ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITIONS OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC., AND INDIANA GAS COMPANY, INC. D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. FOR: (1) APPROVAL OF AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR FEDERALLY MANDATED NATURAL GAS TRANSMISSION AND DISTRIBUTION PROJECTS, AND THE COSTS THEREOF, RELATED TO COMPLIANCE WITH VARIOUS FEDERALLY MANDATED REQUIREMENTS RELATING TO NATURAL GAS PIPELINE SAFETY AND INTEGRITY; (2) APPROVAL OF CERTAIN TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM PROJECTS, AND THE COSTS THEREOF, UNDERTAKEN FOR PURPOSES OF SAFETY, RELIABILITY, SYSTEM MODERNIZATION, OR ECONOMIC DEVELOPMENT; (3) APPROVAL OF A 7-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 (AND FOR FEDERALLY MANDATED PROJECTS, IN THE EVENT AND TO THE EXTENT THE COMMISSION CONCLUDES THAT SUCH PROJECTS DO NOT MEET THE REQUIREMENTS OF IND. CODE CH. 8-1-8.4, INCLUDING A PROCESS FOR ANNUAL UPDATES TO THE PLAN; (4) APPROVAL OF A RATE ADJUSTMENT MECHANISM AND RELATED AUTHORITY TO UTILIZE ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE CHAPTERS 8-1-8.4 AND 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH FEDERALLY MANDATED AND TRANSMISSION, DISTRIBUTION AND STORAGE PROJECTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); (5) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-8.4 AND 8-1-39; (6) IF NECESSARY, GRANTING OF CONFIDENTIAL TREATMENT FOR CERTAIN CONFIDENTIAL AND PROPRIETARY INFORMATION THAT MAY BE SUBMITTED IN THIS CAUSE; AND (7) APPROVAL OF OTHER RELIEF AS MAY BE APPROPRIATE	)	**CAUSE NO. 44429** **(CONSOLIDATED WITH CAUSE NO. 44430)** **APPROVED:** AUG 27 2014

ORDER OF THE COMMISSION

Presiding Officers:
Carol A. Stephan, Commission Chair
Loraine L. Seyfried, Chief Administrative Law Judge

On November 25, 2013, Southern Indiana Gas & Electric Company ("Vectren South") and Indiana Gas Company, Inc. ("Vectren North"), both d/b/a Vectren Energy Delivery of

Indiana, Inc. (collectively, "Petitioners" or "Vectren") separately petitioned the Indiana Utility Regulatory Commission ("Commission") for, among other things, authorizations and approvals for the following: (i) a certificate of public convenience and necessity ("CPCN") for certain natural gas transmission and distribution projects needed to comply with federally mandated requirements ("Compliance Projects"); (ii) certain transmission, distribution, and storage system projects (and the costs thereof) undertaken for purposes of safety, reliability, system modernization, or economic development ("TDSIC Projects"); (iii) Petitioner's seven-year plan of TDSIC Projects ("TDSIC Plan"); and (iv) a rate adjustment mechanism for recovery of certain costs for the Compliance Projects and TDSIC Plan and deferral of remaining costs. Vectren South filed its petition in Cause No. 44429 and Vectren North filed its petition in Cause No. 44430.

Vectren South and Vectren North filed their respective cases-in-chief separately in each proceeding on November 26, 2013. On December 19, 2013, Vectren South filed a Motion to Consolidate the Evidentiary Hearing in Cause No. 44429 with the hearing in Cause No. 44430. The Presiding Officers consolidated the two proceedings into this Cause and ordered the caption be modified in all future filings to reflect the relief requested by Petitioners in both Causes. On January 15, 2014, Petitioners filed revised direct testimony and supplemental testimony of certain witnesses. A Technical Conference was held on February 4, 2014, at 9:30 a.m., in Room 224, PNC Center, 101 W. Washington Street, Indianapolis, Indiana.

Petitions to intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC"), the Vectren Industrial Group ("Industrial Group"), Steel Dynamics, Inc. ("SDI"), and Nucor Steel-Indiana ("Nucor"). The Presiding Officers granted the petitions, and the Intervenors were made parties to this Cause.

On March 21, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") and the Industrial Group filed their respective direct testimony and exhibits. On April 11, 2014, SDI and Nucor filed cross-answering testimony and Vectren filed rebuttal testimony. On April 23, 2014, the OUCC filed supplemental testimony. Vectren also filed supplemental testimony on May 2, 2014. On May 5, 2014, the Presiding Officers issued a docket entry to which Petitioners responded on the same day.

Based upon a request for a field hearing concerning Vectren South's petition, a field hearing was held at 6:00 p.m. on April 14, 2014, in the City of Evansville, the largest municipality in Vectren South's service area. At the field hearing, members of the public were afforded the opportunity to make statements to the Commission.

An evidentiary hearing was held in this matter on May 8, 2014, at 1:30 p.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of Vectren, the OUCC, Industrial Group, and SDI were admitted into the record without objection. No members of the general public appeared or participated at the hearing.

Based upon the applicable law and evidence presented, the Commission finds:

1. **<u>Notice and Commission Jurisdiction</u>.** Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioners are public utilities as that term is defined in Ind. Code § 8-1-2-1(a) and energy utilities as defined in Ind. Code § 8-1-8.4-3. Under Ind. Code ch. 8-1-8.4 ("Compliance Statute"), the Commission has authority to issue a certificate of public convenience and necessity and to approve cost recovery for projects necessary to comply with federally mandated requirements. Under Ind. Code §§ 8-1-39-10 and -11, the Commission has jurisdiction over a public utility's seven-year plan for eligible transmission, distribution, and storage improvements, including targeted economic development projects ("TEDs") and extension of gas service in rural areas. Under the Compliance Statute, Ind. Code ch. 8-1-39 ("TDSIC Statute"), and Ind. Code § 8-1-2-42, the Commission has authority over certain changes to Vectren's rates and charges. Therefore, the Commission has jurisdiction over Petitioners and the subject matter of this proceeding.

2. **<u>Petitioners' Characteristics</u>.** Petitioners are corporations organized and existing under the laws of the State of Indiana and having their principal office at One Vectren Square, Evansville, Indiana. Petitioners are engaged in rendering gas service in the State of Indiana and own, operate, manage, and control, 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.

3. **<u>Requested Relief</u>.** By their respective petitions, Petitioners request the following relief:

> (1) Approval granting a CPCN for the Compliance Projects (and the costs thereof) designed both to improve the safety, reliability, and integrity of Petitioners' transmission and distribution pipeline systems and to comply with federally mandated requirements;
>
> (2) Approval of the TDSIC Projects (and the costs thereof) undertaken for purposes of safety, reliability, system modernization, or economic development;
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> (3) Approval of Petitioners' TDSIC Plans (and any Compliance Projects, in the event and to the extent that the Commission concludes that any such project does not meet the requirements of Ind. Code ch. 8-1-8.4), including a process for annual updates to the TDSIC Plans and the Compliance Projects;
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> (4) Approval of a rate adjustment mechanism for timely recovery of 80% of the costs of the Compliance Projects and the TDSIC Plans (jointly referred to herein as the "7-Year Plan"), including financing costs incurred during construction;
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> (5) Authorization of the deferral of 20% of the costs of the 7-Year Plan, and interim deferrals of such costs, until such costs are reflected in Petitioners' retail rates; and
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> (6) Approval of other related ratemaking relief and tariff proposals.

4. **Evidence Presented.**

A. **Vectren's Case-in-Chief.** Carl L. Chapman, President and Chief Executive Officer of Vectren Corporation, testified that the gas infrastructure related proposals are designed to ensure compliance with pipeline safety regulations and/or improve the safety and reliability of gas service. He indicated there is no larger issue facing the gas industry than the need to modernize pipeline facilities and take other steps to enhance safety and reliability.

Mr. Chapman testified regarding the recent changes in the operation and regulation of the gas distribution industry, the proposed projects that are being undertaken to ensure compliance with regulations and improve safety and reliability, the benefits derived from the proposed projects, and the estimated costs related to the projects. Mr. Chapman explained that replacement of aging pipeline infrastructure is not a unique issue for Vectren and such programs are underway nationwide. He testified Vectren is proposing programs that are being undertaken to ensure compliance with regulations and to improve public safety and reliability.

Mr. Chapman testified that Vectren chose to seek relief for the Compliance Projects under the Compliance Statute because they are mandatory and including them with other programs would infer that they are open to judgment and debate as to necessity. He testified that all of the proposed infrastructure projects would be beneficial to customers by achieving compliance with regulations put in place to improve public safety and system reliability. He indicated a number of other specific benefits as well, including: (1) prioritized actions to mitigate risks, (2) allowing advance notice to cities and customers through planning, (3) reduced customer bill impacts, (4) ideal timing in light of relatively low gas costs, (5) more jobs, (6) a safe and reliable system needed to obtain new business, (7) long-term reduced construction costs, and (8) potential reduced future costs linked to greenhouse gas emissions. He explained that compliance with pipeline safety regulations is not optional and that implementing a plan to reduce system risks is imperative.

Mr. Chapman described the economic benefits derived from the planned investments, including job creation and extension of infrastructure to serve rural areas, and the importance of the investments. He also explained Vectren's best estimate of the costs of the Compliance and TDSIC Projects. Mr. Chapman indicated that Vectren's past efforts to provide well-founded financial projections and manage capital expenditures, costs and financing activities have been successful as demonstrated through excellent credit ratings. He explained that timely cost recovery supports efforts to attract capital on a cost-effective basis.

Mr. Chapman summarized that in this proceeding Vectren seeks a finding that: (1) public convenience and necessity require that it proceed with the Compliance and TDSIC Projects as set forth in the 7-Year Plan, and (2) a rate adjustment mechanism should be approved under both the Compliance Statute and TDSIC Statute to provide for timely recovery of 80% of the costs incurred.

James M. Francis, Director of Engineering & Asset Management for Vectren Utility Holdings, Inc. ("VUHI"), the parent company of Vectren, described the investments and expenses for projects that Vectren will implement to comply with federal regulations and for safety, reliability, or modernization of Vectren's gas pipeline systems. He addressed investments and expenses for which Vectren seeks recovery through both the Compliance Statute and the TDSIC Statute.

With respect to the Compliance Statute, Mr. Francis provided a chronological history of the federal mandates associated with pipeline safety regulations, particularly focusing on the transmission and distribution integrity management regulations. He described what is mandated by those regulations and identified the investments and expenses associated with compliance. Regarding the TDSIC Statute, Mr. Francis testified about the investments included in Vectren's TDSIC Plan.

Mr. Francis described how both the Compliance and TDSIC Projects were developed, how those projects were prioritized, and how reasonable cost estimates were developed. He explained that although Vectren chose to show the estimated cost of the Compliance Projects within the TDSIC Plan (i.e., the 7-Year Plan) so that the total amount of infrastructure investment is transparent, he also indicated that per the Compliance Statute, Vectren is seeking approval of the Compliance Projects as federally mandated and not as part of the TDSIC Plan. He also testified as to why the 7-Year Plan may change and how Vectren proposes to update its 7-Year Plan.

Thomas L. Bailey, VUHI's Director of Sales, testified regarding Vectren's approach to rural expansion initiatives, the anticipated benefits of such projects, and plans for certain anticipated commercial TEDs. He indicated that neither Vectren South nor Vectren North was seeking approval at this time of any specific TEDs. Mr. Bailey explained that Vectren would likely submit some projects to the Indiana Economic Development Corporation ("IEDC") for its approval once further details become available. He noted that the TDSIC Statute states that TEDs require IEDC review and approval of the projects. After IEDC approval, projects will be submitted to the Commission for approval and inclusion in the TDSIC Plan. Estimated costs of potential projects were included in the TDSIC Plan, not for approval, but for illustrative purposes regarding the expected economic development investment that will likely occur.

Mr. Bailey testified that Vectren proposed its facilities extension policies be amended to allow for extensions to residential and commercial customers located in rural areas, without a facilities extension deposit or other assurance payment, so long as the estimated non-gas cost revenue associated with the extension over a 20-year period is equal to or greater than the estimated cost of the extension. "Rural Areas" was defined as areas within Vectren's service territories that are unincorporated, as well as areas within incorporated towns that can only be reached by installed extensions through unincorporated areas. He proposed a budget for Vectren North of approximately $20 million (over seven years) for extensions to Rural Areas, including approximately $14 million for identified communities and the remaining $6 million for future residential and commercial projects yet to be identified. For Vectren South, he proposed a budget of $1 million. He explained the policy would be administered on a non-discriminatory basis until the dollars are fully utilized. Any budget amounts not fully utilized in one year would be carried forward to the next year's budget. In addition, although the rural extension policy would be administered based on estimated costs, the TDSIC recovery mechanism would reflect the actual capital costs incurred to install the facility extensions.

Mr. Bailey also introduced a study regarding the economic benefits associated with the infrastructure projects in the TDSIC Plan. Specifically, the study indicates that the capital expenditures associated with the modernization and expansion of natural gas service infrastructure will have a visible economic impact in Indiana. For Vectren South, the projects would generate an estimated total of $56.3 million in economic activity, 480 full time jobs, and $1.2 million in increased state and local government revenue based on modernization and construction projects through 2020. For Vectren North, the projects would generate an estimated total of $186.3 million in economic activity and support 1,310 full time jobs in the state, with state and local revenue increasing by approximately $4.4 million through 2020.

M. Susan Hardwick, Vectren Corporation's Senior Vice President, Finance and Assistant Treasurer testified regarding the accounting and finance issues related to the proposed 7-Year Plans.

Ms. Hardwick described the authority that allows Vectren to seek approval of timely recovery mechanisms and associated accounting deferrals for federally mandated projects. Ms. Hardwick explained the Compliance Projects are federally mandated pursuant to transmission and distribution integrity management statutes and Department of Transportation ("DOT") regulations, and thus qualify for timely cost recovery and deferred accounting treatment under the Compliance Statute. Upon receiving the CPCN, Vectren will be allowed to timely recover 80% of the revenue requirement through a periodic retail rate adjustment mechanism, and the remaining 20% will be deferred and recovered by Vectren as part of its next base rate case.

Ms. Hardwick testified that Vectren is requesting approval and subsequent timely recovery and deferred accounting treatment of the costs of the TDSIC Plan under the TDSIC Statute. Consistent with that statute, Vectren proposes to recover 80% of the revenue requirement capturing the approved expenditures and TDSIC costs, and to defer and recover the remaining 20% of the revenue requirement as part of the next base rate case filed with the Commission.

With regard to Vectren South, Ms. Hardwick testified regarding the fixed 7.2% proposed weighted average cost of capital ("WACC") to be utilized for the Compliance Projects, which was the same rate approved in Vectren's last base rate case in Cause No. 43112. With regard to Vectren North, she stated the proposed WACC to be utilized for the Compliance Projects would be fixed at 7.80%, as approved in Vectren North's last base rate case in Cause No. 43298. Ms. Hardwick also explained the proposed WACC to be utilized by Vectren South and Vectren North in their respective TDSIC Plans.

Ms. Hardwick explained that the level of expenses proposed in the 7-Year Plans would likely require Vectren to externally finance the investment, but that the overall WACC could increase slightly over the life of the projects. She testified that the applicable law supported Vectren's ability to attract cost competitive financing.

Ms. Hardwick testified about Vectren's approach for accumulating the eligible costs for recovery under the Compliance and TDSIC Statutes. She explained that Vectren proposes to include the gross plant specific to the new capital investments under the 7-Year Plans.

J. Cas Swiz, VUHI's Director of Regulatory Implementation and Analysis, testified regarding the calculation of the revenue requirement related to the 7-Year Plans. Mr. Swiz also discussed the proposed adjustment to the authorized return amount utilized in the Gas Cost Adjustment ("GCA") net operating income ("NOI") earnings test as a result of the proposed Compliance and System Improvement Adjustment ("CSIA" or "rate adjustment mechanism").

Scott E. Albertson, VUHI's Vice President, Regulatory Affairs and Gas Supply, sponsored the proposed rate adjustment mechanism for recovery of costs incurred by the 7-Year Plans. He explained that Vectren proposes to implement a single regulatory mechanism, the CSIA, for recovery of costs under both the TDSIC Statute and the Compliance Statute. Mr. Albertson testified that the CSIA will allow the Commission to perform a comprehensive review of Vectren's activities with the TDSIC Plans and the Compliance Projects in a single, periodic proceeding.

Mr. Albertson described the CSIA's allocation of costs, rate design, and tariff sheet as well as other proposed changes to Vectren's Tariff for Gas Service. He also explained Vectren's proposal to merge its existing Pipeline Safety Adjustment ("PSA") mechanism with the CSIA.

B. OUCC's Case-in-Chief. Barbara A. Smith, Director of the Resource Planning and Communications Division of the OUCC, explained the OUCC's position regarding Vectren's requested relief. Ms. Smith stated the OUCC recommends that the Commission approve, with conditions, both the TDSIC and Compliance components of the 7-Year Plan. First, she stated the Commission should base its approval upon: (1) the reasonableness of the process and criteria used to evaluate asset replacement priority, (2) the reasonableness of the project cost estimates, and (3) the demonstration of incremental benefits to Vectren's customers. Second, the Commission should adopt the OUCC's recommended on-going reporting requirements, which should include Vectren meeting with the OUCC and other interested stakeholders at least eight weeks prior to each fall tracker filing.

Ms. Smith testified that appropriate project prioritization is important because it facilitates the identification of critical assets and helps ensure ratepayers are receiving the most benefit for the dollars spent. She stated that the OUCC considers Vectren's transmission and distribution prioritization methodology to be acceptable. Ms. Smith also identified the support information that the OUCC considers critical to conduct its due diligence analysis of the TDSIC Plans and Compliance Projects.

Ms. Smith testified that the OUCC does not object to Vectren shifting projects between years or adding new projects to their respective TDSIC Plans or Compliance Projects that had not previously been included as long as Vectren is transparent with the Commission, the OUCC, and other stakeholders regarding the reasons for the shift. She recommended that Vectren's annual report detail each project's progress, including original and revised risk scores. Ms. Smith also expressed general support of Vectren's economic development plans, but disagreed with the proposed definition of "Rural Areas" due to lack of detail.

Regarding the incremental benefits associated with the TDSIC Plans, Ms. Smith testified the OUCC concluded that the projects provide incremental benefits to Vectren's customers by maintaining an adequate level of safety and reliability. She also stated that although it is difficult to quantify the economic value of the incremental benefits, the OUCC has concluded that the project cost estimates are reasonable and the projects are expected to result in some incremental benefits.

Anthony F. Swinger, Director of External Affairs for the OUCC, provided testimony summarizing issues raised by Vectren's customers. Although the majority of consumers expressed opposition to any increase in rates, a few expressed support for the proposed projects as improving safety and reliability.

Edward T. Rutter, Utility Analyst in the Resource Planning and Communications Division of the OUCC, testified that Vectren's project cost estimates within their TDSIC Plans and for the Compliance Projects were reasonable, but stopped short of calling them "best" estimates. Mr. Rutter stated Vectren did not provide either a sufficient level of cost estimate detail or an explanation of the estimating process. He testified the estimates must have been created from basic components such as labor, materials, and overhead, but understanding how the utility derived these basic components is essential to any "best estimate" determination. Mr. Rutter said this information also provides a reference baseline, allowing all parties to easily identify changes when future estimates are refined. He also explained that the optimal time to assess whether estimates are the "best" is during the initial review period for adoption of the TDSIC Plan.

Mark H. Grosskopf, Senior Utility Analyst in the Natural Gas Division of the OUCC, discussed Vectren's rate adjustment mechanism for recovery of costs and evaluated the proposed CSIA, including the proposal to merge Vectren's existing PSA with the CSIA. Additionally, he evaluated the proposed CSIA allocation of costs, rate design, customer rate impact, tariff sheet, and proposed changes to Vectren's Tariff for Gas Service.

Mr. Grosskopf recommended approval of Petitioners' proposed CSIA mechanism, including separate TDSIC Plan and Compliance Project components. He recommended approval of the merger of the current PSA mechanism into the Compliance Projects' component of the CSIA, as a separate calculation within the Compliance Projects, with continued reporting of the cost detail and support as currently provided in the PSA tracker filings. Finally, he proposed that all approved CSIA costs be recovered through a volumetric rate design for all customer classes.

Heather R. Poole, Senior Utility Analyst in the Natural Gas Division of the OUCC, testified regarding new capital investments, ratemaking and accounting treatment, accounting for project costs, and the revenue requirement and schedules for the requested relief. She recommended Vectren reduce the new capital investments for all replaced assets by the net book value of the replaced asset included in the last base rate case. Ms. Poole stated Vectren's existing rates and charges, set forth in Cause Nos. 43298 and 43112, include a return on rate base that includes the original cost of assets being replaced. Ms. Poole testified allowing Vectren to include the new investment, without any reduction for the old asset being replaced, allows Vectren to double recover a return on investments in the CSIA mechanism. She also recommended that because the deferral of 20% of eligible revenue requirement amounts for subsequent recovery in base rates are already grossed up for income taxes, the return on these amounts should not be grossed up again when they are included in Vectren's next base rate proceeding with the Commission.

Ms. Poole recommended the Commission require all work papers related to the revenue requirement schedules be filed at the same time as the CSIA filing due to the limited amount of time the OUCC has to review the CSIA filings. Regarding the GCA earnings test, she recommended Vectren also include the expenses associated with the TDSIC and Compliance Projects in the calculation of the earnings test. Finally, she stated the OUCC reserved the right to continually review and address all items included in the CSIA tracker filings with each future tracker filing.

Bradley E. Lorton, Utility Analyst in the Natural Gas Division of the OUCC, testified regarding Vectren's planned cost of common equity for use in the calculation of the WACC. He recommended that the Commission require Vectren to update its capital structure with each six month CSIA filing. He also recommended that updates to the capital structure for the TDSIC Plan be as of the date of valuation of Vectren's expenditures for which it is seeking ratemaking treatment. Finally, he indicated the Commission should recognize the CSIA tracker as a reduction in risk to be taken into account when determining Vectren's cost of common equity in future rate cases.

C. <u>Industrial Group's Case-in-Chief</u>. Nicholas Phillips, Jr., Managing Principal with Brubaker & Associates, Inc., explained that Vectren proposes to allocate TDSIC Plan and Compliance Project costs based on the margin revenue for rate classes as approved in the last base rate case order, and also proposes to allocate Compliance Project costs in the same manner. He testified that Vectren's approach was applied consistently except for Vectren North's Rate 270, Long-Term Contract Service, which does not use the margin for Rate 270, because it apparently was not subject to change in Cause No. 43298. Mr. Phillips stated that the best approach, and the one he recommended, is to include Rate 270 margin revenue to develop the appropriate factor for that class. Mr. Phillips presented revenue allocators for Rate 270 based on margin revenue, which he stated provides an accurate and consistent approach for the allocation of TDSIC Plan and Compliance Project costs in Vectren North and South.

D. <u>SDI's and Nucor's Cross-Answering Testimony</u>. Kevin C. Higgins, Principal with Energy Strategies, LLC, recommended the adoption of Mr. Phillips' proposal regarding allocation of TDSIC Plan and Compliance Project costs to customer classes. He stated that Mr. Phillips' recommendation to allocate these costs to Vectren North's Rate 270, Long-Term Contract Service, on the basis of margin revenue is consistent with the allocation method utilized by Vectren for other customer classes and is an equitable approach to cost allocation.

E. <u>Vectren's Rebuttal</u>. Mr. Francis responded to recommendations made by OUCC witnesses Edward Rutter and Barbara Smith regarding aspects of the implementation of the TDSIC Plans and Compliance Projects and specifically recommendations regarding cost estimating, risk modeling, and the amount and types of information requested as part of the annual updating process.

Mr. Francis testified that the OUCC and Vectren agree on many aspects of Petitioners' proposal and the OUCC's recommendations, and he noted the OUCC acknowledges the proposal's benefits and the quality of the risk modeling and project prioritization that has been done. He stated that Vectren agrees to meet with the OUCC and other Vectren stakeholders to discuss the TDSIC Plan and Compliance Project changes and identify variances from the proposals at least eight weeks prior to the fall CSIA filing. He also testified that Vectren would agree to the same reporting requirements for the TDSIC Plan and Compliance Project cost components and would identify substantive, unresolved stakeholder issues in its CSIA case-in-chief.

Mr. Francis also testified that Vectren is open to evaluating the content of its reporting if additional detail would aid the OUCC and stakeholder review. He indicated that Vectren would explain and vet whether projects were part of the original plan, cost estimates have been updated, and modifications to the plan are necessary in the fall CSIA meeting.

Mr. Francis noted that Vectren had some concerns with the OUCC's recommendations regarding: (1) the timing and level of detail requested to be provided with respect to the cost estimates for each project, particularly those in the later years of the 7-Year Plans; (2) creation of a single, searchable, sortable, electronic list of each asset evaluated, including the installation year; and (3) the amount of information that the OUCC has requested to engage in an ongoing assessment of the TDSIC and Compliance Projects.

In supplemental testimony, Mr. Francis proposed clarifications to address the reports that Vectren will provide to stakeholders in the annual stakeholder meeting preceding the fall CSIA filing. Mr. Francis testified that these clarifications addressed the OUCC's concerns and that the OUCC has agreed these reports will provide the information Ms. Smith testified was necessary in her direct testimony.

Mr. Swiz responded to various revenue requirement issues raised by Ms. Poole. He stated that the OUCC's proposed netting of rate base outside a general rate proceeding is inappropriate because the proposal conflicts with the statutes establishing the mechanisms Vectren seeks to implement in this proceeding, it selectively updates rate base outside a general rate case, and violates sound utility accounting principles related to retirements of group assets.

Mr. Swiz agreed with the OUCC's recommendation regarding the subsequent recovery of the deferred balance related to the 20% of eligible revenue requirements not recovered in the CSIA. He also agreed with the OUCC's recommendation to include the expenses associated with the TDSIC and Compliance Projects in the calculation of the earnings test.

Ms. Hardwick responded to certain issues raised by Mr. Lorton. She accepted the OUCC's recommendation to use an updated capital structure in the calculation of the TDSIC Plans' revenue requirement with each six-month CSIA filing. If adopted, within each semi-annual CSIA filing, Vectren will update the capital structure and the WACC to match the actual book balances as of the cut-off date of each filing. Ms. Hardwick disagreed with the OUCC recommendation of recognizing the impact of the CSIA recovery mechanism on Vectren's overall operating risk and return on equity in future rate cases since this issue has no bearing on the statutes supporting Vectren's request to use the cost of equity approved in Vectren's most recent base rate cases for purposes of the CSIA. She also noted that the OUCC agrees with the return on equity percentages proposed by Vectren in this proceeding.

Mr. Albertson responded to certain issues raised by Mr. Grosskopf and Mr. Phillips. He noted that Mr. Grosskopf recommends approval of the proposed CSIA and approval of a merger of the PSA mechanisms with the CSIA. Mr. Albertson also agreed that Mr. Phillips' proposed allocation for Vectren North's Rate 270 was reasonable. He testified that costs incurred pursuant to the TDSIC Statute and Compliance Statute and recoverable in the CSIA should be applicable to Rate 270 customers, unless a particular Rate 270 customer's special contract explicitly exempts the applicability of new rate adjustment mechanisms to that customer.

Regarding Mr. Grosskopf's proposal that Petitioners recover CSIA costs through a volumetric rate design, Mr. Albertson stated he did not agree with that proposal. Mr. Albertson testified that Vectren continues to support fixed CSIA charges for residential customers. He stated that the CSIA is a new rate adjustment mechanism and need not be limited by or restricted to rate designs implemented in base rates or for other adjustment mechanisms. He also indicated that the residential customer class is homogeneous and it is appropriate to recover the residential fixed costs through a uniform fixed charge and that a cost of service study is not required to reach this conclusion.

Mr. Bailey responded to certain issues raised by Ms. Smith. He testified that, consistent with the OUCC's recommendation, Vectren is agreeable to keeping the Commission and OUCC updated about the status of any TEDs through the CSIA filing process. Such updates would include updates about the IEDC approval process, any detailed construction plans for such projects, the estimated construction schedules for such projects, and any updated project cost estimates.

Regarding the OUCC's disagreement with Vectren's definition of "Rural Areas," Mr. Bailey explained why he believes Vectren's definition is reasonable and should be approved. He stated the purpose of the statutory provision relating to rural extensions is to facilitate the extension of natural gas distribution service to areas that are currently unserved and provide cost saving opportunities to customers by affording access to natural gas. Mr. Bailey testified the proposed definition effectuates the intent of the legislature.

5. **<u>Statutory Requirements</u>.** Petitioners have proposed relief in this proceeding pursuant to both the Compliance Statute and TDSIC Statute. The Compliance Statute requires an energy utility seeking to recover costs incurred to comply with federally mandated requirements to obtain a CPCN. Ind. Code § 8-1-8.4-6.

A CPCN may be issued only if the Commission: (1) finds that the public convenience and necessity will be served by the proposed compliance project, (2) approves the projected costs associated with the proposed compliance project, and (3) makes a finding on each of the factors set forth in Ind. Code § 8-1-8.4-6(b). Ind. Code § 8-1-8.4-7(b). A compliance project is defined as one undertaken by an energy utility related its compliance with federally mandated requirements. Ind. Code § 8-1-8.4-2. Federally mandated requirements include, "[s]tandards or regulations concerning the integrity, safety, or reliable operation of: (A) transmission; or (B) distribution; pipeline facilities." Ind. Code § 8-1-8.4-5(5).

If the Commission approves a proposed compliance project and projected federally mandated costs associated with the project and issues a CPCN, then:

> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

Ind. Code § 8-1-8.4-7(c).

The TDSIC Statute permits a public utility to petition the Commission for approval of the utility's seven-year plan for eligible transmission, distribution, and storage improvements. Such improvements include new or replacement gas transmission, distribution or storage projects that: (1) a utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas; (2) were not included in the utility's rate base in its most recent rate case; and (3) were either designated in the utility's seven-year plan and approved by the Commission under Ind. Code § 8-1-39-10 or approved as a TED under Ind. Code § 8-1-39-11. Ind. Code § 8-1-39-2.

Ind. Code § 8-1-39-10(b) requires, after notice and hearing, that the Commission issue an order that includes:

> (1) A finding of the best estimate of the cost of the eligible improvements included in the plan;
> (2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan; and
> (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.

Further, "[i]f the commission determines that the public utility's seven (7) year plan is reasonable, the commission shall approve the plan and designate the eligible transmission, distribution, and storage improvements included in the plan as eligible for TDSIC treatment." *Id.*

6. <u>Commission Discussion and Findings</u>. In this proceeding, Petitioners propose a comprehensive seven-year investment program that consists of two components: (1) projects to comply with federal pipeline safety mandates, and (2) transmission and distribution projects that facilitate the reliable and safe provision of gas service through system modernization, as well as service to rural areas. To provide such improvements in a systematic manner, Petitioners have reflected both components in one overall plan with a seven-year term, i.e., the 7-Year Plan. By the end of the term, rate cases will be filed to seek inclusion of the investments into new base rates.

The Commission has previously observed that:

> [t]he legislature has created multiple avenues for a utility to seek recovery of plant investments, some of which may overlap. However, the fact that a utility has several options for relief does not foreclose the opportunity for the utility to seek relief under multiple avenues.

Northern Indiana Public Service Co., Cause No. 44311, p. 16 (IURC 10/10/2013). Here, Petitioners have sought relief under both the Compliance Statute and the TDSIC Statute, apportioning some projects under the Compliance Statute and others under the TDSIC Statute. Accordingly, the Commission reviews the projects separately under the specific requirements of each statute.

A. <u>Petitioners' Federally Mandated Requirements</u>. The DOT has enacted a series of regulations designed to promote the safe delivery of natural gas to customers using transmission and distribution facilities operated by local distribution companies. In response to these regulations, Petitioners have engaged in a risk modeling and facility assessment process to determine the system projects necessary to comply with these safety regulations. Not surprisingly, the regulations and risk modeling have identified the need to replace the oldest remaining pipeline infrastructure as the highest priority projects to be undertaken. The regulations also drive data gathering and facility testing to increase Vectren's knowledge of the transmission and distribution facilities used to serve customers and, as a result of such ongoing evaluation of the integrity of the system, identify the projects needed to improve performance and ensure public safety, thereby mitigating risk.

Petitioners' witness Francis described the Compliance Project selection process used by Vectren to identify and design the transmission and distribution projects that will both ensure regulatory compliance and create a safer and more reliable system. Mr. Francis also described the technology used to evaluate facility data and support the process of identifying the necessary compliance projects. OUCC witnesses Smith and Rutter reviewed Petitioners' processes, modeling, and projects and agreed that the identified Compliance Projects were well designed to provide compliance and deliver the benefits of a safer and more reliable system. Petitioners and the OUCC also agreed that new data and ongoing risk modeling would lead to project refinements and re-prioritization over time; therefore, the 7-Year Plan would need to be updated over time.

1. Compliance Projects. As indicated above, the Compliance Statute defines a compliance project as:

> a project that is:
> (1) undertaken by an energy utility; and
> (2) related to the direct or indirect compliance by the energy utility with one (1) or more federally mandated requirements.
> (b) The term includes:
> (1) an addition; or
> (2) an integrity, enhancement, or a replacement project;
> undertaken by an energy utility to comply with a federally mandated requirement described in IC 8-1-8.4-5(5).

Ind. Code § 8-1-8.4-2. Petitioners are both energy utilities as that term is defined in Ind. Code § 8-1-2.5-2. Therefore, we must determine whether Petitioners' proposed Compliance Projects are necessary to directly or indirectly comply with a federally mandated requirement.

Petitioners' witness Francis testified that Vectren is subject to federal DOT regulations that establish pipeline safety requirements for pipeline operators that transport natural gas and other fuels. He explained that these regulations establish design, construction, testing, inspection, operation, and maintenance requirements that apply to the various pipeline system components. These regulations require Petitioners to establish a transmission improvement management plan, a distribution improvement management plan, identify high consequence areas along transmission pipeline routes, conduct a risk assessment to identify threats to the integrity of transmission pipeline systems, complete a baseline assessment and subsequent reassessments of its transmission pipeline, remediate conditions found during an assessment, and evaluate and implement preventative and mitigation measures to minimize future threats. Mr. Francis testified that Petitioners will be making a number of investments in Compliance Projects as presented in the 7-Year Plan.

The Compliance Statute specifically defines a federally mandated requirement as including projects required to comply with standards or regulations concerning the integrity, safety, or reliable operation of transmission or distribution pipeline facilities. Ind. Code § 8-1-8.4-5(5). The Compliance Projects are driven by the need to comply with regulations concerning the integrity, safety, and reliability of Petitioners' transmission and distribution pipeline facilities. Petitioners have provided a sufficient description of the federally mandated requirements. We therefore find that the Compliance Projects constitute "compliance projects" within the meaning of the Compliance Statute.

2. Public Convenience and Necessity. Petitioners' witness Francis explained the benefits to customers and the public in general from the Compliance Projects. The investments that Petitioners' propose to make promotes safety by constantly evaluating the gas transmission and distribution system, making repairs, and implementing other mitigation efforts to reduce the likelihood of damage or failure that could allow the release of natural gas and lead

to damage. Customers will further benefit from these investments from increased reliability. By minimizing facility failures or damage potential customers are less likely to be without gas service during repairs or service. Petitioners have also identified synergies that allow Petitioners to utilize their resources, both physical and capital, in a more efficient manner as a result of the investments in the Compliance Projects. Based on the evidence presented, we find that the Compliance Projects promote the public convenience and necessity.

3. Reasonableness of Compliance Project Costs. Petitioners presented cost estimates to support the projected costs of the Compliance Projects. Petitioners' witness Francis testified Petitioners utilized preliminary engineering and experience with similar work to create estimates within an industry accepted scoping range. He also described how over time projects would receive refined estimates based on more detailed design work, and that this process closely resembles the AACE International recommended practices for cost estimating.[1] Petitioners submitted their cost estimate for review by EN Engineering, a highly experienced pipeline engineering firm. EN Engineering provided a report finding Petitioners' estimating approach to be reasonable and consistent with industry practice. *See*, Pet. Ex. JMF-37S and JMF-37N.

The OUCC reviewed detailed project cost estimates and the cost inputs relied upon by Petitioners as well as a five year history of estimated project costs and found that Petitioners' estimates had historically been reasonably accurate and that the estimates for purposes of setting forth the Compliance Project costs are also reasonable. Based on the evidence presented, we find that the Petitioners have adequately described the Compliance Projects' costs and provided reasonable cost estimates.

4. Section 6(b) Factors. Ind. Code § 8-1-8.4-7(b)(3) requires the Commission to make findings on each of the factors set forth in Ind. Code § 8-1-8.4-6(b), which include: (1) a description of the federally mandated requirements, (2) a description of the projected federally mandated costs, (3) a description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements, (4) alternative plans that demonstrate the proposed project is reasonable and necessary, (5) information as to whether the proposed project will extend the utility's useful life and the value, and (6) any other factors the Commission considers relevant.

As more fully explained above, with respect to the first two factors, we find that Vectren has adequately described the federally mandated requirements and the projected costs. With respect to the third factor, no party disputed that the Compliance Projects are necessary to comply with federal mandates. Petitioners' witness Francis explained the Compliance Projects will involve taking remedial action to correct poor or damaged pipe coating, dents and gouges, puddle welds, corrosion, wall thinning, shallow or exposed pipe, obsolete equipment, miter or wrinkle bends, retired fittings, cracked pipe or appurtenances, poor welds, and fittings or weld material protruding into the pipeline. The DOT's regulations require Petitioners to take these remedial actions. Petitioners may also be required to invest in additional infrastructure to mitigate risks, such as installing automatic shut-off or remotely controlled valves. Petitioners

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[1] AACE (Association for the Advancement of Cost Engineering) International is a non-profit organization providing certification and resources in total cost management and cost engineering.

also explained the process by which they will update the list of Compliance Projects in the fall CSIA stakeholder meetings to ensure projects with the maximum impact on safety and reliability are addressed first. Thus, the Compliance Projects will enable Petitioners to comply with federal DOT requirements.

As to the fourth factor, Petitioners' witness Francis explained that many of the federal requirements are prescriptive in terms of how utilities must comply and establish minimum assessment, remediation and mitigation requirements. He also explained that Vectren used a risk modeling approach to compliance that examined whenever possible assessment alternatives and alternative preventive and mitigative measures. Thus, there are no feasible alternatives to the Compliance Projects because of the prescriptive nature of the federal requirements. Alternatives to risk-based requirements would be either outdated, higher risk, or would not achieve compliance.

Finally, because many of the proposed Compliance Projects consist of asset replacements and remediation of discovered conditions, it is clear that the useful lives of some of Petitioners' existing natural gas transmission and distribution pipeline systems will be extended. Such extension will further enhance Petitioners' ability to provide safe and reliable gas service in compliance with federal regulations.

5. Issuance of CPCN. Based on the foregoing findings, we grant Petitioners a CPCN for the Compliance Projects. The Compliance Projects will serve the public convenience and necessity of Petitioners' customers, as well as others located near Petitioners' infrastructure, and are necessary to comply with federal mandates. As a result, the Compliance Projects qualify for cost recovery under the Compliance Statute.

B. Petitioners' TDSIC Plans.

1. Petitioners' TDSIC Plans. Petitioners request approval of their individual TDSIC Plans pursuant to Ind. Code § 8-1-39-10. Vectren North's TDSIC Plan includes an estimated $230.7 million of capital improvement projects over calendar years 2014 through 2020. Vectren South's TDSIC Plan includes an estimated $41.1 million of capital improvement projects over calendar years 2014 through 2020. Each TDSIC Plan includes general categories of spending, separated primarily by function rather than specific projects in Years 2 through 7, with specific projects for Year 1 more defined. Each TDSIC Plan is comprised of the following categories of projects: (1) System and Pressure Improvements, (2) Storage Operations, (3) Instrumentation and Communications Equipment, (4) Public Improvement Projects, (5) Service Replacements, and (6) Economic Development Projects.

Petitioners' witness Francis testified that the TDSIC Plans involve projects that will provide beneficial improvements in terms of safety, reliability, or system modernization, and that the improvements are important to provide reliable service to Petitioners' customers. Petitioners also indicated that they would need flexibility to move investment amounts between categories of work to reflect findings during detailed designs, for emerging issues identified during normal operations and assessments, and to otherwise respond to changes identified through risk modeling and the capture of new data.

Petitioners and the OUCC agreed that the TDSIC Plans need to be flexible. The evidence demonstrates that Vectren engaged in considerable analysis and thought in developing the TDSIC Plans. However, the TDSIC Plans are reflective of the characteristics of the gas system and Petitioners' customer needs at the time the TDSIC Plans were prepared. OUCC witness Smith testified that forcing a static seven-year plan when it is likely individual asset characteristics will change could cause ratepayers to pay for projects with a revised, lower risk scoring. She stated that the OUCC does not object to shifting a project between years or adding a new project to the TDSIC Plans that was not previously included as long as Petitioners are transparent with the Commission and the OUCC regarding the reasons for the change.

As we have previously found, the development and subsequent regulation of a multi-year plan that is sufficiently detailed while affording reasonable flexibility to adapt to changes in need and priority over time is a balancing act that requires a utility sponsored and supported process and the application of the regulating agency's expertise in applying the underlying statutory framework. *Northern Indiana Public Service Co.*, Cause No. 44403, p. 18 (IURC 4/30/2014); *Northern Indiana Public Service Co.*, Cause No. 44370, p. 11 (IURC 2/17/2014). The evidence of record demonstrates Petitioners reviewed all of their transmission and distribution assets to create their TDSIC Plans. Petitioners' TDSIC Plans provide a reasonably detailed overview of what types of projects need to be undertaken, and why these types of projects are necessary. Furthermore, a primary feature of the TDSIC Plans is the inclusion of a defined roadmap for how Petitioners intend to achieve their objectives of maintaining safe, reliable service for their customers.

Although we understand the need for flexibility to adapt to changing circumstances, Vectren has included both Compliance and TDSIC Projects in a comprehensive 7-Year Plan. Because we have specifically found that the Compliance Projects are accurately categorized as necessary to comply with federal requirements, we fully expect those projects to remain Compliance Projects and absent a change in federal requirements, not shifted to the TDSIC Plan. Similarly, we expect TDSIC Projects to remain in the TDSIC Plan and not shifted to the list of Compliance Projects.

Based on the evidence presented in this proceeding, and as discussed further below, we find that Petitioners have presented a plan that, when regulated as outlined in this Order, meets the requirements of Ind. Code § 8-1-39-10.

2. <u>Best Estimate of the Cost of Eligible Improvements</u>. Ind. Code § 8-1-39-10(b)(1) requires that an order approving a TDSIC plan must include a finding that the cost of the TDSIC plan represents "the best estimate of the cost" of the proposed eligible improvements contained therein.

Like the cost estimates for the proposed Compliance Projects, Petitioners' Director of Engineering described Vectren's use of preliminary engineering and experience with similar work to create estimates within an industry accepted scoping range for the TDSIC Projects. He explained that over time projects would receive refined estimates based on more detailed design work. Petitioners also submitted their cost estimates for review by EN Engineering, which provided a report finding Petitioners' estimating approach to be reasonable and consistent with industry practice.

The OUCC reviewed detailed project cost estimates and the cost inputs relied upon by Petitioners as well as a five year history of estimated project costs. The OUCC determined Petitioners' estimates had historically been reasonably accurate and that the estimates for purposes of setting forth the costs of the TDSIC Plan are also reasonable.

Petitioners and the OUCC both provided testimony supporting the need for a flexible TDSIC plan that could be updated over time to reflect changes in project priority, cost estimates, and other changes in system conditions. Ultimately, after further discussion between the parties related to the execution of such updates, Petitioners' witness Mr. Francis provided supplemental testimony outlining the parties' agreement on the information, including project details and costs, to be provided as part of such TDSIC Plan update.

Based on the evidence presented, we find that the TDSIC Plans are consistent with the best cost estimate requirements. In addition, we find that the update process agreed to by Petitioners and the OUCC, with the additional requirement that projects not be shifted between the Compliance and TDSIC components unless there is a change in federal requirements, represents a reasonable approach to providing for the necessary updating of the TDSIC Plans over the seven-year period.

3. Public Convenience and Necessity. Ind. Code § 8-1-39-2 defines eligible transmission, distribution, and storage system improvements as projects undertaken for purposes of safety, reliability, system modernization, or economic development.

Petitioners' witness Francis identified several results of the TDSIC Plans that would benefit the public. First, the projects will improve the integrity of the pipeline system, impacting safety and reliability. They will introduce modern materials and equipment that eliminate certain threats that may exist with older infrastructure. Second, customers will benefit through investments that will minimize the likelihood of a failure and reduce excavation damages caused by customers through improved processes in record keeping and locating. In addition, executing a long-term project will result in better utilization of capital dollars than if executed in an independent and unplanned manner, offering opportunities for economies of scale that should help derive a lower overall cost by minimizing costs related to mobilization, materials management, and design. Implementing in a long-term approach will also facilitate coordination with other stakeholders, particularly the various communities that Petitioners serve, and aid in their own planning efforts.

No party offered evidence demonstrating that the TDSIC improvements included in the TDSIC Plan were unnecessary for the continued safe and reliable service to customers or that the public convenience and necessity did not, or would not, require the TDSIC investments to be made.

Ind. Code § 8-1-2-4 requires Petitioners provide reasonable and adequate service to their customers. In addition, Ind. Code § 8-1-2-87(d) requires that the public interest be served and that the public convenience and necessity require the provision of gas distribution service by Petitioners within their authorized service territory. Based on the evidence presented, we find that Petitioners have sufficiently supported that the investments described in their TDSIC Plans are reasonably necessary for them to continue to provide reasonable and adequate retail service to the customers in their assigned service territories. Therefore, we find that the public convenience and necessity requires or will require the eligible improvements included in the TDSIC Plans.

With regard to Petitioners' proposed rural extension projects, Ind. Code § 8-1-39-2 provides that eligible improvements include, among other things, projects that a public utility undertakes for purposes of economic development, including the extension of gas service to rural areas, and that are either: (1) designated in the public utility's seven-year plan, or (2) approved as a TED under Ind. Code § 8-1-39-11. Vectren South did not request approval of any specific TEDs, but instead proposed to include in its TDSIC Plan approximately $1.0 million for extension of natural gas lines into currently unserved rural areas and $1.0 million for project work for the I-69 corridor. Vectren North, however, identified specific communities for which extensions had been evaluated. The approximate cost of such extensions would be approximately $13.2 million.

Petitioners' witness Bailey testified that Vectren evaluated the Legislative directive to consider policies to extend into rural areas and developed a detailed action plan. This plan derived from an evaluation of Petitioners' service territories and identification of those communities within rural areas that would meet a 20-year payback test. Petitioners have identified those communities, presented the economic analysis to serve those communities, and presented a plan to provide extensions at a cost of approximately $14.2 million over the life of the TDSIC Plan.

Petitioners proposed to define "rural areas" as those areas within Vectren's service territories that are unincorporated as well as areas within incorporated towns that can only be reached by installing extensions through unincorporated areas. Although the OUCC generally supported Petitioners' plans to serve customers in rural areas, they opposed Petitioners' proposed definition based on the lack of detail in the TDSIC Plans. We agree with the OUCC that Vectren's proposed definition is unduly expansive in its seemingly unlimited inclusion of incorporated towns, particularly given the lack of defined projects. Accordingly, we find that rural extensions shall be limited those areas within Vectren's service territories that are unincorporated. To the extent that Vectren believes a particular extension project to an area that includes an incorporated town should be considered a rural extension project because it could not otherwise receive natural gas service, then Vectren may propose such project for consideration in its annual update to its TDSIC Plans. In addition, consistent with prior decisions, we further find that the approximate $14.2 million allocated for rural extensions is limited to the use of rural extensions identified in the TDSIC Plans and shall not be used to fund project cost increases or other improvement projects.

Based on the evidence presented, we find that Petitioners' approach to extending their gas system to rural areas as discussed and modified herein is consistent with Ind. Code ch. 8-1-39 and should be approved. Petitioners' proposal is intended to bring natural gas service to currently unserved customers who may be able to realize a savings from the lower cost of natural gas as compared to the cost of propane. We also authorize Petitioners to modify their tariffs to permit a longer pay-back period for extensions to rural areas. This revision will help bring the benefits of lower-cost natural gas service to areas that would otherwise remain unserved.

4. Incremental Benefits Attributable to the TDSIC Plans. Ind. Code § 8-1-39-10(b)(3) requires the Commission to determine that the estimated cost of the eligible improvements included in the TDSIC Plans are justified by the incremental benefits attributable to the TDSIC Plans. Mr. Francis testified that the TDSIC Plans will provide operational, customer and cost benefits. Operational benefits include improved safety and reliability, decreased system risk through replacement of older and obsolete equipment, and introduction of modern materials. He stated customers will benefit through improved system integrity, reduced threats of failure, improved emergency response and customer education, and reduced excavation damages. The long-term nature of the TDSIC Plans is also expected to result in better utilization of capital dollars. Mr. Bailey also explained benefits from extending natural gas service to rural areas.

The OUCC agreed that the proposed projects included in the TDSIC Plans provide incremental benefits to Petitioners' customers through enhanced safety and reliability. OUCC witness Smith testified that although the OUCC was able to review the project cost estimates and discern if a given project provides incremental benefits, it is difficult to quantify the economic value of the incremental benefits and undertake a meaningful cost/benefit analysis. Noting that a simple formula cannot satisfy whether or not the incremental benefits justify the estimated costs, Ms. Smith testified that the OUCC concluded the project cost estimates were reasonable and that the projects will result in incremental benefits to Petitioners' system.

Based on the evidence presented, we find that Petitioners have sufficiently demonstrated that the estimated costs of the TDSIC Plans' improvements are justified by the reasonably expected incremental benefits attributable to them. As noted earlier, Petitioners' TDSIC Plans consist largely of replacement projects based upon the age and current condition of Petitioners' facilities. In determining the eligible improvements to be included in the TDSIC Plans, Petitioners completed a comprehensive risk analysis that took into account both the probability and the consequences of failure. Petitioners' TDSIC Plans contain solutions that will enhance customer and employee safety, avoid outages, preserve and improve operational integrity, provide equipment protection, and meet evolving customer demands through a long-term planning process that provides opportunities to gain economies of scale.

5. Reasonableness of TDSIC Plans. Based upon our review of the evidence, the Commission finds Petitioners' TDSIC Plans to be reasonable and should be approved as set forth herein. The OUCC supports approval of the Plans, subject to the imposition of ongoing reporting requirements as well as updated or new work order level estimates in Petitioners' CSIA filings prior to a project's commencement. Petitioners and the OUCC have reached a consensus on these ongoing reporting and update requirements as represented in Petitioners' Exhibit JMF-Supp1. Petitioners' TDSIC Plans appropriately and reasonably address Petitioners' 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 to rural areas. These are activities from which customers are reasonably expected to benefit.

C. Updates to the 7-Year Plans. Ind. Code § 8-1-39-9(a) requires that a public utility update its seven-year TDSIC plan as a component of the TDSIC periodic automatic adjustment filings. Aside from inclusion for approval of any TEDs, the TDSIC Statute is silent as to what should be included in the update. The same is true with regard to the adjustment mechanism under the Compliance Statute.

In accordance with Mr. Albertson's testimony, the Commission finds it reasonable that Petitioners make their CSIA filings every six months beginning September 1, 2014.[2] The September filing shall provide project detail similar to Year 1 of the original TDSIC Plans for the next upcoming year of the 7-Year Plans. Petitioners shall also update the estimated required annual expenses for the remaining years of the 7-Year Plans, including the amount for the rural gas extensions segment. In Petitioners' other semi-annual adjustment filings (to occur in March), Petitioners shall provide updates that include intra-year changes and long-term changes as appropriate. We also find it reasonable that in updating the 7-Year Plans, Petitioners shall continue to refresh their prioritization analyses as new information about the system becomes available. As the factors driving the analyses change, the risk profile of Petitioners' system will also change which will require adjustments to equipment and project ranking.

We recognize that the statute requires the Commission issue an order in the tracker proceeding within 90 days, which is a shorter time frame than the 210 days afforded the initial plan filing and its approval. Consequently, we find that an informal process is needed, in addition to the 90-day formal tracker process, to ensure stakeholders and the Commission are afforded a sufficient opportunity to evaluate updates and revisions to the Petitioners' 7-Year Plans.

Because the Petitioners have provided a satisfactory roadmap for reaching their objectives with their 7-Year Plans, we believe an informal process that allows stakeholders to address their issues prior to Petitioners' filing the tracker is appropriate in this proceeding. It is our expectation that Petitioners' will move their upcoming year-specific projects into a work order level of detail, similar to that which it has provided and we have approved for Year 1. Thus, at least eight weeks before each fall tracker filing, Petitioners shall meet with the OUCC and other interested stakeholders to discuss the upcoming tracker filing and identify all variances from the approved 7-Year Plans. Vectren shall also provide a report identifying future projects for each year of the 7-Year Plans that includes a column identifying a preliminary cost estimate and, to the extent projects are moved, modified or eliminated, identifying and explaining such changes. Vectren shall provide additional detailed engineering and completed third party reviews as the reviews are completed for projects to be implemented in the next calendar year. Vectren shall further identify and explain significant variances between the proposed budgets and the actual expenses for projects completed during the prior and upcoming calendar year. Petitioners must also identify any TEDs for which they will be seeking recovery under Ind. Code ch. 8-1-39. We are approving this process so that the issues between the parties are identified in advance of the September CSIA to afford the highest potential that any issues can be vetted in the proceeding within the statutory timing constraint. We also direct Petitioners to identify any issues not resolved among the stakeholders in their direct testimony.

We find that these processes will reasonably balance the needs of Petitioners for investment recovery confidence and customers for prudent investment assurance. In the event

[2] Based on the date of issuance of this Order, we recognize that the initial proposed filing date of September 1, 2014 may no longer be practicable. In such event, Vectren shall consult with the parties concerning a revised filing date and so notify the Commission under this Cause of the agreed upon date.

that these processes break down, we reserve the ability to modify them when considering updates to the 7-Year Plans.

D. **CSIA Mechanism.** Petitioners' propose adoption of a CSIA Mechanism to recover 80% of the costs associated with the Compliance Projects and TDSIC Plans. Petitioners also propose merging their approved PSA with the CSIA to promote efficiency. Consistent with our findings below, we authorize Petitioners to implement CSIA mechanisms for recovery of the 80% of the Compliance and TDSIC Project costs and merger of the PSA into the CSIA. Petitioners' shall file with the Commission's Natural Gas Division revised tariff sheets consistent with the formats set forth in Petitioners' Exhibits SEA-4N-6N and 4S-6S as well as with our findings below.

1. Customer Class Revenue Allocation. Pursuant to the TDSIC Statute, Petitioners propose to use the revenue allocation percentages approved by the Commission in their most recent base rate cases. The Compliance Statute does not address cost allocation methodology, so for purposes of the comprehensive 7-Year Plans, Vectren proposes to use this allocation methodology for all investment and costs recovered through the CSIA. The allocation method used in the rate cases was based upon customer class margins. However, in the approved settlement of Vectren North's rate case, Rate 270 special contract customers received no direct cost allocation, and therefore, in its case-in-chief, Vectren North proposed that those contract customers would pay the same unit charge to be billed to its Rate 260 customer class.

Industrial Group witness Phillips proposed a modification to this allocation approach for Vectren North. Mr. Phillips testified that the Rate 270 customer class should be based on the class' rate case margin, and a resulting independent allocation percentage should be applied to this Rate 270 class. He showed that the applicable cost allocation percentages for all other classes were reduced as a result of the creation of this additional margin based rate class. Mr. Phillips also pointed out that Vectren South's allocation methodology already reflects a separate rate class.

On rebuttal, Petitioners' witness Albertson agreed with Mr. Phillips that, for purposes of the CSIA, it is reasonable to create a Rate 270 customer class to which CSIA costs are directly allocated while retaining the relative basis of the rate case margin allocation. No parties opposed this proposed allocation methodology.

Based upon our review of the evidence, we find that the allocation methodology proposed by the Petitioners, as modified for Vectren North by agreement of the parties, is a reasonable approach consistent with the TDSIC statute and should be approved for the CSIA.

2. Rate Design. Petitioners propose that the revenue requirement for the 7-Year Plan to be recovered via the CSIA mechanism to be filed twice each year. Petitioners also propose that the CSIA costs be recovered from residential customers via a fixed monthly charge and from all other customers using a volumetric charge. Petitioners proposed this design for a number of reasons, including: (1) the infrastructure costs being recovered are fixed in nature and do not vary with customer use; (2) residential customers are a homogenous group with similar service needs requiring similar facilities—residential customers benefit equally from new pipes, valves and service lines; and (3) from a policy standpoint, placing these gradually

increasing fixed costs in a fixed charge is consistent with the spirit and intent of a straight fixed-variable rate design and the Commission's Order in Cause No. 43180.

The OUCC opposed the use of a fixed charge for several reasons, including: (1) altering Petitioners' fixed charges is inconsistent with the settlement agreements governing Petitioners' last rate cases; (2) changes to cost of service study elements, particularly those singling out a particular rate class, are more properly addressed in a rate case; and (3) the PSA mechanism being merged into the CSIA has historically been recovered volumetrically.

Contrary to the OUCC's arguments, we do not find that Vectren's proposal violates or is inconsistent with the settlement agreements approved in their last rate case, which provided for recovery of the allocated rate base revenue requirement from residential customers through a combination of a monthly customer facilities charge and a volumetric charge. Petitioners have not proposed a modification to the design of their base rates and the customer facilities charge is not being adjusted. Rather, Petitioners' proposal simply addresses the rate design for cost recovery of the Compliance and TDSIC Projects. Furthermore, consistent with the Commission's Order in *Richmond Power & Light*, Cause No. 40434 (IURC March 19, 1997), settlement agreements are of limited value in subsequent proceedings. Nor does the fact that the PSA mechanism historically recovered costs on a volumetric basis necessitate a finding that the rate design for the CSIA should be the same.

With regard to the OUCC's arguments concerning changes to cost of service study elements, Petitioners explained that residential customers are a homogenous group with similar service requirements and for which the fixed costs associated with receipt of gas service do not vary with the level of use. Thus, even without a cost of service study, we find that a fixed charge rate design for this type of infrastructure investment program adheres to accepted cost causation principles.

Based on the evidence presented, we approve Petitioners' proposal to recover the CSIA costs from residential customers via a fixed monthly charge. As noted by Petitioners, in a recent investigation into rate design alternatives for natural gas utilities, the Commission found that, "straight fixed variable rate designs are attractive because they align basic cost causation principals of ratemaking." *Commission Investigation*, Cause No. 43180 at 10 (IURC October 21, 2009). The nature of these infrastructure replacement and improvement costs, which are fixed costs that equally benefit customers by improving system reliability and safety and increase gradually over time, make the CSIA well-situated to use a fixed charge. Consequently, Petitioners' proposed CSIA rate design is consistent with the objective of gradually moving fixed costs to serve residential customers into a fixed charge.

3. Petitioners' TDSIC Plans. Ind. Code § 8-1-39-9(a)(2) requires a petition seeking recovery of TDSIC costs to include a utility's seven-year plan. As part of their case-in-chief, Petitioners set forth their proposed TDSIC Plans in Petitioners' Exhibit Nos. JMF-1N, -1S, -46N and -46S and therefore satisfied the requirement set forth in Ind. Code § 8-1-39-9(a)(2). We note that in each semi-annual CSIA filing, Petitioners will update their TDSIC Plans pursuant to Ind. Code § 8-1-39-9(a) and in accordance with the specific parameters set forth herein.

4. Projected Customer Impacts. Petitioners' witness Albertson provided the total yearly revenue percentage change for the TDSIC and Compliance components of Petitioners' respective 7-Year Plans. Based on our review of the evidence, and given that no specific factors are proposed in this proceeding, we find that Petitioners provided sufficient information regarding the projected effects of the TDSIC Plans on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).

5. Adjustment to Net Operating Income. Petitioners request authority to increase the net operating income approved in Petitioners' last base rate cases to include the earnings associated with the CSIA filings for purposes of the Ind. Code § 8-1-2-42(g)(3) earnings test.

Petitioners' witness Swiz testified that Petitioners will adjust their statutory NOI earnings test by increasing their authorized NOI by the incremental earnings from approved CSIA filings. This calculates the after-tax return on investment that will be added to the authorized NOI.

Ind. Code §§ 8-1-39-13(b) and 8-1-8.4-7(c)(1) require an adjustment to a public utility's authorized return for purposes of Ind. Code § 8-1-2-42(g)(3) to reflect incremental earnings from the TDSIC Plans and Compliance Projects. Based on our review of these statutes and the evidence in this Cause, we find that Petitioners' request to increase the authorized net operating income approved in Petitioners' last base rate cases to include earnings associated with the CSIA filings for purposes of Ind. Code § 8-1-2-42(g)(3) earnings test is reasonable, consistent with the TDSIC and Compliance Statutes, and should be approved.

6. Determination of Pretax Return. For the Compliance Projects' revenue requirement component of the CSIA, Petitioner proposed to use the WACC "most recently approved by the commission" in each of the Petitioners most recent base rate cases. No party opposed this relief. We find this methodology is consistent with Ind. Code § 8-1-8.4-7(c) and shall be approved.

For the TDSIC Projects' revenue requirement component, Petitioners proposed to use a WACC based upon their actual December 31, 2013 capital structure, inclusive of the typical items included in base rate case capital structure. The OUCC recommended Petitioners use an updated capital structure in the calculation of its TDSIC Plan revenue requirement with each six month CSIA filing. Petitioners' accepted the OUCC's recommendation. Agreeing that the OUCC's recommendation is reasonable, we find Petitioners shall use an updated capital structure in the calculation of the TDSIC Plan revenue requirement with each six-month CSIA filing.

Apart from Petitioners' agreement with the OUCC's position that the cost of capital applicable to the TDSIC Plans shall be updated in each CSIA filing, the parties did not oppose Petitioners' proposed cost of capital calculation to be used for the CSIA, including agreement on the use of the cost of equity from the last base rate case of each of the Petitioners to calculate CSIA costs. The OUCC also explained its position that at the time of future base rate proceedings, the existence of the CSIA mechanism should be considered as causing a reduction to risk and therefore placing downward pressure on Petitioners' cost of common equity. Petitioners responded that a comprehensive review of risk, which considered all elements of the Petitioners' operations including the CSIA, would continue to occur during base rate cases.

Further, Petitioners disagreed that the CSIA reduces risk because of the unprecedented magnitude of the planned infrastructure investments over the next seven years, as well as other increased operational risks. We agree that this issue may be appropriately raised and addressed in each Petitioners next base rate case.

7. Treatment of Replaced Asset Investment Cost. The OUCC argues that the proposed CSIA will allow Vectren to recover a full return on and return of the new infrastructure investments as well as continued recovery of a full return on and return of amounts associated with the replaced infrastructure. Ms. Poole testified that Vectren will be recovering for assets that are no longer used and useful and such double recovery is not in the public interest. Thus, the OUCC recommended that Petitioners reduce the new capital investment for all replaced assets by the net book value of the replaced assets included in Petitioner's last base rate case. In support of its position, the OUCC cited to the Commission's Orders in *Northern Indiana Public Service Company, Inc.*, Cause No. 42150 ECR 21 (IURC October 16, 2013) and *Indiana American Water Company, Inc.*, Cause No. 42351 (IURC February 27, 2003).

Petitioners disagreed with the OUCC's recommendation and responded by arguing that it conflicts with the TDSIC and Compliance Statutes, selectively updates rate base outside a general rate case, and violates sound utility accounting principles related to retirement of group assets.

Although we understand the OUCC's concern and position, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery under either the TDSIC or Compliance Statute. Our February 17, 2014 Order in Cause No. 44371 recognized that Ind. Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. The Compliance Statute is also explicit about costs to be recovered and those that are excluded. Ind. Code § 8-1-8.4-4(b) specifically excludes only "fines or penalties assessed against or imposed on an energy utility for violating laws, regulations, or consent decrees related to a federally mandated requirement." Notably absent is any specific exclusion of infrastructure replaced in the course of complying with federal mandates. Nor do the Commission cases cited by the OUCC, both of which were decided under different statutes, provide sufficient support or precedent for accepting the OUCC's recommendation in this case. In addition, the TDSIC statutes requires a general rate case before the expiration of the utility's seven-year plan, which provides a built in mechanism to update the net investment of the utility. Thus, we decline the OUCC's recommendation.

8. Merger of PSA into CSIA. Petitioners propose to merge their existing PSAs with the CSIAs and eventually discontinue the PSAs. Under this proposal, the PSA costs incurred through December 31, 2013 would continue to be included for recovery in the PSA while the mandated operation and maintenance ("O&M") expenses incurred on and after January 1, 2014 will be deferred and included in the CSIA. Petitioners will file an annual PSA filing in mid-2014 to recover applicable costs for the applicable remaining months in 2013 that would continue through December 2016 to properly amortize previously approved for recovery in the PSAs, which have recently been extended for a three-year period. At the conclusion of the respective three-year extension periods, Petitioners will transfer any remaining

over- or under-recovery variances to the CSIA and discontinue the PSA. The currently approved annual PSA caps for transmission and distribution integrity management costs would continue to apply on a prorated basis. No party opposed Petitioners' proposal for merging their PSAs into the CSIAs. We find this consolidation appropriate and should be approved.

E. Accounting Authority. Petitioners propose to defer for subsequent recovery as part of their respective next general base rate cases 20% of the revenue requirement of the Compliance Projects and TDSIC Plans including financing costs on projects under construction, post in-service carrying costs, deferred O&M expenses, projected incremental depreciation, and property tax expenses.

Ind. Code § 8-1-8.4-7(c)(2) provides that "[t]wenty percent (20%) of approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in-service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission." No party opposed Petitioners' proposed methodology for deferring 20% of the Compliance Projects. Based on our review of the evidence, we find that 20% of the federally mandated costs associated with the Compliance Projects shall be deferred in accordance with Ind. Code § 8-1-8.4-7(c)(2) consistent with the methodology described in Petitioners' Exhibits JCS-1N and -1S. Because we find this proposal complies with the Compliance Statute, Petitioners' proposal is approved.

Ind. Code § 8-1-39-9(b) provides that 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." No party opposed Petitioners' methodology for deferring 20% of the TDSIC costs. Based on the evidence presented, we find that 20% of the TDSIC costs shall be deferred in accordance with Ind. Code § 8-1-39-9(b) consistent with the methodology described in Petitioners' Exhibits JCS-1N and -1S.

While the OUCC did not oppose Petitioners' methodology for deferral of the remaining 20% of project costs not recovered in the CSIA, it did note that the amounts should not be grossed up again for income taxes when they are included in Petitioner's next base rate proceeding. Petitioners agreed with this methodology.

Petitioners also propose to defer and subsequently recover incremental O&M and depreciation expense on an interim basis prior to inclusion in the CSIA. O&M expenses related to the Compliance Projects will be charged to FERC Account 182.3 and those costs will be included in the CSIA. Petitioners propose to defer 80% of the depreciation expenses from the Compliance Projects and the TDSIC Plans from their in-service dates until depreciation expense is included for recovery in the CSIA. We find Petitioners' proposal reasonable and Petitioners shall be permitted to defer and subsequently recover these costs through the CSIA.

F. Average Aggregate Increase in Total Retail Revenues Resulting from TDSIC. Petitioners' witness Albertson presented Petitioners' projected yearly revenue percentage change resulting from the 7-Year Plan in Petitioners' Exhibits SEA-3N and -3S. These exhibits demonstrate that the CSIA will gradually reflect the costs resulting from the Compliance Projects and TDSIC Plans in customers' rates and thereby help to smooth the impact of those costs on the Petitioners' customers. Petitioners' witness Swiz explained that the increase in the TDSIC component revenue requirement ("TDSIC Requirement") will be calculated by taking the recoverable TDSIC Requirement in the current CSIA, less the prior recoverable portion of the TDSIC Requirement in the prior CSIA. This amount will be compared to 2% of the retail revenues from the prior twelve-month period. Mr. Swiz explained that if the increase in the TDSIC Requirement exceeds the 2% threshold, then the recoverable increase will be limited to the amount equal to the 2% retail revenues and any amount in excess will be deferred for future purposes.

Ind. Code § 8-1-39-14(a) requires the Commission to find that an approved TDSIC will not "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." A public utility's total retail revenues do not include TDSIC revenues associated with a TED. We have previously found this determination requires comparing the increase in TDSIC revenue in a given year with the total retail revenues for the past 12 months. *See Northern Indiana Public Service Company, Inc.*, Cause No. 44371, p. 20 (IURC February 17, 2014).

We find the Petitioners' proposal ensures the TDSIC being approved herein will not result in an average aggregate increase in total retail revenues of more than 2% in a twelve-month period and is consistent with Ind. Code § 8-1-39-14(a). Any increase exceeding 2% will be excluded from the CSIA and instead deferred for future recovery in a rate case.

G. <u>CSIA Timing</u>. 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." Ms. Hardwick testified that the Commission issued an order changing Vectren South's basic rates and charges in Cause No. 43112 on August 1, 2007. Vectren North last received an order changing its basic rates and charges in Cause No. 43298 on February 13, 2008. Petitioners filed their Petitions under Ind. Code § 8-1-39-9(c) on November 25, 2013. Accordingly, we find that this Cause was filed more than nine months after Petitioners' last general rate case in accordance with Ind. Code § 8-1-39-9(c).

Ind. Code § 8-1-39-9(d) also provides 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." Therefore, both Vectren North and Vectren South shall file a petition with the Commission for review and approval of their respective basic gas rates and charges before the expiration of Petitioners' TDSIC Plans 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." Petitioners' witness Albertson testified that Petitioners propose to file their petitions and cases-in-chief supporting the CSIA 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. He stated the petitions filed on September 1 will be based on capital spend and expenses through the previous six-month period ended June 30, while the petitions filed on March 1 will be based on capital spend and expenses through the previous six-month period ended December 31. We find that Petitioners' proposed timeline for its CSIA filings is consistent with Ind. Code § 8-1-39-9(e) and is reasonable and should be approved. Vectren North's initial semi-annual filing following the issuance of this Order shall be filed under Cause No. 44430 TDSIC 1. Vectren South's initial semi-annual filing following the issuance of this Order shall be filed under Cause No. 44429 TDSIC 1.

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

1. The Compliance Projects are compliance projects undertaken to comply with federally mandated requirements within the meaning of Ind. Code ch. 8-1-8.4.

2. Petitioners shall be and hereby are granted a certificate of public convenience and necessity for the Compliance Projects.

3. Year 1 of the TDSIC Plans constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.

4. The TDSIC Plan categories contained in Years 2 through 7 of Petitioners' TDSIC Plans 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 as set forth herein.

5. Petitioners' TDSIC Plans are reasonable and approved as set forth herein.

6. Petitioners are authorized to implement their CSIA Rate Schedule as described in Petitioners' Exhibit Nos. SEA-1N and SEA-1S pursuant to Ind. Code §§ 8-1-39-9(a) and 8-1-8.4-7(c)(1) to effectuate the timely recovery of 80% of eligible and approved capital expenditures, TDSIC Plan, and Compliance Project costs.

7. Petitioners' proposed method of calculating a pretax return under Ind. Code § 8-1-39-13 is hereby approved.

8. Petitioners are authorized to defer post in service TDSIC Plan and Compliance Project costs, including carrying costs based on the WACC approved herein, on an interim basis until such costs are recovered for ratemaking purposes through Petitioners' proposed CSIA mechanism or otherwise included for recovery in their respective base rates through their next general rate case.

9. Petitioners are authorized to allocate the costs associated with their respective TDSIC Plans and Compliance Projects in accordance with our findings set forth herein.

10. Petitioners shall be and hereby are authorized to assess the CSIA as a fixed monthly charge to residential customers.

11. Petitioners are authorized to defer 20% of eligible and approved capital expenditures and TDSIC Plan costs under Ind. Code § 8-1-39-9(b). Petitioners are also authorized to recover the deferred capital expenditures and TDSIC costs as part of Petitioners' next general rate cases.

12. Petitioners are authorized to defer 20% of eligible and approved capital expenditures and Compliance Project costs under Ind. Code § 8-1-8.4-7(c)(2). Petitioners are also authorized to recover the deferred capital expenditures and Compliance Project costs as part of Petitioners' next general rate cases.

13. Petitioners are authorized to merge their approved PSAs with the CSIAs as set forth herein.

14. Petitioners' are authorized to adjust their net operating income to reflect any approved earnings associated with the CSIA for purposes of Ind. Code § 8-1-2-42(g)(3) pursuant to Ind. Code §§ 8-1-39-13(b) and 8-1-8.4-7(c)(1).

15. Petitioner's proposed process for updating the 7-Year Plan in future CSIA semi-annual adjustment proceedings is approved as set forth herein. Petitioners shall file their first CSIA on September 1, 2014, unless Petitioners otherwise notify the Commission in accordance with Finding Paragraph 6.C. Vectren South shall file its first CSIA under Cause No. 44429 TDSIC 1 and Vectren North shall file its first CSIA under Cause No 44430 TDSIC 1.

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

STEPHAN, MAYS-MEDLEY AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING:

APPROVED: AUG 27 2014

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