ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF A TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, (2) APPROVAL OF PETITIONER'S PROPOSED COST ALLOCATIONS, (3) APPROVAL OF THE TIMELY RECOVERY OF TDSIC COSTS THROUGH PETITIONER'S PROPOSED TDSIC RATE SCHEDULE, (4) AUTHORITY TO DEFER APPROVED TDSIC COSTS, (5) APPROVAL OF THE METHODOLOGY USED TO CALCULATE THE 2% TEST, (6) APPROVAL OF AN ADJUSTMENT TO ITS GAS SERVICE RATES THROUGH ITS TDSIC RATE SCHEDULE, (7) AUTHORITY TO DEFER 20% OF THE APPROVED TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE, AND (8) APPROVAL OF PETITIONER'S UPDATED 7-YEAR GAS PLAN, INCLUDING ACTUAL AND PROPOSED ESTIMATED CAPITAL EXPENDITURES AND TDSIC COSTS THAT EXCEED THE APPROVED AMOUNTS, ALL PURSUANT TO IND. CODE CH. 8-1-39 AND THE COMMISSION'S ORDER IN CAUSE NO. 44403.	)	CAUSE NO. 44403 TDSIC 1 APPROVED: JAN 28 2015

<u>**ORDER OF THE COMMISSION**</u>

Presiding Officers:
Angela Rapp Weber, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On August 28, 2014, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed a petition with the Indiana Utility Regulatory Commission ("Commission") seeking relief under Ind. Code ch. 8-1-39 with respect to a proposed transmission, distribution and storage system improvement charge ("TDSIC") and approval of NIPSCO's Updated 7-Year Gas Plan ("Updated Plan"). On the same day, NIPSCO filed its direct testimony and exhibits.

On September 9, 2014 and September 10, 2014, the NIPSCO Industrial Group ("Industrial Group")[1] and United States Steel Corporation ("U.S. Steel"), respectively, filed petitions to intervene, both of which were subsequently granted on September 11, 2014. On October 30, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") and the Industrial Group filed their respective direct testimony and exhibits.

[1] The members of the Industrial Group in this proceeding are ArcelorMittal USA, BP Products North America, Inc., Chrysler Group, LLC and Praxair, Inc.

On November 19, 2014, the Industrial Group filed cross-answering testimony and NIPSCO filed its rebuttal testimony and exhibits.

NIPSCO filed updates and corrections to prefiled testimony and exhibits on October 24, 2014, October 31, 2014, November 19, 2014 and December 5, 2014. NIPSCO also responded to a December 4, 2014 Docket Entry on December 5, 2014 and December 17, 2014.

The Industrial Group filed a Motion for Administrative Notice on October 31, 2014, which was granted in a November 13, 2014 Docket Entry. On December 30, 2014, the Industrial Group filed another Motion for Administrative Notice, which was not opposed and is therefore granted.

An evidentiary hearing was held on December 8, 2014, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the evidence of NIPSCO, the OUCC and Industrial Group was admitted into the record and the witnesses were made available for cross-examination. No member of the public appeared or participated at the hearing.[2]

Based on the applicable law and evidence presented, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Ind. Code §§ 8-1-2-1(a) and 8-1-39-4. Under Ind. Code ch. 8-1-39 ("TDSIC Statute"), the Commission has jurisdiction over a public utility's petition to approve rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's base rates and charges to provide for timely recovery of 80% of approved capital expenditures and TDSIC costs. Therefore, the Commission has jurisdiction over Petitioner and subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. Petitioner is engaged in rendering electric and gas public utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the generation, transmission, distribution and furnishing of such service to the public. Petitioner provides gas utility service to more than 821,000 residential, commercial and industrial gas customers in Adams, Allen, Benton, Carroll, Cass, Clinton, DeKalb, Elkhart, Fulton, Howard, Huntington, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Miami, Newton, Noble, Porter, Pulaski, St. Joseph, Starke, Steuben, Tippecanoe, Tipton, Wabash, Warren, Wells, White and Whitley Counties in northern Indiana.

3. **Background and Relief Requested.** On April 30, 2014, the Commission issued an Order in Cause No. 44403 ("7-Year Gas Plan Order") concerning Petitioner's request for

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[2] After the evidentiary hearing, Petitioner and the OUCC submitted proposed orders indicating an agreement had been reached between the two parties concerning issues raised with the 112th Street Project. However, at the time of the submission, the record in this proceeding was closed and no request to reopen the record was made. 170 IAC 1-1.1-17 authorizes the filing of settlement agreements for receipt into the evidence as part of the record and requires the settlement to be supported by probative evidence. Because the parties' agreement has not been submitted into evidence, we do not address it in this Order.

approval of a 7-year plan for eligible transmission, distribution and storage system improvements ("7-Year Gas Plan" or "Plan"), pursuant to Ind. Code §§ 8-1-39-10 and 11. In the 7-Year Gas Plan Order, the Commission held: (1) the projects contained in Year 1 of NIPSCO's 7-Year Gas Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2; (2) the project categories contained in Years 2 through 7 of NIPSCO's 7-Year Gas Plan are presumed "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2, subject to further definition and specifics being provided through the plan update proceedings; (3) the 7-Year Gas Plan is reasonable and approved subject to certain modifications; (4) NIPSCO's proposed definitions of key terms for purposes of interpreting and applying those terms to NIPSCO's 7-Year Gas Plan are approved; and (5) NIPSCO's proposed process for updating the 7-Year Gas Plan in future semi-annual adjustment proceedings is approved.

By its Petition, NIPSCO requests the following relief in this proceeding:

- approval of Petitioner's proposed TDSIC Rate Schedule and accompanying changes to its gas service tariff which will allow for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorization for Petitioner to defer, until recovery through the TDSIC, 80% of the post-in-service TDSIC costs of the TDSIC projects, including carrying costs, depreciation and taxes;

- approval of Petitioner's proposal to use the customer class revenue allocation factor based on firm load approved in Petitioner's most recent retail base rate case (Cause No. 43894);

- authorization to defer 20% of the eligible and approved capital expenditures and TDSIC costs in connection with its 7-Year Gas Plan for recovery in NIPSCO's next general rate case;

- approval of Petitioner's proposed method of calculating pretax return under Ind. Code § 8-1-39-13;

- authorization to adjust its authorized net operating income to reflect any approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(g)(3);

- approval of Petitioner's proposed method of calculating the average aggregate increase in its total retail revenue attributable to the TDSIC to determine whether the TDSIC will result in an average aggregate increase of more than 2% in a twelve-month period;

- authorization and approval of TDSIC factors to become effective for bills rendered by NIPSCO for the months of February 2015 through May 2015 or until replaced by different factors approved in a subsequent filing;

- approval of the Updated Plan, including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in Cause No. 44403; and

- approval to recover 80% of eligible and approved capital expenditures and TDSIC costs in connection with the Updated Plan through the TDSIC and authorization for Petitioner to defer 20% of eligible and approved capital expenditures and TDSIC costs in connection with the Updated Plan, for recovery in its next general rate case.

4. **Evidence Presented.**

A. **NIPSCO's Case-in-Chief.** NIPSCO presented the testimony and exhibits of Frank A. Shambo, Vice President of Regulatory and Legislative Affairs; Mark G. Small, Director of Engineering; Kurt W. Sangster, Vice President of Major Projects; and Derric J. Isensee, Manager, Regulatory Support and Analysis in the Rates and Regulatory Finance Department.

Mr. Shambo testified regarding the background of NIPSCO's petition, the stakeholder outreach conducted pre-filing, the basis for the cost allocation and proposed pretax return, the requested ratemaking treatment for rural extension projects, and the proposal for master meter remediation projects. He stated that NIPSCO is seeking to establish a TDSIC Rate Schedule and approval of a factor to recover costs associated with the 7-Year Gas Plan. Mr. Shambo explained that NIPSCO is requesting approval to use its customer class revenue allocation factor based on firm load that was approved in NIPSCO's most recent base rate case, Cause No. 43894 ("43894 Order").[3] NIPSCO is proposing that the cost of transmission system improvements be allocated among all customer classes consistent with the revenue allocation from the 43894 Order, while distribution system improvement costs would not be allocated to transportation customers receiving service under Rates 428 and 438. He testified that costs associated with storage projects would be allocated in the same manner as distribution costs, and the cost of rural extension projects would be allocated in the same manner as transmission and distribution costs based on the character of the facilities installed.

Mr. Shambo testified that NIPSCO proposes that its pretax return be calculated using its weighted average cost of capital ("WACC") consistent with the methodology approved by the Commission for NIPSCO's 7-Year Electric TDSIC Tracker and as used for other capital trackers, such as NIPSCO's electric Environmental Cost Recovery mechanism. NIPSCO proposes to use 9.9% as the return on equity in the calculation of the pretax return for use in the TDSIC as approved in the 43894 Order.

Mr. Shambo explained NIPSCO's proposed changes to the rural gas extension component of its 7-Year Gas Plan. He said that NIPSCO originally estimated $98.8 million over the course of the 7-Year Gas Plan. But, NIPSCO has revised that estimate in the Updated Plan to $217 million to include all rural customers that are or could become eligible for a gas extension. He testified that NIPSCO is now including all rural customers for several reasons, including: (1) the TDSIC Statute does not distinguish between customers eligible under the 20-year margin test and those under lower threshold tests such as NIPSCO's existing line extension policy, (2) reduced complications associated with record keeping and project management and (3) addressing equities between different customers. He stated that NIPSCO is proposing to credit 80% of actual margins, consistent with the recovery on investments, of the margin associated

[3] In Cause No. 43894, the Commission approved a settlement agreement concerning NIPSCO's rates and charges in a November 4, 2010 Order and a subsequent settlement agreement concerning an extension of those rates and charges in an August 28, 2013 Order.

with all new customers connected through rural extensions. He noted that with this credit, the net impact of this change to existing customers will be $5.7 million over the life of the 7-Year Gas Plan.

Mr. Shambo explained that master meter remediation projects are projects to replace underground distribution facilities behind or downstream of master meters used to feed multiple customers. He stated master meter arrangements have been identified as significant safety risks because the distribution facilities located behind the meter are not owned, operated or maintained by NIPSCO or any other regulated utility. As a result, NIPSCO is not able to verify compliance with the applicable design, construction and operational standards. Although NIPSCO proposed a seven-year budget of $2 million for the remediation of such arrangements in its 7-Year Gas Plan, it did not identify any specific master meter remediation projects that would be undertaken. After review by the Commission's Pipeline Safety Division, NIPSCO has identified specific master meter remediation projects it intends to complete to remediate these types of public safety risks.

Mr. Isensee testified that NIPSCO proposes to file its TDSIC petitions and cases-in-chief by September 1 and March 1 each year, with new rates becoming effective for the six-month periods starting on December 1 and June 1, respectively. The petition filed on September 1 will be based on capital spend and expenses through the previous six-month period ended June 30, while the petition filed on March 1 will be based on capital spend and expenses through the previous six-month period ended December 31. The reconciliation of actual revenues will be completed on a 12-month lag. In accordance with Ind. Code § 8-1-39-9(a) and as required by the 7-Year Gas Plan Order, NIPSCO will also provide a report on the progress of its 7-Year Gas Plan, including any changes such as scheduling changes, proposed project additions or subtractions and proposed changes in cost estimates.

Mr. Isensee testified that NIPSCO proposes to recover 80% of TDSIC costs incurred with respect to eligible TDSIC projects incurred both while the improvements are under construction and post-in-service. He explained that costs will include, but not be limited to, depreciation expense, operations and maintenance ("O&M") expense, property taxes, pretax returns, allowance for funds used during construction ("AFUDC") and post-in-service carrying costs. These costs will be recovered on a historical basis subsequent to the date in which the actual costs were incurred. He noted that while the TDSIC Statute permits the recovery of O&M expenses, the only O&M costs for which cost recovery is sought at this time are those associated with the approved project for the conversion of historical system records to a digital format for incorporation into NIPSCO's geographic information system ("GIS") and other electronic systems.

Mr. Isensee explained that NIPSCO proposes to implement Construction Work in Progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects. Under CWIP ratemaking treatment, NIPSCO will recover, through the TDSIC, financing costs incurred during the construction period attributable to qualifying capital investments. In connection with CWIP ratemaking, NIPSCO will cease accruing AFUDC the earlier of the date in which such expenditures receive CWIP ratemaking treatment through the TDSIC or the date the project is placed in service.

Mr. Isensee stated NIPSCO also proposes to recover 80% of all post-in-service carrying costs incurred in connection with projects approved as part of the 7-Year Gas Plan through the

TDSIC. He said the costs will be determined based on NIPSCO's overall weighted cost of capital and will encompass all financing costs incurred from the in-service date until such projects receive ratemaking treatment.

Mr. Isensee testified that NIPSCO will calculate a revenue requirement in each semi-annual filing consisting of two components: (1) a return of financing costs related to capital expenditures including AFUDC, post-in-service carrying costs and pretax returns and (2) recovery of depreciation expense, O&M and property tax expense associated with the approved TDSIC projects. NIPSCO will then multiply the total revenue requirement by 80% to establish the TDSIC revenue requirement. The return of financing costs related to capital expenditures will be calculated based on the actual TDSIC project costs, net of accumulated depreciation. AFUDC, a subcomponent of the capital costs, will be calculated in accordance with Generally Accepted Accounting Principles ("GAAP"), until such costs are given CWIP ratemaking treatment or are otherwise reflected in NIPSCO's base rates and charges or the TDSIC projects are placed in service, whichever occurs first. He testified that NIPSCO will compute AFUDC amounts and relevant AFUDC rates for eligible TDSIC projects in accordance with the Federal Energy Regulatory Commission ("FERC") or National Association of Regulatory Utility Commission Uniform System of Accounts ("USofA"), which is consistent with GAAP. Post-in-service carrying costs will be calculated and included in the revenue requirement after such projects are placed in service and until such costs are given ratemaking treatment through the TDSIC or are otherwise reflected in NIPSCO's base rates and charges.

Mr. Isensee testified that once the revenue requirement is calculated, NIPSCO will reduce the revenue requirement related to the recoverable post-in-service carrying charges and the pretax return to 80% in accordance with Ind. Code § 8-1-39-9(a). In future filings, the revenue requirement will also include the variance associated with the under- or over-collection of these costs due to the difference between the forecasted volumes used to calculate the rates and actual volumes billed. Finally, NIPSCO will gross-up the revenue requirement for all incremental taxes incurred as a result of the additional revenues.

Mr. Isensee explained NIPSCO's proposal to recover the depreciation expense, O&M expense and property tax expense on a historical basis, with six months of actual expense included in each adjustment proceeding after such costs have been incurred. He said that, once calculated, NIPSCO will reduce the revenue requirement related to the recoverable expenses to 80%. In future filings, the revenue requirement will also include the variance associated with the under- or over-collection of these costs due to the difference between the forecasted volumes used to calculate the rates and actual volumes billed. Finally, NIPSCO will gross-up the revenue requirement for all incremental taxes incurred as a result of the additional revenues.

Mr. Isensee clarified that NIPSCO is proposing one change to the ratemaking methodology that was approved by the Commission in NIPSCO's electric TDSIC proceeding. He noted that the rate on customer deposits used to calculate the overall WACC is fixed on the electric side of NIPSCO's business at the cost approved in Cause No. 43969, which is appropriate because that rate represented a blended cost as of the test period, utilizing the fixed electric deposit rate and the then-effective gas deposit rate. Because the gas rate paid on customer deposits is updated by the Commission, NIPSCO proposes to use an updated deposit rate in its calculation of the recovery of financing costs for this gas proceeding.

Mr. Isensee also explained that NIPSCO proposes to defer and recover 80% of the post-in-service costs, including carrying costs and pretax returns, depreciation, O&M and property tax expense associated with its approved TDSIC projects through the TDSIC adjustment factor. NIPSCO proposes to defer such costs as a regulatory asset until such costs are recognized for ratemaking purposes through NIPSCO's proposed TDSIC adjustment factor or included for recovery in NIPSCO's base rates and charges in its next general rate case.

With respect to the deferral of unrecovered TDSIC costs, Mr. Isensee explained that Ind. Code § 8-1-39-9(b) provides that 20% of the approved capital expenditures and TDSIC costs, including depreciation, pretax returns, AFUDC, post-in-service carrying costs, O&M and property taxes shall be deferred and recovered by the public utility as part of its next general rate case. He said that NIPSCO accordingly requests approval to defer as a regulatory asset 20% of the approved capital expenditures and TDSIC costs and requests to recover the costs as part of NIPSCO's next general rate case. NIPSCO also requests approval to record ongoing carrying charges based on NIPSCO's WACC on these costs until the costs are included for recovery in NIPSCO's base rates and charges in that future case.

Mr. Isensee testified that NIPSCO proposes to depreciate the TDSIC capital expenditures according to each asset's designated FERC account classification. He said that upon being placed in service, each asset will be depreciated according to the FERC account composite remaining life approved by the 43894 Order.

Mr. Isensee testified that if NIPSCO incurs TDSIC costs under the 7-Year Gas Plan that result in a revenue requirement exceeding the percentage increase in a TDSIC approved by the Commission, NIPSCO will defer such costs as a regulatory asset for recovery by the public utility as part of its next general rate case. He stated the retail revenues used in this calculation will be obtained from NIPSCO's operating revenues from the most recent earnings test in NIPSCO's Gas Cost Adjustment proceeding. He noted this methodology is the same as the methodology approved by the Commission in Cause No. 44371, NIPSCO's electric TDSIC proceeding. He also stated NIPSCO does not anticipate exceeding the 2% cap under the Updated Plan.

Mr. Isensee testified that NIPSCO proposes to increase the authorized net operating income approved in the 43894 Order to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(g) earnings test. He stated this proposal is consistent with the way earnings associated with NIPSCO's qualified pollution control property and clean coal technology are treated on the electric side of NIPSCO's operations, and also consistent with the Commission's Order in Cause No. 44371. He explained that NIPSCO calculated the 2% cap in this proceeding by comparing the incremental TDSIC revenues above the last approved TDSIC with the total retail revenues for the past 12 months, which is also consistent with the Order in Cause No. 44371.

Mr. Sangster explained that he was responsible for executing the major projects included in the 7-Year Gas Plan. He provided project-specific detail and information concerning two projects: (1) the system deliverability project (the "112th Street Project") involving the replacement of the feed from Natural Gas Pipeline of America ("NGPL") to NIPSCO's 112th Street Station and (2) project management aspects of the extension of facilities to serve rural customers. With respect to the 112th Street Project, Mr. Sangster stated that the updated cost for the project is $13,348,839, or an increase of $10,720,119. He testified that multiple factors contributed to the increased cost, including significantly higher labor costs, de-watering costs that were not included in the estimate, route changes with unanticipated easement acquisition costs and soil contamination requiring environmental assessment and remediation.

Mr. Small sponsored NIPSCO's Updated Plan and specifically addressed updated cost estimates for several of the projects.[4] He testified that the Updated Plan provides a comprehensive update to the 7-Year Gas Plan which incorporates the results of an updated risk model and project prioritization, an update to the projects that NIPSCO is performing in Year 1, (i.e., the 2014 Projects), specific detail for projects that NIPSCO will perform in Year 2 (i.e., the 2015 Projects), and an update to annual projected expenditures for the remaining years of the Plan in 2016 through 2020.

Mr. Small testified the Updated Plan includes a detailed listing of the projects and their associated costs and compares the cost projections in the 7-Year Gas Plan, by asset class, with the current cost projections shown in the Updated Plan along with a brief explanation of the variance. He testified that the estimated capital cost of the Updated Plan is $862.2 million, including indirect capital and AFUDC, and that the total estimated O&M cost of the Updated Plan is $8.5 million. He included the following table comparing the 7-Year Gas Plan to the Updated Plan:

NIPSCO's Projected Annual Expenditures
(in millions)

	Year 1 2014	Year 2 2015	Year 3 2016	Year 4 2017	Year 5 2018	Year 6 2019	Year 7 2020	Total
7-Year Gas Plan								
Capital	$53.3	$89.2	$109.4	$113.6	$117.8	$113.7	$116.1	$713.1
O&M	$2.5	$3.0	$3.0					$8.5
Updated 7-Year Gas Plan								
Capital	$66.9	$120.7	$128.3	$134.8	$138.9	$134.6	$138.0	$862.2
O&M	$2.5	$3.0	$3.0					$8.5
Change	**$13.6**	**$31.5**	**$18.9**	**$21.2**	**$21.1**	**$20.9**	**$21.9**	**$149.1**

Mr. Small sponsored Petitioner's Exhibit 2-C, an updated risk-based modeling study prepared by EN Engineering used to identify and prioritize the transmission pipeline replacement projects. He stated that NIPSCO did not utilize EN Engineering to identify or prioritize any distribution or storage system projects. The projects and estimates included in the Updated Plan were identified and ranked by NIPSCO.

Mr. Small explained that while the annual cost of the 7-Year Gas Plan is projected to increase in each year of the Plan, two projects (the 112th Street Project and the extension of service into unserved rural areas) make up the vast majority of the overall increase in the projected cost of the Plan. He noted that the projected costs of other projects in the 7-Year Gas Plan have not changed, either individually or in the aggregate, to the same degree. He testified

[4] Petitioner's Exhibit 1-C contains a Revised Exhibit Gas Plan Update-1, which is an update to the 7-Year Gas Plan. NIPSCO intends to follow this naming convention in subsequent updates to its 7-Year Gas Plan to enable comparison and eliminate confusion.

that while it is not possible to know how future events will unfold, two factors make similar cost escalation unlikely. First, the time restrictions associated with the 112th Street Project limited NIPSCO's ability to take commercial steps to limit the exposure to cost escalation, which is not the case for the majority of the projects in the Updated Plan. Second, the increase in costs associated with the rural extension projects was driven by the need to incorporate all rural extensions, which presents a unique circumstance.

Mr. Small testified that the cost estimates for all of the transmission pipeline replacement projects in the 7-Year Gas Plan were re-examined by EN Engineering at NIPSCO's request as a result of the variance with the 112th Street Project and the results have been incorporated in the Updated Plan. He also explained that indirect costs and AFUDC increased by approximately $25 million during the life of the Plan primarily due to the revised approach to rural extensions.

Mr. Small testified that one additional transmission, distribution and storage system improvement project has been identified, which may have to be completed by the end of 2015. He explained that the project involves the potential need to replace a feed from NGPL at NIPSCO's current 134th Street take point and that NIPSCO may undertake preliminary engineering work to assess feasibility of potential solutions to the issue. He testified that due to uncertainty about the necessity and cost of the project, it has not been included in this filing.

Mr. Small also provided updates on the status of several projects in the 7-Year Gas Plan, including shallow pipe remediation, bare steel replacement, in-line inspection ("ILI") capability enhancement, inspection and mitigation projects, master meter remediation, system data integration and rural extensions. Of those projects, he provided testimony about increases in the Updated Plan associated with bare steel replacement, inspection and mitigation and rural extension projects, and testified that the Updated Plan incorporated decreases in the projected budgets for shallow pipe transmission projects and ILI projects.

Mr. Small testified that as engineering for the shallow pipe transmission projects proceeded, it was determined that the prudent path forward was to eliminate projects on shallow transmission pipe segments that were already scheduled to either be retired or significantly reduced in operating pressure as part of the 7-Year Gas Plan. He stated this approach was validated by new data received from a transmission pipe depth survey conducted by NIPSCO in 2014. As a result, three of the four projects were eliminated from Year 1 resulting in a decrease of $3,352,806, and a final estimated cost of $1,677,714.

Mr. Small testified that although there are no changes to the 2014 bare steel replacement projects, there has been an approximate $8.5 million increase in the cost of such projects over the life of the 7-Year Gas Plan. He noted that NIPSCO originally assumed it would be able to replace existing bare steel mains with only 80% of the existing mileage, but additional design engineering now leads NIPSCO to believe a mile for mile replacement is more accurate. Mr. Small testified that NIPSCO has also determined that a majority of the miles requiring bare steel replacement are in the downtown Gary area and will require replacement of larger sized pipes in a heavily urban setting.

Mr. Small testified that since the preparation of the 7-Year Gas Plan, NIPSCO engaged an engineering/planning/construction vendor experienced with ILI projects to assist in the preparation of an ILI feasibility analysis for the pipeline systems to be retrofitted for ILI capabilities. The NIPSCO Transmission Integrity Management Program staff identified specific

ILI projects that will be completed for retrofitting based on preliminary reviews resulting in a decrease in the number of projects and a reduction in cost of approximately $10 million in Years 5 through 7 of the Plan (2018-2020). He explained that NIPSCO will continue to refine its ILI project listing and projected costs.

Mr. Small testified the distribution system inspection and mitigation projects consist of projects that are identified through ongoing inspection programs conducted by the NIPSCO Gas Operations Group and accommodate the replacement of facilities based on conditions encountered in the field. He explained that an increase of approximately $5.1 million over the life of the Plan is warranted based on an anticipated increase in distribution regulator stations requiring replacement from recent field inspection and regulator station replacement data. Mr. Small stated that as NIPSCO captures data from ongoing inspections done by field crews, lists of prioritized projects are developed to optimize compliance and continue operation of a safe infrastructure. He explained the field operations teams complete annual inspections and full mechanical inspections on a five-year interval on each regulator to ensure safe operation. The data from these inspections is reviewed by operations and integrity groups to drive the capital asset replacement, which is based on a comprehensive comparison of data. He testified the current list of regulator stations in need of replacement is included in 2015 and 2016 as part of the inspection and mitigation budget in the Updated Plan.

Mr. Small testified that master meter remediation projects involve the replacement of high-risk underground gas facilities behind master meters, and the reconfiguration of those systems to minimize the safety risk. He explained that while the overall cost associated with these projects has not changed, the timing has. He testified that NIPSCO has been working with the Commission's Pipeline Safety Division to identify the master meter systems in its service territory with the highest priority for replacement. In order to get the identified projects engineered and the needed construction resources arranged, the planned expenditure for these projects in 2014 has been moved out to 2015 in the Updated Plan. However, the cost over the life of the 7-Year Gas Plan remains at the original estimate of $2 million.

Mr. Small testified the Updated Plan still includes a total of $8.5 million in costs associated with the research of legacy paper records and the integration of that data into NIPSCO's GIS. He explained that NIPSCO progressed with the initial steps in converting system integrity data from disparate paper records and individual databases into the corporate GIS prior to approval of the 7-Year Gas Plan by contracting for the scanning and indexing of approximately 71,000 linens and the indexing of 900,000 service cards. He testified that although portions of the conversion process began prior to approval of the 7-Year Gas Plan, the balance of expenditures have been incorporated into the Updated Plan beginning in mid-2014. NIPSCO anticipates performing several major activities in 2014, including overall data assessment, pre-conversion development of a source data matrix, GIS architecture refinements, service card viewer enhancements, grid mapping of GIS, data model design and GIS platform roadmap, completion of the pilot conversion process, and the transmission pipe center-line addition to GIS. He explained that commencing in January 2015, the full conversion project will factor in the preparatory work completed in 2014.

Mr. Small also identified the major activities associated with the system data integration project spanning the 2015 to 2016 time frame. He stated that the system data integration project will result in GIS attribute updates for both transmission and distribution assets, and that NIPSCO expects to allocate costs for this project to distribution and transmission using the ratio of the pipe types on the system. Mr. Small testified that the Updated Plan does not reflect any changes in cost or scope for the system data integration project at this time, but that the conversion of analog records and incorporation into NIPSCO's digital systems is a very complex process. Greater clarity around project scope and costs can be expected following pre-conversion workshops and pre-production demonstration projects scheduled for completion in December 2014.

B. OUCC's Case-in-Chief. The OUCC presented the testimony of Barbara A. Smith, Director of the Resource Planning and Communications Division; Edward T. Rutter, Utility Analyst in the Resource Planning and Communications Division; and Mark H. Grosskopf, Senior Utility Analyst in the Gas Division.

Ms. Smith presented the OUCC's recommendations regarding NIPSCO's bare steel replacement and 112th Street projects as well as the OUCC's review of other project changes. With respect to the bare steel replacement projects, Ms. Smith noted that NIPSCO does not currently know what mileage of bare steel that needs to be replaced and will not know that information until completion of field verification through 2015 and the paper conversion project scheduled through 2016. She also questioned the extent to which NIPSCO utilized local Gary Operations personnel when assessing the proper level of bare steel replacement. She stated the OUCC recommends the Commission deny NIPSCO's requested $8.5 million budget increase until additional information is available to evaluate the estimate since the proposed increase in capital spend is not scheduled to begin until 2018.

With respect to the 112th Street Project, Ms. Smith noted that NIPSCO considered this project to be the highest priority TDSIC project and indicated the original cost estimate contained considerable detail with a +/- 20% accuracy range. Ms. Smith testified the OUCC wants any project performed in a safe manner, but that the OUCC's frustration lies in NIPSCO's lack of attention to the project's routing until after NIPSCO received Commission approval for the project and its associated $3,322,780 cost. She noted that NIPSCO offered several reasons for the increased cost and specifically responded to the increase in labor costs, the need to re-route the pipeline extension, which required de-watering and increased easement expense and the increased contingency.

Ms. Smith testified the OUCC recommends that the Commission emphasize that the "best" estimate requirement in the TDSIC Statute should not be taken lightly. She said that because NIPSCO did not fulfill its responsibility by sufficiently reviewing a third-party estimate for a project to be completed in the next year, it has in essence removed the ratepayer protection built into the TDSIC Statute for requiring the "best" estimates. She testified the OUCC recommends the Commission deny NIPSCO's request to increase the TDSIC budget and deny NIPSCO cost recovery through the tracker for any amount over the original estimate for the 112th Street Project. She testified NIPSCO may include any actual 112th Street Project expenses over $3,322,780 in its next base rate case for cost recovery consideration by the Commission.

Ms. Smith also questioned why NIPSCO did not perform the shallow pipe analysis prior to its inclusion as a Year 1 project. She stated that while genuine project cost reduction is welcomed, the total 7-Year Gas Plan budget still includes the $3,352,806 amount for shallow pipe projects that can be transferred to other yet-to-be-defined projects now that the 7-Year Gas Plan is approved, and NIPSCO failed to specify any additional O&M that will need to be spent on the mitigation. Finally, Ms. Smith testified the OUCC appreciates that NIPSCO is waiting until it has the master meter project details defined before moving forward and is pleased that NIPSCO is consulting with the Pipeline Safety Division with respect to those projects.

Mr. Grosskopf testified he is in agreement with the revised calculations included within the schedules presented by NIPSCO witness Isensee. He recommended approval of NIPSCO's rate factor calculation methodology, subject to exceptions for (1) customer class revenue allocations and (2) calculation of total rate adjustment factors to accommodate his recommendation concerning customer margins associated with rural extensions. Mr. Grosskopf recommended approval of NIPSCO's TDSIC rate factor calculation methodology with several exceptions.

Mr. Grosskopf testified that, depending on the outcome of the appeal currently pending in Cause No. 44371, a revision may need to be made to the 2% retail revenue cap test calculation. He noted the same was true with regard to the netting of investments in new capital by the net book value of replaced assets included in the last base rate case.

Mr. Grosskopf testified that NIPSCO's proposed allocation of TDSIC distribution costs deviated from the allocation method approved in its last rate case and changes the allocation of distribution system improvement costs significantly. He stated that the allocation of distribution costs to residential customers would be 73.19% rather than the 66.82% approved in the last rate case. Mr. Grosskopf supported his assertion through reference to the cost of service study filed by NIPSCO witness Ronald Amen in Cause No. 43894 that proposed to allocate a portion of distribution costs to transportation customers. Mr. Grosskopf recommended NIPSCO's TDSIC calculation be amended so that TDSIC distribution costs are allocated to each rate class using the same allocation percentage as applied to transmission costs on Exhibit 2, Schedule 4 of Attachment FAS-1 to Petitioner's Exhibit 1, with the corrected distribution allocations applied to Column (D) on Exhibit 1, Schedule 7 of Attachment FAS-1 to Petitioner's Exhibit 1. In contrast to distribution costs and consistent with Mr. Amen's cost of service study, Mr. Grosskopf recommended that storage costs be allowed as currently proposed by NIPSCO.

Mr. Grosskopf testified this proceeding is the first of a series of TDSIC filings which he believes complies with the periodic filing requirements of Ind. Code § 8-1-39-9(a). He testified that the actual costs submitted for recovery in subsequent TDSIC filings should not be considered approved before the OUCC has had an opportunity to review these costs in the context of a TDSIC tracker petition for recovery, with comprehensive testimony and exhibits supporting such costs. He stated that the Commission would then render a decision on whether or not these costs may be recovered.

Mr. Grosskopf disagreed with NIPSCO's calculation of depreciation expense for recovery in the TDSIC. He stated Exhibit 1, Schedule 4 of Attachment FAS-1 to Petitioner's Exhibit 1, only accommodates reporting depreciation expense for approved TDSIC capital additions and should also account for depreciation expense on the asset retirements resulting from the approved TDSIC capital additions. At the hearing, Mr. Grosskopf testified that NIPSCO currently has a unique situation regarding depreciation expense and that because of a depreciation credit agreed to in a settlement in Cause No. 43894, NIPSCO's current rates do not include depreciation expense on its gas assets. He concluded that netting depreciation expense for these retired assets is unnecessary in this case, but that when the depreciation credit included in NIPSCO's current base rates expires, the net reduction of depreciation expense for retired assets will again be an issue for the OUCC.

Mr. Grosskopf testified that NIPSCO's proposal to credit margin revenue received for rural extensions balances the interests of the utility and the ratepayers, and that the absence of a margin credit on rural extensions would be a significant oversight in TDSIC cost recovery for any other utility collecting TDSIC cost recovery revenue on rural extension investments. He recommended approval of NIPSCO's proposed 80% margin credit for rural extensions for each TDSIC filing. However, he disagreed with the margin credit being limited to 80% of total margin revenue. He said that margin revenue needs to offset TDSIC revenue completely; therefore the 20% margin revenue from rural extensions should be deferred until NIPSCO's next base rate case and matched as a credit to the TDSIC revenue deferred over the same period.

Mr. Rutter testified NIPSCO's Updated Plan includes projects from the 7-Year Gas Plan and some project estimates originally scheduled for Year 1 have been delayed, accelerated or modified based on either a change in scope or a change in unit price. Specifically, the OUCC recommends approval of the Updated Plan as modified to reflect removal of $37,392 from total net investments in transmission, distribution and storage system improvements (expenditures incurred prior to the May 1, 2014 cutoff date); removal of $107,000 in O&M expense for non-TDSIC capital work; and removal of the updated cost estimates concerning the bare steel replacement project and a portion of the 112th Street Project.

C. <u>Industrial Group's Case-In-Chief</u>. The Industrial Group presented the testimony of Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates.

Mr. Phillips noted that NIPSCO proposes to make $862 million in capital expenditures over the next seven years, while its original cost rate base in its last base rate case was only $318 million. He explained that, prior to that rate case, NIPSCO had gone more than 20 years without a rate case. During that period, NIPSCO's high depreciation rate reduced its original cost rate base because NIPSCO spent considerably less on capital additions than its annual depreciation expense. He noted that from 1988 to 2008, NIPSCO's depreciation expense was $474.3 million in excess of its capital additions.

Mr. Phillips testified that new depreciation rates were approved as part of a settlement in Cause No. 43894 based on a NIPSCO sponsored depreciation study, which lowered NIPSCO's depreciation rate from 5.5% to 1.58% and included an agreed depreciation credit equal to the amount of gas service depreciation expense. He said the purpose of the depreciation credit was to help close the gap between the book value of NIPSCO's gas assets and their remaining useful life, with new capital additions as the most significant factor in closing that gap.

Mr. Phillips noted that NIPSCO is seeking approval of the Updated Plan, which increases capital expenditures from $713 million to $862 million. He stated that under NIPSCO's proposal, ratepayers will be providing additional funds for capital expenditures while there is still a significant gap between NIPSCO's fair value and original cost rate base. He considered it inappropriate to layer original cost ratemaking through the TDSIC while using the fair value approach in setting NIPSCO's current base rates. 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. He noted NIPSCO had not previously replaced any of its transmission system. He also compared NIPSCO's proposal to the range of considerations that could be examined in a rate case.

Mr. Phillips testified that in the 43894 Order, NIPSCO was authorized a rate of return of 5.49% on its fair value rate base with a 7.0% rate of return on equity. He noted that in recent gas cost adjustment filings, NIPSCO reported excess earnings ranging from $4.6 million to $11.8 million, indicating NIPSCO is earning above its authorized return. He said for the 12 months ending June 30, 2014, NIPSCO earned a total rate of return of 14.6% on its original cost rate base. Mr. Phillips pointed out that NIPSCO proposes a 6.46% rate of return on the planned investments, which is higher than the 5.49% authorized in the rate case. He stated 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, noting that trackers reduce risk and do not justify an increased return.

Mr. Phillips noted the interpretation of the 2% cap under the TDSIC Statute is being addressed in a pending appeal, and the appellate determination could impact the level of recoverable tracker revenues. Therefore, he recommended any rate relief in this case should be granted only on an interim basis subject to refund or, in the alternative, the level of capital additions subject to TDSIC treatment should be limited to $318 million, the amount of NIPSCO's original cost rate base as of its most recent rate case. He considered it unreasonable as a matter of ratemaking policy to permit a utility to increase its original cost rate base of $318 million by $862 million to $1.18 billion through a tracker. He stated that tracking capital expenditures at the magnitude proposed by NIPSCO with the proposed rate of return would not be in the public interest and would not result in just and reasonable rates.

Mr. Phillips, however, supported the proposed cost allocation presented by NIPSCO. He testified that separating transmission investment allocation from distribution properly follows cost of service principles and is consistent with the method approved by the Commission in connection with NIPSCO's 7-Year Electric Plan. He explained distribution costs should not be allocated to customers served from the transmission system because those customers do not use distribution mains.

Mr. Phillips also agreed with NIPSCO's proposal to credit added margin received from new rural customers as an offset to the TDSIC. He recommended extending that proposal to include all new margins for increased sales above those used for ratemaking in the last rate case.

Regarding the 112th Street Project, Mr. Phillips noted NIPSCO exceeded its original estimate by 300% or more. He stated that although NIPSCO suggested ratepayers will generally see lower costs as a result of the TDSIC tracker, cost-effectiveness or enhanced budgetary and planning certainty has not resulted in this instance. He stated that even though NIPSCO knew with certainty by June 2013 that the NGPL feed would be taken out of service, it failed to act expeditiously to request bids for this work. Mr. Phillips stated that allowing NIPSCO to recover the increased costs through the TDSIC tracker would render meaningless the statutory protections requiring the best estimate of costs and cost justification.

D. <u>Industrial Group Cross-Answering Testimony</u>. Mr. Phillips addressed the OUCC's recommendations relating to the customer class revenue allocation. He disagreed with Mr. Grosskopf's suggestion that distribution costs should be allocated to all customers.

Mr. Phillips stated Mr. Grosskopf's reliance on an interpretation of a cost of service study that was not approved or used as the basis for revenue allocation in NIPSCO's last rate case is misplaced. He noted that the cost of service study and the allocation proposed by NIPSCO in its last base rate case indicated residential rates should be increased. Yet under the settlement approved in the 43894 Order the residential class received a rate decrease, which demonstrated that the approved rates were not based on NIPSCO's cost of service study.

Mr. Phillips testified that new distribution investment should be allocated only to distribution customers. He said the OUCC's proposal would over-allocate costs to high pressure transmission customers on Rates 428 and 438, who do not use the distribution system in the delivery of gas and should not be charged with costs associated with a distribution system they do not use.

Mr. Phillips concluded that allocating distribution costs to high pressure customers served by NIPSCO's transmission system would be unfair and contrary to cost of service principles. He stated the cost allocation presented by NIPSCO best reflects cost causation, the results of the last rate case and the statutory standard.

E. <u>NIPSCO's Rebuttal</u>. Mr. Shambo disagreed with Mr. Grosskopf's recommendation that NIPSCO be required to credit depreciation expense for depreciation associated with assets replaced as part of the 7-Year Gas Plan. He explained that NIPSCO's base rates for gas service do not recover depreciation expense on gas assets based on the 43894 Order, resulting in no depreciation expense to include as an offset. Mr. Shambo added that the Commission rejected that approach in NIPSCO's electric TDSIC proceeding in Cause No. 44371 and noted that the issue is currently pending before the Indiana Court of Appeals.

He also disagreed with Mr. Grosskopf's recommendation that NIPSCO be required to defer margins received from rural extensions over and above the 80% that NIPSCO proposes as a credit to its TDSIC factor as an offset against the 20% of deferred TDSIC expenses. He stated that margin credits are not required by the TDSIC Statute and such credits are therefore voluntary.

Mr. Shambo also disagreed with Mr. Grosskopf's assertion that transportation customers taking service from transmission facilities under Rates 428 and 438 should be allocated distribution-related TDSIC costs. He explained that Mr. Grosskopf inappropriately relied on the cost of service study prepared by NIPSCO witness Ronald Amen in Cause No. 43894 because the rates approved by the Commission in that Cause were not based on Mr. Amen's study but rather reflected a percentage reduction to the then-effective rates. He testified that NIPSCO's proposed treatment of gas TDSIC distribution costs is a reasonable method to accomplish the alignment of the cost causation with cost allocation because those customers did not benefit from distribution assets.

Mr. Shambo also addressed Mr. Phillips's recommendation that cost recovery for investments in the 7-Year Gas Plan be capped at $318 million. He testified that the Commission rejected an identical recommendation from Mr. Phillips in approving NIPSCO's 7-Year Gas Plan in Cause No. 44403, and Mr. Phillips offered no additional evidence in support of his recommendation that was previously denied by the Commission.

Mr. Shambo disagreed with Mr. Phillips that NIPSCO's pretax return should be calculated based on a 5.49% fair value return or a 7.0% return on equity. He testified the return component of the settlement in Cause No. 43894 used a pre-inflation 9.9% return on equity adjusted downward using a 2.9% inflation reduction to result in a 7.0% return on equity that, in combination with NIPSCO's capital structure as of December 31, 2009, and actual debt costs, was used to derive a 5.49% overall return on a fair value basis.

Mr. Shambo testified that the 7.0% advocated by Mr. Phillips is not an appropriate return on equity for use in establishing the return for new TDSIC infrastructure investments because it inappropriately incorporates a 2.9% downward adjustment for inflation that was used for purposes of the settlement. He explained that inflation can by definition only be measured over the passage of time, and thus cannot be an appropriate consideration in determining the return on an asset from the day it is installed. He said Mr. Phillips's recommendation is flawed and results in an understated pretax return by incorrectly discounting the return based on an inapplicable inflation adjustment.

Mr. Small responded to concerns with the 112th Street Project. He testified that given the uncertainty surrounding the long-term availability of the NGPL line, NIPSCO initially requested an engineering estimate for alternatives to the 112th Street feed in January 2013. EN Engineering provided a feasibility study on February 20, 2013, that evaluated two alternative routes, one along Indianapolis Boulevard and the other along the lakefront of Lake Michigan. Mr. Small testified that the feasibility study was completed as a Class 3 estimate, with an expected accuracy range of -20% to +30%. He noted the estimate specifically excluded easement and environmental remediation costs.

Mr. Small testified that although NIPSCO initially decided to pursue the lakefront route due to safety issues, the final route for the project was not determined until much later because of necessary additional engineering, facility siting and land availability investigations. He stated that when NIPSCO was informed in April 2013 of the likelihood that the NGPL line would be decommissioned, it began the process of estimating costs to complete the 112th Street Project, including costs not in the EN Engineering feasibility study. In early June 2013, EN Engineering was released to prepare detailed engineering for the project.

Mr. Small testified the primary hurdle for designating the final route was siting the regulator station because it dictated the route of a portion of the project and impacted some of the design parameters. He stated the property owner of the original site selected was unwilling to negotiate, and NIPSCO had to investigate a number of other sites before identifying the final location. He stated that although the 7-Year Gas Plan contemplated the lakefront route, the final route was not finalized until after the evidentiary hearing in Cause No. 44403.

Mr. Sangster also responded to concerns raised with the 112th Street Project. He explained that in March 2014, NIPSCO's Major Projects Group was assigned responsibility for the larger TDSIC projects, such as the 112th Street Project. He stated the route for the 112th Street Project was finalized in March 2014, and land acquisitions were completed in April 2014. On April 30, 2014, the same day that the 7-Year Gas Plan Order was issued, NIPSCO issued a request for proposal ("RFP") seeking fixed-cost, firm bids, and a contract was awarded on July 31, 2014.

Mr. Sangster explained NIPSCO's RFP process and provided the RFP timeline for the 112th Street Project. He stated that NIPSCO solicited fixed-price bids, rather than open-book, due to the need to complete the project by a certain date and the likelihood of encountering complications associated with the lakefront route.

Mr. Sangster testified that the bids received were substantially higher than anticipated. He said the largest contributing factor was the increase in labor costs, which appears to have resulted from EN Engineering underestimating the complexity of the lakefront portion of the project. Although EN Engineering assumed a Chicago hourly labor rate, which NIPSCO considered reasonable, the number of labor hours was underestimated. He said this was due to the need for open trenching, rather than use of directional boring, and the extensive amounts of underground facilities associated with the lakefront route through industrial brownfields. Mr. Sangster testified that NIPSCO was not aware of the understated labor costs and relied heavily on EN Engineering for the development of the cost estimates provided in Cause No. 44403 because NIPSCO did not have recent experience with large projects.

With respect to the other increased costs associated with the 112th Street Project, Mr. Sangster testified that (1) construction contract costs increased primarily as a function of the complexity of the project along the lakefront, (2) engineering and inspection cost increases were driven primarily by the uncertainty and additional engineering associated with the siting of the regulator station and necessary environmental remediation, (3) de-watering costs, which were not originally included, were incurred due to the proximity of the lake, (4) land costs increased due to the need to acquire property rights for the regulator station and limited easements to accommodate the new facilities and (5) contingency costs increased as a function of the overall estimated cost of the project.

Mr. Sangster testified that NIPSCO was unaware that the overall cost of the 112th Street Project would significantly exceed its estimated cost until bids were received on May 23, 2014. He said the increased costs were driven by circumstances and conditions in the field, not by the timing. He said EN Engineering's underestimation of the complexity of the project would not have been remedied by issuing the bids earlier.

Finally, Mr. Sangster testified that in light of the issues with the 112th Street Project NIPSCO asked EN Engineering to re-evaluate its cost estimates for other TDSIC projects and expressed confidence in those estimates. He said that NISPCO has also taken additional steps to improve its ability to accurately estimate costs by developing a TDSIC Planning and Estimating Group within its Major Projects Group.

5. <u>Commission Discussion and Findings</u>. Given the interrelationship of issues presented for our review, we first consider Petitioner's Updated Plan, then address Petitioner's proposed TDSIC adjustment methodology and proposed TDSIC 1 factor.

A. <u>Findings and Conclusions Regarding Updated Plan</u>. Ind. Code § 8-1-39-9(a) requires a utility to update its seven-year plan with each TDSIC petition the utility files, a requirement also echoed in the 7-Year Gas Plan Order. As we have indicated in other Commission proceedings, the TDSIC Statute is silent as to what should be included in an update and therefore we review the Updated Plan by applying the framework of requirements set forth at Ind. Code § 8-1-39-10(b) for approval of an initial seven-year plan and those established in the 7-Year Gas Plan Order. In the 7-Year Gas Plan Order, we found that:

> in the context of our approval of NIPSCO's 7-Year Gas Plan, we will presume the categories of spending identified in the Plan for Years 2 through 7 are eligible for TDSIC treatment. Because we expect these eligible project categories will become better defined in terms of specificity as their respective investment year

> comes of age, provided the specific projects fall within the approved project categories, this presumption of eligibility will be assigned to specific projects in the annual updating process as further described below.
>
> * * * *
>
> [T]he Commission finds it reasonable that NIPSCO make its TDSIC filings every six months beginning September 1, 2014. The September filing shall provide project detail similar to Year 1 of the original 7-Year Gas Plan for the next upcoming year of the Plan. NIPSCO shall also update the required annual spends for the remaining years of the 7-Year Gas Plan, including the amount for the rural gas extensions segment.

7-Year Gas Plan Order at 24-25. We also approved an informal process whereby NIPSCO would meet with the OUCC and other interested stakeholder's at least eight weeks before each tracker proceeding to discuss the upcoming filing and identify variances from the approved 7-Year Gas Plan. NIPSCO was also instructed to identify any issues unresolved among the stakeholders in its case-in-chief filing. *Id.* at 25-26.

In this case, NIPSCO requests approval of its Updated Plan, including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in the 7-Year Gas Plan Order. The Updated Plan was attached to the Verified Petition and admitted into the record as Petitioner's Exhibit 1-C. The Updated Plan is largely consistent with the plan approved in the 7-Year Gas Plan Order and contains updates of cost estimates for Year 1, a comprehensive overview of all proposed projects by project category and Gas FERC Account for all seven years of the Plan, a detailed project list and cost estimates for Year 2 and a revised project risk ranking.

NIPSCO submitted evidence demonstrating that it complied with the informal process established in the 7-Year Gas Plan Order for meeting with stakeholders to discuss the upcoming TDSIC filing. NIPSCO also addressed the unresolved issues in its case-in-chief filings.

1. <u>Best Estimate of the Cost of the Eligible Improvements</u>. NIPSCO presented detailed evidence supporting its cost estimates contained in the Updated Plan, including instances of both increases and decreases in projected project costs. Ind. Code § 8-1-39-9(f) provides that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates." Three issues were raised in this proceeding addressing concerns with whether the Updated Plan includes a best estimate of the cost of certain improvements: (1) the increase in cost for the rural extension projects, (2) the increase in cost for the 112th Street Project and (3) the increase in cost for the bare steel replacement projects.

Based on our review of the evidence, we find that NIPSCO has provided sufficient support for the updated estimates of the cost of the eligible improvements included in the Updated Plan, except with regard to the 112th Street Project and the bare steel replacement projects as set forth further below. The evidence shows the cost estimates for the investments included in the Updated Plan were based on NIPSCO's experiences for similar work and EN Engineering estimates that have been "re-visited." NIPSCO also provided sufficient evidence detailing the cost estimates for the particular projects to be completed in Year 2. Therefore, we find that the cost estimates contained in the Updated Plan, with the exception of the updated costs estimates for the 112th Street Project and the bare steel replacement projects for years 2016 – 2020, are reasonable.

a. <u>Rural Extension Projects</u>. NIPSCO originally estimated $98.8 million in rural extensions would be performed during the life of the 7-Year Gas Plan, with approximately $13.3 million of those expenditures occurring in Year 1. NIPSCO now projects rural extensions of $217 million over the life of the Plan with approximately $23 million of those expenditures occurring in Year 1. Mr. Shambo testified that NIPSCO underestimated the challenges associated with rural extensions and now proposes to include all rural gas extensions, both those that qualify using the 20-year margin test under Ind. Code § 8-1-39-11 and those that may qualify under NIPSCO's existing line extension policy. In an effort to reduce the impact to existing customers, NIPSCO proposes to provide an 80% credit to the TDSIC tracker for actual margins received from all new customers added under the rural extension projects.

Neither the OUCC nor the Industrial Group opposed or challenged the accuracy of the revised cost projections for rural extension projects. However, both took issue with NIPSCO's margin credit proposal, which is discussed further below in Paragraph 5.B.

While we question NIPSCO's assertions concerning the difficulty in separately tracking and administering the two types of rural extensions for which it is authorized, we find the inclusion of all rural customers in the updated estimate to be reasonable when considered with NIPSCO's margin credit proposal. A key aspect of the TDSIC statute is to provide for the extension of natural gas service into rural areas. NIPSCO indicated that many rural customers wanting natural gas service may require a monetary contribution under its existing six-year line extension policy. However, the inclusion of these types of customers in the TDSIC rural extension projects will allow them to be subject to a 20-year margin test. Mr. Small testified that the rural extension projects included in the Updated Plan are projected to pass the 20-year test identified in Ind. Code § 8-1-39-11. This means that under NIPSCO's revised approach, a 20-year projection of margins associated with the projects compared to the cost to build them results in the projects being cost-effective. The addition of the estimated 46,000 new customers will also grow NIPSCO's customer base allowing operating costs to be spread over that larger customer base and benefitting all natural gas customers. And, NIPSCO's proposal to credit back actual margins from new customers added under the rural extension projects effectively eliminates the impact on existing customers while new customers will continue to provide overall system benefits well beyond this seven-year period.

b. <u>112th Street Project</u>. The Updated Plan includes project costs that have increased to more than $14 million from the projection of $3.4 million contained in the 7-Year Gas Plan.[5] NIPSCO explained that the estimate increased due to a route change that resulted in increased labor costs, de-watering costs, real estate acquisition expenses and environmental remediation costs. Both the OUCC and the Industrial Group recommended the Commission deny NIPSCO's request to recover the increased cost associated with the 112th Street Project.

[5] NIPSCO's response to the Commission's December 4, 2014 Docket Entry projects the final cost of the 112th Street Project to be $14,164,070.

As the OUCC noted, NIPSCO referred to the 112th Street Project estimate in Cause No. 44403 as a "best" estimate, containing considerable detail and having a +/- 20% accuracy level. Ind. Code § 8-1-39-9(f) requires "specific justification" by the utility when costs exceed the approved estimate. To "justify" means "to show to be just or right," "to defend or uphold as warranted or well-grounded," "to show a satisfactory reason or excuse for something done."[6] This does not mean that the utility may simply detail the reasons why the increase occurred. Rather, the utility must explain why the increase in best estimated costs (i.e., costs that were considered to be highly reliable) is reasonable or warranted under the circumstances presented. The requirement that a utility present a best estimate of costs, combined with a need for specific justification before excess costs may be recovered in rates, provides balance to the regulatory process, imposes a degree of rigor in the preapproval process, and protects ratepayers from unjustified cost overruns.

NIPSCO has been aware of the potential retirement of the NGPL line, its impact on customers, and had been discussing the need for alternative facilities for some time prior to EN Engineering conducting the feasibility study in early 2013. NIPSCO learned with some certainty in April 2013 that the NGPL line would be decommissioned and the 112th Street Project had been identified by NIPSCO as its highest priority project. Yet based on the evidence presented, we question whether NIPSCO's actions are consistent with those that a utility would reasonably employ for such high priority projects and share both the OUCC's and Industrial Group's concerns.

The evidence demonstrates that the largest component of the cost increase is related to increased labor costs. NIPSCO initially indicated that this increase was likely due to the combination of the known time sensitivity of the project and the project's complexity. Both the OUCC and Industrial Group pointed out that the time pressure could have been mitigated by NIPSCO if it had issued the RFP earlier. NIPSCO knew as early as April 2013 that the NGPL line would be decommissioned, yet the 112th Street Project was not assigned to the Major Projects Group until March 2014, and the RFP was not issued until April 30, 2014, the same day on which the 7-Year Gas Plan Order was issued. By the time the contract was awarded in July 2014, only five months remained before the NGPL line was to be retired.

On rebuttal, NIPSCO contested the suggestion that it failed to act expeditiously and indicated that the largest contributing factor was EN Engineering's underestimation of the complexity of the project. Mr. Small confirmed that the decision to use the lakefront route had been made in March 2013, and EN Engineering had been released to prepare detailed engineering in early June 2013. He explained that a determination of the final route along the lakefront, however, was delayed due to issues involved with the siting of the regulator station on property which the owner did not wish to sell. He admitted this situation is not unusual. Although Mr. Sangster indicated that there is no reason to believe the bids would have been significantly different had the RFP been issued earlier, it is reasonable to assume that if the RFP had been issued earlier, the issues with the EN Engineering estimate as discussed further below would have been discovered earlier and could have possibly been addressed in a different manner.

With respect to EN Engineering's underestimation of the complexity of the project, Mr. Sangster explained that although an appropriate labor rate was used, EN Engineering

[6] http://dictionary.reference.com/browse/justify?s=t

underestimated the hours of labor involved in the project. The evidence indicates that although EN Engineering was aware the lakefront route involved construction through an industrial area congested with underground facilities, it assumed that the pipe could be installed with directional boring, which is a less labor intensive process than open trenching. NIPSCO explained that directional boring is not feasible in areas with substantial amounts of existing underground facilities. NIPSCO further explained that because of the proximity to Lake Michigan and the low elevation, the excavation trenches were prone to flooding; therefore, de-watering expenses, which had not been contemplated, were incurred. Mr. Sangster also explained that EN Engineering's estimate did not anticipate the need to acquire additional easements outside the public rights-of-way or the encountering of environmental contamination. All of these factors contributed to the project's total increased costs.

NIPSCO had advance notice of at least 18 months that the NGPL line would be retired and knew that it would be unable to provide service to affected customers if it did not have alternative facilities in place by the end of 2014. Yet, NIPSCO did not commence construction until less than six months prior to the line's retirement. The 112th Street Project was NIPSCO's highest priority project. Recognizing its lack of recent experience with large projects, NIPSCO retained EN Engineering to develop a cost estimate in June 2013 to fulfill its statutory obligation to provide a "best" estimate of the project. In Cause No. 44403, NIPSCO expressed confidence in the estimate from its contractor, which was described as an industry expert. While it is certainly appropriate for utilities to seek assistance in areas outside its experience or expertise, it is not appropriate for the utility to shift all responsibility for any errors onto the contractor at the expense of ratepayers. Under the TDSIC Statute, it is ultimately the utility's responsibility to ensure sufficient actions are taken to provide a reasonably detailed and accurate estimation of the project for approval. Based on the evidence presented, the Commission concludes that NIPSCO failed to sufficiently and timely investigate the costs associated with its high priority project's preferred lakefront route prior to submitting its best estimate to the Commission in October 2013.

Accordingly, we find that NIPSCO failed to reasonably justify the substantial increase in cost and that cost recovery for the 112th Street Project should be limited to the best estimate provided by NIPSCO in Cause No. 44403 inclusive of the 20% contingency percentage. NIPSCO may defer for recovery in its next base rate case the difference between the amount authorized in Cause No. 44403 for recovery herein and the actual cost of the project.

While we understand that substantial capital projects involve elements of risk with respect to scope and cost as they progress, we strongly encourage (1) the development of improved estimation techniques and project management practices that will reduce the likelihood of significant changes such as those experienced with the 112th Street Project in the future, and (2) adoption of improved internal and external communication protocols to mitigate the likelihood that the circumstances present with NIPSCO's 112th Street Project will recur in subsequent filings.

c. **<u>Bare Steel Replacement Projects</u>.** NIPSCO proposed to increase its seven-year budget for bare steel replacement projects by approximately $8.5 million because NIPSCO believes its original estimate of an 80% mileage replacement rate is incorrect. NIPSCO indicated that it has determined a majority of the miles requiring replacement are in the downtown Gary area and include replacement of a significant amount of larger pipe than originally projected.

The OUCC recommended the Commission deny NIPSCO's request at this time and that NIPSCO resubmit its proposal in the Fall 2016 or 2017 TDSIC tracker filing because (1) the amount of bare steel existing and needing replaced is not currently known and will not be known until the end of 2016 when the system data integration project is complete, and (2) NIPSCO's proposed increase in bare steel capital spend is not scheduled to begin until 2018.

We agree with the OUCC. The Commission's approval of the project categories in the 7-Year Gas Plan Order was presumptive and premised on the submission of detailed estimates for work in the upcoming year in subsequent TDSIC filings. 7-Year Gas Plan Order at 24. The evidence shows the bare steel replacement projects for which the increased costs were identified are not scheduled to occur until 2018 and the updated cost estimates for the 2016-2020 bare steel replacement projects are not detailed cost estimates. Although we appreciate that NIPSCO provided updated information regarding the bare steel replacement projects for years 2016-2020 to keep us abreast of the information NIPSCO knows at this time, we find that the updated estimate does not provide the best estimate of the cost of those projects and should not be included in the Updated Plan. We expect NIPSCO to include projected changes in its cost estimates for bare steel replacement projects in future TSDIC filings consistent with its obligation to provide best estimates and sufficient justification for any increases as required by the TDSIC Statute.

2. Public Convenience and Necessity. Mr. Small testified that consistent with the 7-Year Gas Plan, the eligible improvements included in the Updated Plan will serve the public convenience and necessity. Mr. Small explained that NIPSCO's Updated Plan follows the requirements of the TDSIC Statute by making investments for the purposes of safety, reliability, system modernization and economic development consistent with public policy and the public interest. No evidence was presented in this Cause to contest the public convenience and necessity associated with the Updated Plan.

NIPSCO has a statutory obligation to provide adequate retail service in its certificated gas service territory pursuant to Ind. Code § 8-1-2.3-4(a). It performs this obligation for the public convenience and necessity. We find that NIPSCO has sufficiently supported that the investments described in its Updated Plan are reasonably necessary for it to continue to provide adequate retail service to its customers. Therefore, consistent with our findings in Cause No. 44403 relating to the 7-Year Gas Plan and based upon the evidence presented in this proceeding, we find that the public convenience and necessity requires or will require the eligible improvements included in the Updated Plan as approved herein.

3. Incremental Benefits Attributable to the 7-Year Gas Plan. Mr. Small testified that, like the 7-Year Gas Plan, the Updated Plan is intended to provide benefits in the form of investments to maintain and improve system reliability through the capacity of the system to deliver gas to customers when they need it, replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system, investment in data and technology required for the gas system integrity program and the extension of gas facilities into rural areas. With respect to rural extensions in particular, he explained that the Updated Plan is projected to increase the number of rural customers served over the life of the Plan to more than 46,000.

In the 7-Year Gas Plan Order (at 23), we found that "NIPSCO's 7-Year Gas Plan contains solutions that will enhance customer and employee safety, avoid outages, preserve operational integrity, provide equipment protection, and meet evolving customer demands." Based on our review of the evidence, the facts underlying that conclusion have not changed. Therefore, consistent with our findings in Cause No. 44403 and based upon the evidence presented in this proceeding, we find the estimated costs of the eligible improvements included in the Updated Plan as approved herein are justified by the incremental benefits attributable to the Updated Plan.

4. **Reasonableness of NIPSCO's Updated Plan.** As indicated above, the Updated Plan includes the best estimate of the cost of the eligible improvements except with regard to the proposed increases for the 112th Street Project and the bare steel replacement projects, the public convenience and necessity requires or will require the eligible improvements included in the Updated Plan, and the estimated costs of the eligible improvements are justified by the incremental benefits attributable to the Updated Plan. The Updated Plan also contained a detailed project list and cost estimates for Year 2 and a revised risk ranking of NIPSCO's projects. Like the 7-Year Gas Plan, NIPSCO's Updated Plan continues to appropriately and reasonably address NIPSCO's aging infrastructure through projects intended to enhance, improve and replace system assets for the provision of safe and reliable natural gas service, as well as the cost-effective extension of service into rural areas. Although the costs associated with rural extensions have increased substantially over the original estimate, the overall impact of those projects is reduced by NIPSCO's proposal to credit 80% of the margins associated with customers served by those projects.

We also note that the Industrial Group again recommended that capital expenditures included in the 7-Year Gas Plan for recovery through the TDSIC be limited to $318 million. We addressed this issue in the 7-Year Gas Plan Order. Specifically, we found (at 24) that simply because a utility should have made more capital investments in the past, such decisions do not address the need for the utility to make investments now. We also noted (at 20) that the Legislature considered the balance between the utility's need for timely cost recovery for necessary investments with the need to limit the rate impacts to customers through the provision of Ind. Code §§ 8-1-39-9(f) and 8-1-39-14. Accordingly, we again decline to impose any cap or other limit beyond that provided for in the TDSIC Statute.

Therefore, based on the evidence presented, we find that the Updated Plan, except with respect to the 112th Street Project and bare steel replacement project cost increases, is reasonable. We further find that NIPSCO has sufficiently defined the Year 2 projects to be considered eligible for TDSIC treatment. We continue to expect that the presumed eligible project categories in Years 3 through 7 of the Updated Plan will become better defined in terms of specificity as their respective investment year comes of age.

B. **Findings and Conclusions Regarding Proposed TDSIC Mechanism.** Under Ind. Code § 8-1-39-9(a), "...a public utility that provides electric or gas utility service may file with the commission rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs." The remaining 20% of approved capital expenditures and TDSIC costs may be deferred for future recovery under provisions of Ind. Code § 8-1-39-9(b), which provides:

> [a] public utility that recovers capital expenditures and TDSIC costs under subsection (a) shall defer the remaining twenty percent (20%) of approved capital

> expenditures and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, and shall recover those capital expenditures and TDSIC costs as part of the next general rate case that the public utility files with the commission.

Thus, Section 9 of the TDSIC Statute provides that 80% of eligible TDSIC costs may be recovered through a semi-annual tracking adjustment, and the remaining 20% is deferred for recovery in the utility's next general rate case.

NIPSCO presented detailed evidence concerning its proposed TDSIC adjustment mechanism. With three exceptions, no party offered evidence that contested the ratemaking methodology proposed by NIPSCO for the calculation of either the statutory TDSIC adjustment or the amount to be deferred for future recovery. The three contested issues were (1) the return on equity component of the calculation of pretax return under Ind. Code §§ 8-1-39-3 and 8-1-39-13, (2) the proposed allocation of distribution-related TDSIC costs among customer classes and (3) the proposed margin credit associated with rural extension projects.

We note that the OUCC initially took issue with NIPSCO's proposal to record depreciation expense on new capital investments. Mr. Grosskopf questioned the propriety of permitting recovery of depreciation expense on capital additions through the TDSIC mechanism without also making an offset for reduced depreciation on corresponding capital retirements. However, as Mr. Grosskopf acknowledged at the hearing, under the terms of the settlement in Cause No. 43894, depreciation expense is offset by a credit and is not presently being recovered in NIPSCO's base rates. Therefore, the treatment of depreciation expense for tracked investment in relation to any depreciation on retired assets included in base rates will not be an issue ripe for consideration until the depreciation credit mechanism approved in the 43894 Order expires.

1. <u>Calculation of Pretax Return</u>. Ind. Code § 8-1-39-13(a) sets out the factors the Commission may consider in determining the appropriate pretax return for purposes of calculating TDSIC costs:

> (1) The current state and federal income tax rates.
> (2) The public utility's capital structure.
> (3) The actual cost rates for the public utility's long term debt and preferred stock.
> (4) The public utility's cost of common equity determined by the commission in the public utility's most recent general rate proceeding.
> (5) Other information that the commission determines is necessary.

NIPSCO proposes to use 9.9% as the return on equity in the calculation of the pretax return for new TDSIC infrastructure investments as approved in NIPSCO's most recent gas base rate proceeding. The Industrial Group, however, contends that the 5.49% fair value return from the settlement approved in the 43894 Order should be used as the basis for the calculation of pretax return associated with NIPSCO's gas TDSIC investments and that a 7% return on equity is the appropriate rate.

Based on the evidence presented, we find that NIPSCO's proposed 9.9% return on equity is appropriate. As explained by Mr. Shambo, a return on equity of 9.9% was agreed upon by the parties in Cause No. 43894 and was then adjusted downward by an inflation factor to reach an agreed-upon fair return. Inflation is intended to measure change in price over time. Since the TDSIC investments are new, inflation should not be included in the return on those assets.

2. Allocation of TDSIC Distribution Costs. NIPSCO proposes that the cost of transmission system improvements be allocated among all customer classes consistent with the revenue allocation from Cause No. 43894, while distribution system improvement costs would not be allocated to transportation customers receiving service under Rates 428 and 438. The costs associated with storage projects would be allocated in the same manner as distribution costs, and the cost of rural extension projects would be allocated in the same manner as transmission and distribution costs based on the character of the facilities installed.

The OUCC contends that the TDSIC costs associated with distribution system projects should be allocated to both distribution and transportation customers using the same percentages proposed by NIPSCO for transmission projects, consistent with the cost of service study prepared by NIPSCO in Cause No. 43894.

The Industrial Group supported NIPSCO's proposed allocation, and pointed out that the cost of service study prepared by NIPSCO in Cause No. 43894 was neither used nor approved in establishing the rates approved in the 43894 Order.

Based on our review of the evidence, we find NIPSCO's proposal that the revenue allocation factor be adjusted for Transportation Rates 428 and 438 is a reasonable method to accomplish the alignment of the cost causation with cost allocation, under the evidence-specific conditions presented in this proceeding together with the 43894 Order, for the purpose of allocating distribution costs in a manner that comports with Ind. Code § 8-1-39-9(a)(1). We find it is appropriate to adjust the allocation factors approved in the 43894 Order by removing Rates 428 and 438 from the calculation for purposes of allocating distribution related TDSIC costs so that rate classes that do not use the distribution system are not allocated distribution costs.

3. Deferral of Rural Extension Margins. In connection with NIPSCO's proposed increase in rural extension projects, NIPSCO proposes to credit 80% of actual margins associated with new customers connected through the rural extension program, consistent with the TDSIC percentage tracked recovery on investments. Mr. Shambo testified that NIPSCO now projects total rural extension investments of $217.7 million (an increase of $118.9 over the 7-Year Gas Plan), and estimates that these investments will result in $72.7 million in charges to customers through the TDSIC tracker over the life of the Plan. NIPSCO's proposed 80% margin credit from new rural customers is estimated to be $67.0 million for the same period resulting in a net impact to existing customers of $5.7 million over the life of the Plan – a substantial reduction in recovery relative to the 7-Year Gas Plan.

The OUCC disagreed with NIPSCO's proposal to limit margin credits to 80% of total margin revenue. Mr. Grosskopf stated that capturing 20% of test year rural extension revenue in the next rate case ignores the fact that the utility received and retained 20% of the margin revenue in each of the preceding years. The OUCC recommended the remaining 20% margin revenue from rural extensions be deferred until the next base rate case, and matched as a credit to the TDSIC revenue deferred over the same period, for net revenue recovery in the next rate case.

The Industrial Group recommended that NIPSCO's proposal to provide a credit for new margin should be expanded to include increased sales and margins from the level used to design rates in the last base rate case, from each rate class.

Based on the evidence presented, we find that NIPSCO's proposed 80% margin credit is a reasonable concession to help mitigate its proposed increase in rural extension projects. Under NIPSCO's proposal, ratepayers will ultimately pay less for rural extensions through the TDSIC than what was approved in the 7-Year Gas Plan Order. NIPSCO's proposed margin credit was offered voluntarily because such credits are not required under the TDSIC Statute. Therefore, we decline to adopt the proposals advocated by the OUCC and the Industrial Group. We also note that pursuant to the settlement approved in Cause No. 43894, the parties will have an opportunity to seek review of NIPSCO's base rates for gas service in November 2017.

C. <u>Findings and Conclusions Regarding Proposed TDSIC 1 Factors</u>. In reviewing NIPSCO's proposed initial TDSIC 1 factors to be effective for the billing months of February through May 2015, we first address whether NIPSCO's petition in this Cause meets the requirements set forth in Ind. Code § 8-1-39-9 and then address the remaining calculations supporting the proposed factor.

1. <u>Section 9 Requirements</u>. Ind. Code § 8-1-39-9(a) provides in relevant part that the petition must:

> (1) use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order;
>
> (2) include the public utility's seven (7) year plan for eligible transmission, distribution, and storage system improvements; and
>
> (3) identify projected effects of the plan described in subdivision (2) on retail rates and charges.

As discussed earlier, NIPSCO is requesting approval to use its customer class revenue allocation factor based on firm load that was approved in the 43894 Order. Exhibit 2, Schedule 4 of Attachment FAS-1 to Petitioner's Exhibit 1 shows the approved allocation. Having rejected the OUCC's proposal concerning the allocation of distribution-related TDSIC costs, and because no other evidence was presented contesting the accuracy of NIPSCO's proposed cost allocation methodology in this Cause, we find that NIPSCO's proposal properly allocates approved capital expenditures and TDSIC costs to the various customer classes in accordance with Ind. Code § 8-1-39-9 (a)(1).

As part of its case-in-chief, NIPSCO attached its 7-Year Gas Plan as well as its proposed Updated Plan. Therefore, NIPSCO has satisfied the requirement set forth in Ind. Code § 8-1-39-9(a)(2). We note that in each semi-annual TDSIC filing, NIPSCO must update its 7-Year Gas Plan pursuant to Ind. Code § 8-1-39-9(a) and in accordance with the specific parameters set forth in the 7-Year Gas Plan Order.

With regard to the projected effects on retail rates and charges, Mr. Isensee sponsored Exhibit 2, Schedule 6 to Attachment FAS-1 of Exhibit 1 which identifies: (1) NIPSCO's original calculation of the projected effect of the 7-Year Gas Plan on retail rates and charges included in NIPSCO's original case-in-chief in Cause No. 44403; (2) the projected effect of the 7-Year Gas Plan on retail rates and charges based on ratemaking provisions as proposed in this proceeding and (3) the projected effect of the Updated Plan on retail rates and charges based on ratemaking provisions as proposed in this proceeding. The exhibit also summarizes the total estimated revenue requirement for each rate class from 2014 to 2020. NIPSCO estimated the average monthly bill impact for a typical residential customer using 72 therms per month is $0.08.

Accordingly, we find that NIPSCO has provided sufficient information regarding the projected effects of the Updated Plan on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).

2. Past and Future Rate Case Timing and TDSIC Timing. Ind. Code § 8-1-39-9(c) states that "[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility's basic rates and charges with respect to the same type of utility service." Mr. Shambo testified that NIPSCO's current base rates and charges were set by the Commission's 43894 Order. Accordingly, we find that this proceeding was filed more than nine months after NIPSCO's last base rate case in accordance with Ind. Code § 8-1-39-9(c).

Ind. Code § 8-1-39-9(d) states that "[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility's approved seven (7) year plan, petition the commission for review and approval of the public utility's basic rates and charges with respect to the same type of utility service." Mr. Shambo testified that NIPSCO intends to comply with this requirement, and we find that NIPSCO shall petition the Commission for review and approval of NIPSCO's base gas rates and charges before the expiration of NIPSCO's 7-Year Gas Plan pursuant to Ind. Code § 8-1-39-9(d).

Ind. Code § 8-1-39-9(e) states that "[a] public utility may file a petition under this section not more than one (1) time every six (6) months." Mr. Shambo testified that NIPSCO intends to file a petition for a TDSIC adjustment seeking recovery of its TDSIC costs approximately every six months. Mr. Isensee testified that NIPSCO proposes to file its petition and case-in-chief by September 1 and March 1 each year, with new rates becoming effective for the six-month periods starting on December 1 and June 1, respectively. We find that NIPSCO's filing in this proceeding is consistent with Ind. Code § 8-1-39-9(e) and is reasonable.

3. Billing Period. In this proceeding, NIPSCO requests approval of TDSIC factors to be applicable to bills during the months of February 2015 through May 2015 to effectuate the timely recovery of 80% of TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution and storage system improvements. Mr. Isensee testified the TDSIC factors include TDSIC costs incurred through June 30, 2014.

4. Semi-Annual Revenue Requirement – Capital. NIPSCO requests approval of a total adjusted semi-annual revenue requirement associated with a return on eligible transmission, distribution and storage system improvements ("T&D Assets") incurred through June 30, 2014, of $215,725 (Exhibit 1, Revised Schedule 5, Line 3 of Attachment FAS-1 to Petitioner's Exhibit 1). The 80% recoverable adjusted semi-annual revenue requirement associated with a return on the T&D Assets is $172,580 (*Id.* at Line 9). The 20% portion of the adjusted semi-annual revenue requirement associated with a return on the T&D Assets is $43,145 (*Id.* at Line 6).

The total cost of the T&D Assets incurred through June 30, 2014, upon which NIPSCO requests authority to earn a return is $4,448,773 (Exhibit 1, Second Revised Schedule 2, Line 3 of Attachment FAS-1 to Petitioner's Exhibit 1). Mr. Isensee testified this total includes AFUDC, other indirect costs and is net of accumulated depreciation. He stated the AFUDC related to TDSIC projects was calculated in accordance with the USofA, which is consistent with GAAP. Mr. Isensee testified that if the Commission approves the proposed ratemaking treatment for costs of the T&D Assets incurred through June 30, 2014, NIPSCO will cease accruing AFUDC on construction costs once the incurred costs receive CWIP ratemaking treatment, are otherwise reflected in base rates or the project is placed in service, whichever occurs first.

NIPSCO proposes to use a full WACC, including zero-cost capital, to calculate pretax return and provided that the WACC should be updated in each semi-annual TDSIC filing to reflect an updated capital structure and cost of debt. The calculation of NIPSCO's updated total WACC is shown on Exhibit 2, Schedule 1 of Attachment FAS-1 to Petitioner's Exhibit 1. Mr. Isensee explained that the annual revenue requirement for the return on investment is calculated by multiplying the June 30, 2014 net book value of all transmission, distribution and storage system projects by the debt and equity components of NIPSCO's weighted cost of capital. The product of this calculation is then multiplied by 50% in order to calculate a semi-annual revenue requirement. This semi-annual amount is then multiplied by the revenue conversion factor and further reduced to 80%, as seen in Exhibit 1, Revised Schedule 5 of Attachment FAS-1 to Petitioner's Exhibit 1, in order to determine the total return-related revenue requirement to be recovered for bills rendered for the months of February through May 2015.

Because we rejected the Industrial Group's proposal concerning the appropriate cost of equity to be included in the calculation of pretax return and no other evidence was presented that contested NIPSCO's calculation of the semi-annual revenue requirement, we find that NIPSCO's request to begin earning a return on the value of the T&D Assets incurred through June 30, 2014, as set forth above, complies with the TDSIC tracker methodology approved in this Order and is approved subject to our findings in paragraph 5.A. above. We further find that NIPSCO's proposed total semi-annual revenue requirement associated with the T&D Assets and the 80% recoverable semi-annual revenue requirement as set forth above have been calculated in compliance with the TDSIC tracker methodology approved in this Order and is approved subject to our findings in paragraph 5.A. above.

5. Reconciliation. Mr. Isensee testified NIPSCO is not including a reconciliation of revenues and costs in this filing because this is the first filing for this mechanism and no previous factors were in effect. The first reconciliation of revenues and costs included in this proceeding will be included in Cause No. 44403 TDSIC 3, which will be filed in September 2015.

6. Calculation of TDSIC Factors. Mr. Isensee sponsored Exhibit 1, Revised Schedule 7 of Attachment FAS-1 to Petitioner's Exhibit 1, which shows the calculation of the TDSIC factors by rate code based on the total adjusted semi-annual revenue requirement of $341,101 (Exhibit 1, Revised Schedule 5, Line 14 of Attachment FAS-1 to Petitioner's Exhibit 1). He testified the factors are calculated by combining the various components of the allocated revenue requirement and dividing those components by forecasted volumes to compute a billing factor for bills rendered during the months of February through May 2015. Mr. Isensee sponsored Exhibit DJI-2, revised page 6 of Petitioner's Exhibit 4 (Appendix F – Transmission, Distribution and Storage System Improvement Charge (First Revised Sheet No. 157)) showing the TDSIC factors proposed to be applicable for bills rendered during the months of February through May 2015.

OUCC witness Grosskopf testified that, based on his analysis, NIPSCO's proposed TDSIC factors for the billing months of February through May 2015 appear to comport with the ratemaking and accounting treatment authorized by the TDSIC Statute. OUCC witness Rutter recommended acceptance of the revised exhibits filed by NIPSCO to remove $37,392 of costs that were incurred prior to March 1, 2014, from the total amount of investment in TDSIC projects upon which Petitioner seeks to earn a return.

Based on the evidence presented, we approve NIPSCO's implementation of TDSIC factors calculated in accordance with our findings in this Order and for such factors to be applicable to bills rendered during the months of February through May 2015 or until replaced by new factors. We decline to adopt the OUCC's request to make the factors approved in this proceeding interim and subject to refund pending the outcome the appeals the Commission's Orders in Cause Nos. 44370 and 44371. Although the appeals of those Orders address related issues concerning the Commission's interpretation of the TDSIC Statute, those cases involve findings specific to NIPSCO's electric TDSIC cases.

7. <u>Deferred TDSIC Costs</u>. Mr. Isensee sponsored Exhibit 1, Revised Schedule 9 of Attachment FAS-1 to Petitioner's Exhibit 1, which shows 20% of the total revenue requirements calculated in Exhibit 1, Revised Schedule 5 of that same Attachment. He testified the amount included in Column F represents ongoing carrying charges, based on NIPSCO's weighted cost of capital, on all TDSIC costs deferred through June 30, 2014. He stated these costs will be included for recovery in NIPSCO's base rates in its next general rate case. Based on the evidence presented, we authorize NIPSCO to defer 20% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements as approved in this Order, including ongoing carrying charges, in its next general rate case.

8. <u>Average Aggregate Increase in Total Retail Revenues Under Ind. Code § 8-1-39-14</u>. Ind. Code § 8-1-39-14(a) provides that:

> [t]he commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a twelve (12) month period. For purposes of this subsection, a public utility's total retail revenues do not include TDSIC revenues associated with a targeted economic development project.

Mr. Isensee sponsored Petitioner's Exhibit 1, Revised Schedule 8 of Attachment FAS-1 to Petitioner's Exhibit 1, which shows that there is no amount in excess of 2% of retail revenues for the past 12 months. Mr. Isensee testified that consistent with the Commission's Order in Cause No. 44371 approving NIPSCO's electric TDSIC, NIPSCO has calculated the 2% cap by comparing the increase in TDSIC revenues in a given year with the total retail revenues for the past 12 months. He stated the retail revenues used in this calculation represent the revenues related to the 12 months ended June 30, 2014, obtained from Cause No. 43629 GCA 31. Based on this evidence, we find that NIPSCO's proposed TDSIC 1 factors will not result in an average aggregate increase in NIPSCO's total retail revenues of more than 2% in a 12-month period.[7]

6. <u>Confidential Information</u>. NIPSCO filed a motion for protective order on August 28, 2014, which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on September 11,

[7] Although we are not specifically approving NIPSCO's proposed TDSIC 1 factors because we require additional information to verify the correct TDSIC factors based on our findings in this Order, any change will not result in an average aggregate increase higher than that identified by NIPSCO.

2014, finding such information to be preliminarily confidential, after which such information was submitted under seal. We find all such information 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. NIPSCO's Updated Plan as set forth in Petitioner's Exhibit 1-C, with the exception of the updated cost estimates associated with the bare steel replacement projects and the 112th Street Project, is approved.

2. The projects included in Year 2 of the Updated Plan and approved in this Order are designated as eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-2.

3. NIPSCO's proposed methodology for calculating its TDSIC adjustment is approved as set forth in Paragraph 5.B. above.

4. NIPSCO shall file under this Cause, prior to placing in effect the approved TDSIC factors, an amendment to its rate schedules with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment. Along with the rate schedules, NIPSCO shall include a derivation of rates based on the semi-annual revenue requirement as approved in Paragraph 5.C.4.

5. NIPSCO is authorized to recover 80% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements as approved in this Order in its rates and charges for gas service beginning with the February 2015 billing month.

6. NIPSCO is authorized to defer 20% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements as approved in this Order and recover those deferred costs in its next general rate case. NIPSCO is authorized to record ongoing carrying charges based on the current overall WACC on all deferred TDSIC costs until such costs are recovered in NIPSCO's base rates as a result of its next general rate case.

7. NIPSCO is authorized to defer all approved TDSIC costs, including depreciation, pretax returns, AFUDC, post-in-service carrying costs, O&M and property taxes, on an interim basis, until such costs are recognized for ratemaking purposes through Petitioner's proposed TDSIC mechanism or otherwise included for recovery in NIPSCO's base rates in its next general rate case.

8. NIPSCO is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(g)(3)(c) pursuant to Ind. Code § 8-1-39-13(b).

9. The information filed by Petitioner in this Cause pursuant to its motion for a protective order 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.

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

<u>STEPHAN, MAYS-MEDLEY, HUSTON, WEBER, AND ZIEGNER CONCUR:</u>

APPROVED: JAN 28 2015

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission