

**COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION**

In the Matter of:

The Application of Duke Energy Kentucky,)
Inc., for (1) a Certificate of Public Convenience)
and Necessity Authorizing the Construction of)
an Advanced Metering Infrastructure; (2)) Case No. 2016-00152
Request for Accounting Treatment; and (3) All)
Other Necessary Waivers, Approvals, and)
Relief.)

**DUKE ENERGY KENTUCKY, INC.'S RESPONSE TO
THE ATTORNEY GENERAL'S
MOTION TO DISMISS WITHOUT PREJUDICE**

I. Introduction

Comes now Duke Energy Kentucky, Inc. (Duke Energy Kentucky), by and through counsel, and hereby requests that the Kentucky Public Service Commission (Commission) deny the Attorney General's (AG) Motion to Dismiss (Motion). The AG's Motion is based upon: (1) conclusory statements that have no basis in fact; (2) misapplication of the Commission's regulations; (3) disregard of prior Commission precedent, and (4) a disregard of recent precedent. Additionally, the AG's Motion is premised upon incorrect assumptions and mischaracterizations of regulatory proceedings in other jurisdictions. Duke Energy Kentucky's Application for a Certificate of Public Convenience and Necessity (CPCN) to construct an advanced metering system (Meter Upgrade) follows the precise roadmap ordered by the Commission in its recently concluded "Smart Grid Administrative Case" Case No. 2012-00428,¹ and is fully supported in the record. The Company's Application contains a detailed cost-benefit

¹ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016).

analysis, and an explanation of the benefits that will inure to customers, exceeding those advanced metering applications previously approved by this Commission.² The Company's Application fully explains these customer benefits in terms of reduction of specific costs and the ability to develop new and enhanced basic services that the Company cannot currently provide under the existing metering technologies.

Because the AG's Motion lacks valid or substantive justification for dismissal of the Company's Application, it should be denied. The Company's Application for a CPCN to construct the Meter Upgrade should proceed in its current docket and be evaluated upon its merits now, not arbitrarily delayed until some future rate proceeding.

II. Argument

The AG bases its Motion on the following three arguments:

- [The Company's] Cost-Benefit Analysis Failed to Consider Stranded Costs Arising from the Retirement of Existing Meters;³
- [The Company] failed to satisfy the legal requirements for a CPCN for the proposed Smart Meter Plan;⁴ and
- [The Company's] Proposed AMI CPCN should be considered in the context of its next base rate proceeding.⁵

The AG is wrong on all counts and its claims do not provide basis for dismissal.

A. Duke Energy Kentucky's Cost Benefit Analysis and Request for Deferral are Reasonable.

1. Duke Energy Kentucky's CPCN and Deferral Requests comply with applicable regulations.

The AG's first argument in favor of dismissing the Company's CPCN Application is that

² See e.g., *Application of Kenergy Corp., for an Order issuing a Certificate of Convenience and Necessity to install an Automated Metering and Infrastructure System, Case No. 2014-00376*, (Ky. PSC February 24, 2015).

³ AG Motion at 1.

⁴ AG Motion at 2.

⁵ AG Motion at 3.

the Company's cost-benefit analysis included in its Application "failed" to take the undepreciated net book value of its existing metering infrastructure into consideration. The AG's argument is unsound in that it incorrectly presumes that Duke Energy Kentucky: (1) was required to perform a cost-benefit analysis to support its CPCN; and (2) was explicitly required to have factored into such analysis the costs of the net book value of retired meter assets. The AG's Motion does not cite to any law, rule, or regulation that supports such claims. And the Commission did not require it in its recently concluded Smart Grid Administrative Case.⁶

The filing requirements necessary to support a CPCN filing for a new construction before the Commission are prescribed by regulation. 807 KAR 5:001 Section 15(2)(a)-(f) provides that a utility's application must include:

- (a) The facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity;
- (b) Copies of franchises or permits, if any, from the proper public authority for the proposed construction or extension, if not previously filed with the commission;
- (c) A full description of the proposed location, route, or routes of the proposed construction or extension, including a description of the manner of the construction and the names of all public utilities, corporations, or persons with whom the proposed construction or extension is likely to compete;
- (d) One (1) copy in portable document format on electronic storage medium and two (2) copies in paper medium of:
 - 1. Maps to suitable scale showing the location or route of the proposed construction or extension, as well as the location to scale of like facilities owned by others located anywhere within the map area with adequate identification as to the ownership of the other facilities; and
 - 2. Plans and specifications and drawings of the proposed plant, equipment, and facilities;
- (e) The manner in detail in which the applicant proposes to finance the proposed construction or extension; and
- (f) An estimated annual cost of operation after the proposed facilities are placed into service.

⁶ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky. PSC April 13, 2016).

Nowhere in the aforementioned minimum filing requirements is a full cost-benefit analysis discussed. Indeed, the only “cost” component explicitly mentioned relates to the estimated annual cost of operation. The Commission has reviewed the Company’s Application in this proceeding and determined that it met the minimum filing requirements set forth by the rule.⁷ Therefore, any claim that the Company’s Application is deficient, such that it warrants dismissal without hearing, is unsupported and inconsistent with Commission precedent. This Commission has previously approved CPCN applications for smart meter deployment plans and the establishment of regulatory assets for undepreciated meter retirements without a cost-benefit analysis including such retired meter asset balances.⁸ The AG’s Motion should be denied based upon prior determinations alone.

Notwithstanding the lack of any Commission requirement for a cost-benefit analysis to support a CPCN, the Company did submit one here to: (1) demonstrate the magnitude of benefits this Meter Upgrade investment is projected to produce for customers; and (2) support the Company’s request for deferral related to the necessary early retirement of the existing metering infrastructure to effect the Meter Upgrade. The business case for the Meter Upgrade is independent of the costs of metering infrastructure already included in base rates that would have to be retired. However, the accounting impact of the meter retirement, if Duke Energy Kentucky’s regulatory asset request is denied, and it is required to write-off the entire meter

⁷ See No Deficiency Letter, April 28, 2016.

⁸ See e.g., *Application of Kenergy Corp., for an Order issuing a Certificate of Convenience and Necessity to install an Automated Metering and Infrastructure System, Case No. 2014-00376*, (Ky.PSC February 24, 2015); *Application of Nolin Electric Cooperative Corporation for an Order Pursuant to 807 KAR 5:001 and KRS 278.020 Requesting the Granting of a Certificate of Public Convenience and Necessity to Install an AMI System, Case No. 2014-00436* (Ky. PSC February 13, 2015). See e.g., *In the Matter of the Request of Kenergy Corp for Approval to Establish a Regulatory Asset in the Amount of \$3,884,717 Amortized over a ten (10) Year Period, Case No. 2015-00141* (Ky.PSC. August 31, 2015); authorizing Kenergy to record a regulatory asset for the loss on the disposal of its electro-mechanical meters based on the undepreciated balance of the meters retired at the time of their retirement, and that the amortization period for the asset will be addressed in their next rate case. See also, *In the Matter of the Request of Shelby Energy Cooperative for Approval to Establish a Regulatory Asset in the Amount of \$443,562 and Amortize the Amount Over a Period of Five Years Case No. 2012-00102* (Ky. PSC April 16, 2012). Approving Shelby’s deferral request and five year amortization period.

balance at once, is relevant to Duke Energy Kentucky's operations, as well as its shareholders. Given the Company's relative size, such a financial impact to the Company is certainly a factor in the Company's ability and willingness to proceed with the Meter Upgrade investment.

2. The AG's allegations regarding meter retirement deferral costs are unsupported and irrelevant.

The AG and its witness describe Duke Energy Kentucky's estimated \$9.7 million in undepreciated meter assets to be retired as a 20 percent "premium" over and above the estimated \$49 million estimated total cost of the Company's Meter Upgrade. The AG's characterization of the Company's regulatory asset request is incorrect and misleading because it misinterprets the Company's analysis. There is no such "premium." The "ratio" of the remaining book value of the Company's undepreciated meters to its overall deployment cost is an unfounded metric, and the AG's witness offers no explanation of its relevance or perspective. Nonetheless, even if one assumes this manufactured metric is relevant, Duke Energy Kentucky's retired meter asset value to deployment cost "ratio" is wholly in line with, and even less than, that of other companies whose deployments and regulatory assets have been previously approved by the Commission.

In Case No. 2014-00376, the Commission granted CPCN approval for Kenergy Corporation's \$9.7 million advanced metering infrastructure (AMI) upgrade.⁹ Subsequently, in Case No. 2015-00141, the Commission approved Kenergy's request for a regulatory asset for the loss on its disposal of electro-mechanical meters based on the undepreciated balance at the time of their retirement, which Kenergy estimated as \$3,884,717 as of December 31, 2014. Using the AG's logic, the value of the regulatory asset approved for Kenergy equates to an

⁹ *Application of Kenergy Corp., for an Order issuing a Certificate of Convenience and Necessity to install an Automated Metering and Infrastructure System, Case No. 2014-00376, (Ky.PSC February 24, 2015).*

approximate 40 percent “premium” over the Kenergy program’s deployment cost.¹⁰ Similarly, in Case No. 2006-00286, the Commission authorized a CPCN for Taylor County RECC (Taylor) to invest \$4.1 million for automated meter reading (AMR) meters, systems and equipment.¹¹ Subsequently, in Case No. 2008-00376 the Commission authorized the creation of a \$1.2 million regulatory asset for retired meter expense which, again, using the AG’s analysis, represents an approximate 29 percent “premium” over Taylor’s AMR system deployment costs.¹² Likewise, in Case No. 2009-00489, the Commission authorized South Kentucky RECC’s (South Kentucky) CPCN application, approving a \$19.5 million (including \$9.5 million in grants) investment to implement an AMI infrastructure.¹³ In its subsequent rate case, the Commission authorized accounting treatment for recovery of \$3.7 million in early meter retirements through deferred debit and a 15 year amortization period. To illustrate the absurdity of the AG’s “ratio,” South Kentucky’s deferral represented approximately 19 percent of its total AMI deployment cost when one ignores the fact that South Kentucky received an approximate \$9.5 million in federal grants toward its AMI deployment. However, when one factors in the federal grant, which reduced the overall AMI deployment cost, the AG’s analysis would result in a 37 percent

¹⁰ *In the Matter of the Request of Kenergy Corp for Approval to Establish a Regulatory Asset in the Amount of \$3,884,717 Amortized over a ten (10) Year Period*, Case No. 2015-00141 (Ky. PSC. August 31, 2015); authorizing Kenergy to record a regulatory asset for the loss on the disposal of its electro-mechanical meters based on the undepreciated balance of the meters retired at the time of their retirement, and that the amortization period for the asset will be addressed in their next rate case. Although the Commission held that the actual amount of the asset would be based upon the date of the meter retirement, the meter deployment was to occur during 2015 and 2016, so all meter retirements would also be completed during 2016. The actual final value of the regulatory asset, including depreciation, would nominally reduce the total asset.

¹¹ *See In the Matter of the Application of Taylor County Rural Electric Cooperative Corporation for a Certificate of Public Convenience and Necessity*, Case No. 2006-00286 (Ky. PSC October 5, 2006); Approving Taylor’s June 13, 2006, CPCN Application. Exhibit E, page 4 of 4 of the Application shows the estimated cost breakdown of Taylor’s \$14 million construction plan, which, among other things, included AMR meters investments at approx. \$3.2 million and approx. \$872,568 in AMR systems and equipment over 3 years.

¹² *In the Matter of the Filing of Taylor County Rural Electric Cooperative Corporation Requesting Approval of Deferred Plan for Retiring Meters*, Case No. 2008-00376 (Ky. PSC December 9, 2008).

¹³ *In the Matter of the Application of South Kentucky Rural Electric co-operative Corporation for a Certificate of Convenience and Necessity to Install an Advanced Metering Infrastructure System (AMI)*, Case No. 2009-00489 (Ky. PSC January 19, 2010.)

“premium” of early retired meter expense to South Kentucky’s AMI deployment costs.¹⁴ The comparison of the meter retirement value to deployment costs is a meaningless exercise, and even if it were relevant, the Company’s expected value in proportion to deployment costs pales in comparison to the scope of similar deployments in the Commonwealth.

3. The Company’s cost-benefit analysis is sound.

The AG’s argument with respect to the Company’s cost-benefit analysis merely represents the AG’s opinion as to the sufficiency of information contained in the Company’s analysis. The AG admits as much, stating “AG believes that in analyzing the cost-benefit impact of any CPCN project upon ratepayers, it is absolutely vital that all costs should be taken into consideration.”¹⁵ Notwithstanding, the prior discussion regarding the lack of any legal requirement to conduct a cost-benefit analysis as part of a CPCN, or that the Company’s deferral request be included in a cost-benefit analysis, the AG’s opinion as to sufficiency of information is a matter for the AG to argue at hearing or on brief. It is most certainly not a fatal flaw warranting dismissal of the Company’s Application.

Regardless, the AG alleges that the Company: (1) “inexplicably failed” to include the meter retirement costs in its analysis; and (2) that when such costs are included the costs of the proposed project exceed the estimated benefits by a significant factor are both without merit.

First, the Company did not include the undepreciated meter asset value in its cost-benefit analysis because the Company could not foresee the treatment of the asset ultimately preferred by the Commission in terms of amortization periods, or the timing of the creation of the asset that would be necessary to include in the cost-benefit analysis. Second, as discussed below,

¹⁴ *In the Matter of the Application of South Kentucky Rural Electric Cooperative Corporation for an Adjustment of Electric Rates*, Case No. 2011-00096, (Ky. PSC March 30, 2012); Approving, among other things, accounting treatment of the \$3.7 million in early meter retirement expense and a 15 year amortization period. *See also, Id.* (Ky. PSC May 11, 2012); affirming regulatory treatment and amortization on rehearing.

¹⁵ AG Motion at 2.

including the undepreciated asset in the cost benefit analysis is not necessary to demonstrate the benefits of the program outweigh its costs if one compares the correct numbers from the Company's analysis. The AG's argument boils down to a semantic disagreement with the presentation of the Company's supporting materials, rather than a failure of the Company to provide those materials.

The AG claims that when one factors the undepreciated retired meter asset value as part of the total project costs, the total costs outweigh the benefits. But the AG's conclusion is both unsupported and incorrect. The AG and its witness did not provide any basis, explanation, or analysis for reaching such a conclusion. One can only assume that the AG and its witness are errantly comparing the *nominal value* of the early retired meter asset balance (estimated at \$9.7 million) to the *net benefits of deployment that were discounted to a present value* as part of the Company's cost-benefit analysis (approximately \$7.4 million), essentially, comparing apples to oranges.¹⁶ The \$9.7 million undepreciated asset is a nominal value that, if at all, should be evaluated in the context of the *nominal net benefits* of the program, *not the net present value of the net benefits*. When one looks at the data supplied in public exhibit DLS-4, and compares the \$9.7 million estimated early meter retirement balance (a nominal figure) to the portion of the analysis that shows the nominal net benefit of \$45.6 million,¹⁷ it is clear that the project benefits still exceed the project costs, including the undepreciated retired meter asset, by a significant amount.

If, however, one wants to compare the \$9.7 million undepreciated meter asset to the net-present value of overall program net benefits, one must first also discount the \$9.7 million to a

¹⁶ *Emphasis added.* See Confidential Attachment DLS-4 to the Direct Testimony of Donald L. Schneider for the detailed cost-benefit analysis. Duke Energy Kentucky's analysis shows both the nominal (life of deployment) projected net benefit as well as a discounted present value of such benefits.

¹⁷ Confidential Attachment DLS-4 to the Direct Testimony of Donald L. Schneider, projecting a total nominal benefit of approximately \$46 million over the life of the asset on a nominal basis.

present value number. Fundamental rate-making principles dictate that if the Company's regulatory asset is approved, the \$9.7 million sum will be amortized over some period of years and incorporated into the test year revenue requirement. The implication is that the Company will not recover the \$9.7 million amount immediately; instead, it will be recovered over some period of time, as determined by the Commission. Indeed, the Commission has previously required such regulatory assets to be deferred over the same period as the new advanced meters are being depreciated.¹⁸ The greater the length of time over which the regulatory asset is amortized, the less it represents in terms of its "present value," and the lower the impact on a net present value basis. However, absent knowing the amortization period of the regulatory asset, the AG cannot make a reasonable or valid comparison against the net-present value of overall program's net benefits because the amortization period of the regulatory asset is a necessary component to making such analysis. Thus the AG's argument is foundationless and its Motion to Dismiss should be denied.

4. Duke Energy Kentucky has met its burden to establish a regulatory asset for retired meter costs.

The Company's cost-benefit analysis serves two purposes. Although not mandatory, it confirms that the requested CPCN is reasonable, and if approved, will enable the deployment of advanced technology that will result in benefits to customers. The cost-benefit analysis also demonstrates that the Company's regulatory asset request meets the Commission standard for allowing such accounting treatment. The AG ignores this second purpose. As explained in the Company's Application, the Commission has exercised its discretion to approve regulatory assets where a utility has incurred:

¹⁸ *In the Matter of the Application of South Kentucky Rural Electric Cooperative Corporation for an Adjustment of Electric Rates*, Case No. 2011-00096, (Ky. PSC March 30, 2012); Approving, among other things, accounting treatment of the \$3.7 million in early meter retirement expense and a 15 year amortization period. *See also, Id.* (Ky. PSC May 11, 2012); affirming regulatory treatment and amortization on rehearing.

- (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning;
- (2) an expense resulting from a statutory or administrative direction;
- (3) an expense in relation to an industry sponsored initiative; or
- (4) an extraordinary or nonrecurring expense that overtime will result in a saving that fully offsets the cost.¹⁹

In exercising discretion to allow the creation of a regulatory asset, the Commission's overarching consideration has been to evaluate the context in which the regulatory asset is sought to be established and not necessarily the specific nature of the costs incurred.²⁰ Duke Energy Kentucky's request to create regulatory assets for the early retirement of electro-mechanical meters, the obsolete automated metering solution pilot meters, and metering inventory satisfies the criteria because the requested regulatory assets would represent extraordinary or non-recurring expense that over time will result in a result in a savings that fully offsets the costs. The primary utility cost savings achieved through the Metering Upgrade is the ability to eliminate monthly meter reading expense attributed to deploying personnel on a daily basis to manually read each and every gas and electric meter during a billing cycle. The Company's cost-benefit analysis demonstrates the savings that are estimated to be achieved over the life of the deployment, when looked at through the correct lens explained above, fully offsets the costs of

¹⁹ See *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Case No. 2008-00436 (Final Order) (Ky. P.S.C., Dec. 23, 2008); *In the Matter of the Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset*, Case No. 2008-00456, (Final Order) (Dec. 22, 2008); *In the Matter of the Application of Kentucky Utilities Company for an Order Approving the Establishment of a Regulatory Asset*, Case No. 2008-00457, (Final Order) (Ky. P.S.C., Dec. 22, 2008); *In the matter of the Joint Application of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain Payments Made to the Carbon Management Research Group and the Kentucky Consortium for Carbon Storage*, Case No. 2008-00308, (Final Order) (Oct. 30, 2008); *In the Matter of the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations*, Case No. 2001-00169, (Final Order) (Dec. 3, 2001).

²⁰ *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Case No. 2008-00436 (Final Order) (Dec. 23, 2008).

the proposed regulatory asset. In addition, given the Commission's recent Order in Case No. 2012-00428, the Company's request for a regulatory asset would also satisfy the Commission's second category, an expense resulting from a statutory or administrative direction.²¹

5. The AG's characterization of Duke Energy Indiana's recent settlement is misleading and out of context.

The AG ignores the substantial precedent that exists in the Commonwealth in respect of regulatory treatment for undepreciated meter costs and instead relies upon a recently approved settlement for Duke Energy Kentucky's sister company, Duke Energy Indiana, Inc., (Duke Energy Indiana) to support his Motion. As a result of that case, which the AG describes as "remarkable,"²² Duke Energy Indiana was authorized to implement a \$1.4 billion, seven-year transmission and distribution infrastructure investment plan, that includes discrete tracker recovery outside a rate case, and creation of other regulatory assets (Indiana Proceeding).²³ The AG's allusion to the Duke Energy Indiana settlement is remarkable indeed because it represents a mischaracterization of a non-jurisdictional regulatory proceeding in what appears to be an attempt to mislead the Commission.

It should first be acknowledged that the Indiana Proceeding was far broader in scope than the Meter Upgrade as is proposed herein. The purpose of the Indiana Proceeding, and the resulting Indiana Utility Regulatory Commission (IURC) Order, was to establish a comprehensive multi-year transmission and distribution infrastructure investment program, with

²¹ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016) at 35; *Holding* "Utility investments in Smart Grid and unrecovered book value of replaced equipment shall be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discovery, and Commission approval, if reasonable.

²² Motion at 2. *Emphasis added*

²³ See Attachment 1 hereto, *In the Matter of the Verified Petition of Duke Energy Indiana, Inc. for: (1) Approval of Petitioner's 7 Year Plan for Eligible Transmission, Distribution and Storage System Improvements, Pursuant to Ind. Code 8-1-39-10; (2) Approval of a Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment and Deferrals, Pursuant to Ind. Code 8-1-30-0; (3) Approval of Certain Regulatory Assets; (4) Approval of Voluntary Dynamic Pricing Riders; and (5) Approval of a New Depreciation Rate for Advanced Meters*, Cause No. 44720 (IURC June 29, 2016).

deferrals, and cost recovery mechanisms outside of a base rate proceeding.²⁴

In the Indiana Proceeding, the IURC ultimately approved a comprehensive *settlement* among nine parties authorizing Duke Energy Indiana to implement a \$1.4 billion transmission and distribution investment plan, allowing the tracker recovery of 80 percent of the costs, and deferral the remaining 20 percent.²⁵ The program approved by the IURC was significantly broader in scope than just an AMI program. For example, compared to the \$1.4 billion in total program costs, Duke Energy Indiana's initial application included approximately \$192 million for an AMI meter upgrade and a request for deferral of the undepreciated meters to be retired early, which would also be recovered via a discrete recovery mechanism.

As part of the negotiated settlement achieved in the Indiana Proceeding, Duke Energy Indiana agreed to not include the capital costs for its proposed AMI meter upgrade proposal in the tracker recovery plan, but instead to seek recovery in a base rate proceeding (not unlike what Duke Energy Kentucky is proposing herein).²⁶ Additionally, as part of the comprehensive settlement, Duke Energy Indiana agreed not to seek recovery of the undepreciated net book value of the meters that would be retired as a result of the AMI deployment.²⁷ It is indisputable that in the context of any settlement, parties negotiate and concessions are made to resolve the matter.

What the AG "*remarkably*" fails to mention in its Motion, is that in exchange for the aforementioned concessions regarding its proposed AMI investment and the implementation of the tracker and deferral of the \$1.4 billion infrastructure investment plan, the terms of the settlement approved by the IURC also included: 1) deferral of up to \$60 million in depreciation expense associated with the AMI investment for future rate case recovery; 2) deferral of \$15

²⁴ Attachment 1, Indiana Order at 3.

²⁵ *Id.* at 31; *See also*, Settlement Agreement, accompanying Indiana Order.

²⁶ Settlement Agreement at 4.

²⁷ *Id.* at 5.

million in post-in-service carrying costs (PISCC) for the AMI project; 3) a ten-year recovery of PISCC; 4) company-retained benefits; 5) fifteen year depreciation rates for the AMI meters; and 6) agreement by all parties to the settlement not to oppose the inclusion of the AMI project in Duke Energy Indiana's base rates.²⁸

Nonetheless, if the AG is suggesting that Duke Energy Kentucky should “develop an alternative” to address the premature retirement of existing assets, “such as its Indiana affiliate did,”²⁹ which, again, allowed that company to implement a multi-year, \$1.4 billion dollar infrastructure investment plan with rider recovery, deferrals, post-in service carrying costs, depreciation rates, retention of benefits by the Company, and agreement by intervenors not to oppose future base rate recovery, the Company is certainly willing to entertain settlement discussions with the AG regarding the treatment of the \$9.7 million regulatory asset the Company requested in this proceeding. Duke Energy Kentucky would certainly welcome such a progressive regulatory model if symmetry between the regulatory models in Indiana and Kentucky is what the AG is seeking. Nevertheless, the AG's Motion in this case should be denied.

6. The AG's claims that the Company's customers will be facing a substantial rate increase when the Company files its next rate case is unsupported.

The AG also alleges that Duke Energy Kentucky has engaged in “extensive capital spending” in the “approximately 10 years since the Company's last rate case,” and thus rate payers will be facing a “very substantial” rate increase. The AG has no support for such a statement. The AG neither sought any such information from the Company in its discovery in this case nor has it provided any independent analysis to derive such a conclusion. Duke Energy

²⁸ Attachment 1, Indiana Order at 32-33, Stipulation accompanying Order at 1-10.

²⁹ AG Motion at 2.

Kentucky continually analyzes its need for a rate case and has a responsibility to all of its stakeholders, including its shareholders, to ensure that it is financially stable. The AG's theory is that the Company has spent an "extensive" amount of money over the last ten years and is apparently waiting to file a rate case until its financial need results in a "very substantial" rate increase. The AG does not define what "very substantial" means, but the Commission should be aware that regulated utilities typically do not wait until their financial conditions are so dire that it warrants a "very substantial" rate increase. Furthermore, utility rate cases and the resulting rate changes are driven by numerous factors, not just capital expenditures. Operations and maintenance costs, depreciation, authorized returns, to name a few, are all items that factor into the magnitude of a rate increase. Moreover, there is absolutely no record evidence showing that the Company has engaged in "extensive capital spending" or that the Company's levels of capital spending have been imprudent or unnecessary to maintain safe and reliable operations and to accommodate continued customer and load growth in its territory. The AG's allegations on this score are irrelevant.

Nonetheless, if the AG had examined Duke Energy Kentucky's growth in utility plant since the Company's 2006 rate case, he would see that the Company's capital expenditures are not extensive. It should also be noted that growth in net plant is a necessary consequence of growth in the number customers. Per the Company's 2006 FERC Form 1 data, Duke Energy Kentucky had approximately 118,000 electric customers. In 2015, that figure stood at approximately 139,000 electric customers. Capital spending is a necessary result of adding almost 18 percent more customers over those ten years.

In sum, the AG's comment about the "extensive capital spending" over the past ten years reflects a lack of analysis and a misunderstanding of the factors that contribute to growth in

utility investment.

B. Duke Energy Kentucky's Application Satisfies the Legal Requirements for a CPCN.

The AG also claims that the Company's Application fails to satisfy the legal requirements for a CPCN, because Duke Energy Kentucky did not survey its customers to determine whether they want a Metering Upgrade. Additionally, the AG argues that to the extent the Company must retire its existing and antiquated metering infrastructure to install the new advanced metering system, that duplication of plant results. The AG misconstrues Kentucky law and the Commission's regulations in reaching such conclusions. The AG's characterizations of the Company's responses to discovery regarding surveys are also misleading.³⁰

1. There is a Legal Standard for Acquiring a CPCN.

The legal standard for acquiring a CPCN is well settled in the Commonwealth. KRS 278.020(1) establishes the standard requiring a utility to seek a CPCN prior to constructing any plant, equipment or property, or facility for furnishing utility services to the public that is not otherwise considered an ordinary extension of an existing system.³¹ But it is the Commission's regulation, 807 KAR 5:001 Section 15(2), which sets forth the necessary burden of proof and minimum filing requirements for receiving a CPCN, providing in relevant part:

New construction or extension. Upon application for a certificate that the present or future public convenience or necessity requires, or will require, the construction or extension of any plant, equipment, property, or facility, the applicant, in addition to complying with Section 14 of this administrative regulation, shall submit with its application:

(a) The facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity;

Thus, to obtain a CPCN, the utility must demonstrate the "need" for the construction or extension. The Kentucky Court of Appeals has found that a demonstration of "need" requires:

³⁰ Motion at 3.

³¹ KRS 278.020(1)

[A] showing of substantial inadequacy of existing service involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed and operated. ...

Second, the inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.³²

That same court further required that to receive a CPCN, the utility must also demonstrate an absence of wasteful duplication.³³ Wasteful duplication has been defined by the Commission as “an excess of capacity over need” and “an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties.”³⁴ The Commission has held that to demonstrate that a proposed facility does not result in wasteful duplication, the applicant must demonstrate that a thorough review of all alternatives has been performed,³⁵ and that the selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.³⁶

2. Duke Energy Kentucky has established “need” as defined by Kentucky Law.

Duke Energy Kentucky’s Application and supporting testimony demonstrate both “need” and the absence of waste. It is noteworthy that nowhere in the Commission’s regulations is it even suggested that “need” must, or can only, be determined by discrete or targeted surveys to customers. In fact, “need” can be established in numerous ways, such as to satisfy or comply with regulatory requirements, including Commission Orders.

³² *Kentucky Utilities Co. v. Pub. Serv. Comm’n*, 252 S.W.2d 885 (Ky 1952).

³³ *Id.*

³⁴ *Id.*

³⁵ *In the Matter of the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky*, Case No. 2005-00142 (Ky. PSC September 8, 2005).

³⁶ *In the Matter Kentucky Utilities Co. v. Pub. Serv. Comm’n*, 390 S.W.2d 175 (Ky.1765). See also, *In the Matter of the Application for East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and necessity to construct a 138 kV Transmission Line in Rowan County, Kentucky*, Case No. 2005-00089(Ky. PSC. August 17, 2005).

This Commission has recently ordered all Kentucky electric utilities to develop internal policies and procedures for making smart grid investments and also to develop procedures to provide customers with access to historic information regarding their energy use in as close to real-time as practical.³⁷ The Commission further ordered each utility to file their respective smart grid investment policies, among other policies, within sixty days.³⁸ AMI investments are necessary to deliver the level of service desired by the Commission. The Commission is not only encouraging these investments, it is directing utilities to make them. The “need” to comply with Commission Orders and, in turn, to make smart grid investments such as the Company’s proposed Metering Upgrade is not only established, but is clear.

The Company’s existing electro-mechanical, manually read, metering technologies cannot deliver the advanced usage information only recently deemed important enough by the Commission to require wholesale jurisdictional utility development of smart metering technology investment policies.³⁹ Similarly, the technology used as part of the Company’s 2006 limited advanced metering pilot (2006 Pilot), albeit state of the art at the time, is incapable of updating in a cost-effective manner and unable to provide the Commission’s desired level of customer usage communication due to technology limitations and issues with bandwidth using power line communication technology.⁴⁰

There is clearly an “inadequacy of existing service” with respect to the existing and antiquated metering technologies currently in use to serve the Company’s customer base, in light of the Commission’s recent Smart Grid Administrative Order and as compared to the capabilities of the proposed Meter Upgrade. Further, due to the “substantial deficiency” stemming from the

³⁷ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016).

³⁸ *Id.* Duke Energy Kentucky filed its policies and served them upon all parties to the proceeding on June 13, 2016.

³⁹ Henning Direct Testimony at 6. “Duke Energy Kentucky’s existing metering infrastructure consists mostly of electro-mechanical meters that are manually read once a month by Company personnel.”

⁴⁰ See Response to AG-DR-01-001. See also, Direct Testimony of Donald L. Schneider at 4-5.

existing infrastructure's technological limitations; the Company simply cannot provide customers with the Commission's desired levels of service or near-real-time usage data information. The fact that the existing electro-mechanical and 2006 Pilot metering technologies cannot be upgraded absent wholesale system replacement, and that such replacement must occur on a total system basis is due to the Meter Upgrade's interconnected and integrated network technology.⁴¹ The "inadequacy" of the current metering infrastructure results in a "substantial deficiency" beyond that which can be supplied by "normal improvements in the ordinary course." Duke Energy Kentucky is proposing to upgrade nearly its entire existing metering infrastructure through a targeted, approximately two-year, deployment plan. Performing this upgrade over a longer time period that is based upon the system's estimated useful life is impractical, inefficient, and not cost effective. The "consumer market" impacted by the Metering Upgrade is "sufficiently large" (Company's entire electric and gas system) making it "economically feasible for the new system or facility to be constructed and operated." As compared to an inefficient end-of-life rolling meter replacement strategy that could take decades, the Meter Upgrade is "economically feasible" to be constructed consistent with the CPCN Legal Standard for determining "need."⁴² Duke Energy Kentucky's Metering Upgrade is needed.

Notwithstanding the Commission's most recent directive, Duke Energy Kentucky has independently demonstrated the specific need for its Metering Upgrade in its Application, the Direct Testimony of Messers Henning, Schneider, and Dr. Weintraub, as well as, through responses to both Staff-issued and AG-issued discovery. The "need" for the Meter Upgrade is apparent through the operational benefits that are enabled by way of cost reduction, safety enhancements, streamlining of outage identification, greater availability and access to customer

⁴¹ See Response to AG-DR-01-84, explaining why the Meter Upgrade cannot be performed on a "rolling" end of useful life basis.

⁴² See e.g., Responses to AG-DR-01-68; AG-DR-01-84; and AG-DR-02-28.

usage data, and future customer programs. The “need” is further supported through independent market surveys across the six-state Duke Energy Corporate footprint, as well as, industry sponsored research included with the Company’s Application.⁴³

Mr. Henning testifies that Duke Energy Kentucky’s Metering Upgrade is necessary to allow the Company to enhance its ability to serve its customers, provide them with greater access to data and control over their energy consumption, and allow the Company to more efficiently manage its costs.⁴⁴ Mr. Schneider discusses the operational benefits can only be achieved through the Meter Upgrade in terms of eliminating manual meter reading, including the numerous internal meters in the Company’s service territory, reduction of “truck rolls”, and more timely communication and outage notifications that are made possible.⁴⁵ Dr. Weintraub further testifies that industry research supports that residential customers are concerned about reliability, cost, predictability of cost, renewable energy, and control and want better communication from their utility.⁴⁶ The Company’s basis for Dr. Weintraub’s statements and the Company’s position is its experience in the utility industry across six states, as well as, independent market research.⁴⁷ Further, Attachment DLS-1 to Mr. Schneider’s testimony includes a study performed by the Institute for Electric Innovation that clearly states customers want greater control over their energy usage and expect their utility to provide guidance on energy related matters.⁴⁸ Additionally, confidential response to AG-DR-01-055 shows the impact of greater control, predictability, and communication on customer satisfaction rates across the utility industry.⁴⁹ All of these concerns and desires are addressed with the Meter Upgrade proposed, yet are ignored by

⁴³ See Response to AG-DR-01-055, Confidential Attachment; and Attachment DLS-1, Direct Testimony of Donald L. Schneider.

⁴⁴ Henning Direct Testimony at 9.

⁴⁵ Schneider Direct Testimony at 12-13.

⁴⁶ Dr. Weintraub Direct Testimony at 4.

⁴⁷ See Response to AG-DR-01-07, AG-DR-01-55,

⁴⁸ DLS-1 at 4.

⁴⁹ Confidential Attachment in response to AG-DR-01-055, submitted under seal.

the AG.

Significantly, the AG's witness does not dispute the fact that the Meter Upgrade will enhance the ability to serve customers and provide them with greater access or control over their consumption. Similarly, AG witness, Mr. Alvarez makes no findings whatsoever that the Meter Upgrade will not enable the Company to more efficiently manage its costs. He does not dispute that the Meter Upgrade enables the operational benefits described by Mr. Schneider or the services enabled by Dr. Weintraub. He only posits in a broad sense that cost-benefit analyses, in general, are more likely than not, to underestimate costs and overestimate benefits.⁵⁰ There is no record evidence that supports such a claim as it relates to the Company's Application.

3. Duke Energy Kentucky's Meter Upgrade does not result in wasteful duplication.

The AG argues that the Company's "plan to prematurely retire useful assets constitutes 'prima facie evidence'" that the Meter Upgrade promotes duplication of plant and results in wasteful duplication.⁵¹ The AG misconstrues the definition of wasteful duplication.

Duke Energy Kentucky is not the first jurisdictional utility to propose to make such a system-wide advanced metering investment, as the Commission has evaluated and approved similar infrastructures in the past.⁵² Indeed, the Commission has conceded that most of the Kentucky jurisdictional electric utilities have migrated to AMR or AMI meters and functionality, or are in the process of doing so,⁵³ and, until recently, the need to file a CPCN for an advanced

⁵⁰ Alvarez at 18.

⁵¹ Motion at 3.

⁵² See e.g., *Application of Kenergy Corp., for an Order issuing a Certificate of Convenience and Necessity to install an Automated Metering and Infrastructure System, Case No. 2014-00376*, (Ky.PSC February 24, 2015); *Application of Nolin Electric Cooperative Corporation for an Order Pursuant to 807 KAR 5:001 and KRS 278.020 Requesting the Granting of a Certificate of Public Convenience and Necessity to Install an AMI System, Case No. 2014-00436* (Ky. PSC February 13, 2015).

⁵³ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies, Case No. 2012-00428* (Ky.PSC April 13, 2016) at 8.

metering upgrade was unsettled.⁵⁴

Nonetheless, the Company's Application is the first such CPCN following the Commission's Smart Grid Administrative Case. In fact, the AG's own witness readily concedes that Duke Energy Kentucky's Metering Upgrade "characteristics, approaches, and technologies... are typical for a combination gas and electric utility."⁵⁵ And that the technologies selected by Duke Energy Kentucky have been "installed for millions, if not tens of millions of U.S. utility customers."⁵⁶ Mr. Alvarez further acknowledges that the Company's CPCN Application is similar to many other similar deployments in that it involves retiring existing assets before the end of their useful lives."⁵⁷ Indeed, the Commission has previously addressed the retirement of existing infrastructure through the granting of deferrals,⁵⁸ recently holding:

Utility investments in Smart Grid and unrecovered book value of replaced equipment shall be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discover and Commission approval, if reasonable.⁵⁹

In short, there is nothing unexpected or surprising contained in the Company's Application as these issues have been addressed before, both by this Commission, and across the nation.

To rise to the level of wasteful duplication and fail the CPCN legal standard, the Company's investment proposal must result in an "excess of capacity over need and an excessive investment in relation to productivity or efficiency and an unnecessary multiplicity of physical

⁵⁴ *Id.* at 10.

⁵⁵ Alvarez direct testimony at 5.

⁵⁶ *Id.*

⁵⁷ *Id.* at 6.

⁵⁸ See e.g., *In the Matter of the Request of Kenergy Corp for Approval to Establish a Regulatory Asset in the Amount of \$3,884,717 Amortized over a ten (10) Year Period*, Case No. 2015-00141 (Ky.PSC. August 31, 2015); authorizing Kenergy to record a regulatory asset for the loss on the disposal of its electro-mechanical meters based on the undepreciated balance of the meters retired at the time of their retirement, and that the amortization period for the asset will be addressed in their next rate case. See also, *In the Matter of the Request of Shelby Energy Cooperative for Approval to Establish a Regulatory Asset in the Amount of \$443,562 and Amortize the Amount Over a Period of Five Years* Case No. 2012-00102 (Ky. PSC April 16, 2012). Approving Shelby's deferral request and five year amortization period.

⁵⁹ *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016) at 35.

properties.”⁶⁰ Thus to equate to wasteful duplication, the productivity and efficiency gains enabled by the Company’s Meter Upgrade investment as compared to maintaining the current metering infrastructure must be unjustifiable or result in multiple metering technologies. Neither is the case.

The Meter Upgrade proposal serves an entirely new purpose than simply billing customers for monthly consumption as is solely provided by the Company’s existing metering infrastructure. The Meter Upgrade is a “gateway technology” that enables the Company to enhance its ability to serve its customers by providing them with greater access to data and control over their energy consumption, develops new and innovative services, as well as, enables the Company to more efficiently manage its costs.⁶¹ The Meter Upgrade is responsive to the Commission’s directive to develop investment policies that provide customers with usage information “as close to real time as practical.”⁶² The Meter Upgrade will enable customer access to hourly and daily usage information, faster connection of service, and greater convenience through elimination of internal manual meter reading or off-cycle meter reading.⁶³ The quantifiable value of these enhancements are contained in the Company’s cost-benefit analysis, which shows a positive business case in terms of anticipated savings by, among other things, a significant reduction in operations and maintenance costs inherent in functioning under a manually-read meter infrastructure.⁶⁴

The Meter Upgrade does not result in “unnecessary multiplicity of physical properties” because it will replace the existing and antiquated infrastructure that can only provide customers with prior month’s consumption information, obtained through manual meter reads or by

⁶⁰ *Kentucky Utilities Co. v. Pub. Serv. Comm’n*, 252 S.W.2d 885 (Ky 1952).

⁶¹ Henning Testimony at 9-12.

⁶² *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016) at 8.

⁶³ Schneider Testimony at 12.

⁶⁴ Confidential Attachments DLS-3 and DLS-4.

estimation. There is no duplication because the Meter Upgrade will be done on a system-wide basis through a targeted and timely deployment, enabling the Company to quickly transition to a single metering infrastructure. Conversely, upgrading the metering system on a rolling basis, as suggested by the AG in discovery,⁶⁵ where advanced meters are not installed until the existing meter's end of useful life (approximately 25 years for electric meters based upon the Company's current depreciation rates) would likely run afoul of the wasteful duplication standard because it would require the Company to maintain multiple meter systems, conduct manual readings for an indeterminate amount of time; and incur higher capital, operations, and maintenance costs for maintaining multiple inventories. Mr. Alvarez's opinion is silent on both the Company's deployment plan and the productivity and efficiency gains enabled through the Meter Upgrade. He merely opines that the precise nature of costs or benefits is *best* considered in base rate proceedings.⁶⁶

The Company has evaluated other reasonable alternatives in proposing its Meter Upgrade. Mr. Schneider describes that the Company followed its investment protocols in evaluating its Meter Upgrade, and explains the cost-benefit analysis that was performed.⁶⁷ Further, in discovery, the Company demonstrated that Duke Energy examined multiple technologies to determine a consistent AMI solution across its entire enterprise.⁶⁸ The Company explained that a Request for Quotation (RFQ) process was initiated and vendors were subsequently scored by multifunction subject matter teams from across the enterprise, in both commercial and technical areas.⁶⁹ Each team used a standardized approach to weight key

⁶⁵ See AG-DR-01-84 and AG-DR-02-28.

⁶⁶ Alvarez at 7. *Emphasis Added.*

⁶⁷ Schneider at 30.

⁶⁸ Response to Staff –DR-01-04.

⁶⁹ *Id.*

attributes within its focus areas, ensuring each vendor was fairly ranked.⁷⁰ At the completion of this exercise, the Itron OpenWay solution platform was identified as the leader and was awarded the RFQ in arriving at the selected plan.⁷¹

The Company has satisfied the CPCN legal standard, established “need,” and demonstrated that its Meter Upgrade proposal does not result in wasteful duplication. The AG’s Motion should be denied.

C. The Commission should evaluate the merits of the Company’s CPCN Application now.

1. The AG simply wishes to delay consideration of the Meter Upgrade.

The true purpose of the AG’s Motion is contained in the Motion’s final argument. The AG believes that the Company’s CPCN Application should be evaluated in a base rate proceeding, arguing that the true impact of the request can only be determined in the context of a rate case.⁷² The AG cannot truly justify its allegations against the Company’s CPCN Application. And if the Commission approves the CPCN now in this proceeding, the prudence and recoverability of costs will still be determined in the next rate case. The benefit of approving the CPCN now is that when the time comes for the Company to file its next rate case, assuming it happens after CPCN approval and commencement of deployment, the Commission will have actual Meter Upgrade costs to review. The same cannot be said if the Company must file a rate case before it can get CPCN authority to commence the investment. As explained below, a rate case is simply not required before a CPCN may be approved.

2. Rate cases are not a prerequisite for a CPCN application.

Under Kentucky law, a CPCN is necessary before any utility begins any construction that

⁷⁰ *Id.*

⁷¹ See *Confidential Attachments in Responses to AG-DR-01-27*, including responses to Duke Energy Corp. issued RFQs.

⁷² AG Motion at 3.

is not considered an ordinary extension of an existing system in the ordinary course of business.⁷³ There is absolutely no legal requirement that a utility can only request or receive a CPCN in the context of a base rate proceeding. The existing process for a CPCN approval is not a novel concept, and the Commission has a long history of evaluating necessary infrastructure investments absent a contemporaneously filed rate recovery mechanism or proceeding. In every CPCN proceeding that is not accompanied by a rate case or a surcharge recovery mechanism, the final rate impact will not, and cannot, be known until a subsequently filed rate case. Indeed, utilities must have the flexibility to make necessary infrastructure investments outside of a base rate test period, or else investments could not occur absent “pancaked” base rate applications. Plant additions would only be added to base rates at their highest value and prior to any depreciation. That is precisely the reason why a separate CPCN requirement exists and is not limited to requests solely within a base rate proceeding. Even if a base rate case were to be required for a utility to request a CPCN, the full rate impact cannot be known until the *next* base rate case *after* the project is complete.

Additionally, the Commission just completed its nearly four-year Smart Grid Administrative Case, having issued its Order less than four months ago. The Commission’s Order was thorough and made numerous findings, none of which required, limited, or even suggested that a CPCN application, such as the Meter Upgrade at issue, should be only considered in a rate case. In fact, the opposite is true. The Commission stated, among other things, that although it would not apply the formal CPCN process to each utility investment decision,⁷⁴ it is appropriate for utilities to obtain CPCNs for major AMR or AMI investments.⁷⁵ There was no limitation or directive that such CPCN filings should only occur in a rate case.

⁷³ KRS 278.020(1).

⁷⁴ Order at 25.

⁷⁵ *Id.* at 11.

Moreover, the AG, a party to the proceeding, did not object or seek rehearing on that issue, or any issue.

To do as the AG suggests, would establish bad precedent that stifles utility investment ability and results in an inefficient use of resources because investment approvals would only come after expensive and time consuming base rate proceedings. Such a policy would serve to increase costs to customers, limit investment in the Commonwealth, and task this Commission's resources by requiring full base rate examinations on top of CPCN determinations of need, irrespective of the magnitude of the investment. The Commission should not allow this to occur and should deny the AG's Motion.

3. Duke Energy Kentucky's 2006 Electric Rate Case does not prohibit the Company's current application.

The AG's citation to Duke Energy Kentucky's 2006 base rate proceeding (2006 Electric Case) as support for the position that the Meter Upgrade must reside in a rate case is inconsequential, and like the AG's other citations to regulatory proceedings, misses the point of the order, which was approval of a settlement.⁷⁶ Contrary to the AG's claims, the only thing "striking"⁷⁷ regarding the Commission's 2006 Electric Case Order was that the Commission found that Duke Energy Kentucky was not even obligated to seek a CPCN to make the \$14 million meter investment proposed.⁷⁸ In other words, the Company could just proceed without first receiving CPCN approval.

⁷⁶ Motion at 3; citing to *In the Matter of the Application of the Union Light Heat and Power Company d/b/a Duke Energy Kentucky for a Final Adjustment of Electric Rates*, Case No. 2006-00172 (KY.PSC December 21, 2006).

⁷⁷ AG Motion at 3.

⁷⁸ *In the Matter of the Application of the Union Light Heat and Power Company d/b/a Duke Energy Kentucky for a Final Adjustment of Electric Rates*, Case No. 2006-00172 (KY.PSC December 21, 2006) at 7.

Additionally, the AG did not mention that the Company's 2006 Electric Case was founded upon a projected or forecasted test year.⁷⁹ In other words, the entire case, including the then proposed \$14 million smart meter investment, was based upon a projection of future costs, not unlike what the Company has included in its current cost-benefit analysis in this proceeding. The difference is that in the 2006 Electric Case, the Commission approved a revenue requirement for the Company that included the proposed smart meter investment and implemented rates to customers, before the Company spent a single dollar on that investment.

Here, Duke Energy Kentucky is merely requesting permission to make the investment, based upon projected data, with cost recovery to be considered sometime after deployment commences, as it is legally permitted to do. This is no different than any other utility investment that is made outside of a discrete surcharge recovery mechanism.⁸⁰ Until Duke Energy Kentucky files a base rate proceeding, rates will not change for customers, and the risk of the investment lies solely with the Company insofar as the investment is not reflected in rates whatsoever. When the Company eventually files its next electric base rate case, the Commission will have its plenary statutory authority to determine whether, and to what extent, the Company's application results in a "fair, just and reasonable rate" for the service rendered.⁸¹ This authority will include review of the Company's balance of plant to determine a fair, just, and reasonable rate. And the AG will have all of its current rights to evaluate the Company's proposal and make its case.

The AG's motion to dismiss appears to be an attempt at delay without any regard to the impacts of its position and would establish a bad precedent whereby a utility would have to file a rate case to invest capital, whether it needed to establish new rates or not. Delaying the Meter

⁷⁹ *Id.* at 1, "On April 27, 2006, Duke Kentucky filed a notice of its intent to file an application for approval of an increase in its electric rates, utilizing a forward-looking test period ending December 31, 2007.

⁸⁰ *See e.g.*, KRS 278.183, authorizing establishment of environmental surcharge mechanisms for environmental recovery costs for coal combustion facilities.

⁸¹ KRS 278.020.

Upgrade until a future rate case will likely serve to increase costs of the program and deny customers the anticipated benefits through cost reductions and enhanced basic services. Duke Energy Kentucky will have to continue its current practice of testing, replacing, and investing in electro-mechanical meters. The current meter balance will likely continue to grow as the Company maintains inventories. The Company will have to maintain existing levels of staffing to support the manual meter reading, and those labor costs will likely continue to rise.

The AG's position to delay CPCN consideration until a base rate case is also illogical from a timing perspective when one considers Kentucky's rate-making regulations and practices. For example, if the Company had filed a base rate case with its CPCN application, whether it had a current deficiency or not, three and a half months ago, using a historic test period, under Kentucky regulations, those base rates will be determined based upon a look back to prior year expense (2015) and plant will be based upon a date certain that occurred in 2015.⁸² In other words, customer's new base rates will not reflect any Meter Upgrade costs or savings, because the Company had not yet received approval to make the investments. It would only be after the costs were incurred, in the next subsequent rate case, that such costs would be includable in rates.

Similarly, if Duke Energy Kentucky had filed a base rate case with its CPCN application using a future (forecasted) test period, the Company's base rates proposed would be based upon the Company's projections for the costs of the capital investment (13 month average) and O&M expense to be incurred during the next 12 months, in this example the period ended December 31, 2017.⁸³ No more, no less. The test period could only reflect savings that would have been projected for the forecasted test period. And the Commission will be left to approve such costs in

⁸² KRS 278.192(1)

⁸³ KRS 278.192(2)(a)

rates without the Company yet having made any investment whatsoever. Delaying the review of the Company's Application to a rate case is inefficient and inconsistent with past Commission precedent. The Commission should proceed with its evaluation of the Company's Meter Upgrade CPCN in this proceeding, just as it has done in the past for similar deployments.

III. Conclusion

For the foregoing reasons, the Commission should deny the AG's Motion and continue its review of the Company's CPCN Application in this proceeding.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.



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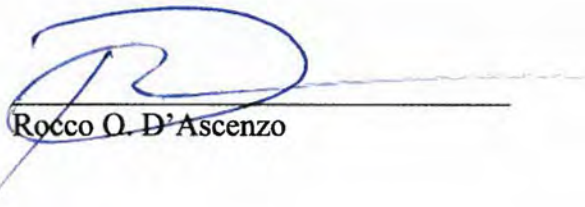
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CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing has been served via electronic mail to the following party on this 27th day of July, 2016.

Rebecca W. Goodman
Executive Director
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Office of the Attorney General
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Rebecca.Goodman@ky.gov



Rocco O. D'Ascenzo

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA,)
INC. FOR; (1) APPROVAL OF PETITIONER'S 7-YEAR)
PLAN FOR ELIGIBLE TRANSMISSION,)
DISTRIBUTION AND STORAGE SYSTEM)
IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-)
10; (2) APPROVAL OF A TRANSMISSION AND)
DISTRIBUTION INFRASTRUCTURE IMPROVEMENT)
COST RATE ADJUSTMENT AND DEFERRALS,)
PURSUANT TO IND. CODE § 8-1-39-9; (3) APPROVAL)
OF CERTAIN REGULATORY ASSETS; (4) APPROVAL)
OF VOLUNTARY DYNAMIC PRICING RIDERS; AND)
(5) APPROVAL OF A NEW DEPRECIATION RATE FOR)
ADVANCED METERS)

CAUSE NO. 44720

APPROVED: JUN 29 2016

ORDER OF THE COMMISSION

Presiding Officers:

Carol A. Stephan, Commission Chair

Jeffery A. Earl, Administrative Law Judge

On December 7, 2015, Duke Energy Indiana, LLC ("DEI") filed its Verified Petition in this Cause. DEI also filed the direct testimony and exhibits of the following witnesses:

- Melody Birmingham-Byrd, President of DEI;
- William H. Fowler, Vice President Design Engineering and Construction Planning–Midwest at Duke Energy Business Services, LLC ("DEBS");
- Donald E. Broadhurst, General Manager Transmission Construction & Maintenance at DEBS;
- Todd W. Pfennig, Director of Estimating, Americas Construction and Procurement Division at Black & Veatch Corporation;
- Donald L. Schneider, Jr., Director, Advanced Metering at DEBS;
- Jeffrey R. Bailey, Director, Pricing and Analysis at DEBS;
- Robert B. Hevert, Managing Partner at Sussex Economic Advisors, LLC; and
- Brian P. Davey, Director, Rates and Regulatory Strategy–Indiana at DEBS.

The following parties intervened in this Cause:

- Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor");
- Citizens Action Coalition of Indiana, Inc. ("CAC");
- Duke Energy Indiana Industrial Group ("Industrial Group");
- Steel Dynamics, Inc. ("SDI");
- Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy");

- Wabash Valley Power Association, Inc. (“WVPA”);
- Environmental Defense Fund (“EDF”);
- Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC (“CSN”); and
- Indiana Municipal Power Agency (“IMPA”).

On February 18, 2016, SDI filed the direct testimony and exhibits of Kevin C. Higgins, Principal in the firm of Energy Strategies, LLC. WVPA filed the direct testimony and exhibits of Gregory E. Wagoner, Vice President, Transmission Operations and Development at WVPA. Hoosier Energy filed the direct testimony and exhibits of William C. Ware, Manager Power Delivery Engineering at Hoosier Energy. And IMPA filed the direct testimony and exhibits of Jack Alvey, Senior Vice President of Generation at IMPA. On February 19, 2016, EDF filed the direct testimony and exhibits of Ronny Sandoval, Director, Grid Modernization at EDF, and Jim Hawley, Director with Mission:data Coalition.

On March 7, 2016, DEI, the OUCC, the Industrial Group, SDI, Hoosier Energy, WVPA, CSN, IMPA, and EDF (collectively “Settling Parties”) submitted a Settlement Agreement.

On March 8, 2016, the OUCC filed Consumer Comments that it had received.

On March 17, 2016, the Settling Parties filed the settlement testimony and exhibits of the following witnesses:

- DEI – Ms. Birmingham-Byrd, Mr. Broadhurst, Mr. Fowler, and Mr. Davey;
- OUCC – Ray L. Snyder and Leon A. Golden, both Utility Analysts in the OUCC’s Resource Planning and Communications Division;
- EDF – Mr. Sandoval;
- Industrial Group – Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc.;
- SDI – Mr. Higgins; and
- WVPA – Mr. Wagoner.

On April 7, 2016, CAC filed the settlement testimony and exhibits of Kerwin L. Olson, Executive Director of CAC.

On April 19, 2016, DEI filed the rebuttal testimony and exhibits of Ms. Birmingham-Byrd, Mr. Fowler, and Mr. Davey, and the Industrial Group filed the rebuttal testimony and exhibits of Mr. Phillips.

The Commission held an evidentiary hearing in this Cause at 9:30 a.m. on May 2, 2016, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. DEI, the OUCC, Nucor, CAC, Industrial Group, SDI, Hoosier Energy, WVPA, EDF, and CSN appeared by counsel and participated at the hearing. No members of the public participated at the hearing.

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

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published as required by law. DEI is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-39-10, the Commission has jurisdiction over a public utility's request for approval of a Seven-Year Plan for eligible transmission, distribution, and storage improvements. Under Ind. Code § 8-1-39-9, the Commission has jurisdiction over a public utility's request to recover eligible transmission, distribution, and storage system costs through a periodic rate adjustment. Therefore, the Commission has jurisdiction over DEI and the subject matter of this proceeding.

2. **DEI's Characteristics.** DEI is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana. DEI is a second-tier, wholly owned subsidiary of Duke Energy Corporation. DEI renders retail electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

3. **Relief Requested.** DEI requests approval of the Settlement Agreement, in its entirety, including approval of DEI's proposed Seven-Year Plan for eligible transmission, distributions, and storage system improvements ("Seven-Year Plan") under Ind. Code § 8-1-39-10. Specifically, DEI requests: (1) a finding that the projects contained in its Seven-Year Plan are "eligible transmission, distribution, and storage system improvements" as defined in Ind. Code § 8-1-39-1; (2) a finding that the best estimate of the cost of the eligible improvements was included in the Seven-Year Plan; (3) a determination that public convenience and necessity require or will require the eligible improvements summarized in the Settlement Agreement and included in the Seven-Year Plan; (4) a determination that the estimated costs of the eligible improvements included in the Seven-Year Plan as summarized in the Settlement Agreement are justified by incremental benefits attributable to the Seven-Year Plan; (5) if and to the extent the Commission determines that the Seven-Year Plan is reasonable, DEI requests the Commission approve the Seven-Year Plan and designate the eligible transmission, distribution and storage system improvements included in the Seven-Year Plan as eligible for Transmission, Distribution and Storage System Improvement Charge ("TDSIC") treatment under Ind. Code § 8-1-39-9; (6) deferral of 100% of the depreciation associated with AMI up to \$60 million for recovery in DEI's subsequent retail base rate proceeding; (7) recovery of deferred depreciation associated with AMI over a 10-year period without carrying costs in DEI's next general retail rate case; (8) deferral of post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's subsequent retail base rate proceeding; (9) recovery of the deferred post-in-service carrying costs associated with the AMI project over a 10-year period without carrying costs in DEI's subsequent retail base rate case; (10) approval of DEI's ratemaking proposals, including the transmission and distribution ("T&D") Infrastructure Improvement Cost Rate Adjustment, Standard Contract Rider No. 65 ("T&D Rider" or "Rider 65"), for recovery of 80% of the \$1.408 billion Seven-Year Plan costs, and deferral with carrying costs of 20% of the Seven-Year Plan costs for subsequent recovery in DEI's next general retail electric base rate case; (11) approval of DEI's proposed process for updating the Seven-Year Plan in future annual proceedings consistent with the Settlement Agreement; and (12) approval of a depreciation rate specific to the advanced meters deployed as part of the AMI project.

4. DEI's Case-In-Chief Evidence.

A. **Ms. Birmingham-Byrd.** Ms. Birmingham-Byrd testified that in developing the Seven-Year Plan, DEI focused on improvements that maintain reliability and modernize the T&D grid to enable additional value-added customer services and options now and in the future. Ms. Birmingham-Byrd testified that while reliability is job number one for electric service providers, consumers have come to expect more, better, and faster information about all the services and products they consume. She testified that the Seven-Year Plan contains investments that will allow DEI to reduce unplanned outages, pinpoint fault locations faster, reduce the scope of customer outages, reduce the length of customer outages, and provide better, faster, more accurate information to customers about the cause of the outage and the expected time of restoration. In addition, certain resiliency investment projects are designed to strengthen the delivery system from threats due to severe weather, improving overall reliability.

Ms. Birmingham-Byrd testified that the Seven-Year Plan cost estimates are DEI's best estimates of the costs at this time, but that DEI expects the estimates to change over time as DEI moves to more detailed engineering and construction plans. The cost estimates have been reviewed for reasonableness by a third-party consultant, Black & Veatch. Ms. Birmingham-Byrd testified that as the Seven-Year Plan develops, engineering progresses, and contracts are entered into for labor, materials, and construction, DEI will update its cost estimates in future T&D Rider filings. Ms. Birmingham-Byrd also provided testimony concerning the reasonableness of the overall rate impact of the Seven-Year Plan. DEI is aware of the need to balance rate impacts with the need and value of the Seven-Year Plan. As a result, the average annual rate impact is slightly less than 1%—below the 2% annual cap permitted by Ind. Code § 8-1-39-14(a).

Ms. Birmingham-Byrd provided testimony regarding the economic development impacts on the State of Indiana. The proposed Seven-Year Plan is estimated to create or support an estimated average of 2,700 jobs per year in the U.S. for each of the seven years of the plan (or 840 jobs per year in Indiana). These jobs include both direct jobs and indirect or induced jobs that are created or supported by the Seven-Year Plan investment. The Seven-Year Plan is also estimated to produce about \$184 million in additional state and local tax revenue. The direct jobs created from this investment will be a mix of contractor and direct employee hires and could include construction and maintenance, engineering, project management, operating, and other technical support positions.

Ms. Birmingham-Byrd testified that the Seven-Year Plan is reasonable and provides substantial customer benefits, while limiting investments to those needed to maintain a reasonable level of reliability, to modernize the grid responsibly, and to maintain a manageable rate impact.

B. **Mr. Fowler.** Mr. Fowler provided testimony on the Distribution portion of the Seven-Year Plan. Mr. Fowler testified that the majority of year-one estimates are AACE Class 2 estimates with all units identified by substation and circuit, with 30% to 70% of detailed engineering complete. The majority of year-two estimates are AACE Class 3 estimates with units identified by substation and circuit. The unit cost is a combination of the historical actual cost with approximately 10% to 40% of the total units engineered. Estimates for years three through seven are AACE Class 4 estimates with units identified by substation and circuit. The units are then

parametrically modeled (a cost estimating methodology that combines actual historical data with statistical data to develop cost estimates) using historical actual cost and a standard 3% escalation per year to derive projected cost. As the project implementation year approaches, actual engineering design estimates will be developed at a Class 3, and then at a Class 2 level prior to being submitted to the Commission as part of DEI's annual detailed work plan. Mr. Fowler testified that contingency is included in the project cost estimates and is the result of the Monte Carlo simulation at the 50% Probability ("P50") confidence level. Since projects go into service each year, contingency is broken out for each year. At the end of each year any unused contingency held for that year is eliminated and does not carry over into future years. Mr. Fowler testified that DEI will make updates to its Plan at least annually. He testified that DEI is requesting recovery of project-related O&M that is incurred while the capital projects are under construction, as is standard practice in the utility industry. Mr. Fowler testified that he has a high confidence in the estimating process.

Mr. Fowler provided Petitioner's Exh. 2-A, which is an overview of the Seven-Year Plan, including a seven-year summary of the projects and cost estimates. He also provided an overview of DEI's electric distribution system. DEI serves over 800,000 customers through approximately 22,000 miles of distribution lines. A significant portion of DEI's system was constructed in the 1960s, 70s, and 80s, and is approaching its life expectancy. Mr. Fowler explained that DEI used an organic, bottom-up approach to selecting the projects included in the Seven-Year Plan. System planners and engineers selected projects based upon age, system conditions, and the availability of grid modernization equipment. Numerous factors were analyzed to determine an appropriate timeline for constructing the projects in a planned and risk-based manner, including availability of materials and labor resources. Projects were selected based on their improvement to system integrity and reliability, with the benefit to customers in mind.

Mr. Fowler testified that projects were included in a risk model to quantify the level of risk reduction benefits achieved by the Plan and to prioritize specific assets for investment within some of the projects. No projects were intentionally included or excluded based on risk reduction levels. Rather, the experience and expertise of DEI's engineering staff was used to ultimately select projects for the Seven-Year Plan. The replacement assets chosen are aging or deteriorating assets.

Mr. Fowler identified the distribution projects included in the Seven-Year Plan in Petitioner's Exh. 2-C and Confidential Exhs. 2-B and 2-D. He testified that the Distribution Workplan includes inspection-based projects that are on planned cycles. These assets require a dedicated inspection per location to evaluate each component condition based on criteria often unique to each project category and specific to each site condition. These assets are so numerous that they require inspection on planned cycles over a period of years. He testified that DEI only proposed inspection-based projects where the work involved is highly repetitive, the assets are numerous, and the projects have well-defined, unitized cost estimates. Mr. Fowler testified that not all of DEI's annual T&D spending was included in the Plan. DEI has a multitude of projects and programs that are not included in the Seven-Year Plan. He testified that DEI will routinely reprioritize projects within the submitted Seven-Year Plan based on the best interest of its customers.

Mr. Fowler testified that the Integrated Volt-VAR Controls (“IVVC”) project provides real-time monitoring and the ability to make voltage adjustments to the distribution system, which is estimated to ultimately reduce overall system voltage by approximately 2% on impacted circuits. This equates to an estimated 1.4% load reduction for impacted circuits, providing cost savings to customers. Engineering studies were completed by DEI to determine which circuits to deploy IVVC on to deliver the best results. The studies resulted in a plan for IVVC to be installed on approximately 50% of the total quantity of Company-owned substations and circuits. This represents approximately 6,800 MW of peak retail load under IVVC control. DEI completed a cost-benefit analysis, which demonstrated that the IVVC project is estimated to provide a benefit of \$219 million over a 20-year life.

Mr. Fowler also described how DEI will update the Commission and intervenors if there are changes to the Seven-Year Plan. DEI plans to make updates to its Seven-Year Plan annually. The Seven-Year Plan includes alternate projects to attempt to deal with the likelihood of change. DEI proposes that the Commission designate these alternate projects as eligible projects, to allow for the option of moving them into the Seven-Year Plan. DEI commits that the overall costs of the Seven-Year Plan would not be substantially changed by substituting these alternate plans.

Mr. Fowler testified that Black & Veatch conducted an independent cost review of DEI’s Seven-Year Plan capital cost estimates and estimating process. Black & Veatch concluded that the process used for project cost estimating and the project cost estimates were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes.

Mr. Fowler testified that Black & Veatch also helped DEI develop a risk profile analysis. The results of the risk profile analysis shows a total T&D system risk reduction of 31% over the Seven-Year Planning period. The risk profile analysis demonstrates that the Seven-Year Plan results in tangible risk reduction and reliability benefits. The Seven-Year Plan also improves the operational efficiency of DEI’s T&D system, as well as improves upon the overall customer experience and enables a number of customer benefits and programs in this filing and in future years. Mr. Fowler testified that the project and programs included in the Seven-Year Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

C. Mr. Broadhurst. Mr. Broadhurst provided details of the Transmission Line and Transmission and Distribution Substation components of the Seven-Year Plan. He testified that the T&D Substation and Transmission Line projects will reduce outage occurrences and outage durations and improve power quality for transmission level and distribution level residential, commercial, and industrial customers. Mr. Broadhurst provided Petitioner’s Confidential Exh. 3-A, which is a cost estimate for the Transmission Line and T&D Substation components of the Seven-Year Plan. In addition, the individual project workplans and additional, supporting cost estimate information was provided in Confidential Exhs. 3-D and 3-E.

Mr. Broadhurst explained how the Transmission Line and T&D Substation project cost estimates were developed. The T&D substations or transmission lines were identified as candidate projects based on numerous factors, including history of outages caused by equipment issues and equipment identified for replacement due to poor performance or operational issues. Once a

substation or line was selected for an upgrade project, a detailed project scope was identified. From this detailed, asset-specific project scope, an AACE Class 4 estimate of the project was calculated and used for the majority of projects in Years 4-7 of the Seven-Year Plan. Class 4 estimates for T&D Substation-related projects are parametric estimates calculated based on the estimated cost for a typical unit of work, and the number of such units to be included in the project. To identify the unit costs, project estimates were developed for approximately 65 different asset replacement activities by DEI Energy estimating engineers. Also, for some activities the project estimate for a specific comparable recent project was used as the typical unit cost. Class 4 estimates for Transmission Line projects were created by developing averages of recently bid capital projects and calculating average costs per mile and per support structure. These unit costs were then applied to Seven-Year Plan project work scopes. Mr. Broadhurst testified that as these projects approach their targeted in-service year, a detailed AACE Class 3 estimate will be prepared utilizing the project estimation workbook. He stated that all projects planned for Year 2 of the Seven-Year Plan (2017) and many of the projects planned for Year 3 (2018) currently have Class 3 or better estimates prepared. He explained that as projects come even closer to their targeted in-service year, updated materials and labor cost estimates are used to further update the project estimation workbook as an AACE Class 2 estimate. Mr. Broadhurst testified that all projects included in Year 1 of the Seven-Year Plan currently have a Class 2 estimate prepared. Mr. Broadhurst explained that providing better than a Class 4 AACE estimate for the latter years of the Seven-Year Plan would be inefficient and unrealistic due to the influence of many external factors over the next seven years, including changes to labor rates, materials rates, engineering or design analysis, changes to project scope, rules and standards changes, and system growth or other load changes.

Mr. Broadhurst testified that specific project-related O&M, incurred during the construction of the capital projects, has been estimated and requested in this proceeding. The T&D Substation project-related O&M and capital estimates are in Petitioner's Confidential Exhibits 3-A and 3-D. The Transmission Line project-related O&M and capital estimates are in Petitioner's Confidential Exhibits 3-A and 3-E. In addition, examples of work orders for both T&D Substation and Transmission Line projects have been provided in Petitioner's Confidential Exhibit 3-F.

Mr. Broadhurst testified that the Commission can be assured that the estimates are "best estimates" because DEI's engineering team has decades of experience developing cost estimates and constructing the assets that are included in the T&D Substation and Transmission Line plans. Further, Black & Veatch reviewed DEI's cost estimates and cost estimating methodology, finding the process reasonable and the cost estimates and AACE estimate levels accurate. Mr. Broadhurst also testified that contingency is added to the base cost estimates of the project categories to cover estimated uncertainty and risk, as recommended per AACE guidelines.

Mr. Broadhurst testified that from the 615 potential projects scoped and estimated, DEI selected 323 projects at 280 T&D Substations and 144 projects on 81 Transmission Lines for inclusion in the Seven-Year Plan. The Seven-Year Plan also identifies 46 projects at 42 T&D substations, and 8 projects on 8 transmission lines that DEI plans to complete on the transmission system jointly owned with IMPA and WVPA. Mr. Broadhurst explained that these projects are not included for cost recovery in the Seven-Year Plan. In addition, DEI identified 36 projects at 35 T&D Substations and 58 projects on 26 Transmission Lines as "Alternate" projects. Mr. Broadhurst testified that project summaries for the Transmission Line and T&D Substation

projects are in Petitioner's Exhibits 3-B and 3-C. The summaries include what assets have been selected for replacement, how they were selected, the types of equipment that will be replaced, and the significant customer benefits that will result from the projects.

Mr. Broadhurst testified that flexibility and the ability to update the Seven-Year Plan with additional projects is critical, as system conditions change over time. He testified that DEI plans to file annual updates to the Seven-Year Plan. In addition to updating project costs, schedule, and benefits, there could be a need to move some projects into or out of the Plan. DEI requested that the Commission designate the Alternate projects it has identified in its case-in-chief as eligible projects, so that in future TDSIC mechanism filings DEI would have the option of moving them into the Seven-Year Plan without substantially changing the overall costs of the Seven-Year Plan. Mr. Broadhurst further testified that the projects and programs included in the Seven-Year Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

D. Mr. Pfennig. Mr. Pfennig testified that Black & Veatch conducted an independent cost review of DEI's Seven-Year Planning capital cost estimates and estimating process. The review evaluated estimates for reasonableness based on Black & Veatch's experience and the information and backup data received from DEI for its cost estimates. He testified that Black & Veatch concluded that the process DEI used for T&D project cost estimating was reasonable and the project cost estimates reviewed were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes. He further testified that DEI spent an incredible amount of time and resources in developing the Seven-Year Plan and associated cost estimates and, in his opinion, have met the requirement for what is necessary to show that they provided a best estimate.

Mr. Pfennig explained how Black & Veatch conducted its analysis. He testified that a total of nearly 24% of the entire Seven-Year Plan capital costs were reviewed, which is statistically significant. Mr. Pfennig testified that it is not reasonable for DEI to have Class 2 or 3 estimates for years 3-7 of the Seven-Year Plan due to the amount of engineering and site investigation that would be needed. Mr. Pfennig concluded that DEI's estimates are the best estimate of the projects identified in the Seven-Year Plan, given the available data and a reasonable balance of the cost and benefit to develop the estimates. He also testified that the assumptions DEI used in its cost estimating process are reasonable.

E. Mr. Schneider. Mr. Schneider provided a detailed overview of the Advanced Metering Infrastructure ("AMI") proposal. He testified that the project involves a 4.5 year phased deployment of approximately 829,500 meters, a communications network, and back office systems. DEI will install advanced meters for its residential and commercial customers and for any large commercial and industrial customers that do not already have advanced meters installed. Deployment will occur over the first 4.5 years of the Seven-Year Plan, with a ramp up in years two and three. He explained that the AMI meters and communication infrastructure will be deployed by district on a rolling basis triggered by district completion metrics, rather than waiting to complete one district completely before beginning on a neighboring district.

Mr. Schneider testified that advanced meters have two-way communications capability and can be used for interval usage measurement, tamper detection, voltage and reactive power

measurement, and net metering. He testified that DEI will install a neighborhood area network (“NAN”) and use a third-party-provided wide area network (“WAN”) to make use of the advanced meters’ two-way communications capability. The NAN represents the network connecting advanced meters to grid routers through a radio frequency (“RF”) mesh architecture. Range extenders may be used to extend the mesh signal to meters that would otherwise be outside the reach of the mesh network. He explained that routers aggregate the communications from advanced meters within the NAN and transmit them to the WAN. They also communicate commands, firmware/program updates, and instructions from the WAN out to the advanced meters within the NAN. DEI will utilize secured communications over public cellular networks in Indiana as its WAN. The back office systems consist of the Meter Data Management (“MDM”) system, which processes usage and event data from the advanced meters. Processing involves validating, editing, estimating, and packaging data for billing and other uses. Mr. Schneider testified that all meters will transmit interval kilowatt-hour (“kWh”) usage data for billing purposes as well as time-tagged event and alert data such as tamper alerts. Some meters will transmit voltage, amperage, phase angle, or other data, as needed to improve system models for system planning, increased efficiencies with respect to outage restoration, and other system operations purposes.

Mr. Schneider testified that DEI is proposing technology proven not only across the industry, but specifically proven by Duke Energy in other jurisdictions, particularly in Ohio and in the Carolinas, that DEI will benefit from. Mr. Schneider described the changes customers will see in their service after the new metering solution is installed, including the ability to view hourly interval usage data from the previous day via the customer web portal, the elimination of monthly walk-by meter reads, remote service activation or deactivation, and improved outage restoration.

Mr. Schneider testified that DEI performed a customer cost-benefit analysis for the new metering solution, which showed a net present value (“NPV”) of approximately \$113 million. The payback period for the investment is approximately 8.6 years and 10.1 years on a net present value basis. Additionally, a sensitivity run for the AMI cost-benefit analysis that recognizes the potential for additional benefits that AMI could enable in the future results in a NPV of approximately \$193 million. Mr. Schneider testified that the estimated cost for deploying the AMI solution is about \$192 million over the Seven-Year Plan. The cost estimate is at least an AACE Class 3 level. He testified that the base cost-benefit analysis and the sensitivity both demonstrate that there are quantifiable benefits that substantially outweigh the costs of the Plan. Mr. Schneider also testified that many of the benefits included in the Plan will naturally flow to customers through DEI’s existing riders, such as the fuel adjustment clause rider. A large part of the customer benefits are operational cost savings gained through expense reductions related to meter reading, truck roll reductions, consumer order worker reductions, and outage assessment reductions. Smaller operational cost savings include reduced estimated bills and improved vegetation management utilizing voltage sag data from meters. He testified that the TDSIC mechanism will include a credit equivalent to the ongoing AMI operating costs minus the quantifiable ongoing AMI benefits that do not already flow to customers in other riders. Mr. Schneider testified that the cost-benefit estimates are reasonable.

F. Mr. Bailey. Mr. Bailey provided testimony regarding four optional rate offerings DEI intends to offer upon approval and implementation of AMI, two for residential and two for small commercial service. He explained that these are time-of-use rates with seasonal and

time-based on-peak and off-peak price differentiation. He testified that the time-of-use rates are revenue neutral. Mr. Bailey described the variable peak pricing component of the rate design where customers are incented to either reduce load or pay a more appropriate price for the electricity they do consume during high-priced time periods. Mr. Bailey testified that these new rates will be entirely voluntary. In addition, DEI will offer customers a first-year, one-time bill guarantee. At the end of the first year of service, a bill comparison will be presented to the customer and if the customer paid more under the new rates relative to the standard rate, they will receive a credit for the difference. He testified that DEI will attempt to obtain at least 5,000 customers per year for five years following approval and implementation of the AMI metering solution. Mr. Bailey also described DEI's request for authority to modify certain Standard Contract Riders such that they include a kW demand charge applicable to these new rate schedules.

G. Mr. Hevert. Mr. Hevert testified that DEI's currently authorized return on equity ("ROE") of 10.50% is within a reasonable range of analytical results, and neither capital market conditions nor the presence of the TDSIC mechanism justifies a reduction to the ROE. Mr. Hevert provided an overview of the analyses that led to his ROE recommendation. He testified that he relied on three widely accepted approaches: (1) the Discounted Cash Flow model, including the Constant Growth, and Multi-Stage forms; (2) the Capital Asset Pricing Model; and (3) the Bond Yield Plus Risk Premium approach. In addition, his recommendation takes into consideration DEI's cost recovery mechanisms and the current capital market environment.

H. Mr. Davey. Mr. Davey provided testimony about the rate impacts of the Seven-Year Plan. Mr. Davey testified that DEI is requesting authority to recover 80% of the retail jurisdictional share of the Seven-Year Plan costs through the new proposed Rider 65 under Ind. Code § 8-1-39-9(a). He stated that this would include depreciation, O&M, extensions and replacements, property taxes, and pretax returns on eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post-in-service. In addition, DEI requests authority to accrue post-in-service carrying costs until the Seven-Year Plan projects are included in retail rates. He testified that DEI requests deferral for subsequent recovery of the retail jurisdictional portion of the remaining 20% of allowance for funds used during construction ("AFUDC"), post-in-service carrying costs, operation and maintenance expense, taxes, and depreciation expense using a regulatory asset account (FERC CFR Account 182.3) until such costs are fully reflected in DEI's retail base rates after a general retail electric base rate case. DEI also requests that carrying costs on these deferred costs be accrued using DEI's overall weighted cost of capital as most recently approved by the Commission. He stated that AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. He testified that the post-in-service carrying costs will be accrued on approved capital expenditures, including accrual on previously computed post-in-service cost amounts, from the in-service date until such costs are included in DEI's rates under Rider 65 or in base rates.

Mr. Davey also testified that the retail jurisdictional portion of post-in-service operation and maintenance, depreciation, tax expense, and post-in-service carrying costs will be deferred with respect to Seven-Year Plan costs from the in-service date until the cost is included in DEI's rates under Rider 65 or in base rates. He testified that for purposes of inclusion in the T&D Rider, DEI will consider both the FERC accounting and whether the function is a transmission or

distribution service. Mr. Davey testified that DEI will not be netting depreciation for retired assets against the depreciation for the new assets being added in the Seven-Year Plan, as this is more appropriately accomplished in a base rate case. He testified that the requested depreciation rate of 6.67% for the new meters is based on their 15-year expected useful life.

Mr. Davey testified that DEI is requesting approval for the creation of a regulatory asset for the existing meters that will be replaced under the Seven-Year Plan. The estimated increase in depreciation expense to fully depreciate the meters over their shorter estimated remaining life would be \$9 million over the first 4.5 years of the plan. He testified that rather than recovering the higher amount of depreciation expense over the shorter remaining lives of the meters, DEI proposes to include the difference between the depreciation expense under the current depreciation rate and what the new depreciation rate would be in a regulatory asset and amortize it over the estimated remaining life of the meters (approximately 17 years). DEI also requests the authority to continue to earn a return on these meters whether in rate base or a regulatory asset. Mr. Davey testified that this accounting treatment is in accordance with Generally Accepted Accounting Principles (“GAAP”).

Mr. Davey testified that DEI proposes to update Rider 65 at least annually. He testified that Rider 65 recovers 80% of the retail jurisdictional portion of the costs associated with the Seven-Year Plan projects and would include financing costs, O&M directly associated with the construction of the project, O&M savings and O&M expenses associated with AMI, depreciation, and taxes. The costs also include the program plan development and support costs from Black & Veatch. In addition, DEI proposes to include the estimated \$40.5 million net AMI savings credit in the T&D Rider. Mr. Davey testified that DEI proposes to use the return on common equity approved by the Commission in the most recent general retail electric base rate case of 10.5%. He testified that DEI proposes to allocate the transmission, distribution excluding meters, and meters revenue requirement developed for Rider 65 to the rate groups based on the revenue requirement by rate group for these same three categories from the last retail base rate case, Cause 42359. Costs will be billed to individual customers within a rate group based on kilowatt-hour sales except for customers served under Rate HLF, which will be based on non-coincident kW demands. Wholesale customers will also be allocated a portion of the Seven-Year Plan costs. Mr. Davey testified that DEI proposes to use forecasted amounts for O&M, depreciation, and property taxes, based on annual cut-off dates. The financing costs on invested capital would be on an actual basis based on the same annual cut-off dates. He stated that DEI would true-up both of these amounts to actual levels of O&M, depreciation, and property taxes and to actual kWh sales levels in subsequent Rider proceedings. He testified that DEI proposes to make annual filings of Rider 65 that would include an update to the remaining years of the Seven-Year Plan. Mr. Davey also testified that DEI is proposing to include the expenses incurred for retaining Black & Veatch in this proceeding, and to include the Black & Veatch costs associated with providing testimony and supporting DEI’s filing in this proceeding and amortizing all Black & Veatch costs over a three-year period.

Mr. Davey testified that although the rate impact of the Seven-Year Plan will vary based on a number of variables, the total annual average retail rate impact compared to retail revenue is estimated to be slightly less than 1% over the seven-year period. Mr. Davey stated that if an actual

amount exceeds the two percent annual statutory cap, DEI requests approval to defer recovery of the TDSIC costs above the cap under Ind. Code §8-1-39-14(b).

5. Intervenor's Case-in-Chief Evidence.

A. **EDF.** Mr. Hawley recommended that DEI be required, as part of its AMI deployment, to embrace customer and authorized third party access to smart meter data for energy management services so customers can receive the significant energy savings made possible by AMI technology. Mr. Hawley testified that DEI should be providing customers with their usage and billing data as part of basic utility service, without charge, via Green Button Connect My Data. In addition, customers should receive real-time access to detailed energy usage data in order to get the full availability of customized energy efficiency and demand response programs through the home area network radios contained in the advanced meter.

Mr. Sandoval testified that DEI's IVVC proposal is generally reasonable and should be approved by the Commission. He testified that although DEI's proposed number of IVVC installations is significant, DEI should continue to periodically examine the cost-effectiveness of potential IVVC deployments across circuits that have been excluded from the existing selection criteria. He recommended that DEI file periodic reports on the voltage reductions achieved by IVVC and the resulting energy usage reductions. The updates should also include the carbon reduction and greenhouse gas impact of its IVVC deployment. In addition, Mr. Sandoval testified that DEI's Integrated Resource Planning ("IRP") should be used to inform and quantify the potential benefits that may be realized through IVVC and distribution automation deployment. If the investments identified in the proposed Seven-Year Plan can defer investments or reduce operational costs identified in the IRPs or other capital investment plans, those benefits should be recognized and accounted for in the Seven-Year Plan.

B. **Hoosier Energy.** Mr. Ware testified regarding the relationship between Hoosier Energy and DEI regarding transmission, substation and distribution delivery points, and interconnections. He testified that Hoosier Energy is supportive of DEI's Seven-Year Plan because increased investment in the power delivery system will reduce the number and duration of transmission-related outages thus improving overall reliability to retail consumers. Mr. Ware testified that Hoosier Energy has worked with DEI to identify specific transmission and substation upgrades and replacements that will have the most beneficial impacts. He testified that Hoosier Energy and DEI have met on several occasions to understand the nature and scope of DEI's Seven-Year Plan and have agreed to biannual meetings to address progress and discuss potential future upgrades. Mr. Ware testified that Hoosier Energy supports Plaintiff's Seven-Year Plan as a reasonable method of providing transmission system upgrades and improvements.

C. **IMPA.** Mr. Alvey testified that IMPA currently provides the full electric power requirements of 59 member communities in Indiana and one Ohio town and owns generation assets in Indiana, Illinois, and Kentucky. IMPA also owns transmission assets known as the Joint Transmission System (or "JTS") through an agreement with DEI and WVPA. He testified that transmission performance is important to IMPA's members, who provide electric distribution service to more than 100,000 retail customers. Mr. Alvey testified that increased investment in the JTS, as described in DEI's Seven-Year Plan, will improve reliability of service

to IMPA's members and their retail customers. He testified that IMPA estimates that it will invest approximately \$60 million as its share of the costs in the Joint Transmission System over the next seven years to improve reliability and accommodate additional load growth. IMPA and its members are most interested in infrastructure replacement to remove outdated and worn structures and the upgrade from manual switches to automatic switches. Mr. Alvey testified that IMPA has met with DEI on several occasions to understand the nature and scope of its Seven-Year Plan and will continue to meet to discuss work plans and help identify projects that will directly improve transmission service operated and maintained by DEI through the JTS.

D. SDI. Mr. Higgins recommended that DEI's AMI proposal be rejected as part of the TDSIC. However, in the event the AMI proposal is approved as part of the TDSIC recovery, DEI's request for deferred accounting treatment for its retiring meters should be rejected and TDSIC recovery for AMI should be limited to plant classified in FERC accounts 350 through 374. Mr. Higgins further testified that DEI's proposed allocation of TDSIC mechanism revenue requirement is unreasonable and inequitable and should be rejected. He argued that the revenue requirement is insufficiently specific within the HLF customer group because it did not recognize voltage differentiation. HLF tariff rates are properly differentiated by voltage consistent with the principle of cost causation, reflecting among other things, the fact that customers taking service at transmission voltage use either none, or very little of, the distribution system. DEI's TDSIC mechanism for HLF customers should be modified to properly reflect voltage differentiation applicable to the cost categories in the Seven-Year Plan using the cost allocation factors determined in Cause No. 42359. Mr. Higgins also testified that DEI should be required to include the effects of any applicable bonus tax depreciation in DEI's TDSIC revenue recovery and further testified that the TDSIC mechanism should not apply to non-firm or interruptible load.

E. WVPA. Mr. Wagoner testified that transmission performance is very important to WVPA's members. WVPA has 393 wholesale delivery points serving its 23 distribution cooperatives, which in turn are providing electric service to approximately 350,000 retail customers. Increased investment in the JTS will reduce the number and duration of transmission related outages, thus improving overall reliability to its distribution cooperative members and their retail customers. Mr. Wagoner testified that WVPA and its members have experienced an increasing trend in the number and duration of transmission-related outages due to the aging transmission infrastructure. Increased investment in the transmission systems from which its members receive service, such as the JTS owned by DEI, WVPA, and IMPA, will result in a demonstrable improvement in the overall reliability of service by its members to their customers. Mr. Wagoner testified that WVPA estimates that it will invest approximately \$100 million in the JTS related to normal activity, and an additional \$42 million under DEI's Seven-Year Plan over the next seven years to improve reliability and accommodate additional load growth. He testified that WVPA and its members have met with DEI on several occasions to understand the nature and scope of DEI's Seven-Year Plan, and will continue to meet at least twice a year.

6. Evidence Supporting the Settlement Agreement.

A. DEI. Ms. Birmingham-Byrd provided an overview of the Settlement Agreement, including the following terms: (1) a cap on Seven-Year Plan costs of \$1.408 billion,

with the flexibility for DEI to adjust the projects within the Plan as circumstances dictate, such as system changes, reliability issues, or reasonable and prudent cost changes; (2) recovery of a maximum of 80% of \$1.408 billion in capital and associated project O&M via Rider 65 over the seven-year period, with 20% authorized to be deferred for subsequent recovery; (3) removal of AMI project capital and O&M costs from the Plan; (4) deferral of certain AMI project capital costs; (5) a reduced return on equity of 10% for the T&D Rider; and (6) associated ratemaking treatment. She testified that the \$1.408 billion cap constitutes a reduction in capital costs of \$397 million from the December 7, 2015, Seven-Year Plan (“Original Plan”). The Settlement Agreement removes approximately \$192 million in AMI projects from the Seven-Year Plan and from the TDSIC ratemaking treatment; approximately \$175 million in transmission capital improvements; and approximately \$30 million in distribution capital improvements from the TDSIC ratemaking treatment.

Ms. Birmingham-Byrd explained that the Settlement Agreement authorizes DEI to use any project or program included in the Original Plan (excluding AMI) to make up the \$1.408 billion total Plan cap. In other words, the \$30 million in distribution projects and the \$175 million in transmission projects that were removed from TDSIC ratemaking treatment are still considered part of the Seven-Year Plan as alternate projects and can be used to replace projects in the Plan, if needed. However, the cumulative cost caps included in the Settlement Agreement limit the TDSIC ratemaking treatment to \$1.408 billion in capital costs over seven years. The Settling Parties agree that DEI should have the flexibility to move projects from one year to another within the Seven-Year Plan. In addition, DEI is not obligated to implement the entirety of the Seven-Year Plan or to implement the full \$1.408 billion capital cost cap amount over seven years. As a result, Ms. Birmingham-Byrd testified that the Settling Parties request that DEI be authorized to implement components of the Seven-Year Plan in good faith up to the \$1.408 billion cap over a seven-year period. Under the Settlement Agreement, DEI will update its Seven-Year Plan at least annually, at which time it will present Seven-Year Plan updates to the Commission and Settling Parties, consistent with the TDSIC statute.

Ms. Birmingham-Byrd testified that DEI has agreed to remove AMI capital and O&M costs from the Seven-Year Plan. If DEI proceeds with AMI, the estimated net savings associated with the AMI project will be retained by DEI until a subsequent retail base rate case. The Settlement Agreement also authorizes the deferral, without carrying costs, of 100% of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent retail base rate proceeding. In addition, the Settling Parties agree that DEI should be authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent retail base rate proceeding. DEI will recover these amounts over a ten-year period without carrying costs in its subsequent retail rate case. Ms. Birmingham-Byrd testified that the Settling Parties have agreed not to oppose inclusion of an AMI project into rate base and DEI’s base rates at the time of its retail base rate case, subject to normal prudence review, including a review of the associated AMI costs. In addition, the Settling Parties agree to request approval of a new depreciation rate for the new AMI meters based on a 15-year life. Ms. Birmingham-Byrd testified that DEI agrees to drop its request for a regulatory asset associated with the current meters and if DEI proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner. In

addition, as part of the Settlement Agreement, DEI agrees to withdraw its proposal to offer time of use rates.

Ms. Birmingham-Byrd testified that DEI agrees to develop, evaluate, and project the cost-effectiveness for an energy efficiency/demand response pilot program that leverages smart thermostats and customer engagement platforms for energy and demand savings. DEI will consult with its Energy Efficiency Oversight Board (“OSB”) and EDF in designing the program. Ms. Birmingham-Byrd testified that DEI will present its proposal to its OSB on or before such time as the AMI meters are certified for approximately 25% of DEI’s system. In addition, DEI commits to good faith discussions with EDF to evaluate the feasibility of technology tests and an initial pilot that will allow for near real-time energy data access to customers. Ms. Birmingham-Byrd testified that the Settlement Agreement is reasonable and in the public interest.

Mr. Fowler provided settlement testimony related to the distribution portion of DEI’s Seven-Year Plan. He testified that DEI has agreed to reduce the distribution circuit improvements by a cumulative \$30 million, consisting of a targeted reduction of \$6 million in each year from 2018-2022. He explained that the \$30 million in distribution projects will remain available as alternate projects to provide flexibility in implementing the Seven-Year Plan. The alternate projects contained in the Original Plan have been removed from the Seven-Year Plan. Mr. Fowler testified that the contingency amounts for the distribution projects in years 2018-2022 were reduced in an amount proportional to the reduction in planned work for each of those years, based against the Original Plan. He testified that the revised Plan includes \$54.2 million of distribution project-related O&M, which was also decreased. Mr. Fowler explained that DEI leveraged the knowledge of its internal company resources to identify the reduction of projects that pose the lowest impact to the plan objectives. No projects were totally eliminated; instead, DEI reduced the scope on selected projects. DEI elected not to reduce scope on any projects that support Distribution Automation (“DA”) or IVVC, both of which have significant customer benefits. Mr. Fowler testified that DEI will update the Seven-Year Plan annually in TDSIC mechanism proceedings. In addition, DEI will provide a report on its IVVC plan in each rider proceeding. DEI has also agreed to review further expansion of IVVC to include additional circuits, and will provide a cost/benefit analysis of this expansion in a future TDSIC mechanism proceeding or base rate case.

Mr. Fowler provided a revised Risk Profile Analysis showing a total T&D system risk reduction of 29% over the Seven-Year Planning period—compared to 31% in its Original Plan. He testified that the overall risk on the T&D system will be reduced from the risk that exists today, and will lead to an increase in the reliability and integrity of DEI’s transmission and distribution system. The revised Seven-Year Plan will provide significant customer benefits like real-time outage notifications, shorter outage duration, fault isolation, and fewer overall outages. In addition, the implementation of IVVC will reduce energy usage on enabled circuits, resulting in lower generation fuel usage and less emissions.

Mr. Broadhurst provided settlement testimony regarding the changes to the transmission and distribution substation portion of the Seven-Year Plan. He testified that DEI has agreed to reduce the transmission line and substation investment by a cumulative \$175 million in capital costs from the Original Plan, consisting of a reduction of approximately \$43.8 million in each year

from 2018-2021. The \$175 million in transmission projects will remain available as alternate projects to provide DEI needed flexibility in implementing its Seven-Year Plan. Mr. Broadhurst testified that the contingency allocated for transmission projects in years 2018-2021 was reduced in an amount proportional to the reduction in planned work for each of those years. The revised Plan also includes a reduced amount of transmission project-related O&M of about \$4.8 million. Mr. Broadhurst explained that DEI did not remove any type of transmission project from the Seven-Year Plan in its entirety. Projects were selected for elimination to achieve the reduction targets with as little reduction as possible to the benefits provided by the Plan. He also explained that the alternate projects contained in the Original Plan were removed as part of the Settlement Agreement. Under the Settlement Agreement, DEI will be able to use the \$175 million in projects eliminated from the transmission portion of the Seven-Year Plan as alternative projects. Mr. Broadhurst testified that although the Plan was reduced in scope, the Seven-Year Plan will improve the reliability, resiliency, and integrity of the transmission and distribution systems in Indiana. It will also provide significant customer benefits like real-time outage notifications, shorter outage durations, fault isolation, and fewer overall outages.

Mr. Davey testified that the revised proposed Rider 65 will have two categories of revenue requirements, transmission and distribution excluding meters. DEI proposes to allocate the transmission and distribution (excluding meters) revenue requirements developed for Rider 65 to the rate groups based on the revenue requirement by rate group for these same two categories from DEI's last retail base rate case, Cause No. 42359. He testified that under the terms of the Settlement Agreement, DEI agrees to modify its proposed Rider 65 allocation factors for rate HLF and LLF customers by using the respective delivery voltage revenue levels approved in DEI's last base rate case. Other rate groups are unaffected by this change. Regarding SDI's special contracts, the TDSIC mechanism will be applicable to the HLF portion of their demand, but not the Day-Ahead Pricing portion. Mr. Davey testified that the Settling Parties have agreed to an ROE for the Seven-Year Plan rider of 10.0%. In addition, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC mechanism, and base retail rates will not be adjusted for these items.

Mr. Davey testified that at the time of DEI's subsequent base rate case, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will, subject to a normal prudence review in the TDSIC mechanism proceedings, be included in rate base and DEI's new base rates and subject to the ROE and allocation factors that are ultimately determined by the IURC in such retail base rate case. Similarly, the 20% of the T&D improvements that have been deferred with carrying costs will be included in retail rates and rate base and any AMI deferrals will be included in rates. He testified that if there remain years in the Seven-Year Plan after the subsequent retail base rate case order, all caps will remain in effect for 2016-2022 and any TDSIC mechanism would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case. He also testified that the Settlement Parties agree that the Seven-Year Plan starts in calendar year 2016 and Year One of the Plan includes projects that go in-service in 2016.

Mr. Davey testified that the total annual average retail rate impact of the Seven-Year Plan compared to retail revenue is estimated to be slightly less than 0.75% over the seven-year period,

which is below the 2% annual average cap provided for in Ind. Code § 8-1-39-14. However, should an actual amount exceed the two percent annual cap and cumulative capital expenditures are below the cumulative capital costs cap, DEI requests approval to defer recovery of the TDSIC costs above the two percent annual cap pursuant to I.C. § 8-1-39-14(b).

Mr. Davey testified that the Settling Parties agree that DEI should be allowed to defer 100% of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent retail base rate proceeding. DEI will recover the deferred depreciation over a 10 year period, without carrying costs, in its subsequent retail rate case. In addition, the Settling Parties agree that DEI should be authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent retail base rate case proceeding. The Settling Parties agree that DEI should be approved to recover the deferred post-in-service carrying costs over a ten-year period without carrying costs in its subsequent retail rate case. To calculate the carrying costs on the AMI project, DEI will use the debt only post-in-service carrying costs rate of 4.72% until the \$15 million is reached after which no additional post-in-service carrying costs will be deferred. Mr. Davey testified that there could be a materially adverse earnings impact to DEI if the AMI deferrals are not approved. He also testified that the Settling Parties agreed to a new depreciation rate for the new AMI meters based on a 15 year life. DEI has agreed to drop its request for a regulatory asset associated with the current meters and if DEI proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner. He testified that there would no changes to current base rates for this issue. Mr. Davey testified that the Settling Parties have agreed that if DEI proceeds with AMI, the estimated net savings associated with the AMI project (\$39.69 million over seven years) will be retained by DEI until a subsequent retail base rate case. In addition, the Settling Parties agree not to oppose inclusion of an AMI project into rate base and DEI base rates at the time of the subsequent retail base rate case subject to normal prudence review, including a review of the costs associated with the project. Mr. Davey also testified that DEI agrees to drop its request for approval of the new proposed rate options.

B. Industrial Group. Mr. Phillips testified that the Industrial Group recommends approval of the Settlement Agreement. Mr. Phillips testified that the Settlement Agreement reduces DEI's requested capital expenditures by \$397 million and reduces the return on equity used in the determination of revenue requirements for the TDSIC mechanism from 10.5% to 10.0%. He also testified that the cost caps contained in the settlement are important because they reduce the risk of construction cost increases to ratepayers over the Seven-Year Plan. The Settlement Agreement also spreads the reductions over the seven years of the plan to protect ratepayer savings. Mr. Phillips testified that cost-based revenue allocation factors used in the Settlement Agreement appropriately apportion the TDSIC costs among and within DEI's rate classes. Mr. Phillips testified that the Settlement Agreement is reasonable and in the public interest. It reasonably mitigates the rate increase for all classes including the residential class, provides DEI's large industrial customers a better chance to be competitive in the national and global markets they compete in, allows DEI to receive sufficient revenues to efficiently and economically provide service within its service area, and helps maintain the economic stability of DEI's large industrial customers and the economic viability of the entire area.

C. **EDF.** Mr. Sandoval testified that EDF is satisfied with the changes DEI made in the Seven-Year Plan as a result of the settlement negotiations, and believes the Plan is reasonable and should be approved. He testified that DEI has agreed to file periodic reports on its IVVC system, which will show the voltage reductions, energy savings, and greenhouse gas emission reductions from IVVC. Also, DEI will consider expanding its IVVC system at the time of its next Seven-Year Plan or base rate case, and to provide a cost/benefit analysis of system expansion at that time. Mr. Sandoval testified that DEI has agreed to develop two innovative energy efficiency pilot programs: (1) “bring your own thermostat” program to allow customers to link the smart meter to their existing thermostat; and (2) “home energy monitor” to provide customers with a device to monitor how much energy they are using in real-time. With the “bring your own thermostat” program, customers could volunteer to receive an alert during high load conditions. DEI would briefly shut off the compressor on the customer’s air conditioner, with the fan continuing to circulate cool air.

D. **OUC.** Mr. Golden testified that DEI’s Seven-Year Plan distribution system circuit improvement projects focus on safety, reliability, system modernization, or most often, some combination of the three. He testified that DEI’s evidence explains the nature of the project, the expected benefits, and provides sufficient engineering background and support for the OUC to conclude that each project is reasonable from an engineering standpoint.

Mr. Golden testified that DEI’s transmission line upgrade projects focus primarily on replacing obsolete equipment and addressing system reliability issues. As a result of the Settlement Agreement, DEI has reduced the number of transmission line upgrade projects to 124 specific projects on 77 transmission lines, including replacements of transmission poles, crossarms, static wires, and 69 kV line rebuilds. Mr. Golden testified that each transmission substation and transmission line upgrade project will improve safety, reliability, or system modernization. DEI has explained the nature of the projects, expected benefits, and provided sufficient engineering background and support for the OUC to conclude each project is reasonable from an engineering standpoint.

Mr. Golden testified that the benefits of these projects, when considered in conjunction with the annual TDSIC cost caps, total Seven-Year Plan cost cap, the cost reductions for both transmission and distribution customers and all other terms of the Settlement Agreement, form a fair and balanced compromise. He testified that the Settlement Agreement promotes the ongoing improvement of DEI’s infrastructure at a reasonable cost, and the public interest is served by fairly balancing both customers’ and the utility’s interests. Mr. Golden testified that the OUC recommends the Commission approve the Settlement Agreement in its entirety.

Mr. Snyder explained the OUC’s investigation into the reasonableness of DEI’s proposed estimated capital expenditures in the Seven-Year Plan. Mr. Snyder testified that DEI’s confidential workpapers provide work order level detail and support for each of the distribution system category and transmission system category projects. He recommended the Commission accept the cost support data provided as sufficient for DEI’s transmission system and distribution system estimates to qualify as “best” estimates as required by I.C. § 8-1-39-10(b)(1). Mr. Snyder also recommended the Commission approve, as “eligible improvements” the projects and programs summarized in Petitioner’s Exhibit 2-A, and approval of the Settlement Agreement.

E. SDI. Mr. Higgins testified that the Settlement Agreement reflects a reasonable balancing of interests among the Settling Parties and produces a result that is in the public interest. Through negotiation among the Settling Parties, the overall TDSIC funding level has been reduced relative to DEI's initial filing, AMI costs have been removed from TDSIC funding while allowing for capped deferrals of specified AMI costs, and voltage differentiation is properly recognized for HLF and LLF customers in the TDSIC mechanism. Mr. Higgins testified that the Settlement Agreement appropriately and reasonably addresses voltage differentiation by modifying DEI's initially-proposed allocation factors to allocate the Seven-Year Plan revenue recovery for rate HLF and LLF customers using the respective delivery voltage revenue levels approved in Cause No. 42359. Further, this modification does not affect the total TDSIC costs allocated to HLF (or LLF), nor does it affect the total TDSIC costs allocated to any other customer group. The incorporation of this modification into the Settlement Agreement produces a result that is clearly in the public interest. Failure to recognize voltage differentiation in the TDSIC mechanism as provided in the Settlement Agreement would be inconsistent with the principles of cost causation and would be inconsistent with the statutory requirement to use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order. Absent recognition of voltage differentiation in the TDSIC mechanism, each HLF customer would pay the same TDSIC mechanism charge for the distribution system cost category, irrespective of the voltage at which the customer takes service. Similarly, absent recognition of voltage differentiation in the TDSIC mechanism, each LLF customer would pay the same TDSIC mechanism charge for the distribution system cost category, irrespective of the voltage at which the customer takes service. Mr. Higgins testified that such outcomes would be fundamentally unreasonable.

Mr. Higgins further testified that the Settlement Agreement provides that the TDSIC mechanism will be applicable to the HLF portion of SDI's special contract demand, but not to the Day-Ahead Pricing portion. He explained that because the SDI special contract did not exist in 2004 when DEI's revenue allocation was set, there were no costs allocated to what is now the Day-Ahead Pricing portion of SDI's special contract. Under the terms of the Settlement Agreement, the majority of SDI's load will be subject to the HLF-Transmission-Bulk charge. Mr. Higgins recommended that the Commission approve the Settlement Agreement in its entirety, without changes or conditions.

F. WVPA. Mr. Wagoner testified that the Settlement Agreement reaches an acceptable balance between future investment in DEI's transmission and distribution systems to improve reliability and performance at an acceptable financial level. WVPA recommends that the Commission approve the Settlement Agreement, without modification.

7. CAC's Evidence Opposing the Settlement Agreement. Mr. Olson testified that the CAC is concerned that DEI has not filed a base rate case since 2002. He stated that the most equitable method to determine whether rates charged by a monopoly utility are just and reasonable is to go through the process of a general rate case, rather than through CPCNs and other trackers. He testified that CPCNs and their associated cost recovery allow utilities to recover costs from ratepayers for projects, which are not, and may never be, used and useful in providing actual utility service to ratepayers. This pre-approval process shifts the burden of proving that costs were

prudently incurred onto the public, and shifts the majority of the investment risk onto captive ratepayers and away from DEI's voluntary investors. Mr. Olson testified that the CAC opposes the use of most trackers, as they are inherently unfair to ratepayers as they allow the monopoly utilities to raise rates when their costs go up without looking at where their costs have gone down.

Mr. Olson testified that, according to the IURC 2015 Residential Bill Survey, over 34% of DEI's monthly bill comes from trackers, which is a much higher percentage when compared to the customers of I&M, NIPSCO, and Vectren. In addition, DEI is the only investor-owned electric utility in Indiana that has not been before the Commission for a base rate case in more than 5 years. Mr. Olson testified that the percentage of a monthly bill coming from trackers has steadily increased since 2009, peaking at nearly 22%, according to the 2015 Residential Bill Survey. He said that DEI's non-FAC related trackers have increased from 10.78% of the monthly bill in 2009 to 21.62% in 2015.

Mr. Olson testified that under the TDSIC statute, a public utility may not file a petition within 9 months after the date on which the commission issues an order changing the public utility's basic rates and charges. He testified that 138 months have elapsed between DEI's current base rates (May 18, 2004) and the filing of the petition in this case. From a policy perspective, a reasonable person could deduce that the legislature would not find it reasonable to approve a TDSIC tracker for a utility with base rates established over 138 months ago, more than the 9-month trigger included by the legislature. Mr. Olson also testified that the TDSIC statutory requirement that a utility file a base rate case before the end of its approved Seven-Year Plan would lead a reasonable person to draw the conclusion that the legislature contemplated that no more than seven years was the appropriate interval between base rate cases. Should the Commission award DEI the use of the TDSIC tracker, DEI would not be required to file a base rate case until 2023, which would mean 21 years would lapse between DEI's petitions for a base rate case.

Mr. Olson testified that allowing another substantial tracker on captive customers' bills is neither just nor reasonable. The tracker reduces DEI's exposure to risk and uncertainty, but in doing so, it transfers that exposure to risk to DEI's customers, who can least afford it. He testified that the poverty rate in Indiana has increased to 29.3% between 2007 and 2013. He believes that it is immoral and unethical to require these already struggling entities and households to realize even higher monthly electric bills, when the reality is that DEI can afford and is obligated to make these investments. Mr. Olson testified that since DEI has increased its transmission and distribution investment since the last rate case by \$800 million, it must not need to recover that money in the short term or it would file a base rate case. So evidently, DEI does not need the upfront capital, which means DEI does not need the tracker.

Mr. Olson testified that DEI's Seven-Year Plan, as modified by the Settlement Agreement, does not satisfy the public convenience and necessity threshold or provide incremental benefits for the estimated costs. He stated that DEI has not adequately considered the public's convenience and necessity in investing in energy efficiency and other *non-wires* alternatives in lieu of sinking substantial ratepayer money into costly T&D upgrades. Mr. Olson also recommend that the Commission investigate DEI's zero customer participation in its demand response, especially as a *non-wires* alternative to costly T&D investments. He believes distributed generation is another *non-wires* alternative. Mr. Olson cites to a Northeast Energy Efficiency Partnerships report which

discusses passive and active deferral as two ways in which energy efficiency programs can defer T&D investments.

In conclusion, Mr. Olson suggests the Commission deny DEI's Seven-Year Plan until DEI sufficiently invests in energy efficiency as a resource and irons out problems with its demand response tariff and low distributed generation penetration. The Commission should also require DEI to do a more robust analysis of such *non-wires* alternatives prior to submitting its TDSIC proposals. However, if the Commission approves DEI's Seven-Year Plan, pursuant to the Settlement Agreement, Mr. Olson suggests DEI should be required to make a determination as to whether each project might be a good candidate for a *non-wires* approach with criteria determined by the Commission, analyze the types of customers in the affected load areas and identify the types of *non-wire* alternatives that could potentially be applicable and effective, and immediately implement a pilot project to test the efficacy of *non-wires* alternatives in deferring future T&D investments that would be run by an independent third party.

8. Settling Parties' Rebuttal Testimony.

A. **DEI.** Ms. Birmingham-Byrd testified that the Settling Parties disagree with the CAC's assertion that the benefits of the Seven-Year Plan, as modified by the Settlement Agreement, do not justify the costs of the Plan. She testified that replacing aging infrastructure, targeting degrading components, upgrading equipment, and improving poor performing circuits all will benefit customers through maintaining and modernizing a safe, reliable T&D system. In addition, the modernization components of the Plan will enable deployment of enhanced equipment providing more timely and accurate information about outages to customers and will enable additional customer products and service offerings today and in the future. DEI's testimony related to risk reduction on the T&D system and the cost/benefit analysis for IVVC and AMI fully support the benefits of the Seven-Year Plan and the AMI deferrals.

As to the CAC's testimony regarding DEI's insufficient investment in energy efficiency and demand response, Ms. Birmingham-Byrd testified that, although not relevant to investments included in the Seven-Year Plan, DEI has an extensive history of strong support for energy efficiency and demand response programs going back to the 1990s. DEI's latest energy efficiency plan was recently approved by the Commission, and DEI has very successful demand response programs for commercial and industrial customers under its PowerShare® and Power Manager® programs. DEI added two new demand response programs to its recently approved 2016 portfolio of programs. DEI's IVVC Project included in the Seven-Year Plan, is estimated to provide energy reductions of over 1% on impacted circuits.

Ms. Birmingham-Byrd testified that DEI considered its low income customers in developing the Seven-Year Plan, which includes investments that improve the efficiency of the system and enables additional energy efficiency programs. DEI actively works with customers on issues such as billing payment arrangements and deferring service disconnects, as well as providing energy efficiency programs targeted to low income customers. Ms. Birmingham-Byrd testified that DEI's Seven-Year Plan considered the impact on customer rates by ensuring that the average rate increase was initially no more than 1% per year. The Settlement Agreement further

reduces this rate impact to approximately 0.75% per year, which is significantly below the 2% provided for in the TDSIC statute.

Mr. Fowler testified that there are no efficiency measures that remove the need to replace aging assets that are impacting DEI's system power quality and reliability. Those assets need to be replaced to deliver the related benefits to customers. Mr. Fowler testified that DEI has no load growth projects in its Seven-Year Plan. All projects are related to repairing, replacing, or modernizing existing T&D assets. He stated that there are no projects in the Seven-Year Plan that are related to load growth that could potentially be delayed by investment in energy efficiency or demand response. Mr. Fowler testified that the IVVC project within DEI's Seven-Year Plan enables the distribution grid to operate more efficiently, allowing for the voltage to be lowered an average of approximately 2% at the distribution substation on enabled circuits, while maintaining voltage within regulatory limits for all customers. He testified that this equates to an estimated 1.4% reduction in demand load on these circuits, resulting in cost savings to customers through lower energy usage and generation fuel savings. In response to Mr. Olson's proposal to halt DEI's Seven-Year Plan until DEI "sufficiently invests in energy efficiency," Mr. Fowler responded that prolonging the relief requested in this proceeding will do nothing beneficial for DEI's customers. Rather, it will prolong the upgrades necessary for DEI to maintain its transmission and distribution systems. Additionally, DEI's Risk Model Profile shows doing nothing will erode DEI's system performance and actually increase costs if the improvements are delayed.

Mr. Davey testified that the 2015 IURC bill survey referenced by Mr. Olson shows that DEI's 2015 total residential monthly bill was below the Indiana average. This demonstrates that DEI's use of riders has not resulted in unreasonable residential rates compared to other Indiana investor-owned electric utilities. He testified that a larger portion of a customer's bill being recovered via tracker rates just means that a larger portion of the total rates are under continuous detailed review and scrutiny in tracker proceedings. In addition, as utilities have been required to comply with various environmental and other federal mandates over time, the General Assembly has recognized these increased and continuing cost pressures and responded with legislation that enables the costs resulting from these mandates to be recovered through customer rates via the use of trackers. Mr. Davey also points out that DEI has not over-earned under the earnings test during 2009-2015, which is another data point supporting that DEI's rates, including rates as a result of using trackers, are reasonable. Mr. Davey testified that the TDSIC statute does not require a utility to have a base rate case prior to filing for a TDSIC Plan. DEI plans to petition the Commission for a review and approval of its rates charges before the expiration of the Seven-Year Plan, as required by the TDSIC statute.

B. Industrial Group. Mr. Phillips testified that he disagreed with Mr. Olson's statement related to the effect of the issuance of a CPCN in a TDSIC case. Mr. Phillips testified that he does not believe that the effect of the issuance of a CPCN under Ind. Code 8-1-8.5 and Ind. Code 8-1-8.7 is the same as the effect of a CPCN issued under the TDSIC statute, and that the "used and useful" requirement still applies to TDSIC costs. Mr. Phillips testified that the Industrial Group does not believe that Mr. Olson's conclusion on this point presents a reason to reject the Settlement Agreement.

9. Terms of Settlement Agreement. The Settling Parties entered into a Settlement Agreement that resolved all of their issues in this proceeding. The significant terms of the Settlement Agreement are as follows:

A. Overall Scope of Seven-Year Plan. DEI reduced the projects and programs that are eligible for TDSIC ratemaking treatment in its Seven-Year Plan to a maximum of \$1.408 billion of capital expenditures plus related project O&M and TDSIC Costs. This includes eliminating the AMI project, approximately \$175 million in transmission capital improvements, and \$30 million in distribution capital improvements from TDSIC ratemaking treatment. The Settling Parties agreed that DEI provided sufficient project detail and program descriptions and sufficient cost estimates. Further, the Settling Parties agreed that the costs of the Seven-Year Plan are justified by the incremental benefits of the plan.

B. Alternative Project List. The Settling Parties agreed to authorize DEI to utilize any non-AMI project as proposed in this Seven-Year Plan to make up the \$1.408 billion in total plan expenditures.

C. Cost Cap. The Settling Parties agreed to cap the capital investment in each year of the Seven-Year Plan as proposed in the chart below.

	2016	2017	2018	2019	2020	2021	2022	Total
Capital cost as filed	\$ 113.9	\$ 269.9	\$ 318.2	\$ 295.6	\$ 270.1	\$ 277.8	\$ 259.6	\$ 1,805.1
Remove AMI capital cost	\$ (22.0)	\$ (56.2)	\$ (57.0)	\$ (48.4)	\$ (6.7)	\$ (0.7)	\$ (0.7)	\$ (191.8)
Remove a portion of transmission capital cost			\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ -	\$ (175.0)
Remove a portion of distribution capital cost	\$ -	\$ -	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (30.0)
Capital cost as adjusted	\$ 91.8	\$ 213.7	\$ 211.4	\$ 197.5	\$ 213.7	\$ 227.3	\$ 252.9	\$ 1,408.3
Cumulative capital cost as adjusted	\$ 91.8	\$ 305.5	\$ 517.0	\$ 714.4	\$ 928.1	\$ 1,155.4	\$ 1,408.3	

D. AMI. DEI agreed to remove AMI project capital and O&M from the Seven-Year Plan. To the extent DEI implements the AMI project before its next base rate case, DEI may retain any savings associated with the AMI project. The Settling Parties agreed to allow DEI to defer 100% of the depreciation without carrying costs associated with the AMI project, up to a maximum of \$60 million. The Settling Parties have also agreed to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's next base rate case. The carrying costs will be calculated using DEI's long-term debt cost rate of 4.72% until the \$15 million is reached. In addition, DEI agreed to drop its request for a regulatory asset associated with its current meters.

E. Customer Programs. DEI agreed to develop, evaluate, and project the cost effectiveness of an EE/DSM pilot program that leverages smart thermostats and customer engagement platforms. If DEI pursues the AMI program outside of the Seven-Year Plan, it will activate the meters' internal radio. DEI committed to good faith discussions with EDF to evaluate the feasibility of technology tests and initial pilot that will allow for near real time energy data access to customers.

F. **Reporting Requirements.** DEI agreed to provide a report on its IVVC project in the TDSIC mechanism proceedings because the related investments will not be included in DEI's energy efficiency rider.

G. **Return on Equity.** DEI agreed that the ROE for projects in the Seven-Year Plan will be 10.0%.

H. **Allocation Factors.** There are no changes to DEI's proposed allocation factors among rate classes. DEI agreed to modify its proposed allocation factors and allocate Seven-Year Plan revenue for rate HLF and LLF customers using the delivery voltage revenue levels approved in DEI's last base rate case.

10. Commission Discussion and Findings.

A. **Statutory Requirements.** Ind. Code § 8-1-39-10(a) permits a public utility to petition the Commission for approval of the public utility's Seven-Year Plan for eligible transmission, distribution, and storage improvements.

Ind. Code § 8-1-39-10(b) states that after notice and a hearing, and not more than 210 days after the petition is filed, the Commission shall issue an order that includes the following:

- (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 the incremental benefits attributable to the plan.

If 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 the TDSIC treatment.

Ind. Code § 8-1-39-2 states:

As used in this chapter, "eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas

Therefore, we will first review DEI's Seven-Year Plan as provided in the Settlement Agreement, then determine whether the projects outlined meet the definition of "eligible transmission, distribution, and storage system improvements" and whether public convenience and necessity require or will require the proposed projects. We will then determine whether DEI has provided a best estimate of the costs of the projects and whether the estimated costs of the projects are justified by their incremental benefits.

B. Settlement Agreements. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission “loses its status as a strictly private contract and takes on a public interest gloss.” *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission “may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement.” *Citizens Action Coalition*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition of Ind., Inc. v. Public Service Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission’s own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code ch. 8-1-2, and that such agreement serves the public interest.

C. DEI’s Seven-Year Plan. The initial question we must answer is whether DEI’s Seven-Year Plan is a plan as required by Section 10(a). In construing a statute, the primary goal is to determine and give effect to the intent of the Legislature. *Ind. Civil Rights Comm’n v. Alder*, 714 N.E.2d 632, 637 (Ind. 1999). When the statute is clear and unambiguous, we need not apply any rules of construction other than to require that words and phrases be given their plain, ordinary and usual meanings. *City of Carmel v. Steele*, 865 N.E.2d 612, 618 (Ind. 2007). The Merriam-Webster Dictionary defines a plan as “a set of actions that have been thought of as a way to do or achieve something.”

The Settling Parties request approval of a plan that includes an estimated \$1.408 billion of capital improvement projects over calendar years 2016 through 2022. DEI has provided a detailed list of discrete projects for inclusion in its Seven-Year Plan. Ms. Birmingham-Byrd testified that DEI “spent thousands of hours defining individual projects for all seven years of the plan, including location, expected project scope, and cost estimates broken down into material, labor, indirects, allowance for funds used during construction (“AFUDC”), O&M, and contingency.”

The Settling Parties agreed to reduce the capital expenditures eligible for TDSIC ratemaking treatment to \$1.408 billion. The Settling Parties also agreed, however, to allow DEI to include all projects summarized in Petitioner’s Exhibit 2-A and detailed in the exhibits and workpapers of Mr. Howard Fowler and Mr. Donald Broadhurst (other than AMI) as eligible improvements in its Seven-Year Plan. This represents approximately \$1.613 billion in possible projects. Under the terms of the Settlement Agreement, DEI will have approximately \$205 million in alternate projects designated as eligible projects for the Seven-Year Plan that subsequently may be moved into the Seven-Year Plan for recover under the TDSIC mechanism. Each of the newly identified alternate projects includes a detailed cost estimate. DEI testified that these alternate projects are needed to maintain the flexibility to make needed reliability and modernization

improvements. To the extent that DEI uses projects on the alternate list, DEI shall explain its decision in future TDSIC proceedings.

The evidence of record is that DEI reviewed its T&D system and came up with a plan that addresses aging infrastructure and modernizes the electric grid in DEI's service territory. The Seven-Year Plan includes projects designed to improve the reliability and integrity of the system and projects that will modernize an aging system. Further, DEI used a third party to analyze the current risk of its T&D system and quantify how the proposed plan expenditures would reduce that risk over time. DEI provided detailed descriptions of each component of its plan, how each project provides customer benefits, and how each project helps to maintain safe, reliable service. No party provided any evidence that DEI's Seven-Year Plan does not meet the requirements of Ind. Code § 8-1-39-10(a). Based on the evidence presented, we find that DEI provided a plan that meets the requirements of Ind. Code § 8-1-39-10(a).

D. Eligible Improvements and 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. Ms. Birmingham-Byrd testified that the Seven-Year Plan will increase the safety, reliability, and integrity of the T&D system. No party provided any evidence that any of the projects or improvements in the Seven-Year Plan did not meet the statutory requirements of the TDSIC Statute.

Based on the evidence provided in this proceeding, we find that DEI has sufficiently supported the investments described in its Seven-Year Plan. These projects are reasonably necessary for DEI to continue to provide adequate retail electric service to its customers. No party opposed the inclusion of any particular project in the Seven-Year Plan or provided evidence that a particular project does not meet the criteria outlined in Ind. Code § 8-1-39-2. Therefore, based on the evidence presented in this proceeding, we find that the projects included in the Seven-Year Plan constitute eligible transmission, distribution, and storage system improvements and that public convenience and necessity require or will require the eligible improvements included in Seven-Year Plan.

E. Best Estimate of the Cost of the Eligible Improvements. Ind. Code § 8-1-39-10(b)(1) requires a finding that the best estimate of the cost of the eligible improvements was included in the Seven-Year Plan. No party contested DEI's cost estimates, cost estimating techniques, or Black & Veatch's independent review and concurrence with the Seven-Year Plan's cost estimates and DEI's cost estimating process.

While we have encouraged utilities to improve the level of accuracy and completeness of their cost estimates prior to seeking Commission pre-approval for a project, we have also recognized that the circumstances of a project may dictate the appropriate range of accuracy. *See Northern Indiana Public Service Company*, Cause No. 44012 at 18 (IURC 12/28/2011). In evaluating the best estimate of the Plan, we note that DEI identified specific projects and cost estimates for each year of its Seven-Year Plan. Further, DEI had Black & Veatch perform an independent review of its cost estimates and cost estimating techniques, and Black & Veatch concluded that DEI's cost estimates and cost estimating process are reasonable. We also note that

DEI has agreed to cap the overall amount of costs included in the TDSIC mechanism, which provides additional certainty of the cost to customers. Accordingly, we find that that DEI has provided reasonable cost estimates for its proposed Seven-Year Plan and has provided sufficient support for its cost estimates and that the cost estimates provided by DEI are the best estimates of the Seven-Year Plan components. Notwithstanding this finding, we retain our continuing jurisdiction over these matters and will, in the future, review any updates to the Seven-Year Plan and Seven-Year Plan cost estimates, consistent with the statute and the Settlement Agreement.

F. Incremental Benefits Attributable to the Seven-Year Plan. The evidence presented shows that DEI has considerable aging infrastructure on its electric transmission and distribution system. The evidence supports DEI's position that these assets need to be replaced. DEI's Seven-Year Plan puts forth a plan that addresses these needed replacements in a cost efficient and prioritized manner. DEI engaged Black & Veatch to perform a quantitative risk assessment of these assets. The analysis demonstrates that DEI will maintain a reasonable level of risk on its T&D system after investing in the Seven-Year Plan components. These investments are necessary to maintain reliability of the T&D system. We find the analysis performed, along with the qualitative improvements and customer benefits identified provides sufficient evidence to support the assertion that the Seven-Year Plan provides incremental benefits justifying the estimated costs of the projects. Additionally, DEI provided a robust cost-benefit analysis for the IVVC project. This analysis indicates that there is a significant, quantifiable benefit attributable to that project.

The CAC opposed the Settlement Agreement on the grounds that DEI should review various EE and DSM options before proceeding with a Seven-Year Plan. As DEI provided in its rebuttal testimony, however, the Seven-Year Plan provides improvements to and replacement of existing assets. The evidence that the CAC relied upon indicates that EE and DSM will have little to no effect on reducing the need for upgrades on existing T&D equipment.

Based on the direct testimony of DEI and the settlement testimony of the Settling Parties, we find that DEI has provided sufficient evidence that the estimated costs of the eligible improvements included in the Seven-Year Plan are justified by the reasonably expected incremental benefits attributable to the plan.

G. Whether DEI's Seven-Year Plan is Reasonable. Based upon our review of the evidence presented and our discussion above, we find that DEI's Seven-Year Plan is reasonable. We also find that DEI has provided sufficient evidence that its cost estimates are best estimates, that public convenience and necessity require or will require the eligible improvements in the Seven-Year Plan, and that the benefits of the Seven-Year Plan project benefits justify its costs. Therefore, we find that the Seven-Year Plan is reasonable, and we approve the Seven-Year Plan.

H. Establishment of a TDSIC. DEI requests approval of its proposed T&D Rate Schedule and accompanying changes to its electric service tariff, which will allow for timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs under Ind. Code § 8-1-39-9. We must first determine whether DEI's petition in this Cause meets the various requirements of Section 9. Ind. Code § 8-1-39-9(a) states:

Subject to subsection (c), a public utility that provides electric or gas utility service may file with the commission rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs. The petition must:

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

1. **Customer Class Revenue Allocation.** DEI requested approval to use its customer class revenue allocation factors based on firm load that was approved in its last general base rate case. In the Settlement Agreement, the Settling Parties agreed to a modification of the proposed allocation factors to allocate the Seven-Year Plan revenue for rate HLF and LLF customers within each rate group using the respective delivery voltage revenue levels approved in DEI's last base rate case. Other rate groups are unaffected by this change. The Settling Parties agreed that using such factors complies with the TDSIC statute.

Ind. Code § 8-1-39-9(a) requires DEI to use the customer class revenue allocation factor based on firm load developed in the most recent retail base rate case. The evidence shows that, as required in the statute, the revenue allocation factors proposed by the Settling Parties correspond with the allocation factors approved by the Commission in Cause No. 42359.

2. **Adjustment of Net Operating Income for Purposes of Ind. Code § 8-1-2-42(d)(2).** As provided for in Ind. Code 8-1-39-13(b), DEI requests authority to increase the authorized net operating income initially approved in Cause No. 42359 and modified by subsequent Commission orders, to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test. Based on our review of the TDSIC statute and the evidence in this Cause, we find that DEI's request is reasonable and should be approved.

3. **TDSIC Mechanism.** Pursuant to Ind. Code § 8-1-39-9, DEI proposes to recover approved capital expenditures and TDSIC costs through Rider 65, as submitted in the settlement testimony of Mr. Davey. Rider 65 would recover 80% of the retail jurisdictional portion of the costs associated with the Seven-Year Plan projects and would include financing costs, depreciation, project O&M, and taxes.

DEI also requests authority from the Commission to accrue post-in-service carrying costs until the TDSIC ratemaking treatment eligible Seven-Year Plan projects are included in retail rates. These carrying costs will accrue at rates equal to DEI's overall weighted cost of capital most

recently approved by the Commission.¹ AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. DEI proposes that the retail jurisdictional portion of operation and maintenance, depreciation, tax expense, and post-in-service carrying costs be deferred with respect to Seven-Year Plan costs from the in-service date until the cost is included in DEI's rates under Rider 65 or in base rates.

No party took issue with DEI's proposed Rider 65 tracking mechanism. Based on our review of the evidence in this Cause, we approve DEI's proposed TDSIC mechanism.

I. Recovery of Consultant and Expert Witness Fees. DEI has requested recovery of the expenses incurred for retaining Black & Veatch as a consultant and expert witness for this proceeding. Black & Veatch performed a risk analysis of the DEI system, validated the cost estimates provided in this proceeding, and provided an economic development analysis. As a part of this proceeding, Mr. Pfennig of Black & Veatch provided testimony that summarizes these analyses.

Based on the evidence provided by DEI, we find that this is a reasonable request and should be approved. To qualify for TDSIC rate treatment, DEI was required to provide evidence that public convenience and necessity require the projects, that the benefits of the projects outweigh their costs, and that the cost estimates constituted best estimates. DEI hired Black & Veatch to assist with their analysis of those items and to assist in development of the Seven-Year Plan. We have approved similar project development costs in the environmental compliance regulatory proceedings, and find that such treatment is appropriate in this case. DEI is authorized to recover the Black & Veatch fees related to performing its risk analysis, cost estimate review, and economic development analysis and providing support for DEI's filing. DEI shall amortize these fees over a three-year period.

J. Deferral of Remaining 20% of Approved Capital Expenditures and TDSIC Costs. Ind. Code § 8-1-39-9(b) provides that 20% of approved capital expenditures and TDSIC Costs should be deferred for recovery in the utility's next general base rate case. We have approved DEI's Seven-Year Plan and the TDSIC tracker mechanism. We find that the evidence demonstrates that DEI should be authorized to defer as a regulatory asset and recover in DEI's next general base rate case the approved capital expenditures and other TDSIC costs that are not recovered in the tracker proceedings and AFUDC, post-in-service carrying costs, O&M expense, taxes, and depreciation expense until such costs are fully reflected in DEI's retail base rates after a general retail electric base rate case. The carrying costs shall be accrued using DEI's overall weighted cost of capital as most recently approved by the Commission.

K. Average Aggregate Increase in Total Retail Revenues. Ind. Code § 8-1-39-14(a) states that the Commission may not approve a TDSIC rate mechanism if it would result in "an average aggregate increase in a public utility's total retail rates of more than two percent (2%) in a twelve (12) month period." Based on the unambiguous language of Section 14, we find that DEI's proposed calculation that compares the increase in TDSIC revenue in a given year with

¹ The ROE to be used for the T&D Plan Rider is 10.0% as explained by Mr. Davey in his settlement testimony.

the total retail revenues for the past 12 months is consistent with the TDSIC statute. Therefore, we find that DEI's proposed calculation is consistent with Section 14 and should be approved.

L. TDSIC Timing. Ind. Code § 8-1-39-9(c) states that “[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility’s basic rates and charges with respect to the same type of utility service.” The evidence in this proceeding shows that DEI has not received an order in a base rate case since 2004. DEI filed its petition in this Cause on December 7, 2015. We find that this Cause was filed more than 9 months after DEI’s last general rate case in accordance with Ind. Code § 8-1-39-9(c).

The CAC provided testimony regarding the rate impact and timing of DEI’s Seven-Year Plan. The CAC argues that the Commission should deny the Seven-Year Plan proposed by DEI because the base rates were last approved in 2004. Further, the CAC takes issue with the use of trackers by DEI. The CAC also made an argument that the TDSIC statute requires a rate case every seven years and, therefore, if DEI has not had a rate case within seven years, then it cannot utilize the TDSIC Statute.

The TDSIC Statute, although the subject of much litigation over the past few years, specifically requires that a utility wait at least 9 months after a rate case until it files for a TDSIC. Further, a utility must initiate a rate case within seven years after a TDSIC plan begins. DEI has met the nine-month waiting period, and DEI plans to file for a rate case before the expiration of its Seven-Year Plan. We reject the CAC’s argument on these ratemaking issues.

Ind. Code § 8-1-39-9(d) states that “[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility’s approved seven (7) year plan, petition the commission for review and approval of the public utility’s basic rates and charges with respect to the same type of utility service.” Therefore, we order DEI to petition the Commission for review and approval of DEI’s basic retail electric rates and charges by December 31, 2022, which is the last day of DEI’s Seven-Year Plan.

Mr. Davey testified that DEI planned to make filings at least annually. We find that DEI’s proposed timeline for TDSIC filings is consistent with Ind. Code § 8-1-39-9 and is reasonable and should be approved. Therefore, DEI’s initial filing following the issuance of this Order shall be filed under Cause No. 44720 TDSIC 1.

M. AMI. The Settling Parties request that the Commission make limited findings regarding the AMI project proposed by DEI. The capital costs associated with the AMI project were removed from the Seven-Year Plan. In an effort to compromise, the Settling Parties have agreed to allow DEI to defer up to \$60 million in depreciation costs for recovery in a subsequent DEI retail base rate proceeding. Additionally, the Settling Parties have agreed to allow DEI to defer post-in-service carrying costs associated with the AMI project up to \$15. The post-in-service carrying costs will be accrued at DEI’s long-term debt cost of 4.72%. DEI requests to depreciate the meters over 15 years.

Although the capital costs of the AMI project are no longer part of this proceeding, the Settling Parties have requested that we make some limited findings related to the ratemaking treatment of the new meters. We find that the AMI deferrals and proposed depreciation rate are reasonable. The evidence supports the deferral of limited amounts of depreciation and carrying costs as fully set forth in the Settlement Agreement. If DEI pursues its AMI project, the inclusion of AMI in rate base will be subject to a normal prudence review in the next rate case. Further, we find that the evidence supports the request to depreciate the new AMI meters over 15 years.

N. Approval of Settlement Agreement. The Settling Parties presented a Settlement Agreement to the Commission for its approval. Having reviewed all of the evidence in this proceeding, we find that the Settlement Agreement represents a reasonable resolution to this proceeding, and we approve the Settlement Agreement. The Settling Parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 Ind. PUC LEXIS 459 at *19-22 (IURC March 19, 1997).

O. Confidentiality. DEI filed a motion for protection of confidential and proprietary information on December 7, 2015. In the motion and supporting affidavits, DEI demonstrated a need for confidential treatment for: (i) information related to DEI's prospective transmission and distribution projects specific to the identity of transmission and distribution system assets; (ii) detailed cost information for the T&D projects; (iii) internal modeling information that contains generation pricing, fuel forecasts, projected future capital costs for generation projects, and electric market pricing information; and (iv) information independently compiled and developed by third parties used in measuring the financial risk of companies. On January 4, 2016, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. The Settlement Agreement is approved.
2. The projects contained in DEI's revised Seven-Year Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Indiana Code § 8-1-39-2.
3. DEI is authorized to implement its TDSIC Rate Schedule as described in Petitioner's Exhibit 12-A pursuant to Ind. Code § 8-1-39-9(a) to effectuate the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs.

4. DEI is authorized to defer 100% of the depreciation associated with the AMI up to \$60 million for recovery in DEI's subsequent retail base rate proceeding. In addition, DEI is authorized to recover the deferred depreciation associated with AMI over a 10-year period, without carrying costs, in its subsequent retail rate case.

5. DEI is authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's subsequent retail base rate proceeding. In addition, DEI is authorized to recover the post-in-service carrying costs associated with the AMI project over a 10-year period, without carrying costs, in DEI's subsequent retail base rate case. DEI is authorized to depreciate the new meters over a 15-year time period.

6. DEI is authorized to recover 80% of DEI's \$1.408 billion Seven-Year Plan costs through DEI's proposed TDSIC mechanism, Standard Contract Rider No. 65.

7. DEI is authorized to defer 20% of eligible and approved capital expenditures and TDSIC costs with carrying costs under Ind. Code § 8-1-39-9(b) and DEI is hereby authorized to recover the deferred capital expenditures and TDSIC costs as part of DEI's next general rate case.

8. DEI's proposed allocation factors based on the revenue requirement by rate group from the last retail base rate case in Cause No. 42359 are approved.

9. The information filed by DEI in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

STEPHAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: JUN 29 2016

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


Mary M. Becerra
Secretary of the Commission

Duke Energy Indiana, IURC Cause No. 44720

7-Year Plan and Transmission, Distribution and Storage Improvement Charge (“TDSIC”) Settlement Agreement

1. Introduction

This Settlement Agreement (“Settlement” or “TDSIC Settlement”) is entered into by and between Duke Energy Indiana, LLC (and its successors), the Indiana Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group, Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC, Steel Dynamics, Inc., Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative, Inc., and the Environmental Defense Fund (collectively, the “Settling Parties”) solely for purposes of compromise and settlement. The Settling Parties agree that this Settlement resolves all disputes, claims and issues from the Indiana Utility Regulatory Commission (“Commission”) proceeding regarding Duke Energy Indiana’s TDSIC filing in Commission Cause No. 44720, as between the Settling Parties.

2. Duke Energy Indiana T&D Plan

The Settling Parties agree that the Commission should approve, as “eligible improvements” within the meaning of the TDSIC statute (Ind. Code ch. 8-1-39), the projects and programs summarized in Petitioner’s Exhibit 2-A, and detailed in the exhibits and workpapers of Mr. Howard Fowler and Mr. Donald Broadhurst (the “T&D Plan”), with the exception of the advanced metering infrastructure (“AMI”) project. This T&D Plan consists of capital expenditures of up to \$1.613 billion and related project O&M expenditures of up to \$61.9 million over the 7-year period from 2016 through 2022; however, the Settling Parties agree that a maximum of \$1.408 billion of capital, plus related project O&M and TDSIC Costs (as defined in Ind. Code 8-1-39-7) shall be eligible for the TDSIC ratemaking treatment, as discussed further below.

The Settling Parties agree that Duke Energy Indiana has provided detailed project and program descriptions for the T&D Plan, as well as sufficient cost estimates for the projects and programs, as would support a Commission finding that the T&D Plan is reasonable and in the public interest, that the costs of the T&D Plan are justified by the benefits of the plan, and that the estimates summarized on Petitioner’s Exhibit 2-A reflect the best estimates of the T&D Plan costs.

3. Capital Cost Reductions and Cost Cap

a. Notwithstanding the T&D Plan described above, in order to compromise and settle this case, Duke Energy Indiana has agreed to limit recovery through the TDSIC ratemaking treatment of its capital costs actually expended upon its T&D Plan to \$1.408 billion over the

seven-year TDSIC period – a reduction in capital costs of \$397 million from its as-filed T&D Plan. Pursuant to the TDSIC statute, eighty percent (80%) of TDSIC costs shall be recovered through the TDSIC Rider and twenty percent (20%) shall be authorized to be deferred for subsequent recovery with carrying costs (calculated at Duke Energy Indiana’s weighted average cost of capital) in a subsequent rate case. As part of this limit on capital cost recovery, the Settling Parties understand that the total related project O&M amount could also be reduced depending on which projects are ultimately excluded from the TDSIC Rider.

b. The Settling Parties agree that Duke Energy Indiana will remove capital projects from the TDSIC ratemaking treatment as follows: approximately \$192 million in Advanced Metering Infrastructure (“AMI”) project,¹ approximately \$175 million in transmission capital improvements and approximately \$30 million in distribution capital improvements. The Settling Parties request that the IURC approve all (non-AMI) projects and programs included in the T&D Plan and that Duke Energy Indiana be authorized to use any project or program included in its \$1.613 billion T&D Plan to make up the up to \$1.408 billion in total plan capital expenditures over the 7-year period. The Settling Parties further agree that Duke Energy Indiana should have the flexibility to move projects from one year to another within the 7-year plan.

c. The Settling Parties agree that the total 7 year capital to be included in the plan and eligible for TDSIC ratemaking treatment will not exceed \$1.408 billion. This exclusion of projects and programs from the TDSIC Rider recovery and 20% deferred recovery purposes will consist of:

- transmission improvement capital by \$43.8 million per year in 2018 through 2021 of the T&D Plan;
- distribution improvement capital by \$6 million per year in 2018 – 2022.

The table below reflects the agreed upon cumulative capital cost caps as adjusted per year:

Duke Energy Indiana T&D Plan Capital Cost (as adjusted)²

	2016	2017	2018	2019	2020	2021	2022	Total
Capital cost as filed	\$ 113.9	\$ 269.9	\$ 318.2	\$ 295.6	\$ 270.1	\$ 277.8	\$ 259.6	\$ 1,805.1
Remove AMI capital cost	\$ (22.0)	\$ (56.2)	\$ (57.0)	\$ (48.4)	\$ (6.7)	\$ (0.7)	\$ (0.7)	\$ (191.8)
Remove a portion of transmission capital cost			\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ -	\$ (175.0)
Remove a portion of distribution capital cost	\$ -	\$ -	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (30.0)
Capital cost as adjusted	\$ 91.8	\$ 213.7	\$ 211.4	\$ 197.5	\$ 213.7	\$ 227.3	\$ 252.9	\$ 1,408.3
Cumulative capital cost as adjusted	\$ 91.8	\$ 305.5	\$ 517.0	\$ 714.4	\$ 928.1	\$ 1,155.4	\$ 1,408.3	

As an example of the TDSIC cost caps effect, if Duke Energy Indiana spent \$81.8 million in 2016, then in 2017 Duke Energy Indiana could spend \$213.7 million plus \$10 million carried

¹ See Section 5; AMI is removed from TDSIC ratemaking treatment and from the 7-year T&D Plan.

² The capital spend that makes up the \$1.408 billion will be identified in settlement supporting testimony.

forward from 2016. As another example, if Duke Energy Indiana spent \$111.8 million in 2016, then Duke Energy Indiana would only put through the TDSIC Rider 80% of the capital associated with \$91.8 million for 2016, and retain the ability to move \$20 million into a future year of the plan as long as the cumulative capital cost as adjusted is not exceeded in any year (for instance, if 2017 expenditures were \$193.7 million, the cumulative capital cost as adjusted plus the \$20 million from 2016 would be the capped amount of \$305.5 million for 2017).

d. The Settling Parties agree that the T&D Plan starts in calendar year 2016 and Year one of the plan includes projects that go in-service in 2016.

4. Plan Flexibility

a. Nothing in this Settlement or in the T&D Plan obligates Duke Energy Indiana to implement the entirety of the T&D Plan (approximately \$1.613 in capital costs over 7 years) or to implement the full \$1.408 billion capital cost cap amount over 7 years. Rather, Duke Energy Indiana shall be authorized to implement components of the T&D Plan in good faith up to the \$1.408 billion cap over a seven year period, as outlined herein, but shall have flexibility to adjust the plan as circumstances dictate, consistent with paragraph 3(b) above, such as system changes, reliability issues, or reasonable and prudent cost changes. Duke Energy Indiana shall update its T&D Plan at least annually, and shall present such T&D Plan updates to the Commission and Settling Parties, consistent with the TDSIC statute.

b. As to the addition of new projects in the 7-year T&D Plan (or the projects identified as alternates in Duke Energy Indiana's case-in-chief), the Settling Parties each reserve the right to take any position on such issue in future proceedings. However, the recovery of a maximum of 80% of the incurred costs associated with the \$1.408 billion in capital and associated project O&M via the TDSIC Rider, and 20% deferral of such costs shall not be adjusted.

5. AMI

a. Duke Energy Indiana agrees to remove the AMI project capital and O&M from the TDSIC ratemaking treatment and 7-year T&D Plan.

b. The Settling Parties agree that if Duke Energy proceeds with AMI, the estimated net savings associated with the AMI project (*i.e.*, \$39.69 M over 7 years) will be retained by Duke Energy Indiana until a subsequent retail base rate case.

c. The Settling Parties agree to support an amended petition in this proceeding, citing the IURC's general accounting authority, seeking approval of the Settling Parties' agreement that Duke Energy Indiana should be authorized to:

i. Defer 100% without carrying costs of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent Duke Energy Indiana retail base rate proceeding. Duke Energy Indiana will recover the deferred depreciation over a 10 year period without carrying costs in its subsequent retail rate case.

ii. Defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent Duke Energy Indiana retail base rate proceeding. Duke Energy Indiana will recover the deferred post-in-service carrying costs over a 10 year period without carrying costs in its subsequent retail rate case. To calculate the carrying costs on the AMI project, Duke Energy Indiana will use the debt only post-in-service carrying costs rate of 4.72% until the \$15 million is reached after which no additional post-in-service carrying costs will be deferred.

d. The Settling Parties agree not to oppose inclusion of an AMI project into rate base and Duke Energy Indiana base rates at the time of the subsequent Duke Energy Indiana retail base rate case subject to normal prudence review, including a review of the costs associated with the project.

e. The Settling Parties agree to the request for IURC approval of a new depreciation rate for the new AMI meters based on a 15 year life, as proposed by Duke Energy Indiana.

f. Duke Energy Indiana agrees to drop its request for approval of the new proposed rate options. Duke Energy Indiana agrees to meet in good faith with interested settling parties prior to re-filing for approval of such proposed rate options.

g. Duke Energy Indiana will develop, evaluate, and project the cost effectiveness for an energy efficiency /demand response pilot program that leverages smart thermostats and customer engagement platforms for energy and demand savings. The proposal will allow customers to use existing thermostats if the thermostats are compatible with the program and using existing thermostats will improve the cost-effectiveness of the pilot program. Duke Energy Indiana will consult with its Energy Efficiency Oversight Board (OSB) and Environmental Defense Fund in designing the program and will use good faith efforts to include more than one choice of compatible thermostats. Duke Energy Indiana will present such proposal to its OSB on or before such time as the AMI meters are certified for approximately 25% of the Duke Energy Indiana system. Environmental Defense Fund may join the OSB as a non-voting member.

h. The company intends to install the AMI meters with the radio activated. However, given cyber security rules/guidelines/regulations Duke Energy Indiana must test the feasibility and security of enabling the pairing of home energy system devices and/or applications to the AMI radios. Duke Energy Indiana commits to good faith discussions with EDF to evaluate the feasibility of technology tests and an initial pilot that will allow for near real time energy data access to customers (such as a smart meter app), after the AMI meters are certified for approximately 25% of the Duke Energy Indiana system. No particular technology or method of allowing for the near real time energy data access to customers has been decided as that will part of the evaluation.

6. Existing Meters

Duke Energy Indiana agrees to drop its request for a regulatory asset associated with the current meters and if Duke Energy Indiana proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner.

7. Other Ratemaking Terms

a. **Integrated Volt Var Control (“IVVC”).**

i. Duke Energy Indiana has included its IVVC investment in the TDSIC plan and does not intend to include such investments in its energy efficiency rider.

ii. Duke Energy Indiana intends to move forward with its IVVC plan as proposed in its case-in-chief. Duke Energy Indiana estimates it will spend approximately \$198 million in capital and project O&M on its IVVC project in the seven-year TDSIC period.

iii. Duke Energy Indiana will provide a report on its IVVC plan in its TDSIC Rider proceedings substantially similar to the Duke Energy Ohio Distribution System Efficiency Metrics-IVVC and including the estimated greenhouse gas emission reductions.

iv. Duke Energy Indiana agrees to consider a further expansion of the IVVC plan to additional circuits after the 7 year TDSIC plan and to provide the costs/benefits of such expansion in a subsequent TDSIC proceeding and/or subsequent retail base rate case. Settling Parties understand there are constraints to providing IVVC on some circuits due to distribution substation and/or circuit ownership.

b. **ROE.** The ROE for the TDSIC Rider will be 10%.

c. **Netting of Depreciation.** There is no netting in the TDSIC Rider of depreciation or return, meaning, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC Rider, and base retail rates will not be adjusted for these items.

d. **Allocation Factors.** There are no changes to Duke Energy Indiana's proposed allocation factors for the TDSIC rider among rate classes. Duke Energy Indiana agrees to modify its proposed allocation factors and allocate the T&D Plan revenue recovery for rate HLF and LLF customers using the respective delivery voltage revenue levels approved in Duke Energy Indiana's last base rate case (IURC Cause No. 42359). Other rate groups are unaffected by this change. The Settling Parties agree that using such factors complies with the TDSIC statute. Regarding the Steel Dynamics Inc. special contract, the TDSIC Rider will be applicable to the HLF portion of their demand, but not to the Day-Ahead Pricing portion.

e. **Base Rate Case.** There are no commitments related to retail rate case timing beyond what is required in the TDSIC Statute. At the time of the subsequent base rate case, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will, (subject to a normal prudence review in the TDSIC Rider proceedings), be included in rate base and the Duke Energy Indiana's new base rates and subject to the ROE and allocation factors that are ultimately determined by the IURC in such retail base rate case. Similarly, the 20% of the T&D improvements that have been deferred with carrying costs will be included in retail rates and rate base and any AMI deferrals will be included in rates. If there remain years in the 7 year T&D Plan (or a new T&D plan) after the subsequent retail base rate case order, all caps will remain in effect for 2016 – 2022 and any TDSIC Rider would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case.

f. **Other.** All other issues are as proposed in Duke Energy Indiana's case in chief testimony and exhibits.

8. Regulatory and Procedural Terms

a. The Settling Parties agree that the evidence to be submitted in support of this Settlement, along with the evidence of record, together constitute substantial evidence to support this Settlement and provide a sufficient evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement. The Settling Parties shall prepare and file with the Commission as soon as reasonably possible, testimony and proposed order(s) in support of and consistent with this Settlement.

b. This Settlement is a complete and interrelated package that is intended to resolve all issues between the Settling Parties as to Duke Energy Indiana's filing in Cause No. 44720, including the amended petition, that were or could have been raised.

c. The Settling Parties will not appeal or seek rehearing, reconsideration or a stay of a Final Order approving this Settlement in its entirety or without change or condition(s) unacceptable to any adversely affected Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement), except with the agreement of all Settling Parties on the issues to be subject to rehearing, reconsideration or appeal.

d. The Settling Parties agree to support in good faith the terms of this Settlement before the Commission and further agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement before any appellate courts, or on rehearing, reconsideration, remand or subsequent or additional related proceedings before the Commission.

e. The Settling Parties also agree to support or not oppose this Settlement in the event of any request for a stay by a person not a party to this Settlement or if this Settlement is the subject matter of any other state proceeding.

f. The Settling Parties shall remain bound by the terms of this Settlement Agreement and shall continue to support or not oppose all the terms of the Settlement on appeal, remand, reconsideration, etc., even if the Commission rejects the Settlement. However, in the event that the Settlement is rejected by the Commission and such rejection is ultimately upheld on rehearing, reconsideration, and/or appeal, at the point when all such proceedings and appeals are complete, this Settlement Agreement shall become void and of no further effect (except for provisions which have already been fully implemented or that are explicitly stated herein to survive termination/voiding).

g. If the Commission approves the Settlement in its entirety, or approves the Settlement with modifications that are not unacceptable to affected Settling Parties, and such Commission approval is ultimately vacated or reversed on appeal, the Settling Parties agree to support or not oppose the terms of this Settlement in any additional proceedings before the Commission (as well as any subsequent appeals). In such situation, the Settling Parties agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement or the subject matters herein, on remand or in additional related proceedings before the Commission.

h. The positions taken by the Settling Parties in this Settlement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Settlement. This provision shall survive termination/voiding of this Agreement.

i. It is understood that this Settlement is reflective of a good faith negotiated settlement and neither the making of the Settlement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except as necessary to implement or enforce this Settlement Agreement. It is also understood that each and every term of the Settlement Agreement is in consideration and support of each and every other term.

j. The Settling Parties will support this Settlement before the Commission and request that the Commission expeditiously accept and approve the Settlement. This Settlement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

k. The Settling Parties will file this Settlement and testimony in support of this Settlement. Such supportive testimony will be agreed-upon by the Settling Parties and offered into evidence without objection by any Settling Party and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement and evidence conditionally, and if the Commission fails to approve this Settlement in its entirety without any change or with condition(s) unacceptable to any adversely affected Settling Party, the Settlement and supporting evidence may be withdrawn and the Commission will continue to proceed to decision in the affected proceedings, without regard to the filing of this Settlement.

l. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise. This provision shall survive termination/voiding of this Agreement.

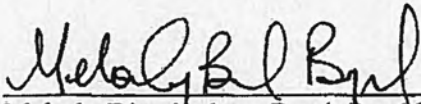
m. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

n. This Settlement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

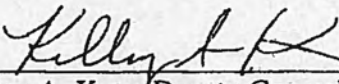
ACCEPTED AND AGREED TO THIS 7th day of MARCH 2016:

[Signature pages to follow]

For Duke Energy Indiana, LLC



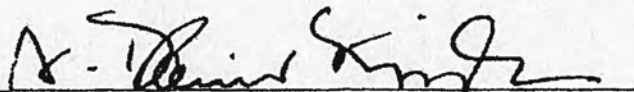
Melody Birmingham-Byrd, President
Duke Energy Indiana, LLC



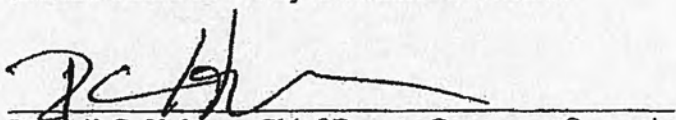
Kelley A. Karn, Deputy General Counsel
Duke Energy Indiana, LLC

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For the Indiana Office of Utility Consumer Counselor:



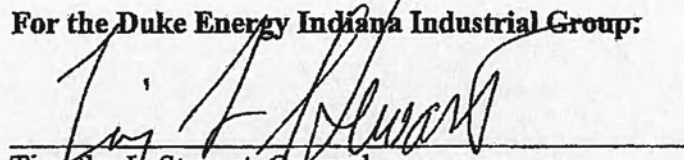
A. David Stippler, Consumer Counselor
Indiana Office of Utility Consumer Counselor



Randall C. Helmen, Chief Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor

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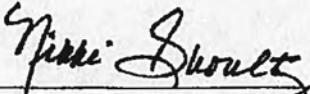
For the Duke Energy Indiana Industrial Group:



Timothy L. Stewart, Counsel
Duke Energy Indiana Industrial Group

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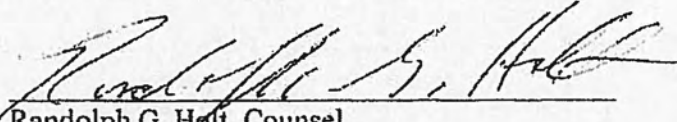
For Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC:



Nikki G. Shoultz, Counsel
Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC

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For Wabash Valley Power Association, Inc.:



Randolph G. Hoyt, Counsel
Wabash Valley Power Association, Inc.

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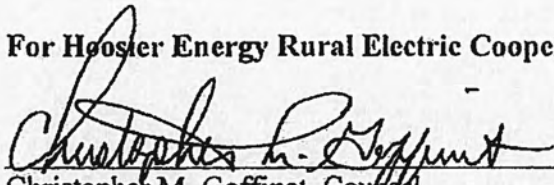
For Indiana Municipal Power Agency:



Peter J. Prettyman, General Counsel
Indiana Municipal Power Agency

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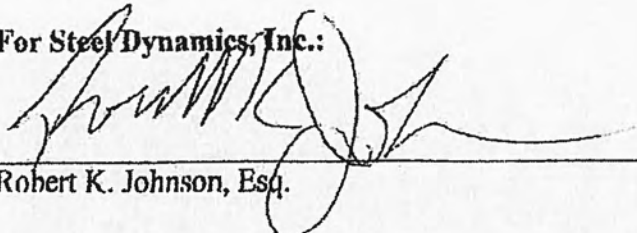
For Hoosier Energy Rural Electric Cooperative, Inc.:



Christopher M. Goffinet, Counsel
Hoosier Energy Rural Electric Cooperative, Inc.

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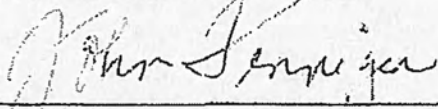
For Steel Dynamics, Inc.:



Robert K. Johnson, Esq.

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For Environmental Defense Fund



John Finnigan, Lead Attorney

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