BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Filing by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company of a Grid Modernization Business Plan	)))))	Case No. 16-0481-EL-UNC

**OHIO EDISON COMPANY,
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND
THE TOLEDO EDISON COMPANY GRID MODERNIZATION BUSINESS PLAN**

Introduction

On August 4, 2014, Ohio Edison Company, The Cleveland Electric Illuminating Company ("CEI") and The Toledo Edison Company (collectively, "the Companies") filed their fourth Electric Security Plan ("ESP IV") with the Public Utilities Commission of Ohio ("Commission") in Case No. 14-1297-EL-SSO entitled "Powering Ohio's Progress."[1] Through the initial application and several stipulations, including the Third Supplemental Stipulation and Recommendation ("Third Supplemental Stipulation") filed on December 1, 2015, ESP IV offers comprehensive benefits to customers, including protections against future market risks. Powering Ohio's Progress represents a solid plan for Ohio's energy future at a time when customers need it most.

The Third Supplemental Stipulation sets forth a number of ambitious tasks, including the Companies' commitment to file within 90 days of the filing of the Third Supplemental Stipulation (i.e., by February 29, 2016) a grid modernization business plan "that highlights future initiatives

[1] *In re: Application of [the Companies] for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan*, Case No. 14-1297-EL-SSO (Aug. 4, 2014) (hereinafter "ESP IV Case").

for Commission consideration and approval."[2] As part of this commitment, the Companies were to include in the plan a timeline for the Companies to achieve full smart meter implementation with data and transfer capabilities and examples of grid modernization initiatives, such as advanced metering infrastructure ("AMI"), distribution automation ("DA"), and Integrated Volt/VAR Control ("IVVC"). The business plan, as well as several other commitments made in the Third Supplemental Stipulation, is discussed below.

The Grid Modernization Business Plan

For some time, FirstEnergy has dedicated significant resources to explore smart grid technologies. For more than five years, the Companies studied smart grid technologies in a pilot area within CEI's service territory through their "Smart Grid Modernization Initiative" ("SGMI Project"). The SGMI Project focused on, among other things, grid modernization techniques that improved system reliability. Then, in 2014, pursuant to a commitment made by the Companies through their Energy Efficiency and Peak Demand Reduction Portfolio Plans in Case Nos. 12-2190-EL-POR, *et seq*, the Companies undertook a conservation voltage reduction ("CVR") Study. This CVR Study models energy conservation potential on each of the 2,878 distribution circuits that comprise the Companies' Ohio distribution system. And, the Companies' utility affiliates in Pennsylvania are implementing an AMI deployment plan that will provide smart meters and related infrastructure to all of their more than two million Pennsylvania customers. The knowledge gained through these various experiences provided significant insight into many of the assumptions that underlie the Grid Modernization Business Plan ("Plan") that is attached hereto as Exhibit A.

[2] ESP IV Case, 14-1297-EL-SSO, Third Supplemental Stipulation at 9 (December 1, 2015).

The development of the Plan is an important step to advance and modernize the Companies' electric distribution delivery system throughout their respective service territories. However, the Companies recognize that other interested parties also have knowledge, experience and expertise with regard to smart grid technologies and have valuable insight into ways to deploy such technologies. Therefore, the Companies view the filing of the Plan as the starting point for a collaborative process in which interested parties will have the opportunity to not only provide feedback on the Plan as presented by the Companies herein, but also to make suggestions on the development of a grid modernization strategy that will work best for the Companies' system to provide the greatest benefits to the Companies' customers. The Companies look forward to working with all interested parties to finalize such a strategy through a series of discussions.

The Plan demonstrates the Companies' dedication to smarter technologies that will strengthen and modernize their distribution system while providing significant benefits to customers. The Companies' distribution system will experience maximum distribution system efficiency and reliability through projects such as DA, while projects such as IVVC and AMI may reduce energy consumption and peak demand, and thereby reduce generating plant emissions, and enhance a customer's shopping experience. The Plan demonstrates that, when these technologies are deployed together, significant synergies can be realized and a comprehensive modern grid system can be developed that: (i) improves system reliability; (ii) reduces operating costs; (iii) enhances non-operational benefits to customers and society; (iv) provides customers with information to better manage their electricity consumption; and (v) provides more detailed information to competitive retail electric service ("CRES") providers. Therefore, each of the scenarios included in the Plan for consideration are comprehensive solutions that incorporate full deployment of AMI and ADMS, together with DA and IVVC to varying degrees.

The Companies spent the past 90 days evaluating various scenarios, each of which involved AMI, IVVC, DA and an Advanced Distribution Management System ("ADMS"). Notwithstanding this relatively short time frame, the Companies were able to design several potential solutions, develop preliminary estimates of costs and potential benefits, and document their findings. As more fully discussed in the Plan, the Companies have identified three scenarios that provide significant customer benefits after factoring in the cost to deploy the technologies. In addition to these three scenarios, the Plan includes the following items as outlined in the Third Supplemental Stipulation,[3] all of which would advance and modernize the electric distribution delivery business and promote customer choice:

- A timeline for the Companies to achieve full smart meter implementation with data and transfer capabilities;
- A provision that the data would be customer owned and that it would be made available to CRES providers and third parties certified by the Commission upon written authorization from the customer, pursuant to Commission rules and State law; and
- Identification of opportunities to leverage smart meter related investments being made in Pennsylvania that could benefit smart meter implementation in Ohio.[4]

The Plan provides a summary of the Companies' findings resulting from their 90-day analysis, with the expectation that the Plan would provide a catalyst for a broader discussion with all interested parties as part of a future Smart Grid collaborative process. At the first meeting, which is anticipated to be the first of several collaborative discussions, the Companies would provide a more in-depth explanation of the assumptions made, the models used and the analyses performed in the development of this Plan. This meeting, and the information provided at this

[3] The Third Supplemental Stipulation also provides for cost recovery and semi-annual updates that will occur if any of the Plan is implemented. *See* Third Supplemental Stipulation at 10.
[4] *Id.* at 9-10.

meeting, would form the foundation on which to develop a smart grid strategy that is most beneficial for the Companies' customers. Interested parties would be encouraged to ask questions and provide additional insight into the development of a future project.

Proposed Timeline to Transition to a Straight Fixed Variable Cost Recovery Mechanism

Through the Third Supplemental Stipulation the Companies also agreed to address another of the ESP IV benefits – a timeline for a transition to a proposed straight fixed variable ("SFV") cost recovery mechanism for residential customers' base distribution rates.[5] Exhibit B, attached hereto, sets forth this timeline, which contemplates the filing of an Application for Tariff Approval ("ATA") case with the Commission by April 3, 2017. It is further anticipated that interested parties would have an opportunity to provide input regarding the merits and details of an SFV rate design at a future date. In that ATA proceeding, and as set forth in the proposed timeline, the Companies will suggest that the resulting SFV mechanism be phased in over a period of three years, beginning on January 1, 2019, so as to comport with the rate making principle of gradualism.

Discussions Related to Distributed Generation and Net Metering Tariffs

In the Third Supplemental Stipulation, the Companies further committed to discuss with Staff issues related to distributed generation and net metering tariffs – tools that assist customers in making choices that suit their energy needs.[6] In furtherance of that commitment, the Companies met with Commission Staff on January 28, 2016 to facilitate a discussion on actions that would potentially remove barriers for distributed generation and to also discuss net metering tariffs. During that discussion, Staff made several recommendations, including one that would have the Companies: (i) update their Interconnection Tariffs to reflect the recent revisions to

[5] *Id.* at 12-13.
[6] *Id.*

Rule 4901:1-22, O.A.C. Interconnection Services; and (ii) update their Small Generation Tariff to reflect new PURPA Rule: OAC 4901:1-10-34 Compliance with PURPA. The Companies will consult with Staff on the update of these tariffs and will be submitting redline versions of the tariffs for Staff review and comment prior to filing. Staff also recommended that the Companies update their reporting practices to include Qualifying Facilities and types of connections for the same, and to update their webpage related to interconnections. The Companies are working with Staff on those recommendations. The Companies will likewise consult with Staff on the forms issued by the Commission that are required to be used to report on distributed generation interconnection status.

Conclusion

As discussed above, the Companies, as a part of the stipulated ESP IV Case, made significant commitments to modernize their distribution system and promote customer choice. The filing of the Plan is an important step toward that goal. However, there is additional work to be done. It is the Companies' desire to use the attached Plan as a catalyst to spur discussions with interested parties -- many of whom have knowledge, experience and expertise in smart grid technologies and can provide valuable insight into effective deployment of these technologies. The Companies submit this Plan consistent with the commitments made in the Third Supplemental Stipulation, with the intention to engage in a collaborative process where they can answer any questions regarding the Plan and work to develop a grid modernization strategy that that will work best for the Companies' system to provide the greatest benefits to the Companies' customers. The Companies look forward to working with all interested parties in moving the Plan forward.

Respectfully submitted,

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Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company
Grid Modernization Business Plan

INTRODUCTION

On August 4, 2014, Ohio Edison Company ("Ohio Edison"), The Cleveland Electric Illuminating Company ("CEI") and The Toledo Edison Company ("Toledo Edison") (collectively, "the Companies") filed their fourth Electric Security Plan ("ESP IV") with the Public Utilities Commission of Ohio ("Commission") entitled "Powering Ohio's Progress.[1] Through the initial application and several stipulations, including the Third Supplemental Stipulation and Recommendation ("Third Supplemental Stipulation") filed on December 1, 2015, ESP IV offers comprehensive benefits to customers, including protections against future market risks. Powering Ohio's Progress represents a solid plan for Ohio's energy future at a time when customers need it most.

The Third Supplemental Stipulation sets forth a number of ambitious tasks, including the Companies' commitment to file by February 29, 2016 a grid modernization business plan "that highlights future initiatives for Commission consideration and approval."[2] As part of this commitment, the Companies were to include in the plan a timeline for the Companies to achieve full smart meter implementation with data and transfer capabilities and examples of grid modernization initiatives, such as advanced metering infrastructure ("AMI"), distribution automation ("DA"), and Integrated Volt/VAR Control ("IVVC"). Pursuant to the terms of the Third Supplemental Stipulation, the Companies submit this Grid Modernization Business Plan ("Plan"). The Plan first provides a general overview of the study performed by the Companies and then a description of several potential smart grid modernization scenarios for further discussion, collaboration and consideration.

While various FirstEnergy electric utilities across multiple states have devoted significant resources to the study of smart grid technologies, the Companies recognize that other interested parties also have knowledge, experience and expertise with regard to smart grid technologies and have valuable insight into ways to deploy such technologies. Therefore, the Companies view the filing of this Plan as the starting point for a collaborative process in which interested parties will have the opportunity to not only provide feedback on the Plan, but also to make

[1] *In re: Application of [the Companies] for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan*, Case No. 14-1297-EL-SSO (Aug. 4, 2014) (hereinafter "ESP IV Case").

[2] ESP IV Case, Third Supplemental Stipulation at 9 (December 1, 2015).

suggestions on the development of a grid modernization strategy that will work best for the Companies' system to provide the greatest benefits to the Companies' customers. The Companies look forward to working with all interested parties to finalize such a strategy through a series of discussions on this Plan.

ABOUT THE COMPANIES

FirstEnergy Corp. ("FirstEnergy") is a diversified energy company headquartered in Akron, Ohio. In Ohio, Ohio Edison, CEI and Toledo Edison, subsidiaries of FirstEnergy, provide electric distribution service to over two million customers. **Ohio Edison** serves approximately 1,038,000 electric utility customers over more than 6,000 square miles in northeast and central Ohio. **CEI** serves approximately 746,000 electric utility customers over more than 1,600 square miles in and around Cleveland, Ohio. **Toledo Edison** serves approximately 308,000 electric utility customers over more than 2,300 square miles in northwest Ohio. Collectively, the service territories of Ohio Edison, CEI and Toledo Edison are comprised of 2,878 distribution circuits.

PLAN DEVELOPMENT

FACTORS CONSIDERED WHEN DEVELOPING THIS PLAN

Under the compressed time schedule dictated by the Third Supplemental Stipulation, the Companies worked hard to develop the Plan, considering not only smart grid initiatives undertaken by other FirstEnergy electric utilities, but also considering other smart grid projects being implemented in Ohio and throughout the country. These initiatives demonstrate the important benefits that smart grid technologies can provide to customers and electric utilities.

FirstEnergy electric utilities' experience with smart grid technologies is not new. The FirstEnergy electric utilities have participated in a number of pilot programs and other smart grid related studies, with three key experiences with distribution modernization technologies informing a significant portion of this Plan:

- In 2014, pursuant to a commitment made by the Companies through their Energy Efficiency and Peak Demand Reduction Portfolio Plans in Case Nos. 12-2190-EL-POR, *et seq.*, the Companies retained an engineering firm to perform a conservation voltage reduction ("CVR") Study. This study models CVR potential for each of the 2,878 distribution circuits making up the Companies' Ohio distribution system. This model estimates: (i) potential annual energy conservation; (ii) potential demand reduction; and (iii) potential reactive power relief. Based upon these results, all 2,878 distribution circuits were ranked for energy conservation potential. The CVR Study results contributed to the IVVC portion of the Plan.

- In 2010, the Companies were awarded a U.S. Department of Energy ("DOE") Smart Grid Investment Grant provided through the American Recovery and Reinvestment Act ("ARRA"). The goal of the grant was to field-deploy smart grid technologies in a pilot area to determine and analyze the capabilities of AMI, DA and IVVC. In Ohio, which was one of three states included within the scope of the grant, the Companies implemented a "Smart Grid Modernization Initiative" (hereinafter, "SGMI Project"), which was performed in a 400-square-mile area southeast of Cleveland, Ohio in CEI's service territory. The SGMI Project focused on, among other things, grid modernization techniques that improved system reliability. Preliminary results from the SGMI Project were used to develop many aspects of the DA portion of this Plan.

- In 2009, pursuant to Pennsylvania Act 129, the Companies' utility affiliates in Pennsylvania (Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company (collectively "the PA Companies")) commenced work on the development of a deployment plan for a smart meter system throughout the PA Companies' service territories. After several years of testing various meter technologies and other related equipment, the PA Companies submitted a smart meter deployment plan that was approved by the Pennsylvania Public Utility Commission in 2014.[3] Deployment of the smart meter infrastructure commenced later that year. As of the end of 2015, approximately 260,000 smart meters and related infrastructure have been deployed in the PA Companies' service territories. The knowledge gained through both the project's preliminary studies and the deployment experience provided significant insight into many of the assumptions that underlie the AMI portion of the Plan.

When developing the various scenarios to be evaluated, the Companies reviewed both Duke Energy – Ohio ("Duke") and AEP – Ohio's successful programs/pilots to modernize their respective distribution systems. These projects, like the scenarios developed by the Companies in this Plan, included AMI deployment coupled with IVVC/DA. As a result of a smart grid project done under a smart grid investment grant, Duke stated that it has "improved operational efficiencies, optimized voltage, automated 'self-healing' disruption response, and expanded smart grid technologies to other service territories using lessons learned."[4] It is believed that all of the scenarios presented in this Plan will likewise improve operational efficiencies, optimize voltage and benefit customers.

Finally, additional studies throughout the country have also addressed the varying implications of smart grid technologies. Several of these studies, which are more fully

[3] *See* Joint Petition of [the PA Companies] for Approval of Their Smart Meter Deployment Plan, Docket Nos. M-2013-2341990, M-2013-2341991, M-2013-2341993, M-2013-2341994, Opinion and Order (entered June 25, 2014).
[4] US Department of Energy "Integrated Smart Grid Provides Wide Range of Benefits In Ohio and the Carolinas", p.2.

discussed in a later section of this Plan, form the basis for many of the assumptions related to the quantification of customer and societal benefits. Also, as part of the Pennsylvania smart meter project, the PA Companies reviewed a number of utilities' smart grid/smart meter projects, including those undertaken by San Diego Gas & Electric, Centerpoint Energy, Texas Utilities, Commonwealth Edison, B. C. Hydro, Southern California Edison, Philadelphia Electric Company and Duquesne Power. This information was also considered while preparing this Plan.

OBJECTIVES

When developing this Plan, the following objectives were considered:

- Develop for further consideration several comprehensive smart grid modernization scenarios that are designed to improve system reliability, reduce operating costs, provide non-operational benefits to customers and society, and provide customers with information to better manage their electricity consumption;

- Develop for further consideration several smart grid modernization scenarios that are designed to provide Certified Retail Electric Service ("CRES") providers with more detailed customer information in a manner that allows for a more robust retail electric market in Ohio;

- Develop for further consideration several comprehensive smart grid modernization scenarios that are compatible with smart grid initiatives being considered and/or implemented by the Companies' utility affiliates in other jurisdictions;

- Develop for further consideration several comprehensive smart grid modernization scenarios that leverage smart meter related investments being made in Pennsylvania; and

- Develop for further consideration several comprehensive smart grid modernization scenarios that leverage the synergies of the individual smart grid initiative components in such a manner as to provide maximum benefits after factoring in the costs of deployment.

SCOPE OF STUDY

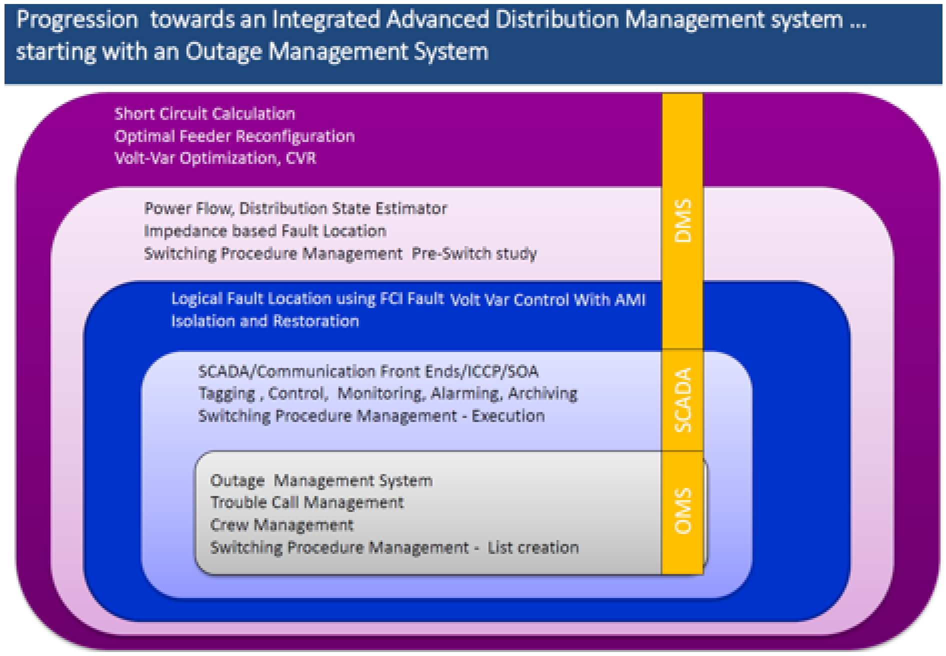
During the compressed time frame in which the Plan was developed, the Companies evaluated various scenarios, each of which involved AMI, IVVC, DA and an Advanced Distribution Management System ("ADMS"). Relying on the results from the selected sample of circuits monitored during the SGMI Project and being informed by work done on the Companies' CVR Study, the Companies developed screening criteria for the selection of circuits that would provide the most improvement through IVVC/DA coupled with full deployment of smart meters. This priority list of circuits was then analyzed assuming different levels of circuit upgrades vis-à-vis the number of customers affected.

Numerous studies have established that distribution modernization technologies yield compelling benefits independently. But the Companies' analysis has demonstrated that, when deployed together, significant synergies can be realized and a comprehensive modern grid system can be developed that: (i) improves system reliability; (ii) reduces operating costs; (iii) enhances non-operational benefits to customers and society; (iv) provides customers with information to better manage their electricity consumption; and (v) provides more detailed information to CRES providers. The Companies' analysis further revealed that both ADMS and AMI are components necessary to support the comprehensive solutions being evaluated in this Plan, regardless of the scenario selected. In light of these findings, the Plan identifies three scenarios that provide significant customer benefits after factoring in the costs to deploy the technologies. Each scenario includes full deployment of AMI and ADMS, along with the modernization of 1500 circuits in Scenario 1; 900 circuits in Scenario 2; and 500 circuits in Scenario 3. For purposes of demonstrating the impacts of slower deployment, Scenario 3 also modifies the deployment schedule, the details of which are discussed in the section of the Plan that discusses AMI timelines.

TYPES OF TECHNOLOGY

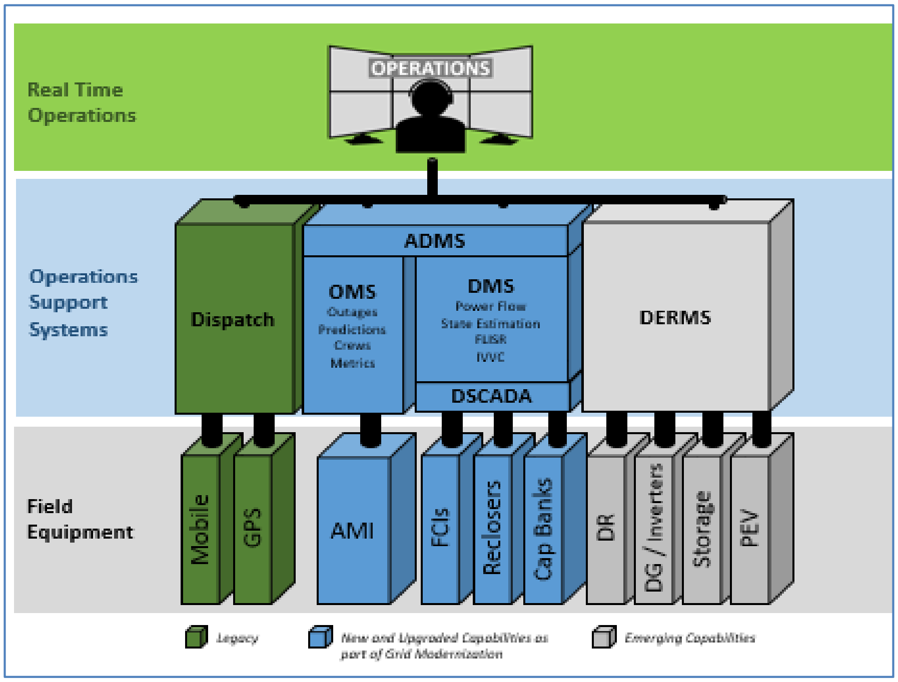
Advanced Distribution Management System (ADMS)

ADMS is the real-time operations platform used by distribution grid operators to consolidate pertinent data from various sources, including AMI, DA, and IVVC devices and systems. Building the ADMS starts with adding Distribution SCADA (supervisory control and data acquisition) from Smart Grid end devices, integrating the outage management system, and ultimately adding the ADMS software which controls DA and VVC.



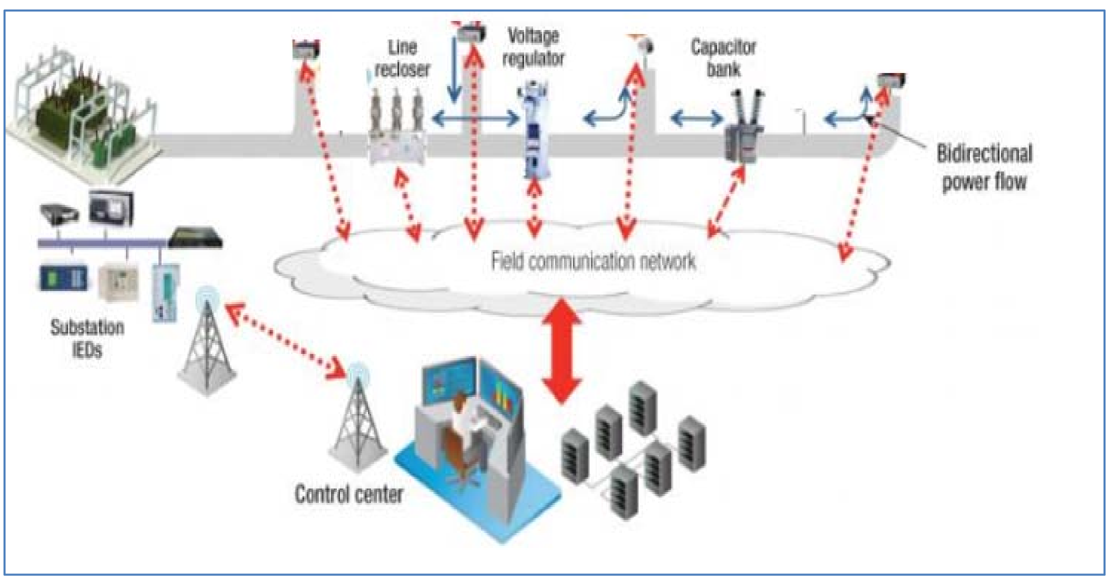
An ADMS significantly expands operational situational awareness through the real time acquisition of system conditions. More importantly, ADMS is the central system that coordinates the other grid modernization components and enhances their effectiveness (e.g. map AMI meters reporting outages, coordinate activities from DA sites to minimize outage extent, synchronize circuit voltages for power restoration).

As indicated in the following figure, in the future, it is believed that ADMS provides a platform to allow operators to communicate with and integrate distributed energy sources and renewable sources such as wind and solar as well as battery storage. This functionality is referred to as Distributed Energy Resources Management Systems ("DERMS").



Distribution Control Platform includes ADMS and DERMS, to support Grid Modernization

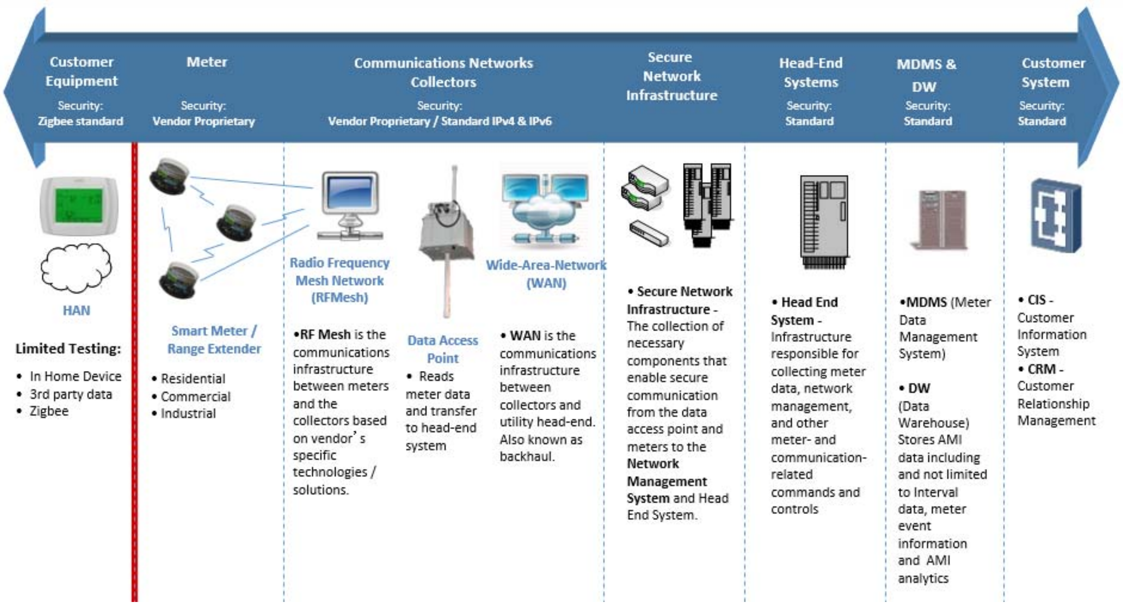
The figure below illustrates the real time information from the distribution system that can be brought into the ADMS through a common communication network for DA and IVVC to facilitate decision analysis.



In all scenarios analyzed by the Companies, it was assumed that the ADMS would be used to monitor the distribution operations for 100% of customers, even if they have opted out of AMI and/or happen to be served by circuits that are not included within the scope of IVVC/DA deployment. It was further assumed that this technology would be deployed over four years.

Advanced Metering Infrastructure (AMI)

AMI comprises digital electric customer meters, a wireless communications infrastructure, and various back-office systems that securely capture and store electricity consumption data as illustrated below:



These technologies allow for greater granularity in measuring customer energy consumption for billing, remote meter reading, and outage assessment. The detailed information also provides customers with the opportunity to better manage their electricity consumption and for CRES providers to offer more sophisticated pricing products, which should, in turn, allow for a more robust Ohio retail electricity market.

For purposes of analysis, it was assumed that AMI technology would be deployed to all of the Companies' customers over a 5-year timeframe for Scenarios 1 and 2 and over an 8-year time frame for Scenario 3. Further, the Plan assumed that customers could opt-out of having an AMI meter measuring their consumption.[5] The Companies have filed Rider AMO to allow for customers to opt out of receiving a smart meter. This rider will need to be updated upon program initiation. Last, for purposes of the Plan, the Companies assumed that AMI equipment currently being deployed in Pennsylvania would also be used in Ohio.

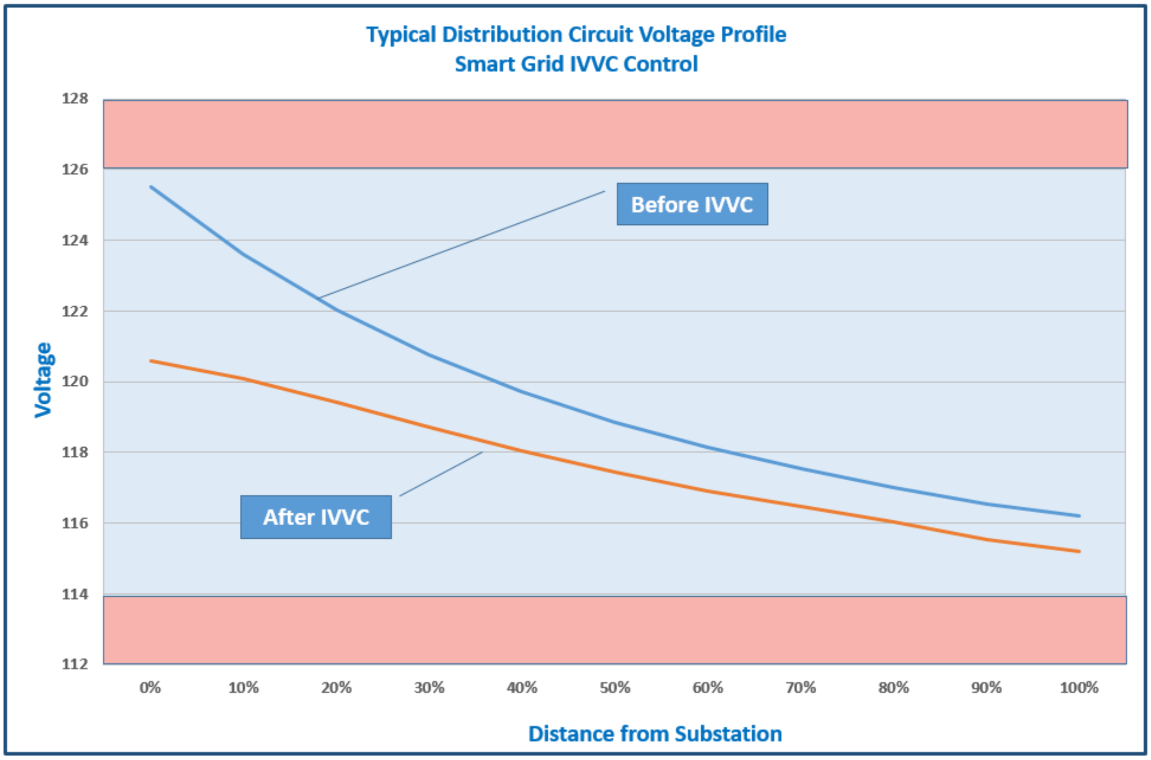
Integrated Volt/VAR Control (IVVC)

IVVC provides opportunities to reduce KWh and KW on the distribution lines. IVVC comprises substation and circuit equipment capable of monitoring and adjusting electrical operational conditions.

Adding capacitors to a distribution circuit allows the voltage to be leveled across the circuit and allows finer control over the voltage at all points along that circuit.

Where possible, some devices can operate on a wireless communications infrastructure. This IVVC system will allow for more consistent voltage to be delivered to all of the Companies' customers, regardless of their distance from the substation, thus reducing the amount of electricity that must be generated, which in turn reduces customer usage.

[5] Based on other Ohio utilities' studies and results from the PA Companies' smart meter deployment, the Companies assume, for purposes of this Plan, that 0.2% of the customers will opt out of receiving a smart meter.

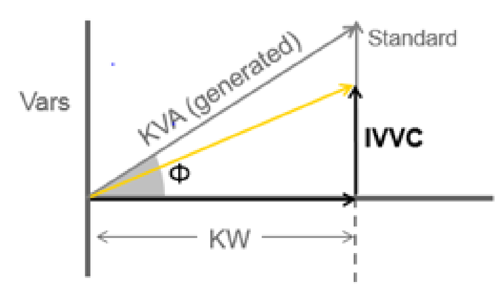


The graphic below shows the mathematical relationship between watts (real power that does work) and Vars (reactive power that allows electricity to flow). Vars are produced by the capacitor banks to boost the voltage along distribution circuit.

- Most useful electric loads are real (kW; this is what utility meters read).
- Generation sources provide both real (kW) and reactive power (kVAR)
- Capacitors both add vars and voltage. By adding capacitors on a line, the generation source can produce fewer vars and at a lower voltage (operate at a PF closer to 1.0)

Cos Φ = Power factor (PF)

$$PF = \frac{Real\ Power\ (KW)}{Apparent\ Power\ (KVA)}$$



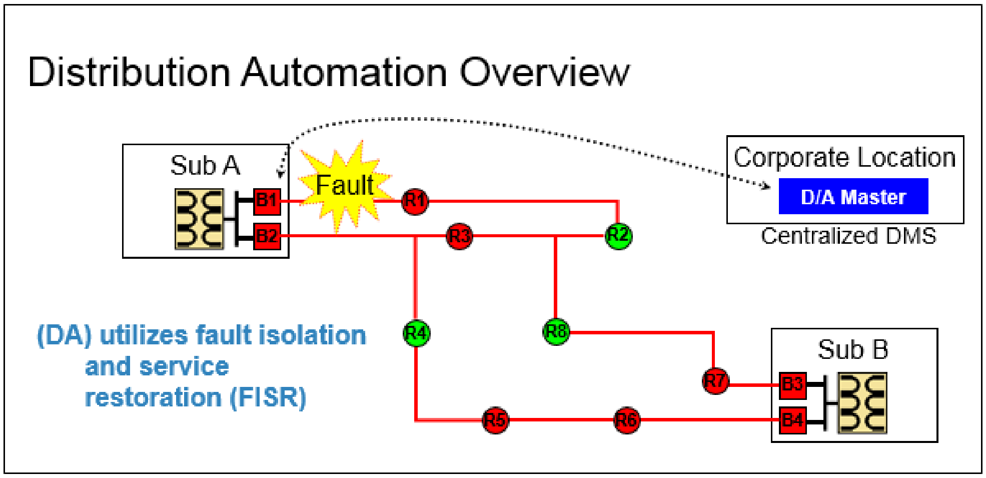
It is anticipated that, regardless of the scenario selected, IVVC technology, in conjunction with the DA technology described below, will be deployed on approximately 100 circuits per year for Scenarios 1 and 2 and 70 circuits per year for Scenario 3 until the number of circuits contemplated in the applicable scenario have been modernized.

Distribution Automation (DA)

DA focuses on improved reliability and is comprised of substation equipment, circuit reclosers, and wireless communications infrastructure. Fault Isolation Service Restoration ("FISR") is a distribution automation application that runs a series of algorithms to determine the optimal operation of reclosers on a feeder so as to minimize both the duration as well as the number of customers affected by a power outage.

This technology can be used to open and close reclosers to connect and disconnect certain portions of the grid as the real time operating conditions warrant. Particularly applicable to service outage situations, this technology provides the capability to automatically maximize the restoration of power from momentary abnormal conditions, minimize sustained customer outages as well as support FISR.

As indicated in the figure below, after a sustained fault is sensed by DA software, end devices like reclosers are commanded to open to isolate the fault. Other devices are commanded to close providing near immediate partial restoration.



Just as with IVVC, it is expected that DA will be deployed on approximately 100 circuits per year for Scenarios 1 and 2 and 70 circuits per year for Scenario 3, the majority of which will be the same circuits as those upgraded for IVVC. Further, for purposes of analysis, the Companies assumed that both DA and IVVC would be simultaneously deployed on each Smart Grid enabled circuit. By deploying both IVVC and DA on the same circuits at the same time, the Companies can avoid the duplication of most of the deployment costs and certain of the fixed costs.

SCENARIOS

As previously discussed, this Plan presents three scenarios for further consideration through a collaboration of interested parties:

Scenario 1

Full deployment of smart meters over a five year period to all customers, an ADMS system, and the integration of approximately 1,500 circuits with IVVC/DA over 15 years, positively impacting approximately 1.6 million customers.

Scenario 2

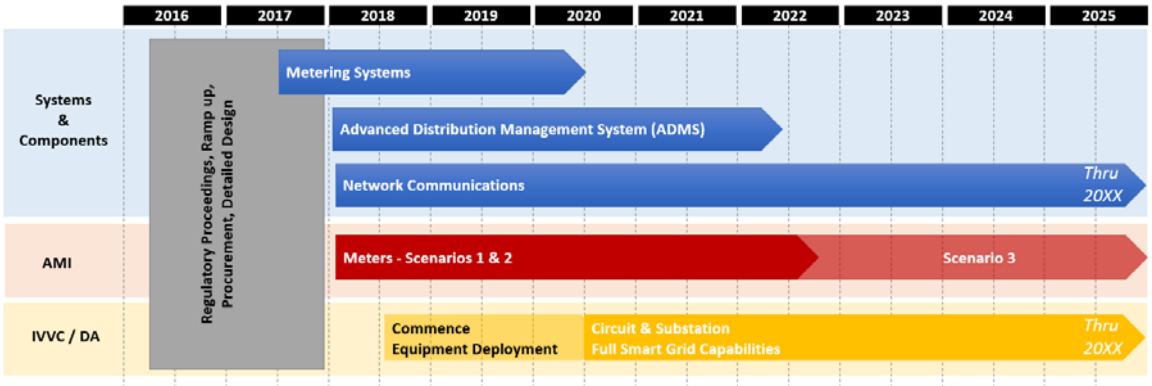
Full deployment of smart meters over a five year period to all customers, an ADMS system, and the integration of approximately 900 circuits with IVVC/DA over 9 years, positively impacting approximately 1.1 million customers.

Scenario 3

Full deployment of smart meters over an eight year period to all customers, an ADMS system, and the integration of approximately 500 circuits with IVVC/DA over 8 years, positively impacting approximately 750,000 customers.

ANTICIPATED TIME LINE

In order to ensure a cost effective deployment and minimize disruptions to customers, the Companies anticipate the need for several work streams to work in parallel. Further, the anticipated timeline assumes that 2016 and 2017 would be dedicated to the vetting of the Plan through a collaborative process and discussions with interested parties on a grid modernization strategy and ideas from parties that produces a solution that best benefits the Companies' customers. During this same time frame, technology detailed design, and formal procurement processing would commence. While the scope and duration of these efforts would vary based on the specific scenario selected, the time frames and efforts pursued in parallel would look largely the same as that set forth below.



Projected smart grid implementation schedule

NOTE: The above schedule assumes a five year deployment period for AMI in Scenarios 1 and 2 and an eight year deployment period in Scenario 3. Similarly, the above schedule assumes that 100 circuits per year will be modernized in Scenarios 1 and 2, and 70 per year in Scenario 3. The end dates for certain IVVC/DA related tasks will be dependent on the Scenario selected.

AMI

For purposes of this Plan, the Companies assumed that AMI's 5-year deployment would begin in late 2017 and would conclude in mid-2022 for Scenarios 1 and 2. Scenario 3 also assumes that deployment would begin in late 2017 but assumes that the deployment will occur over an eight-year period. The AMI deployment would start first for several reasons. First, this infrastructure is needed in order to properly inform and operate much of the functionality of the other components of any grid modernization initiative. Second, benefits specific to this component of the solution can be realized in a relatively short time frame. Third, this component can leverage some systems already in place in the PA Companies' service territories.[6] And, finally, FirstEnergy affiliates have already mobilized staff and contractors for AMI deployment in Pennsylvania and the aforementioned time line would allow for a seamless transition to Ohio as deployment in Pennsylvania progresses. For scenarios 1 and 2, this time line assumes that approximately 125,000 meters would be installed during the last quarter of 2017, approximately 500,000 meters per year would be installed in 2018 through 2021, and the remaining meters would be installed during the first half of 2022. For scenario 3, the time line assumes that approximately 50,000 meters would be installed during the last quarter of 2017 and approximately 300,000 meters per year would be installed from 2018 through 2024. It is currently anticipated that deployment would begin first in CEI's service territory; then, within approximately three months, in Ohio Edison's service territory; and several months after that, in Toledo Edison's service territory. Deployment would start in the most populated areas and radiate out from these metropolitan areas.

[6] It is expected that configuration of already existing key communication infrastructure, data acquisition and back-office systems would begin to be implemented during the first six months prior to the installation of the first meters.

<u>IVVC/DA</u>

It is assumed that ADMS and core network communications enabling IVVC and DA would begin in 2018 to provide a foundation for new capabilities. Time would be needed to design and implement these systems. Individual circuits would be analyzed and engineered to determine optimal placement of circuit devices prior to actual installation. Smart grid devices (circuit and substation devices) would be deployed beginning in 2018 and it is anticipated that the completion of the ADMS would occur in mid-2022.

It is assumed that the IVVC/DA technologies would be rolled out simultaneously among the Ohio operating companies at a rate of approximately 100 circuits per year for Scenarios 1 and 2 and at a rate of 70 circuits per for year for Scenario 3, with each company upgrading an annual number of circuits relative to its size. For purposes of analysis, the Companies assumed that deployment of IVVC/DA technology would commence in mid-2018 and completion of the project would be dependent on the selected scenario.

RATE IMPLICATIONS

For purposes of this Plan, if implemented, cost recovery will be consistent with the terms agreed to by the signatory parties to the Third Supplemental Stipulation in the ESP IV Case,[7] which are set forth below:

The Companies' recovery will be through a rider, and recovery would commence within three months of the issuance of a Commission Order authorizing the implementation of a grid modernization project and would be based on a forward looking formula rate concept that would be subsequently reconciled for actual costs compared to forecasted costs and for actual revenues received compared to revenues forecasted to be recovered.

The return on equity would initially be set at 10.38% (following the ATSI ROE as that rate may be adjusted in the future) with an additional 50 basis points adder. The cost of debt would be set at the embedded long term cost of debt in existence at the time the rider is updated, and the capital structure would be based on the actual capital structure in existence at the time the rider is updated.

All costs incurred would be recovered in Rider AMI, which will be updated and reconciled on a quarterly basis and would remain in effect until such costs are fully recovered. Any operational savings that are produced by the investment and accrue to the Companies, such as reduced meter reading expense, will be credited against the costs during the quarterly update and reconciliation process.

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[7] *See* ESP IV Case, Third Supplemental Stipulation, p. 10.

Legacy Meter Cost Recovery

The existing meters ("Legacy Meters") that will be replaced with smart meters have a current net book value of $184 million. For purposes of estimating costs in this Plan, it was assumed that, the remaining cost of the Legacy Meters would be recovered at an accelerated rate over the AMI deployment period assumed in each scenario resulting in an additional depreciation expense above the current level of expense.

OTHER ISSUES

There are a number of other issues that would have to be addressed should the Companies proceed with a smart grid modernization project. Several of these issues are discussed below:

Meter Data

AMI data will be collected and aggregated for consumption and analysis. It is currently anticipated that customer energy usage data ("CEUD") will be made available through the FirstEnergy website where customers will be able to review their consumption and make more informed choices about their energy usage.

The AMI CEUD will be considered customer-owned and would be made available to CRES providers and third parties upon written authorization of the customer, pursuant to Commission rules and state law. The CEUD will be provided in hourly interval, or an interval less than an hour, and will be bill quality (i.e., it will have gone through the Validate, Estimate and Edit ("VEE") process). The Companies will work with CRES providers to ensure that the bill quality AMI data is provided in a timely manner so that CRES providers can use the AMI data for billing purposes.

Leveraging AMI Investments Being Made in Pennsylvania

In the Plan, the Companies assumed, for AMI,[8] that investments made in Pennsylvania in the areas of software development IT development, common hardware and software costs, mesh network maintenance and certain processes and procedures could be leveraged. These synergies are mainly in the areas of reduced time and labor associated with the development of the grid modernization solutions in Ohio. Leveraging lessons learned through the Pennsylvania project should also improve the implementation process for any grid modernization solution in Ohio. Finally, there appears to be some

[8] It should be noted that the PA Companies' AMI project does not involve DA or IVVC technologies. Therefore, there is nothing in these areas to be leveraged from Pennsylvania.

opportunities to leverage the common hardware and software costs, however, because the AMI solution has not yet been designed for Ohio, estimates of potential savings in this area could not be made with any certainty. Some of the leveraging opportunities are further discussed below:

> AMI Solution Development: Before submitting their smart meter deployment plan to the Pennsylvania Public Utility Commission, the PA Companies spent approximately 30 months studying, evaluating and testing smart meter equipment, thoroughly vetting potential vendors through a comprehensive RFI and RFP process, performing site visits to other utilities in the process of implementing smart meter projects, and engineering the end-to-end smart meter systems and specifications. It is expected that these activities could be streamlined for the AMI portion of an Ohio grid modernization project.
>
> IT Development: Like the AMI Solution Development, a significant portion of the development of the AMI IT solutions has already been done.
>
> External Communications and Internal Training: The PA Companies developed the external communications and internal training materials for smart meter deployment in Pennsylvania. It is expected that much of this material could be used in Ohio with minimal modification.
>
> Common Hardware/Software Costs: Hardware and software was purchased for use in the Pennsylvania smart meter project that can potentially be expanded for use in an Ohio grid modernization project.
>
> Changes in Mesh Network Maintenance: Through their experience in the Pennsylvania smart meter project, the PA Companies have streamlined the mesh network maintenance process.
>
> Processes and Procedures: Many of the activities and resultant processes and procedures related to the Pennsylvania smart meter project have been developed and documented (e.g., project governance approach, business process documentation, deployment strategy, route acceptance/billing certification approach). This is anticipated to reduce the development time required for these activities if there is an Ohio deployment.

Customer Education and Acceptance

Should the Companies proceed with a grid modernization project, the Companies would develop a comprehensive customer engagement and outreach plan. It is anticipated that the Companies would leverage the materials and much of what was learned in Pennsylvania when developing this outreach plan.

Security and Privacy

Cyber security or information technology security focuses on protecting computers, communication networks, applications and data from unintended and unauthorized access. It also ensures confidentiality, integrity and availability of the electronic information communication system. The implementation of security controls should not degrade the grid reliability and availability.

Cyber security is an inherent component of each of the grid modernization technologies that would have to be considered in every facet of implementation should the Companies proceed with a grid modernization project. Like their Pennsylvania counterparts do today, the Companies would draw on lessons learned both within FirstEnergy and throughout the country and would continue to assess cyber security risks and the development of suitable mitigation plans in accordance with industry standards.

Grid Modernization Scenarios for Consideration

The Companies evaluated three comprehensive grid modernization scenarios. Each scenario includes as fixed costs an AMI system that would provide smart meters to every customer not electing to opt out. The estimated costs of AMI were determined utilizing the significant analysis and resultant benefit/cost model created for the Pennsylvania smart meter project as adjusted to Ohio circumstances. The estimated costs of the ADMS system are based on an assessment of current hardware and software costs for such a system.

Each of the three scenarios assumes the modernization of a different number of circuits for IVVC/DA. The selection of the circuits was based upon the work done during the SGMI Project and the CVR Study. Through this work, each of the 2,878 distribution circuits in Ohio was evaluated to determine its individual potential for reliability improvement and energy efficiency. Each of the circuits was then ranked as high versus low potential for distribution automation in terms of reliability improvement expected given the circuit configuration and high, average and low potential for Volt-Var control. The circuits were then ranked to determine which circuits ranked the highest. The Companies then selected the highest ranked circuits, with the actual number selected as indicated in each of the three scenarios.

All costs, as well as the operational cost savings estimates, were determined using a "bottom – up" approach. That is, for each *cost component*, the Companies estimated the number of units needed and valued them based on best estimates of the cost per unit. Conversely, for each operational *cost savings component*, the Companies estimated the number of units that would be reduced and then valued that reduction based on estimates of the cost of each unit. The estimated number of units was based on inputs from various sources, including discussions through a series of workshops with those participating in the different Pennsylvania workstream activities[9] and the results from various studies and projects. For example, as already mentioned, much of the estimated cost and operational benefit data for AMI was based on the PA Companies' experience with their smart meter project. Likewise, most of the costs for IVVC/DA were informed from the SGMI Project and CVR Study, where each distribution circuit was analyzed to determine the exact equipment and infrastructure improvement required for IVCC/DA. The price of a unit was generally based on discussions with vendors or current company pricing.

[9] In Pennsylvania, there were nine workstreams: (i) Solution Framework; (ii) Current State; (iii) Vendor Strategy; (iv) Technology Evaluation and Test Lab; (v) Future State; (vi) Network Communications; (vii) External Communications and Consumer Awareness Strategies; (viii) Change Management and Training; and (ix) a Project Management Office.

The Companies estimated customer and societal benefits using studies completed by independent third parties. Benefits related to improved reliability utilized the DOE Interruption Cost Estimator ("ICE") Calculation Tool and the results from the SGMI Project. Avoided energy and capacity costs were based on the results from the CVR Study, which provided the estimated amount of energy efficiency expected on each circuit, and forecasted energy and capacity prices. AMI-related benefits were based on the results from a study performed by the Smart Grid Consumer Collaborative ("SGCC"), while carbon reduction valuations were based on a combination of the CVR Study (to determine the tons of carbon eliminated) and the works of the U. S. Office of Management and Budget ("OMB") that provided the price per ton of carbon for valuation of the reductions.

SOURCES

<u>ICE Calculation Tool</u>

The ICE calculation tool is an on line tool developed by the DOE in conjunction with the Electric Power Research Institute ("EPRI") and the Lawrence Berkley National Laboratory. It can be used to estimate a customer's cost of a power outage as well as estimate the value of reliability improvements in both a static and dynamic environment. For more information on the ICE tool, go to "icecalculator.com."

<u>SGMI Project</u>

The SGMI Project provided information on the level of reliability improvements that could be achieved on a distribution circuit using various DA equipment. Applying the results from this project, the Companies were able to determine the level of reliability that could be achieved on each of the remaining Ohio distribution circuits, which, in turn, provided data inputs for the ICE calculator.

<u>CVR Study</u>

In 2014, the Companies engaged Dynamic Energy Group, an engineering consulting firm, to develop a model to compute initial CVR potential for each of the 2,878 distribution circuits making up the Companies' Ohio distribution system. This model estimated: i) MWh: Potential annual energy conservation; and ii) kW, kVA: Potential demand reduction.

Based on the results of the model, the circuits were classified as having either high, average, or low potential for enabling conservation efforts and were ranked from highest to lowest potential. The estimated levels of MWh and kW reductions were an input into the calculation of avoided energy and capacity costs. Using a conversion factor, these same estimates were then converted to tons of carbon reduced, which informed the carbon reduction benefit valuation.

SGCC Study

The SGCC studied the potential customer and societal benefits resulting from 24 utilities' smart meter/smart grid projects that were partially funded through the U.S. Smart Grid ARRA Investment Grant program. The results of this study are set forth in an October 2013 report entitled "Smart Grid Economic and Environmental Benefits -- A Review and Synthesis of Research on Smart Grid Benefits and Costs", a copy of which can be found at http://smartgridcc.org/sgccs-smart-grid-environmental-and-economic-benefits-report. The SGCC Study is the basis for the Companies' estimates of customer/societal benefits resulting from carbon reductions through demand response programs facilitated through smart meters, customer participation in time of use rates and revenue enhancements.[10] The SGCC report includes both a "Reference Case" and "Ideal Case" benefits estimate, expressed in "dollar savings per customer per year."[11] The Companies utilized these estimates, delaying initial customer benefits realization for six months to account for CRES providers' marketing and educational activities and then ramping up from the reference case level of participation level (one out of every fifty smart meter customers participating) to the ideal case level (one out of every five smart meter customers participating) by year three of each smart meter life cycle. The SGCC report also contained estimated annual smart meter installations with information to calculate the lag between the meter installation and the realization of operational cost savings benefits.[12]

OMB Study

The OMB is a division of the White House and is charged with promulgating rules and guidelines for all federal agencies. In 2010, OMB established an Interagency Working Group of experts from several federal agencies, including the DOE, the Department of Transportation and the Environmental Protection Agency. This group was charged with studying the social costs of carbon. The Interagency Working Group settled on using three separate, highly respected, and often cited carbon pricing models developed in academia to establish their forecasted price of carbon, which can be found at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. For purposes of estimating the social value of carbon emission

[10] Revenue Enhancement includes customer/societal benefits related to reductions in theft of service more accurate meter readings, and prepayment programs.
[11] On page 45 of the SGCC Report, the Reference Case is described as "conservative" while no characterization of the Ideal Case is offered.
[12] Operational cost savings benefits realization lags by six months in order to recognize the time period between the installation of the smart meter and the actual elimination of the on-site meter read.

reductions, the Companies interpolated the Office of Management and Budget supplied carbon values for years 2020 ($42/Ton) and 2040 ($60/Ton).

SCENARIO SUMMARY

Below is a summary of the three scenarios that the Companies studied with a goal of providing significant customer benefits after factoring in the costs to deploy the technologies. The Companies offer these as a starting point for a collaborative discussion on grid modernization deployment

The table shows the number of customers affected and circuits impacted by various technologies studied under each scenario as well as the net benefits to customers.

OH Smart Grid BC Scenario	AMI		DA/IVVC				Net Benefits (NPV)
	% Customers	# Customers	% Circuits	# Circuits	% Customers	# Customers	
1	100%	2.07M	54%	1557	78%	1.61M	$464M
2	100%	2.07M	31%	883	55%	1.14M	$654M
3	100%	2.07M	19%	551	36%	0.75M	$677M

AMI Costs

Costs for the AMI system were based on information learned through the Pennsylvania smart meter project. The PA Companies developed a robust Benefit / Cost model that the Companies have updated and populated with Ohio-specific data in order to generate the estimates of the costs being proposed as part of this filing. The reasonableness of the cost estimates was also discussed with the vendors currently involved in the Pennsylvania project. Generally, both the capital and O&M costs are comprised of costs for Meters and Network, Staffing, and IT.

ADMS Costs

ADMS costs were estimated based on current pricing for this type of system. Capital costs are generally comprised of hardware, software and staffing, while O&M costs are generally comprised of hardware and software maintenance costs.

IVVC/DA Costs

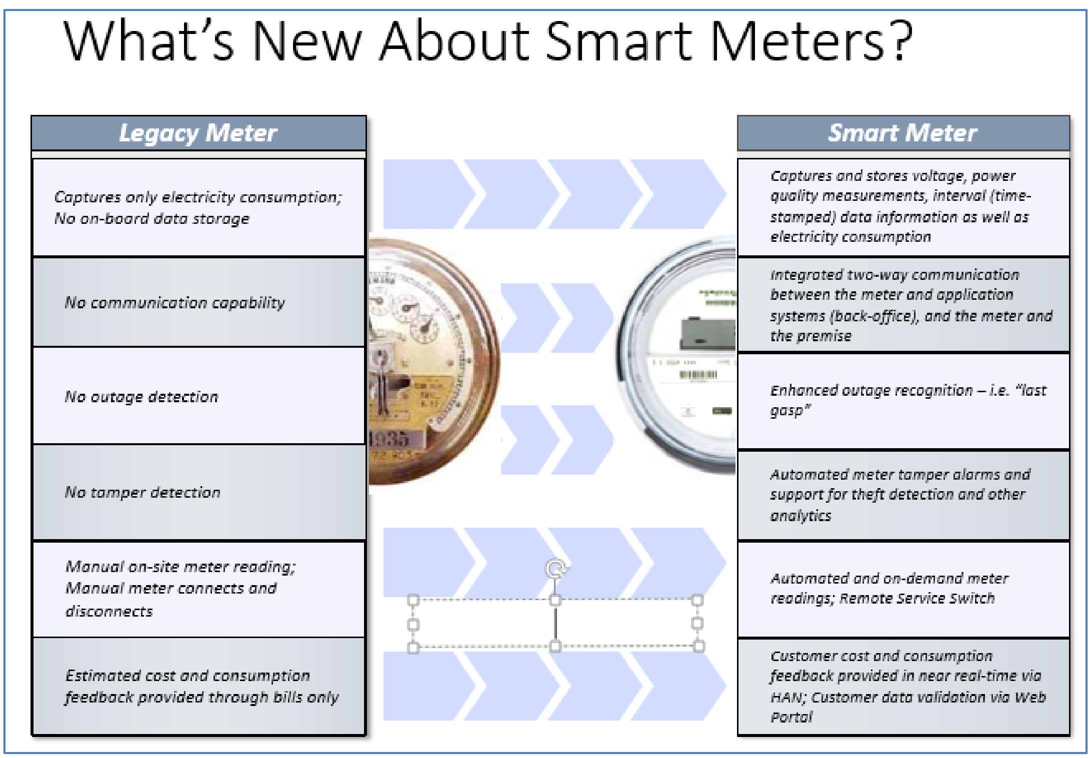
Based upon the results of the SGMI Project and the CVR Study, the Companies could better evaluate the nature of equipment that would be deployed on each individual circuit should it be modernized for IVVC/DA. Using actual current costs for this equipment, the Companies determined a total cost per circuit upgrade. These costs correspond to the circuits selected in each of the three scenarios. Generally, capital costs are comprised of equipment, labor, engineering, network communications equipment and IT configuration. O&M costs are generally comprised of labor for maintenance of equipment.

ANTICIPATED BENEFITS

For purposes of evaluating the benefits associated with each of the three scenarios, benefits were categorized as either "operational benefits" or "customer/societal benefits," the latter of which include Reliability Improvements, Avoided Energy/Capacity Costs, Carbon Reductions and Time of Use ("TOU")/Revenue Enhancement. Operational benefits are estimated cost savings expected to be realized by the Companies through the Plan. Customer/societal benefits (such as the value of shorter outages, the value of time sensitive rates, and reductions in carbon emissions) involve no actual operational savings accruing to the Companies. Below is a discussion of the nature of benefits anticipated to be realized through each of the grid modernization components:

AMI Benefits

Smart metering capabilities are at the very core of each of the grid modernization scenarios. Through previous studies, smart meters are shown to benefit utilities, suppliers and customers alike. Using the smart meters, utilities leverage modern digital and wireless capabilities to migrate away from current metering approaches toward a future that allows remote meter reading and system assessment during both major and minor system outages.



The technology also provides CRES providers and customers with more detailed electric usage information. This should help customers to better manage their electric usage and various smart appliances. The illustration below depicts one vendor, AiMiR's, home energy management platform. [13]

AiMiR Home Energy Management System (HEMS)

AMI may also allow CRES providers to develop sophisticated time differentiated pricing products that are designed to provide incentives for using electricity during off-peak versus on-peak periods. This should allow customers to select customized products that help them save money and manage their electric bills. Benefits specifically identified with AMI technology include:

Remote Meter Reading (Operational Benefit)
AMI will allow for the smart meters to be read remotely, thus eliminating the need for on-site meter reads which may allow for the vast majority of the manual meter reading function to be eliminated. When estimating the anticipated operational cost savings, the Companies used the bottom up approach, factoring in not only the anticipated reduction in personnel, but also the related reductions in employee benefits, employee field equipment, uniforms and other related costs. Further personnel and related reductions were anticipated in meter services, back office and call center operations.

[13] http://www.nuritelecom.com/products/aimir-home-energy-management-system-hems.html.

Customer Participation in Time Varying Rate Programs (Customer Benefit)
AMI will allow the Companies to record more granular information regarding energy consumption quantities and will be able to record the date and time of that consumption. In conjunction with anticipated new time differentiated pricing products sponsored by CRES providers, AMI may allow customers to proactively shift portions of their energy consumption to times of day where energy rates are lower, thus reducing their bills. The value of customers' direct economic benefit resulting from participation in time of use rate programs was estimated based on the results of the SGCC Study.

Remote Connect Activities (Operational Benefit)
In situations where power has been disconnected for any reason, upon restoration criteria being met, power can be restored remotely within minutes, as opposed to current timelines, without the necessity of dispatching field personnel. The estimated operational cost savings benefits were determined using the bottom up approach and, again, are focused on the elimination of labor related tasks.

Remote Disconnect Activities (Operational Benefit)
In situations where customers request their power to be disconnected (e.g., seasonal residence or apartment dwellings), power can be disconnected shortly after the request is submitted without the necessity of dispatching field personnel. Operational cost savings related to this benefit were estimated using the bottom up approach, similar to the remote connect activities. And, although these same capabilities exist for remote disconnection for non-payment of bills, O.A.C. 4901:1-18-06(A)(2) currently requires that the Companies provide customers with personal notice on the day of disconnection of service for nonpayment. Consistent with the Companies' commitment made in the Third Supplemental Stipulation in the ESP IV Case, the Companies will not seek a waiver of this rule provision during the ESP IV period.[14] Therefore, no savings have been estimated for field visits for disconnection for non-payment.

Outage Reporting (Operational, Customer and Societal Benefits)
Current outage assessment activities are primarily determined by substation monitoring for very large outages complemented by customers proactively notifying the Companies of outages they are experiencing. AMI technology allows each individual meter to report to operational systems if they have experienced an outage, allowing for targeted restoration activities to begin much faster. Further, meters can be dynamically pinged to assess if the entirety of an outage has

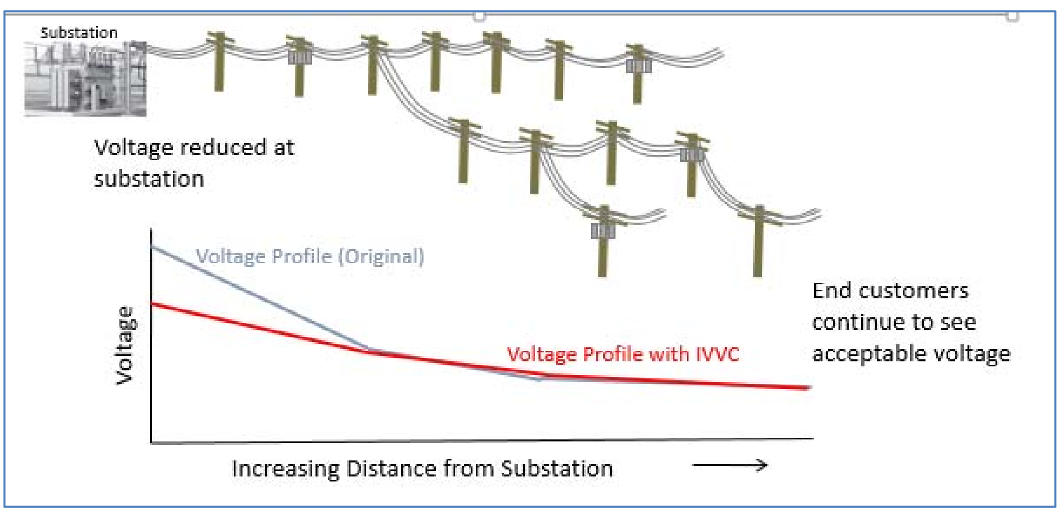
[14] Third Supplemental Stipulation at 10.

been restored or if nested outages require further restoration. These activities generally reduce the duration of an outage, the savings for which is discussed in the IVVC/DA Section below. Remote outage reporting also reduces the number of truck rolls. Operational Savings were estimated using the bottom up approach, while the carbon reduction resulting from fewer truck rolls was based on the OMB data.

Revenue Enhancement (Customer Benefit)
AMI meters utilize sophisticated algorithms to ensure that recorded consumption is accurate and that techniques for theft (e.g., consumption bypassing the meter) are identified quickly. By automatically identifying these scenarios and notifying the Companies' operations personnel, actions can be taken to remediate the situation, thus reducing costs to other customers who would otherwise have to pay for stolen service. The value of this customer benefit is based on the SGCC report.

IVVC (Energy Efficiency) Benefits

Low voltage complaints can emerge for customers who are farther away from a substation. The Companies currently control voltage on the distribution system to ensure all customers are supplied voltage within regulatory requirements. By using various IVVC substation and line equipment, the Companies will have dynamic capabilities to levelize the voltage and operate the grid with greater energy efficiency, thus requiring less generation and resulting in the more efficient use of distribution assets. Managed voltage reductions can translate into reduced energy usage by customers.



Benefits specifically identified with IVVC include:

Energy Efficiency Benefits (Customer Benefit)
There are several modes in which IVVC can operate, but the primary benefit to customers comes from CVR. Some utilities have chosen to operate CVR in "Peak Demand Reduction" mode, which only operates when demand on the system is extremely high. Because this approach limits the potential benefits, the Companies assumed for purposes of analysis that IVVC would run on identified circuits in "24 - 7" mode throughout the majority of the year in order to maximize economic benefits for customers.[15] The estimated energy efficiency customer benefit is based on work done in the CVR Study, where each circuit selected in each of the three scenarios was assigned a value of annual MWh reduction. This reduction was valued at the projected energy prices in each of the applicable years during the life cycle.

Avoided Capacity Benefits (Customer Benefit)
As a result of reducing energy consumption throughout the year, the amount of energy consumed on the peak day is also inherently reduced. The Companies use peak day energy consumption as a key input for calculating their capacity requirements into the future. Thus, by reducing the peak, the Companies can also reduce the amount spent on incremental capacity. The value of this customer benefit was estimated using the same CVR Study previously referenced, which also assigned an estimated annual level of MW reduction on each of the distribution circuits. This MW reduction was then multiplied by the projected capacity costs for the applicable year during the life cycle.

Carbon Reduction (Societal Benefit)
With a reduction in generation comes a reduction in carbon emissions. The amount of the carbon reduction was estimated based on the results from the Companies' CVR Study, where the energy and demand reductions were converted through a formula to annual tons of carbon avoided. The estimate of this societal benefit was determined by taking the annual amount of carbon avoided and multiplying it by the value of a ton of carbon as established by the OMB.

DA (Reliability) Benefits

The Companies' deployment of DA devices would help identify outages, but also provide grid operators with additional flexibility to remotely reconfigure the network. Benefits specifically identified with DA include:

[15] It should be recognized that there will likely be certain operational situations (outage response, low voltage complaints, etc.) in which optimizing the network is a secondary priority to outage restoration and customer satisfaction.

Reliability Benefits (Customer Benefit)
The value of this customer benefit was estimated using the ICE Tool. Inputs for the ICE Tool were based on the results from the SGMI Project. The ICE Tool calculates the value to customers for reduced outages. There is a direct correlation between the level of this benefit and the number of circuits selected for IVVC/DA. For purposes of the three grid modernization scenarios presented above, the data inputs specific to the selected circuits for each scenario were inserted into the ICE model.

Restoration Time Benefits (Operational and Customer Benefit)
When an outage occurs, DA devices would be programed with autonomy to isolate faults and automatically restore power. In the outage area, DA isolates the faulted area, which results in a smaller sustained outage. Customers in the non-faulted area only experience a momentary outage. The DA improvements should reduce the number of sustained outages, which, in turn, should improve SAIFI and SAIDI results for the circuits where DA technology is deployed. Depending on the number of circuits deployed with DA technology, the reliability improvement could be as much as 24 percent. Because DA provides sustained fault isolation it isolates the fault to a smaller area allowing, the trouble crew to commence the repair activity sooner. DA provides benefits to the customer beyond what is typically measured by the Commission for reliability reporting. Reliability reporting exclude Major Events defined by the IEEE 1366 – 2003 2.5 Beta Method and transmission caused outages. Reliability improvements from DA include all outages, to represent reliability seen from a customer perspective.

Remote Reconfiguration Restoration (Operational Benefit)
When multiple DA devices are deployed within a given circuit, these devices support centralized isolation of outage conditions. Following a successful isolation, DA devices can allow downstream portions of the circuit to be quickly reenergized by connecting to other circuits that are operating normally. What normally would require a field crew to correct, the DA equipment can do remotely, thus avoiding the need to dispatch crews into the field. Like the Restoration Time Benefit discussed above, the estimated operational cost savings was determined using a bottom up approach to determine the savings associated with labor reductions and fewer truck rolls.

<u>Advanced Distribution Management System (ADMS) Benefits</u>

The ADMS is the single system that ties together data from AMI, IVVC and DA. This centralized control system enables operators to efficiently monitor and optimize the distribution grid –– managing power reliability to enhance customer satisfaction.

While there were no direct operational saving benefits attributed to the ADMS, other indirect benefits include:

Key enabling technology for IVVC and DA
All of the technologies comprising IVVC and DA have capabilities that can be independently deployed. Their benefits however are significantly expanded when working together as a "team" as coordinated by the ADMS. Based on a detailed ADMS assessment project, the Companies believe that ADMS is essential for unlocking the maximum financial and societal benefits associated with these technologies.

Situational Awareness Benefits (Operational and Customer Benefit)
Access to accurate real-time information has historically been one of the biggest challenges in operating a reliable power system. For purposes of analysis, the Companies assumed that IVVC and DA devices would be deployed with wireless communications capabilities to collect and transmit information to the centralized ADMS. Combined with information from AMI meters, the grid operator would then have reliable and consistently verifiable data from which to make more informed decisions regarding operation of the distribution grid. In so doing, there are numerous tangential benefits, including increased safety for field crews and enhanced reliability benefits for customers, due to expedited response times and ensured grid stability in restoration scenarios.

Synergies/Coordination Benefits (Operational and Customer Benefit)
By bringing information from AMI, IVVC, and DA together in a centralized system, the ADMS is able to leverage information from one capability to enhance the performance of another. Collectively, the ADMS allows each individual component to be stronger and each contributes to enhanced situational awareness. For example:

- AMI meters provide individual customer outage notification to determine outage scope
- AMI meters provide locational voltage details to fine tune IVVC algorithms
- IVVC can help synchronize voltages when closing DA devices at tie points
- IVVC devices can be coordinated as a team to optimize results
- DA devices can be coordinated as a team to optimize results

Other Benefits (Operational and Customer Benefit)
As technology evolves, it is expected that new technologies such as solar deployment, electric vehicles, and battery energy storage, will place new demands on the distribution system. Because ADMS is designed with flexibility to be configured for these and other Distributed Energy Resources, ADMS should be able to accommodate greater operational variability and intermittency.

Other Non-Quantifiable Benefits

There are other intrinsic benefits attributable to grid modernization that cannot be valued with any degree of certainty. For example, not only does IVVC provide energy and capacity reductions, but it also improves voltage quality. Improving voltage across the entire circuit may improve customer satisfaction and customer productivity, depending on circumstances. Further, as more and more customers use sensitive electronics, it is important to optimize the power quality to maintain voltage. Likewise, the DA system will improve reliability and will shorten the duration of outages that do occur. As a result there should be fewer accidents caused by non-functioning street and traffic lights and downed wires. Similarly, with fewer outages, there should be fewer OSHA claims by Company personnel. These and other benefits have not been assigned a monetary value for purposes of this Plan.

CONCLUSION

The Companies, as a part of the ESP IV Case, made significant commitments to modernize their distribution system and promote customer choice. The filing of this Plan is an important step toward that goal. However, there is additional work to be done. It is the Companies' desire to use this Plan as a catalyst to spur discussions with interested parties -- many of whom have knowledge, experience and expertise in smart grid technologies and can provide valuable insight into effective deployment of these technologies. The Companies submit this Plan consistent with the commitments made in the Third Supplemental Stipulation, with the intention to engage in a collaborative process where they can answer any questions regarding the Plan and work to develop a grid modernization strategy that will work best for the Companies' system to provide the greatest benefits to the Companies' customers. The Companies look forward to working with all interested parties in moving this Plan forward.

EXHIBIT B

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

ESP IV – Transition to Decoupled Rates Timeline

Task	Description	Start	End
1	Third Supplemental Stipulation Filed	12/1/2015	
2	90-Day Filing	2/29/2016	
3	Preparation of Case to Transition to SFV Cost Recovery Mechanism for Residential Base Distribution Rates	3/1/2016	4/1/2017
4	File ATA Case Proposing SFV Cost Recovery Mechanism Based on Weather Adjusted Base Distribution Revenue and Lost Distribution Revenue and kWh Sales as of Calendar 2016	4/3/2017	
5	SFV Cost Recovery Mechanism Proceeding	4/3/2017	12/1/2018
6	Interim Update Filing SFV Rates Based on Weather Adjusted Base Distribution Revenue and Lost Distribution Revenue and kWh Sales as of Calendar 2017	4/3/2018	
7	File Final SFV Rates Based on Weather Adjusted Base Distribution Revenue and Lost Distribution Revenue and kWh Sales as of September 2018	11/1/2018	
8	PUCO Order Issued in SFV Case	TBD	
9	File Compliance Tariffs for Years 1-3	12/20/2018	
10	Year 1 of Decoupling in Effect (25% fixed / 75% variable)	1/1/2019	12/31/2019
11	Year 2 of Decoupling in Effect (50% fixed / 50% variable)	1/1/2020	12/31/2020
12	Year 3 of Decoupling in Effect (75% fixed / 25% variable)	1/1/2021	12/31/2021