost rate base. Id. He explained that, prior to Cause No. 43894, NIPSCO had gone more than twenty years without a rate case. Id. at 4. During that period, NIPSCO had a high depreciation rate that lowered its original cost rate base because NIPSCO spent considerably less on capital additions than its annual depreciation expense. Id. at 5. From 1988 to 2008, NIPSCO's depreciation expense was $474.3 million in excess of its capital additions, and between rate cases NIPSCO's original cost rate base declined from $718.8 million to $318 million. Id. at 4-5.

In Cause No. 43894, then, there was a very sizable gap between an original cost return and a fair value return based on replacement cost new, less depreciation, of NIPSCO's rate base assets. See Ex. NP at 4. The Commission approved a settlement utilizing a fair value rate base of $725.7 million, although the original cost rate base was $318 million. Id. The settlement also lowered the depreciation rate and provided for a depreciation credit equal to the depreciation expense, in order to close the gap between book value and the remaining useful life of the assets. Id. at 5. The depreciation credit mechanism was initially scheduled to end in late 2014, but by an agreed extension approved by the Commission the term was extended to November 2020. Id.

Mr. Phillips pointed out that the TDSIC Statute provides for tracking of approved costs, and if the $713 million 7-Year Gas Plan is approved ratepayers would pay substantial amounts in addition to base rates prior to the next rate case. See Ex. NP at 6. Under NIPSCO's proposal, ratepayers would provide funds for capital investments while there is still a significant gap between NIPSCO's fair value and original cost rate base. Id. He considered it inappropriate to layer original cost ratemaking through the TDSIC Statute with the fair value approach used in setting NIPSCO's current base rates. Id. He stated NIPSCO could have spent at least $474.3 million on capital additions from 1988 to 2008 without any change in its rate base, and that level of expenditures would significantly decrease the capital additions required in the 7-Year Gas Plan. Id. at 6-7. He noted NIPSCO had not previously replaced any of its transmission system. Id. at 7; Ex. NP-3. He compared NIPSCO's proposal to the range of considerations that could be examined in a rate case. See Ex. NP at 7.

Mr. Phillips testified that in the last rate case, NIPSCO's authorized rate of return was 5.49% on the fair value rate base with a 7.0% rate of return on common equity. See Ex. NP at 7. In its last three GCA filings, NIPSCO has reported excess earnings ranging from $5.6 million to $8.7 million, indicating NIPSCO is earning above its authorized return and between 13% and 14% on its original cost rate base. Id. at 7-8. NIPSCO's proposal, however, is based on an 8.4% rate of return on the planned investments, higher than the 5.49% authorized in Cause No. 43894 or the fair value rate of return without inflation adjustment of about 6.83%. Id. at 8. Mr. Phillips offered the view that NIPSCO should not be permitted to use a fair value approach to set base rates and then an original cost approach with a higher rate of return for purposes of the TDSIC. Id. at 8-9.

Mr. Phillips explained that the rate implications of NIPSCO's proposal should be considered in connection with the requested approval of the 7-Year Gas Plan in light of the statutory criteria of public convenience and necessity, whether estimated costs are justified by incremental benefits and whether the plan is reasonable. See Ex. NP at 9. He noted that Section 14 of the TDSIC Statute imposes a 2% cap on a TDSIC in relation to the utility's total retail revenues in a 12 month period. Id. at 10. In NIPSCO's case, 2% of annual revenues is about $13 million, but NIPSCO proposes to collect $206 million in incremental revenues during the 7-Year Gas Plan, or a rate increase of about 32%. Id. at 10-11. Mr. Phillips recommended that a

2% cap be applied, limiting the aggregate amount NIPSCO can track in rates to $13 million and thereby alleviating the other concerns he identified. Id. at 11-12.

As an alternative recommendation, Mr. Phillips proposed that the capital additions allowed under the 7-Year Gas Plan be limited to $318 million, which would be a 100% increase in the original cost rate base from the most recent rate case. See Ex. NP at 13. He stated it would be unreasonable to allow a utility to increase its rate base from $318 million to $1,031 million through a tracker, as a matter of ratemaking policy. Id. From 1988 to 2008, NIPSCO's depreciation expense was $474 million in excess of capital additions, and therefore NIPSCO could have completed many of the proposed projects during that timeframe with no increase in rate base. Id. NIPSCO's current base rates reflect special ratemaking driven by the decline in original cost rate base, so that a fair value approach was used that allowed more net operating income than the original cost method, and even so NIPSCO's three most recent GCA filings have shown excess earnings. Id. Mr. Phillips concluded it is not in the public interest to allow NIPSCO to increase its rate base by $713 million through a tracking mechanism. He did not take the position that the planned projects should not be completed, but suggested a cap of a 100% increase in rate base from $318 million in Cause No. 43894 as a limit on capital expenditures approved in the 7-Year Gas Plan. Id.

D. U. S. Steel's case-in-chief. U. S. Steel offered the testimony of Richard W. Cuthbert. See U. S. Steel Ex. 1. Mr. Cuthbert addressed three aspects of NIPSCO's proposal that were unclear and potentially adverse to ratepayers: (1) uncertainty as to how the TDSIC mechanism would be implemented in light of NIPSCO's unusual ratemaking history; (2) uncertainties as to proposed rural extension costs; and (3) uncertainties concerning potential increases to approved amounts arising from future revisions to the 7-Year Gas Plan. Id. at 3.

Mr. Cuthbert stated it is difficult to evaluate the reasonableness of the 7-Year Gas Plan in light of NIPSCO's rate history, in the absence of the rate impact information that NIPSCO anticipates providing in the subsequent tracker proceeding. See USS Ex. 1 at 3-4. He noted NIPSCO's most recent rate case was settled in a short period of time, and the last full review of rates was conducted more than twenty years before that. Id. at 4-5. He considered it important to examine pre-tax return, cost of capital and allocation among customer classes, and without that review it would be premature to determine the reasonableness of the 7-Year Gas Plan. Id. at 6-7. He noted NIPSCO anticipated a 5-month procedural schedule for its upcoming tracker proceeding, but he considered that timeframe inadequate. Id. at 7-8. He proposed that any approval of the 7-Year Gas Plan be conditioned on the presentation of sufficient support and review in the subsequent tracker proceeding, with a 300-day procedural timeline. Id. at 8-9.

Mr. Cuthbert did not have concerns relating to the rural extensions portion of the 7-Year Gas Plan, except that the proposed cost allocation was uncertain. See USS Ex. 1 at 9. Since that aspect of the plan relates to distribution service, he indicated the costs should be allocated to distribution and not transmission customers. Id. If the budgeted funds are not used by NIPSCO for rural extensions, he stated NIPSCO should not be permitted to utilize those funds for other projects. Id. at 10.

In light of the flexibility proposed by NIPSCO to alter projects or change dollar amounts for projects in the 7-Year Gas Plan, Mr. Cuthbert stated the request for unlimited spending flexibility should be denied. See USS Ex. 1 at 10-11. He proposed that cost recovery through the TDSIC mechanism be capped at 80% of the proposed $713.1 million in capital expenditures, with adjustments to specific elements allowable only within that budget. Id.

E. NIPSCO's rebuttal evidence. For its rebuttal submission, NIPSCO offered additional testimony by Frank A. Shambo. See NIPSCO Ex. FAS-R. Mr. Shambo addressed the testimony of Mr. Phillips and Mr. Cuthbert. Id. at 1.

Mr. Shambo stated this case is about the reasonableness and necessity of the proposed investments, not about ratemaking treatment. See Ex. FAS-R at 2. He agreed that NIPSCO's base rates were based on fair value and TDSIC tracker costs would be based on original cost, but disagreed that situation would be problematic. Id. at 3-5. He offered an interpretation of "fair value" and noted original cost is not necessarily equivalent to fair value, and further commented that trackers are based on dollar for dollar recovery of actual or original costs. Id. He also stated that when an asset goes into service its fair value is generally equal to original cost. Id. at 5.

Mr. Shambo reiterated his view that the ratemaking methodology used in the most recent rate case is not relevant to the consideration of the 7-Year Gas Plan. See Ex. FAS-R at 5-6. He noted the parties settled the last rate case and agreed the resulting rates were reasonable and appropriate. Id. at 6-7. He further offered the view that the $318 million figure for original cost rate base did not reflect fair value and would not adequately compensate NIPSCO investors. Id. at 7. He pointed out the rate case settlement also benefitted ratepayers because NIPSCO agreed to forego recovery of $25.7 million in depreciation expense, and increased that amount to $28.4 million by the extension approved in 2013. Id. at 7-8. He stated the TDSIC Statute does not preclude a TDSIC tracker where there is a gap between original cost and fair value rate base. Id. at 8.

Mr. Shambo disagreed with any implication that NIPSCO's rates were too high from 1988 to 2008. See Ex. FAS-R at 8-9. He did not consider it relevant whether NIPSCO could have spent $474.3 million in capital additions between 1988 and 2008 without any change in rate base, and stated the circumstances giving rise to the investments proposed in the 7-Year Gas Plan were not identified during that period. Id. at 9. He expressed skepticism that NIPSCO's net operating income would have been sufficient to support such investments. Id. at 10. He further disputed that NIPSCO's earnings in relation to its authorized return had relevance to the approval of the 7-Year Gas Plan, and stated over a longer term NIPSCO has not been overearning. Id. at 10-12.

Mr. Shambo disagreed that NIPSCO's proposed TDSIC would exceed the statutory 2% cap, as the tracker would not cause a revenue increase exceeding 2% in any 12-month period. See Ex. FAS-R at 12. He disagreed with Mr. Phillips' calculation of the rate increase as 32% because it divides a figure representing seven years of TDSIC revenue by one year's worth of total retail revenue. Id. at 13. He stated Mr. Phillips' alternative recommendation to cap the approved investment at $318 million had no statutory support. Id.

In response to Mr. Cuthbert's testimony, Mr. Shambo stated the record contains all the information needed to determine that the 7-Year Gas Plan is reasonable. See Ex. FAS-R at 14. He noted ratemaking issues can and should be addressed in the subsequent tracker proceeding, and in this case the evidence supports the 7-Year Gas Plan by showing projected investments will not result in revenue increases in excess of the 2% statutory cap. Id. at 14-15. He noted the TDSIC Statute does not prohibit expenditures beyond the 2% cap, but merely defers any such investments to recovery in the next rate case. Id. at 15.

On cross-examination, Mr. Shambo admitted that there was a $474 million gap between NIPSCO's capital additions and depreciation expense between 1988 and 2008. See Tr. at B43. He stated the gap was not driven by the fact that NIPSCO was not spending money because it was, but rather was caused by a very high depreciation rate. Id. at B44. He described the rate case settlement as including a crediting mechanism netting out depreciation expense to zero, but for new investment under the 7-Year Gas Plan the depreciation expense would increase while the credit amount stays constant. Id. at B44-45.

5. Statutory Requirements and Criteria. The TDSIC Statute provides a mechanism for energy utilities to recover specified investments in transmission, distribution and storage systems through a rate tracker, without filing a general rate case. Under Section 10, a utility may petition for approval of a 7-year plan setting forth eligible transmission, distribution and storage system improvements, and the plan may include targeted economic development projects and rural extensions as provided for in Section 11. See Ind. Code §§8-1-39-10, -11. Upon approval of a 7-year plan, the utility may petition under Section 9 to establish a tracking provision by which retail rates are automatically adjusted periodically to recover 80% of the eligible investments. See Ind. Code §8-1-39-9. The other 20% is deferred for recovery in the utility's next general rate case, which must be filed by the expiration of the 7-year plan. Id.

"Eligible transmission, distribution and storage system improvements" are defined as new or replacement projects undertaken for purposes of safety, reliability, system modernization or economic development, including extension into rural areas, that were not included in the utility's rate base as of its most recent rate case and were either designated in an approved 7-year plan or approved as a targeted economic development project. See Ind. Code §8-1-39-2. A "TDSIC" is a transmission, distribution and storage system charge, "TDSIC costs" include specified categories of costs incurred with respect to eligible improvements while under construction and in service, and "TDSIC revenues" are those produced through a TDSIC. See Ind. Code §§8-1-39-6, -7, -8.

This proceeding was brought by NIPSCO pursuant to Sections 10 and 11 of the TDSIC Statute, seeking approval of the 7-Year Gas Plan and proposed targeted economic development projects including rural extensions. The statute calls for the Commission to make the following determinations: (1) the best estimate of the cost of the eligible improvements in the plan; (2) whether public convenience and necessity require or will require the eligible improvements; and (3) whether the estimated costs are justified by incremental benefits attributable to the plan. See Ind. Code §8-1-39-10(b). If the Commission makes those three determinations and finds the 7-year plan is reasonable, the requested approval may be granted and the eligible improvements are designated as eligible for TDSIC treatment. Id. Pursuant to Section 11, targeted economic development projects may be treated as TDSIC costs upon approval by the Indiana Economic Development Corporation, and a utility may extend service in rural areas without a deposit if the extension results in a positive contribution to cost of service over a twenty-year period. See Ind. Code §8-1-39-11.

6. Commission analysis and findings. In connection with NIPSCO's motion to strike portions of the prefiled testimony of Mr. Phillips and Mr. Cuthbert, a dispute arose concerning the scope of this proceeding and the range of considerations properly presented to the Commission in connection with the relief sought by NIPSCO. When Mr. Phillips' testimony was offered at the evidentiary hearing, NIPSCO reiterated its objection and expressed disagreement with the February 17, 2014 Docket Entry denying the motion to strike. See Tr. at A15-16. As a threshold matter, accordingly, the Commission will address the scope of the issues relevant to the statutory factors and standards applicable to this proceeding.

The first step in interpreting a statute is to determine whether the legislature has spoken clearly and unambiguously on the issue. See Rheem Mfg. Co. v. Phelps Heating & Air Conditioning, Inc., 746 N.E.2d 941, 947 (Ind. 2001). A statute is ambiguous and open to construction when it is susceptible to more than one interpretation. Amoco Production Co. v. Laird, 622 N.E.2d 912, 915 (Ind. 1993). When interpreting a statute, the statute must be examined as a whole to avoid excessive reliance on a strict literal meaning or the selective reading of individual words. Farber v. State, 729 N.E.2d 139, 140 (Ind. 2000). A statute is properly read consistent with its underlying objects and purposes, and in light of the effects and repercussions of the interpretation. Livingston v. Fast Cash USA, Inc., 753 N.E.2d 572, 575 (Ind. 2001). A statute should also be construed in harmony with the statutory scheme bearing on the same or related subjects. Sanders v. State, 466 N.E.2d 424, 428 (Ind. 1988). Finally, a statute should not be read in a way that would render any portion meaningless or superfluous, or in a way that would lead to absurd results. Pabey v. Pastrick, 816 N.E.2d 1138, 1148 (Ind. 2004).

Applying those principles, the Commission adopts and reaffirms the conclusions set forth in the February 17, 2014 Docket Entry. Section 10 of the TDSIC Statute recites three findings that the Commission "must include," but the same provision goes on to state that the 7-year plan is subject to approval only if the Commission finds it is "reasonable." See Ind. Code §8-1-39-10(b). An examination as to reasonableness lies within the scope of Commission purview, and is not exhausted solely by the three enumerated findings the order must include. Otherwise, the reference to whether the plan is "reasonable" would be superfluous.

The basic objective of the TDSIC Statute, moreover, is to provide a mechanism by which the costs of specified investments may be recovered through a tracker without filing a rate case. A consequence of the approval sought in this proceeding under Section 10, and an element of relief expressly recited in NIPSCO's Verified Petition (p.7 at (e)), would be a designation of the improvements set forth in the 7-Year Gas Plan as "eligible for TDSIC treatment." See Ind. Code §8-1-39(b). A TDSIC is a "charge" for eligible transmission, distribution and storage system improvements (see Ind. Code §8-1-39-6), and so TDSIC "treatment" is a reference to the tracker recovery mechanism set forth in Section 9.

Contrary to NIPSCO's position, accordingly, the Commission concludes the rate impact of the proposed 7-Year Gas Plan and its relation to NIPSCO's existing base rates and charges are appropriately considered in this proceeding. NIPSCO's rate history and proposal to track the bulk of $713.1 million in planned investments are relevant to the reasonableness of the 7-Year Gas Plan. Such considerations also have a bearing on the statutory criteria calling for findings of public convenience and necessity and justification of the estimated costs by the incremental benefits. NIPSCO's suggestion that the scope of this proceeding is narrowly limited to determinations of whether the projects identified in the 7-Year Gas Plan meet the definition of "eligible transmission, distribution, and storage system improvements" and whether the costs have been properly budgeted does not accurately reflect the breadth of Commission authority in reviewing the requested relief and applying the statutory provisions.

As part of its evidentiary presentation, NIPSCO proposed formal definitions to a number of terms not expressly defined in the TDSIC Statute. With the exception of "Rural Area," discussed in more detail below in connection with NIPSCO's proposal as to rural extensions, the definitions proposed by NIPSCO were neither contested nor endorsed by other parties. The Commission finds NIPSCO's proposed definitions informative of NIPSCO's intended meaning in applying those terms, but does not find that NIPSCO has demonstrated a need to adopt formal definitions beyond the terms of the TDSIC Statute. Where the meaning of particular terms and phrases is not in dispute, it is unnecessary to adopt specific definitions that may or may not be applicable in future cases where questions of interpretation could arise.

The Commission, accordingly, will consider the evidence presented in this cause and apply the statutory standards in order to determine whether and to what extent the relief sought by NIPSCO in connection with its 7-Year Gas Plan should be granted.

A. Eligible improvements. NIPSCO offered evidence to support the conclusion that the identified projects in the 7-Year Gas Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code §8-1-39-2, and supported its selection of projects with an infrastructure analysis assessing potential risks and consequences. See Ex. MGS at 15-23; Ex. MGS-2. The other parties did not dispute that the planned projects were appropriate and should be completed, although they did raise questions regarding the cost estimates and the sufficiency of detail in identifying included projects. See Public Ex. 1 at 10-23; Ex. NP at 13.

NIPSCO emphasized that it was committed to completing the safety and reliability projects presented in the 7-Year Gas Plan, regardless of whether the relief sought in this proceeding is granted and regardless of whether the investments will be recoverable through a TDSIC tracker. See Tr. at B16-17, B23-25. Recovery of costs under the TDSIC Statute is not the sole ratemaking avenue available to support the planned investments, which NIPSCO could alternatively seek to reflect in its base rates through a general rate case. Id.; Ex. NP at 7. In addition, to the extent that some of the projects included in the 7-Year Gas Plan are mandated by federal requirements, NIPSCO could utilize another statutory tracking mechanism to recover costs through rates. See Tr. at B47-48. The question presented here, accordingly, is not whether the proposed projects should be completed or whether the proposed investments are recoverable in rates, but rather whether and to what extent the improvements identified in the 7-Year Gas Plan are eligible for recovery under the terms of the TDSIC Statute.

The sufficiency of the cost estimates and level of detail in specifying the projects included in the 7-Year Gas Plan are addressed below. Subject to the findings on those issues, the Commission finds that the identified projects and categories of projects included in the 7-Year Gas Plan are "eligible transmission, distribution, and storage system improvements" as defined by Ind. Code §8-1-39-2.

B. Best estimate of costs and justification by incremental benefits. The TDSIC Statute calls for evaluation of planned project costs in two respects. First, there must be a determination of the "best estimate" of costs of eligible improvements. See Ind. Code §8-1-39-10(b)(1). Second, the Commission must find the estimated costs are justified by incremental benefits attributable to the plan. Id. §10(b)(3).

NIPSCO submitted a summary of the cost estimates for the 7-Year Gas Plan through Ex. MGS-1. Schedule 1 of that exhibit shows estimated costs for each year broken down by "Project Category." Schedule 2 shows a similar yearly cost summary by FERC account. Schedule 3 sets forth Project Detail for 2014, listing specific projects and estimated costs of each project for Year 1 of the 7-Year Gas Plan. NIPSCO also presented a study prepared by an outside consultant reviewing cost estimates for planned projects (see Ex. MGS-3), but did not submit a Project Detail summary similar to Schedule 3 of Ex. MGS-1 for Years 2 through 7 of the plan.

The form of plan presented by NIPSCO, accordingly, includes individual project detail for the first year of the plan but only expected spending levels by project category for the other six years. See Ex. MGS at 11; Ex. FAS at 8-10. According to NIPSCO, it would be too rigid and would not be practical to prepare a plan detailing every project by year, and the 7-Year Gas Plan is intended to be dynamic, not static. See Ex. MGS at 9-10; Ex. FAS at 21-24. NIPSCO proposes to update the plan annually, and through subsequent filings to provide the project detail for each upcoming year. Id.

Witnesses for other parties contested the sufficiency of the cost estimates presented by NIPSCO. Ms. Smith did not agree that NIPSCO had presented the best cost estimates for all projects, noting there was work order level estimates only for certain projects. See Public Ex. 1 at 23-26. Mr. Cuthbert objected to the unlimited spending flexibility proposed by NIPSCO, which he described as a "blank check" with little or no protection for ratepayers. See USS Ex. 1 at 10-11.

On cross-examination, NIPSCO's witnesses explained the uncertainties relating to projects and cost estimates beyond the first year of the plan. Mr. Small stated that transmission and certain other projects were identified in the 7-Year Gas Plan, but for distribution projects only the first year includes specificity and for other years the plan includes projected spend levels by category. See Tr. at A64-66. He noted distribution deliverability projects are under review for potential inclusion at some point, and specific projects will be identified in the future. Id. at A68-69. He agreed specific projects could not be predicted in advance, nor could their number or magnitude. Id. at A69-70. In that light, the level of expense in a given year could not be predicted, either, as "it's very hard to tell what it will take." Id. at A70-71.

Mr. Shambo, furthermore, anticipated spending flexibility beyond the cost estimates provided in the 7-Year Gas Plan. He stated NIPSCO was seeking approval of the 7-Year Gas Plan, not dollar amounts for individual years. See Tr. at B30-31. He expected that expenditures could shift from projections year to year, and the $713.1 million total could change as well. Id. at B31-33, B49-52. He was unable to say how potential increases would be presented to the Commission, he did not consider the $377 million estimate for transmission projects to be a cap or preclusive of other transmission projects, and he was uncertain whether NIPSCO could exceed the budget for a given category by spending more within the total $713.1 million budget. Id. at B33-42, B49-51. A document prepared by NIPSCO in connection with the internal capital allocation process included comments on "Exit Strategies" and noted that "projects could be eliminated from either seven year plan to reduce TDSIC investment." See IG CX-1 at 9.

Based on this record, the Commission is unable to find that NIPSCO has presented the best estimate for the improvements proposed in the 7-Year Gas Plan. The framework of the TDSIC Statute contemplates the presentation of a 7-year plan with cost estimates for defined projects, not open-ended spending levels for projects to be identified at some point in the future. As the petitioner, NIPSCO has the burden to support the requested relief by providing the best estimate of the investments it seeks to recover through a TDSIC tracker. That burden is not satisfied by establishing a proposed budget for an uncertain number of unspecified projects of unknown magnitude and unpredictable costs. The TDSIC Statute balances the interests of utilities and ratepayers by permitting the tracked recovery of eligible improvements only in accordance with a 7-year plan of ascertainable scope approved by the Commission. The degree of flexibility proposed by NIPSCO, with projects subject to change on an undefined schedule and fluid budgets open to inter-category shifts and uncapped increases, is not susceptible to the determination of sufficiently reliable cost estimates to meet the statutory requirements.

The variability in the 7-Year Gas Plan presented by NIPSCO, similarly, is incompatible with the required showing that the estimated costs are justified by incremental benefits attributable to the plan. Beyond the first year of the plan and specifically identified projects, the proposed spend levels put forward by NIPSCO are not tied to particular improvements that can be measured in terms of incremental benefits or cost justification. For example, only a small portion of the projects planned by NIPSCO are currently required by federal mandates, and even in areas where future federal direction is expected NIPSCO will be interpreting standards to decide what steps to take to maintain safe and reliable service. See Tr. at A84-87. With respect to non-mandatory projects, where judgment is exercised to differentiate what is appropriate from what is excessive, a reasonable delineation of proposed improvements would establish a foundation for assessing the incremental benefits and determining whether the estimated costs are justified, but that is the portion of the 7-Year Gas Plan where NIPSCO relies largely on categories of projects with indeterminate costs and generalities as to potential benefits.

The foregoing considerations do not mean, of course, that a 7-year plan subject to approval under the TDSIC Statute must detail each individual project, when it will be completed and how much it will cost, or that once approved all work must proceed only as scheduled and exactly on budget. The Commission credits the practical perspective offered by NIPSCO's witnesses, to the effect that a workable plan calls for some adaptability as experience is gained and additional information becomes available. See Ex. MGS at 9-10; Ex. FAS at 22-24. As noted by Mr. Small, moreover, in addition to the project detail provided for the first year of the plan, a number of projects have been identified and budgeted with a degree of specificity, such as transmission system improvements, in-line inspection modifications, bare steel replacements and the upgrade of the low-pressure Kokomo system. See Tr. at A64-66.

For reasonably identified projects included in the 7-Year Gas Plan, no party criticized the methodology employed by NIPSCO to establish cost estimates or challenged particular estimates as excessive or unreliable. NIPSCO's proposal to set spend levels for Years 2 through 7 of the plan, however, without tethering the dollar amounts to ascertainable projects and with requested flexibility to shift and exceed budgets on a discretionary basis, does not provide an adequate record for the Commission to determine the best estimate of the cost of planned improvements or to conclude that the estimated costs are justified by incremental benefits attributable to the plan.

C. Public convenience and necessity, reasonableness and eligibility for TDSIC treatment. Section 10(b) of the TDSIC Statute establishes additional criteria that call for the Commission to weigh public interest and reasonableness considerations in deciding whether the planned investments are eligible for TDSIC treatment. The Commission must determine whether public convenience and necessity require or will require the eligible improvements included in the plan, and must also determine whether the 7-year plan is reasonable. Upon approval by the Commission, the planned improvements may be designated as eligible for TDSIC treatment.

In applying the standards of reasonableness and public convenience and necessity, the Commission may take into account a broad range of considerations. The standard of public convenience and necessity calls for examination of the consequences of the proposal as it affects the interests of the ratepaying public. Insofar as NIPSCO seeks to secure a designation of planned projects as eligible for TDSIC treatment, thereby establishing a predicate for recovery of costs through a TDSIC tracker, the relation of the proposed ratemaking treatment to NIPSCO's existing rate structure is material to the reasonableness of the requested relief.

The recovery of specified costs through a rate tracker under the TDSIC Statute stands in contrast to the method of setting basic rates and charges through a rate case. In a general rate proceeding, the utility's investment in plant and equipment used to provide service to the public constitutes the utility's rate base. Based on a representative test year and a comprehensive review of the utility's condition and financial performance, rates are set at a level that permits the utility to cover its reasonable operating expenses and enables it to earn a reasonable return on and return of its rate base assets. In a rate case, the entirety of the utility's operations and financial circumstances are subject to review, with the objective of establishing overall rates and charges that provide a sound foundation for the provision of reliable and efficient utility service. A tracker, on the other hand, provides a mechanism for the automatic recovery of a defined category of costs on top of base rates as set by the utility's most recent rate case.

The question raised here is whether the relief sought by NIPSCO under the TDSIC Statute is inconsistent with or otherwise unreasonable in light of NIPSCO's existing base rates. Prior to its most recent rate case in Cause No. 43894, NIPSCO had gone for more than twenty years without a rate case. See Ex. NP at 4; Adm. Notice 1, Tab 4 at 3. Because of a high depreciation rate in effect during that period, NIPSCO's original cost rate base diminished from $718.8 million to $318 million as of Cause No. 43894. See Ex. NP at 4-5. From 1988 to 2008, NIPSCO's depreciation expense exceeded its capital additions by $474.3 million. Id.; Tr. at B43.

Due to the large gap between an original cost return and a fair value return based on replacement cost new, less depreciation, the Commission approved a settlement in Cause No. 43894 that utilized a fair value rate base of $725.7 million, far above the original cost rate base of $318 million. See Ex. NP at 4; Adm. Notice 1, Tab 4 at 17. The settlement also lowered the depreciation rate and provided for a depreciation credit equal to the depreciation expense, designed to close the gap between book value and the remaining life of rate base assets. See Ex. NP at 5; Adm. Notice 1, Tab 4 at 18. The depreciation credit mechanism was subsequently extended and updated to increase the credit amount. See Ex. NP at 5; Adm. Notice 1, Tab 3.

In this proceeding, NIPSCO seeks approval of capital investments subject to recovery under the TDSIC Statute totaling $713.1 million. See Ex. MGS at 11; Ex. MGS-1. In comparison to NIPSCO's entire rate base assets as of its last rate case, the proposed capital spend at issue is more than twice as large as the $318 million original cost rate base and is comparable in amount to the $725.7 million fair value figure used in the rate case settlement. In other words, the expenditures contemplated in NIPSCO's 7-Year Gas Plan would more than triple its original cost rate base and would double its fair value rate base as reflected in the rate case settlement. See Ex. NP at 3; Tr. at B5-6.

As Mr. Phillips pointed out, because of the differential between depreciation expense and capital additions prior to the last rate case, NIPSCO could have spent an additional $474.3 million on capital projects between 1988 and 2008 without any increase in its original cost rate base. See Ex. NP at 6-7, 13. Without any change in its rate base, NIPSCO during that period could have undertaken projects now proposed as part of the 7-Year Gas Plan, significantly decreasing the proposed level of spending over the next seven years. Id. Mr. Shambo did not dispute the computation (see Tr. at B43), but he did assert that the circumstances giving rise to the investments proposed in the 7-Year Gas Plan were not identified during the period of 1988 to 2008. See Ex. FAS-R at 9. The record, however, does not support that position.

The history is illustrated with the projects proposed by NIPSCO for its transmission system, which account for more than half of the $713.1 million total spend in the 7-Year Gas Plan. See Ex. MGS-1, Schedule 1. NIPSCO admitted that it had not previously invested in replacement projects for the transmission system. See Ex. NP at 7; Ex. NP-3. Even though NIPSCO owns and operates its transmission system, understands its importance to the provision of safe and reliable service and has always been aware of the risks associated with operating a pressurized gas transmission system (see Tr. at A56-57), NIPSCO did not feel it had adequate in-house expertise to assess and prioritize transmission projects and for that reason retained an outside consultant. Id. at A52-53, A55; Ex. MGS at 44. According to Mr. Small, NIPSCO started giving increased attention to the transmission system in 2002 when transmission integrity rules went into effect, and then increased the level of attention more after the San Bruno incident in 2010, but even so considered it appropriate to engage EN Engineering to provide outside expertise in developing the transmission portion of the 7-Year Gas Plan. See Tr. at A57-59.

At the same time, it is apparent that NIPSCO has been aware of the safety and reliability issues relating to the transmission system for many years. The 483 lb. system that serves a number of NIPSCO's largest customers is fed by a single line from Highland Junction. See Ex. SMA at 11-12; Tr. at A23-25. That configuration has been in place since it was installed, and NIPSCO has long been aware of the risks of interruptions from any conditions impacting that single feed. See Tr. at A26-28. One of the transmission projects proposed in the 7-Year Gas Plan involves interconnecting the 483 lb. system with the 600 lb. loop, providing an alternate feed to the 483 lb. system and improving the supply options for customers behind that system. See Ex. SMA at 11-12; Ex. MGS at 28. The 483 and 600 lb. systems have been in the same configuration for decades, but the interconnection was not previously undertaken by NIPSCO. See Tr. at A28-29. Mr. Auld testified the risk of interruption as usage approaches peak design capacity increases for customers farthest from the supply source, and several of NIPSCO's largest customers are located near the end of the single-feed 483 lb. system. See Tr. at A23-25. Harsh winter conditions and service interruptions have occurred over the years, but the operational risks to customers near the end of the 483 lb. system were not previously addressed with the projects now proposed in the 7-Year Gas Plan. Id. at A22-23, A28.

Mr. Small testified that the transmission projects in the 7-Year Gas Plan would replace, retire or reduce the operating pressure on 115 miles of transmission main installed between 1944 and 1960. See Ex. MGS at 27-28. He explained that pipe installed in that era was not subject to welding regulations, pressure testing requirements or documentation standards, and considered it clear that it was time to replace those components to address the safety risks. See Tr. at A87-89. He also admitted, however, that NIPSCO had previously rated the integrity risks associated with that 115 miles of transmission main and was aware that it had been installed over fifty years ago. Id. at A62-64. Mr. Shambo, similarly, pointed out that a line built in the 1940s serves U. S. Steel's operation in Gary, and admitted the risk has been increasing each year as it gets older. Id. at B28-30.

Despite the known age of transmission components and the operational risks arising from the single feed to the 483 lb. system, NIPSCO did not previously undertake the transmission projects included in the 7-Year Gas Plan. In the 2010 settlement of its last rate case, NIPSCO secured base rates predicated on a fair value rate base of $725.7 million, although its original cost rate base had dropped to $318 million. Through the TDSIC Statute, NIPSCO now proposes $713.1 million in capital projects, including $377 million in transmission investments, and if the requested relief is granted NIPSCO would recover the bulk of those costs through a TDSIC tracker paid by ratepayers on top of existing base rates.

The relation in timing between NIPSCO's development of its 7-Year Gas Plan and the passage of the TDSIC Statute authorizing the tracking of costs under a 7-year plan is not entirely clear but is undisputedly not a coincidence. Mr. Small testified the 7-Year Gas Plan was developed concurrently with the TDSIC legislation, and Mr. Shambo suggested the legislation may have been an outgrowth of the planned investments. See Tr. at A83-84, B16-17. What is clear is that NIPSCO is now proposing a substantial increase in capital spending levels, from an annual average of $48.5 million for the five previous years to a proposed $84.9 million. See Public Ex. 3 at 2-3; Tr. at A50-51. Where NIPSCO has not previously replaced any significant portions of its transmission system in the past, it is now proposing $377 million in transmission projects. See Ex. NP at 7; Ex. NP-3; Ex. MGS-1, Schedule 1.

Mr. Shambo characterized the issues raised concerning NIPSCO's rate history as a contention that NIPSCO's rates were too high between 1988 and 2008, and questioned whether NIPSCO had sufficient revenue in that period to undertake further substantial capital projects. See Ex. FAS-R at 8-10. While the characterization does not address the basis of the challenge presented, the implication is far from apparent. It is undisputed that NIPSCO's depreciation expenses exceeded its capital additions from 1988 to 2008 by $474.3 million, and NIPSCO could have invested that level of additional capital during that period without any increase in its original cost rate base. At any point during that interval that NIPSCO deemed its rates insufficient, it could have filed a rate case. As it happened, NIPSCO went for more than twenty years without a rate case, and when it did file in 2010 the result was a rate decreases for all classes. See Adm. Notice 1 at Tab 4, Settlement at 8-10. Even with that rate decrease, NIPSCO has been overearning the past three quarters. See Ex. NP at 7-8. Regardless of rate levels in effect at any point in time, NIPSCO is under an obligation to furnish safe and reliable service, and is expected to make the appropriate investments in its system to do so. If the level of investment requires a rate adjustment, the regulatory process is equipped to address that circumstance. A public utility should not require excess revenue before it will invest in safe and reliable service.

The significance of NIPSCO's rate history, in any event, is not that its rates were too high between 1988 and 2008, but rather that the current base rates as established in Cause No. 43894 were predicated on unique circumstances that render the proposed tracking of massive capital expenditures unreasonable. NIPSCO's TDSIC proposal would more than triple its original cost rate base, after NIPSCO secured base rates using a fair value figure greatly in excess of its original costs. See Ex. NP at 3-5. The proposal would layer original cost ratemaking through the TDSIC Statute on top of the fair value approach used in setting NIPSCO's base rates. Id. at 6. Where the rate of return authorized in the last rate case was 5.49% on the fair value rate base with a 7.0% rate of return on common equity, NIPSCO's proposal is based on an 8.4% rate of return on the planned investment. Id. at 7-9. Where the rate case settlement provided for a depreciation credit that netted out depreciation expense to zero, under NIPSCO's proposal the credit would remain constant as depreciation rises with the proposed capital projects. Id. at 5; Tr. at B44-45. The point presented by Mr. Phillips is that NIPSCO's current base rates reflect special ratemaking driven by the decline in original cost rate base due to two decades of higher depreciation expense than capital additions, and in that context it would be unreasonable and contrary to public interest and ratemaking policy to allow NIPSCO to increase its rate base from $318 million to $1,031 million through a TDSIC tracker. See Ex. NP at 13.

The Commission concludes that the proposed level of expenditures that NIPSCO proposes to track through the TDSIC Statute, in light of its existing rate structure and the circumstances underlying its current base rates, is unreasonable and would not serve the public convenience and necessity. This determination does not suggest or imply that the projects planned by NIPSCO are inappropriate or should not be completed, as indeed NIPSCO has committed to proceeding with safety and reliability projects regardless of the outcome of this proceeding. The conclusion, rather, is that based on NIPSCO's rate history and the derivation of its current base rates, the level of tracked expense proposed by NIPSCO is excessive. At a reasonable point before the proposed $713.1 million in capital projects are reflected in a TDSIC tracker, the predicates and conditions underlying NIPSCO's existing base rates should be revisited through a general rate proceeding.

Mr. Phillips proposed two alternative limitations on the amount of planned capital expenditures approved for recovery under the TDSIC Statute. First, he suggested NIPSCO could be limited to a 2% cap in relation to total retail revenues in a 12-month period, or about $13 million. See Ex. NP at 10-12. His interpretation of the 2% cap as set forth in Ind. Code §8-1-39-14 was contested by NIPSCO. See Ex. FAS-R at 12. The application of the 2% cap under Section 14 of the TDSIC Statute is an issue properly addressed in the context of the future proceeding under Section 9, in which a TDSIC tracker would be established. The Commission, accordingly, reserves a determination on the conflicting views of that provision for resolution in the context of a Section 9 proceeding.

The other alternative proposed by Mr. Phillips called for limiting the approved level of capital expenditures under the 7-Year Gas Plan to $318 million, the amount of NIPSCO's original cost rate base as of its last rate case. See Ex. NP at 13. That approach would have the practical effect of allowing NIPSCO to go no further than doubling its original cost rate base through projects subject to cost recovery under the TDSIC Statute, so that beyond that point NIPSCO would have to file a rate case and reopen the examination of its base rates in order to reflect additional capital investments. The Commission agrees that the more comprehensive analysis of costs and revenues that occurs in a rate case would be reasonable and in the public interest once NIPSCO has made additional capital investments that equal the original cost of its entire rate base assets.

The Commission therefore approves the 7-Year Gas Plan subject to an upper limit of $318 million in capital expenditures. Planned improvements up to that limitation are designated as eligible for TDSIC treatment.

D. Rural extensions. Rural extensions are addressed in Section 11 of the TDSIC Statute, in contrast to transmission, distribution and storage system projects that are reviewed under Section 10. NIPSCO proposed a total of $98.8 million in investment for extensions to provide service to new customers in rural areas, and put forward a proposed "open season" process for determining what projects to undertake in a given year. See Ex. MGS at 39-43; Ex. FAS at 15-20. NIPSCO's proposals with respect to rural extensions were not significantly controverted by other parties, although Mr. Grosskopf noted that revenues derived from the new customers should be accounted for in future filings and Mr. Cuthbert expressed concern as to the allocation of the costs associated with rural extensions among customer classes. See Public Ex. 3 at 4-5; USS Ex. 1 at 9-10.

The Commission finds that the issues raised with respect to NIPSCO's proposals on rural extensions are appropriately addressed in future tracker filings. For purposes of this proceeding, NIPSCO's request to extend service into rural areas is reasonable and is hereby approved by the Commission.

E. <u>Confidentiality</u>. On October 3, 2013, NIPSCO filed a motion for protection and non-disclosure of confidential and proprietary information, which was supported by affidavit stating that that specified materials proposed to be included in NIPSCO's case-in-chief filing constituted trade secret information subject to protection pursuant to Ind. Code §5-14-3-4(a), Ind. Code §24-2-3-2, Ind. Code §8-1-2-29 and 170 I.A.C. 1-1.1-4. By Docket Entry dated October 16, 2013, the Presiding Officers granted the motion and found the information to be confidential on a preliminary basis, and upon that basis NIPSCO submitted the materials at issue on a confidential basis. The Commission finds that the information so submitted is confidential pursuant to Ind. Code §5-14-3-4 and Ind. Code §24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. The projects set forth in Year 1 of the 7-Year Gas Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code §8-1-39-2 and are eligible for TDSIC treatment pursuant to Ind. Code §8-1-39-10(b).

2. Specifically identified projects set forth in Years 2 through 7 of the 7-Year Gas Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code §8-1-39-2 and are eligible for TDSIC treatment pursuant to Ind. Code §8-1-39-10(b), and categories of projects not so identified are not eligible for TDSIC treatment.

3. The 7-Year Gas Plan is approved in part, subject to a limitation of $318 million in capital investment.

4. Capital expenditures up to $318 million pursuant to the 7-Year Gas Plan are designated as eligible for TDSIC treatment.

5. NIPSCO's request to extend service into rural areas is approved.

6. The information filed by NIPSCO pursuant to its motion for protection and non-disclosure of confidential and proprietary information is deemed confidential pursuant to Ind. Code §5-14-3-4 and Ind. Code §24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

ATTERHOLT, MAYS, 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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Shala M. Coe, Acting
Secretary to the Commission