BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

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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 Application for Approval of a Distribution Platform Modernization Plan	))))))	Case No. 17-2436-EL-UNC

OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY APPLICATION FOR APPROVAL OF A DISTRIBUTION PLATFORM MODERNIZATION PLAN

Introduction

Ohio Edison Company, The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company (collectively, the "Companies") provide distribution service to over two million customers in Ohio and have service territories that cover approximately 9,900 square miles and include over 2,800 distribution circuits. Providing safe and reliable electric service to the Companies' customers while continuing to meet those customers' expectations and needs are among the Companies' top priorities. Accordingly, the Companies closely monitor both their reliability performance metrics and customers' expectations as it relates to the reliability of the Companies' electric services.

Since 2010, the Companies have consistently outperformed their Commission-approved reliability standards for both System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI"). The Companies have also conducted periodic customer surveys to better understand customers' perceptions of the service provided by the Companies. While recent customer surveys confirm that the Companies' service aligns with customers' expectations for reliability, these surveys also indicate that customers' expectations continue to increase. Specifically, customers have identified that the most significant way that the Companies can enhance their service is by reducing the length of time it takes to restore power after an outage. Further, the Companies' experience indicates that customers' needs are evolving due to ongoing advancements in technology and other innovations. These evolving dynamics in the provision of distribution service present both a challenge and an opportunity for the Companies to find ways to affordably integrate the new technologies for their customers into the distribution system without jeopardizing safety or reliability.

The Companies have already dedicated significant resources to exploring the implementation of grid modernization technologies as an answer to customers' evolving needs. For more than five years, the Companies have 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. The Companies also prepared and filed a grid modernization business plan ("Business Plan") that highlights future initiatives for Commission consideration and approval.[1] Through these actions, the Companies have gained an increased knowledge of the benefits their customers receive from a modernized grid.

The Public Utilities Commission of Ohio ("Commission") has also expressed a desire to have electric distribution utilities in the State of Ohio address the evolving needs of customers through modernization of the electric grid. In April 2017, the Commission kicked off an initiative called PowerForward – a Commission "review of the latest in technological and regulatory

[1] *See 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. 16-481-EL-UNC.

innovation, to enhance the consumer electricity experience."[2] Through this initiative, the Commission "intends to chart a path forward for future grid modernization projects, innovative regulations and forward-thinking policies."[3] The Commission has engaged many stakeholders to learn what technologies or changes are needed so that "innovative regulations and forward-thinking policies can be developed."[4] As discussed herein, the Companies' mission and, specifically, the Distribution Platform Modernization ("DPM") Plan, aligns with the Commission's efforts.

The Companies fully support the Commission's PowerForward initiative and continue to be active participants in the ongoing effort. Informed by their participation in PowerForward, and the studies, surveys, and pilot programs discussed above, the Companies have identified significant work that must be done to address customers' increasing reliability expectations and evolving needs, while modernizing the Companies' distribution platform and enabling future grid modernization investments. On these bases, the Companies seek approval of the DPM Plan proposed herein and discussed in more detail below.

It is important to note that the DPM Plan should be completed as soon as possible so future grid modernization investments, including those that may be directed by PowerForward, can be implemented in a more efficient and expeditious fashion. Moreover, through the implementation of this DPM Plan now, the Companies will provide customers with immediate reliability benefits and the resulting rate impacts will be more gradual than otherwise might occur to implement grid modernization initiatives. Therefore, in accordance with the Commission's March 31, 2016

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[2] https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/powerforward-faq/.

[3] *Id.*

[4] *Id.*

Opinion and Order[5] and Fifth Entry on Rehearing[6] in ESP IV, O.R.C. 4928.02(D) and the Commission's stated policy initiatives, the Companies hereby respectfully request that the Commission approve their DPM Plan and associated cost recovery as described herein.

The DPM Plan

The DPM Plan, attached hereto as Attachment A, is a portfolio of projects that will provide significant customer benefits. These projects are expected to:

1) result in enhanced reliability of the system and outage restoration for customers, the benefits of which will continue independent of any other additional grid modernization investments that may be undertaken by the Companies;
2) modernize the Companies' existing distribution system, while supporting and enabling additional grid modernization initiatives; and
3) provide for more gradual rate impacts to customers than otherwise might occur to implement grid modernization initiatives.

The DPM Plan is a three-year portfolio of work with total estimated capital expenditures by the Companies of approximately $450 million. These grid modernization projects are incremental to the Companies' current work to maintain safe and reliable electric service and are outside of the Companies' current work plans. The work included in the DPM Plan will transform the distribution system by creating alternate routes for power flow and the ability to reroute power

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[5] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company 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 ("ESP IV"), Opinion and Order at 69-70, 95-96 (March 31, 2016).
[6] *Id.* at Fifth Entry on Rehearing p. 96, ¶ 206 (Oct. 12, 2016).

remotely, which enhances the functionality of the Companies' system to better enable and support future grid modernization investments.

The projects in the DPM Plan and their associated benefits and costs include:

- **Circuit Ties** – These projects create alternative routes for power to flow, thereby providing increased operational flexibility on the Companies' system. As a result, outage durations are reduced as customers can be served from multiple sources. The Companies have identified approximately 300 new tie miles to be created at an estimated cost over three years of $110 million.
- **Reconductoring** – In conjunction with circuit ties, reconductoring facilitates alternative power flows by increasing wire sizes to accommodate increases in load due to rerouted power without overloading smaller conductors that typically are at the ends of circuits. This work contributes to reduced restoration times, and also improves the resiliency of the system as the larger, stronger wire size improves the system's ability to withstand adverse weather conditions. The Companies have identified over 800 circuit miles that will need to be reconductored at an estimated cost over three years of $130 million.
- **Remote-Controlled Reclosers** – These investments decrease the number of customers affected by an outage by allowing circuits to be divided into smaller sections. In addition to fault isolation, reclosers enable remote switching for quicker restoration, and are required to accommodate future distribution automation. The Companies plan to install approximately 1,900 reclosers and associated communication system infrastructure at an estimated cost over three years of $150 million.
- **Data Acquisition Systems**
    - **Supervisory Control and Data Acquisition ("SCADA") System** – SCADA is a software platform that, along with associated communication system and hardware,

allows the Companies to have immediate access to system conditions and operations. The data and control made available through SCADA allows the Companies to analyze and remotely reroute power flows more effectively and efficiently, thereby improving outage restoration times. The SCADA project includes installation of approximately 2,600 additional SCADA devices in substations and on circuits at an estimated total cost of $30 million.

- **Advanced Distribution Management System ("ADMS")** – ADMS is a centralized software platform that integrates all SCADA information and provides a more complete view of the Companies' distribution system. The enhanced data available through ADMS provides for advanced decision analysis that otherwise would need to be done manually using the SCADA information, thereby further improving restoration times by expediting the analysis and providing solutions to reroute power and restore service to customers. The estimated cost of the ADMS platform included in the DPM Plan is $30 million.

Importantly, the above categories of grid modernization projects need to be implemented together to optimize the benefits for customers. The projects in the DPM Plan are investments that will be implemented consistent with good utility practice. These projects are needed for the Companies to continue to meet customers' increasing expectations for reliability and evolving needs, and to enable future grid modernization investments. The investments made as part of the DPM Plan will provide sustainable, long-term benefits to customers. The Companies will seek to mitigate any risks associated with cyber security and risks associated with the installed equipment becoming obsolete or needing to be replaced in the near-term. As demonstrated in Attachment A, the DPM

Plan is estimated to provide nominal benefits to customers of $2.8 billion, compared to estimated costs of $0.8 billion, or a benefit-to-cost ratio of 3.4.

Cost Recovery

The Companies' Advanced Metering Infrastructure/Modern Grid Rider ("Rider AMI") was approved by the Commission in ESP IV to recover, in part, any costs associated with the implementation of grid modernization infrastructure.[7] Accordingly, the costs of any projects approved by the Commission as part of the DPM Plan will be recovered through Rider AMI, consistent with the terms ordered by the Commission in ESP IV. The revenue requirement will include depreciation expense, property tax expense, return on equity, interest expense, income taxes, other associated taxes, and operations and maintenance ("O&M") expense, including incremental O&M expense associated with the ongoing administration, management, tracking, and reporting of the DPM Plan projects. Rider AMI is updated and reconciled on a quarterly basis and is subject to an annual audit by the Commission Staff. The quarterly rider update filings for Rider AMI will include detailed schedules supporting the amounts included for recovery associated with the DPM Plan, including gross plant in-service, accumulated depreciation, accumulated deferred income taxes, rate of return, and each component of the revenue requirement. The annual Rider AMI audit will include a review of the Companies' adherence to the DPM Plan and a determination of whether the amounts sought for recovery associated with the DPM Plan are not unreasonable based on the facts and circumstances known at the time the investments were made. Attachment B and Attachment C show the estimated revenue requirements and rate calculations under the proposed DPM Plan, respectively, and estimated customer impacts from the DPM Plan are

[7] ESP IV, Opinion & Order, p. 69 (March 31, 2016); Fifth Entry on Rehearing, Concurring Opinion of Chairman Asim Z.. Haque, p. 2 (Oct. 12, 2016); Finding and Order (May 25, 2016) (approving proposed tariffs).

summarized in Attachment D. Attachment E provides a template for the quarterly filings for cost recovery of the DPM Plan under Rider AMI.

Witness Testimony

The DPM Plan is further explained in, and supported by, the testimony of six witnesses. The Companies' witnesses, and the general topics that each address in their pre-filed direct testimony, are:

- David J. Karafa – DPM Plan overview, customer benefits and policy objectives;
- Mark Vallo – circuit ties, circuit reconductoring, recloser installations, SCADA;
- Lisa Rouse – ADMS;
- William Beutler – estimated reliability improvements and improved storm restoration times, estimated customer benefits;
- Brandon Bolon – cyber security;
- Brandon McMillen – cost recovery, summary of the cost vs. benefit analysis.

Proposed Timeline for Commission Review

The Companies request that the Commission issue an order approving the DPM plan and associated cost recovery no later than May 2, 2018, so that the Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits. This timeline is reasonable given the fact that the DPM Plan investments are necessary to prepare the Companies' distribution system for future grid modernization investments and the outcome of the PowerForward initiative.

Conclusion

The DPM Plan is needed to address customers' increasing reliability expectations and support customer-focused innovations, while modernizing the Companies' distribution platform and enabling future grid modernization investments. Thus, the Companies respectfully request that the Commission approve its application for the DPM Plan and associated cost recovery through Rider AMI no later than May 2, 2018, so that customers can start to realize the associated benefits.

Respectfully submitted,

<u>/s/ Carrie M. Dunn-Lucco</u>
Carrie M. Dunn-Lucco (#0076952)
Counsel of Record
Joshua R. Eckert (#0095715)
FirstEnergy Service Company
76 South Main Street
Akron, Ohio 44308
cdunn@firstenergycorp.com
jeckert@firstenergycorp.com
Phone: 330-761-2352
Fax: 330-384-3875

James F. Lang (0059668)
Mark T. Keaney (0095318)
CALFEE, HALTER & GRISWOLD LLP
The Calfee Building
1405 East Sixth Street
Cleveland, OH 44114
Phone: 216)-622-8200
Fax: 216-241-0816
jlang@calfee.com
mkeaney@calfee.com

Attorneys for Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

Attachment A

Distribution Platform Modernization Plan

of

Ohio Edison Company

The Cleveland Electric Illuminating Company

and

The Toledo Edison Company

December 1, 2017

OVERVIEW

The Distribution Platform Modernization ("DPM") Plan is a three-year portfolio of work that is comprised of the following types of projects:

- Creating new circuit ties
- Reconductoring
- Installation of remote-controlled reclosers
- Data Acquisition Systems
    - Supervisory Control and Data Acquisition ("SCADA") System
    - Advanced Distribution Management System ("ADMS")

These projects provide immediate benefits to customers in terms of increased reliability, improved outage restoration times, and a modernized distribution platform. Importantly, the above categories of projects need to be implemented together to optimize the benefits for customers. The customer benefits from the DPM Plan will continue independent of any other additional grid modernization investments that may be undertaken by the Companies. The work included in the DPM Plan is incremental to the work required by the Companies to maintain safe, reliable service because it changes the existing architecture and functionality of the Companies' system and modernizes it.

CIRCUIT SELECTION

The work proposed in the DPM Plan is targeted to specific circuits on the Companies' system that are determined to provide the most opportunity for customer benefits in terms of enhanced reliability and support for future grid modernization investment. Circuits that do not meet these criteria would not be included in the DPM Plan. For example, a circuit that historically has not experienced many outages, or a circuit that is geographically isolated in a rural area, may not be a good candidate for the DPM Plan because there is not an opportunity for significant reliability enhancement or future grid modernization investment. The Companies have conducted an analysis of all circuits in their service territories to determine which ones to include in the DPM Plan. This analysis included a review of all relevant historical circuit information, including the number of customers served on the circuits, the number of outages occurring on the circuit, and minutes interrupted. The circuits were also analyzed to determine what improvements could be made to enhance reliability and to modernize the circuit to enable it to support future advanced grid modernization technologies. The Companies then ranked the circuits in terms of potential reliability improvement and supporting future grid modernization investment to determine the best candidates for inclusion in the DPM Plan. Based on this study, the Companies estimate that approximately 1,500 circuits would benefit from the type of work included in the DPM Plan. The DPM Plan includes approximately 700 of these circuits that the Companies estimate would have the most benefits to customers in terms of improved reliability and opportunity for supporting future grid modernization investment. The Companies will continue to monitor, review, and update the list of circuits included in the DPM Plan.

The Companies estimate that the DPM Plan will cover approximately 45% of the eligible circuits (or approximately 25% of the Companies' total circuits), upon which approximately 50% of the Companies' customers are directly served.

DPM PLAN CATEGORIES OF WORK

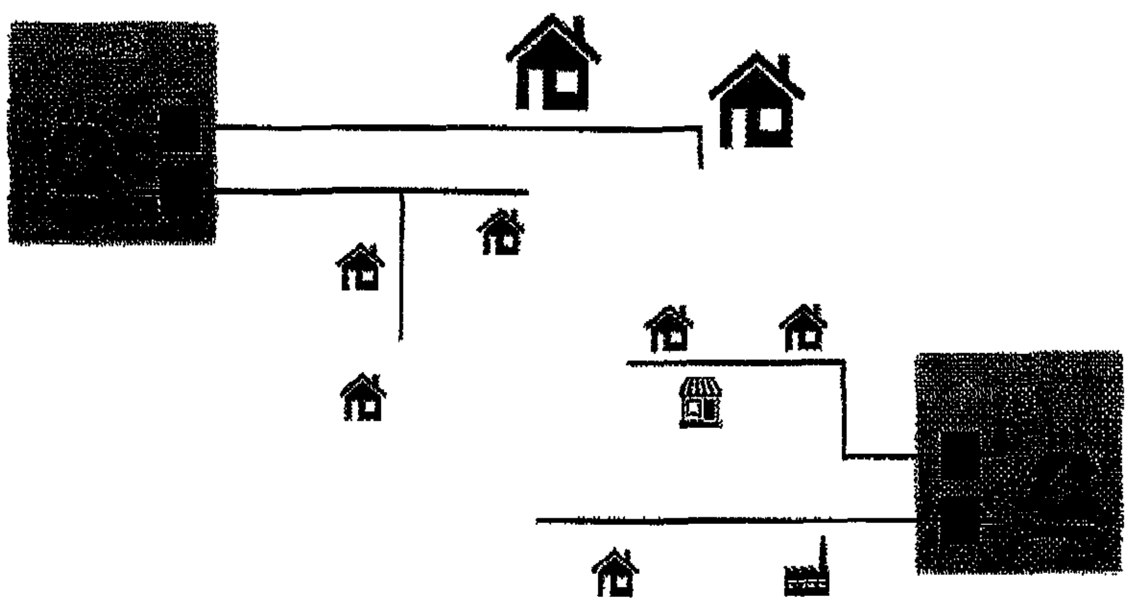
Detailed descriptions of each category of work included in the DPM Plan are provided below.

Creating New Circuit Ties and Reconductoring

Circuit Ties

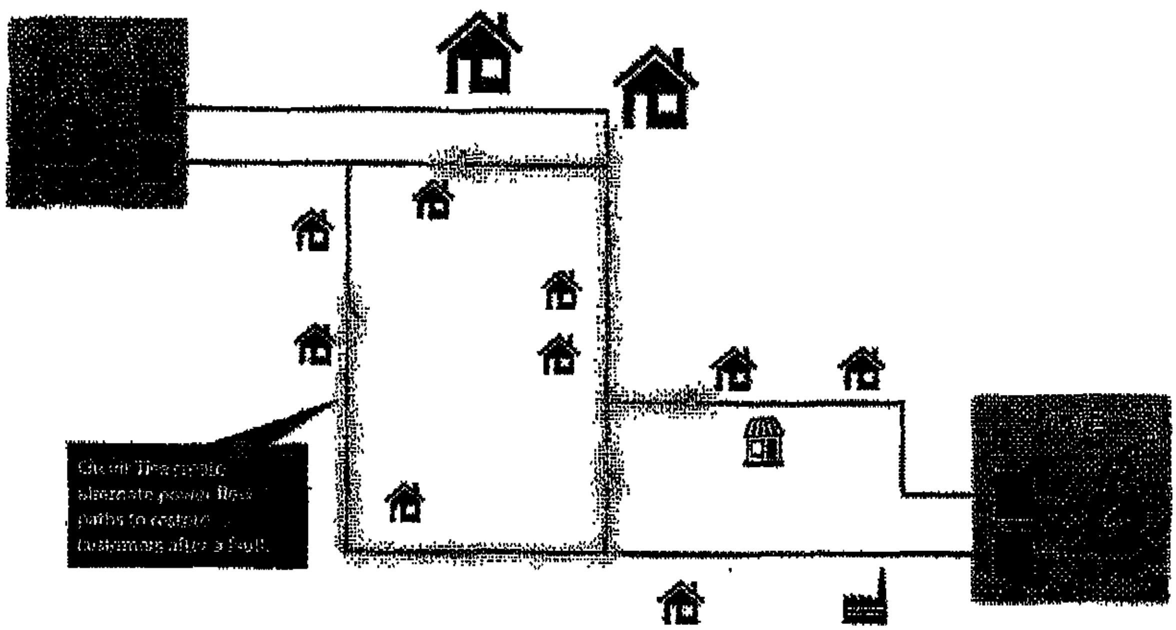
Many of the Companies' distribution circuits were designed as radial systems. In the radial system, power is created at the generation source and delivered through the transmission system to a distribution substation. The power is then distributed to customers along a one-way circuit without alternate paths for power to flow. Under this existing radial system design, a customer is exposed to a potential outage if a fault or disruption were to occur anywhere along the circuit.

In the illustration below, Substation A and Substation B receive power from a generation source and then distribute it to their own set of customers via four independent circuits, each with a one-way path for power to flow. If a fault occurred near breaker A2, all customers served on the remainder of the circuit would experience a sustained outage because they would need to wait for power to be restored at the fault location before their power was restored.



Breakers – A1, A2, B1, B2

By creating new circuit ties, the Companies can connect circuits, creating alternate power flow paths and enabling quicker restoration for customers after a fault. In the illustration below, the four formerly radial circuits are now tied together at four points with manual switches, which enables all customers to be served from either Substation A or Substation B. These manual switches allow for power to be rerouted by manually opening and closing switches in the field. If the same fault were now to occur near breaker A2 after the circuit ties have been installed, a manual switch near the fault can be opened to isolate it and another manual switch located at one of the circuit tie points can be closed, thereby allowing customers on the remainder of the circuit to be served from an alternative path through breaker A1. As a result, the customers will experience immediate benefits through quicker restoration of service as well as increased reliability. While the Companies would still need to do the switching manually in the field, power can be re-routed to serve customers on the remainder of the circuit while the Companies work to restore service at the fault location.



Breakers – A1, A2, B1, B2

Reconductoring

To accommodate potential increases in load associated with rerouting of power, wire size on the Companies' circuits will need to be increased. For example, if a new circuit tie is created to facilitate additional power flows, the size of the existing wires on the circuit will likely need to be increased. Otherwise, even though the circuits are tied together, the conductor will not be able to accommodate the load from the rerouted power and customers will not realize the benefits of improved outage restoration and reliability. Larger wires have the ability to easily transfer load without overloading smaller conductors that typically would be at the ends of the circuits. Increasing wire size also adds to the resiliency of the conductor because larger wires are stronger and less likely to come down or be taken out of service during adverse weather conditions. This improved resiliency yields quicker restoration times for customer during significant outage events.

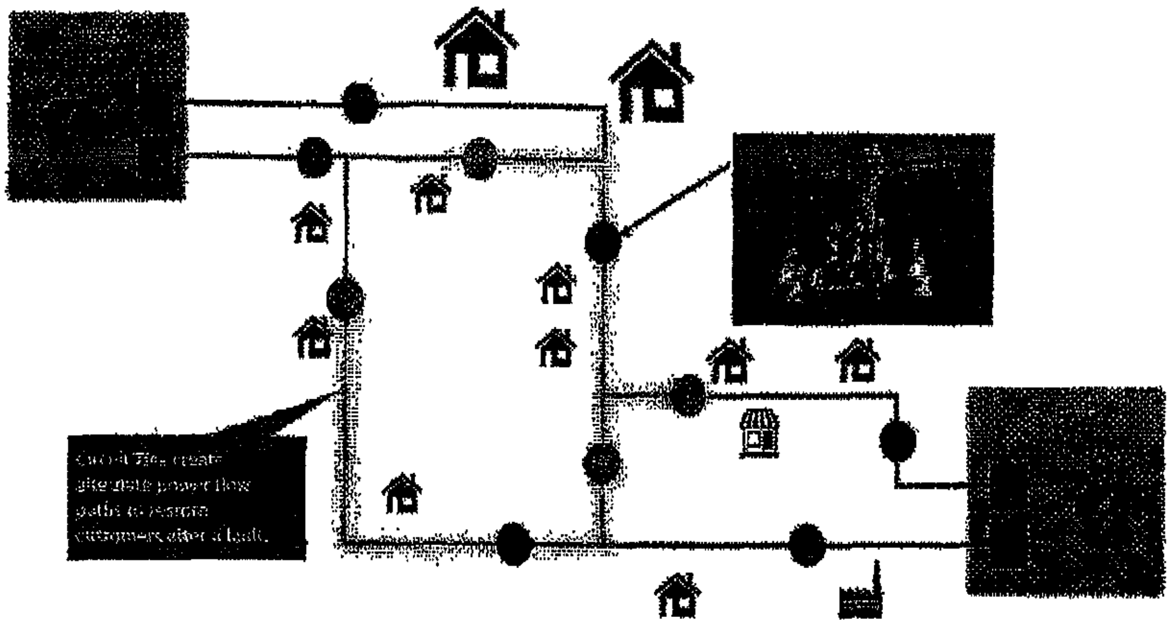
In addition to the immediate customer benefits discussed above, the installation of circuit ties and reconductoring enables the integration of advanced grid modernization technologies and infrastructure in the future. For example, distribution automation is an advanced technology that will allow for faults to be identified and power to be rerouted automatically. Without circuit ties and reconductoring as part of the DPM Plan, the full benefits of distribution automation would not be realized because the Companies' system would not be able to reroute power across alternative paths, thereby defeating the use of the distribution automation technology. The infrastructure installed with circuit ties and reconductoring does not rely on new or emerging technologies. This infrastructure has a proven, sustainable useful life and, as such, is not at risk of becoming obsolete in the near term due to evolving technologies.

The Companies perform work on their circuits and conductors as part of their base capital expenditures needed to maintain safe and reliable service for customers. The preparation for and installation of circuit ties and reconductoring included in the DPM Plan, though, are incremental to the Companies' base capital expenditures because these investments go beyond maintaining the existing infrastructure and instead significantly modify and modernize the architecture and functionality of the Companies' system. These are investments that are needed to help address customers' increasing expectations for reliability and to better enable the grid of the future.

<u>Remote Controlled Reclosers</u>

The second category of projects included in the DPM Plan is the installation of remote controlled reclosers. Reclosers are electronic controlled devices that protect circuit lines, similar to the way circuit breakers work in a home. Reclosers effectively divide the distribution circuit into smaller sections, which allows faults to be isolated to smaller groups of customers and minimize the impacts of outages on customers. Remote controlled reclosers installed as part of this DPM Plan will enable the Companies' system operators to modify power flows on the system from a remote location, by opening or closing the reclosers where needed to restore service to other sections of the circuit. Absent the installation of these devices, customers would experience longer, sustained outages, as either the power flows would need to be rerouted manually at the site or the customers would simply need to wait for service on their circuit to be restored.

The following illustration shows the addition of protective and tie reclosers on the distribution circuits used in the prior examples above. As illustrated below, the installation of circuit ties and reconductoring, along with the addition of remote controlled reclosers, benefit customers by isolating outages to fewer customers and facilitating quicker restoration. For example, if a fault occurred between breaker A2 and recloser R3 prior to installation of recloser R4 or R9, then customers between R4 and R9 would experience a sustained outage. Now, with these improvements, recloser R3 can be remotely opened and recloser R9 can be remotely closed so that the remaining customers on the circuit experience only a momentary outage. This improved restoration is made possible through a combination of circuit ties, reconductoring, and the installation of remote controlled reclosers, as the Companies are now able to re-route the flow of power remotely.



The installation of remote controlled reclosers would further enable the Companies' distribution system for additional grid modernization. Once these reclosers are installed, the Companies will have the ability to control power flows on their system without a physical presence in the field. Without these investments, the Companies would not be able to take the next step in further modernizing the grid by controlling the system automatically through distribution automation. Similar to circuit ties and reconductoring, remote controlled reclosers do not rely on new or emerging technologies and have a proven, sustainable useful life. To function properly and provide the desired benefits to customers, these reclosers also need a reliable communications system. While the effectiveness of the Companies' communication system is subject to changes in technology in the future, any risk of the communication system becoming obsolete or no longer compatible with the remote controlled reclosers can be mitigated. (See section "Supervisory Control and Data Acquisition (SCADA)" below).

The Companies' capital expenditures needed to maintain safe and reliable service for customers do not include systematic and targeted installation of remote controlled reclosers. Accordingly, the preparation for and installation of remote controlled reclosers as part of the DPM Plan is incremental work that adds additional modernization functionality to the Companies' system. These are prudent investments that are needed to help address customers' increasing expectations for reliability and to better enable the grid of the future.

<u>Data Acquisition Systems</u>

Supervisory Control and Data Acquisition (SCADA)

Currently, the Companies rely largely on information obtained from field personnel to evaluate the condition of their distribution system. Providing real-time transparent information to the Companies' distribution system operators improves decision-making and helps them react more quickly to changes in system conditions. An important part of the information system is Supervisory Control and Data Acquisition ("SCADA"). SCADA is a mature technology that has been evolving over several decades. This software platform, and the associated communication system and hardware that supports it, allows operators to have additional information about voltage levels and power flow within the substation and at various locations along the distribution system.

SCADA information assists operators in their decision analysis during outages, and can also allow operators to remotely open and close breakers on the system to mitigate the duration of power outages. The enhanced data availability from SCADA benefits customers immediately, as the Companies will have more visibility into the conditions and operation of their distribution system. These benefits will continue regardless of whether further grid modernization is installed, but they will increase with the installation of future grid modernization investments such as distribution automation, as the information available from SCADA can be used to automatically control the Companies' system.

As stated above, the SCADA system requires a communication system to support it. This communication system is needed for the Companies' system operators to communicate with the remote controlled reclosers. To mitigate potential risks of obsolescence, the Companies have purchased 700 MHz block spectrum radio frequency bandwidth to "future proof" their communication system. This spectrum solution is not included in the DPM Plan, but is expected to meet the required communication needs for the SCADA system, as well as other applications that may arise from the PowerForward initiative or other future grid modernization investments.

Advanced Distribution Management System (ADMS)

An Advanced Distribution Management System (ADMS) integrates all the SCADA information from various substations and circuit locations into one centralized software system. While SCADA devices provide valuable information to the Companies at specific points along their distribution system, the ADMS software enhances the Companies' data availability by providing the Companies' system operators a more complete and aggregate view of the distribution system. The ADMS software is capable of advanced decision analysis regarding power flows to alleviate congestion, provide better power quality, and re-route power in the event of outages.

Similar to SCADA, the enhanced data availability from ADMS benefits customers immediately, as the Companies will have one system that integrates all information regarding the operational conditions of their system. These benefits are self-sustaining. The ADMS platform is needed to allow customers to realize the full benefits of the DPM Plan, though the ADMS will also enable and enhance the benefits of future grid modernization investments in various technologies.

For example, ADMS can support distribution automation functionality, which will automatically isolate and restore large sections of the grid. Where customers would have experienced sustained outages in the past, they instead may see only a flicker or momentary outage of their power.

ADMS would also be a critical component of integrated Volt/VAR control (IVVC). IVVC allows operators to react to distributed energy resources that come online to adjust voltage so that power quality is maintained. ADMS will provide more visibility into these changing voltage conditions.

In addition, ADMS can support the addition of distribution energy resources through a Distributed Energy Resource Management System (DERMS) implemented in the future. This system manages the addition of customer generation sources and integrates their power flow into the distribution system. Additionally, DERMS can actively integrate with IVVC to ensure all customers have adequate power quality.

As grid modernization technology evolves, the Companies will need to understand the evolution and how it impacts the Companies' systems today and in the future. In evaluating possible ADMS solutions as part of the DPM Plan, the Companies intend to research, evaluate and select solutions that are market leaders with the ability to adapt to this changing landscape.

The DPM Plan's investment in ADMS, along with the targeted strategic installation of SCADA, are not included in the Companies' current work plan to maintain safe and reliable service to customers. Installation of these data acquisition systems will provide benefits to customers and support future grid modernization through the collection of critical distribution system data. This will allow the Companies to operate their system more efficiently, limit the number of sustained outages, and provide quicker restoration.

<u>Cyber Security and Privacy</u>

Cyber security or information technology security focuses on protecting the confidentiality, integrity, and availability of technology resources including electronic information, software, computing devices, network devices, or communication services used to create, modify, retrieve, transmit, or store information. The implementation of security controls is critical and should not degrade grid operations, including reliability and availability.

Cyber security is a critical component that would have to be considered and identified in every facet of implementation of each of the grid modernization technologies in the DPM Plan. The DPM Plan will follow defined processes to review, identify, and assess any perceived security risks. Specific categories of work in the DPM Plan that will be subject to this review include the data acquisition systems – SCADA and ADMS. The scope of the review will include design considerations of the network connectivity and the configuration of any hardware and software that will be implemented.

The Companies will draw on experience and lessons learned internally and externally, and will continue to monitor and assess related cyber security risks and suitable mitigation plans. They will continue to maintain a robust cyber security program and a strong cyber security team in place to monitor, assess, and protect against potential cyber security risks associated with the DPM Plan.

ESTIMATED COSTS

The table below shows the estimated scope and total costs (dollars in millions) for programs included in the DPM Plan that the Companies' are seeking approval to recover in Rider AMI.

DPE Component	Project Scope	Year 1	Year 2	Year 3	Total
Circuit Ties	The Companies have identified approximately 300 new tie miles that need to be created mainly in the Ohio Edison territory.	$ 15	$ 35	$ 60	$ 110
Reconductoring	The Companies have identified over 800 circuit miles that need to be reconductored mainly in the Ohio Edison and Cleveland Electric Illuminating Company territories.	$ 15	$ 50	$ 65	$ 130
Reclosers	The Companies have identified circuits where approximately 1,900 reclosers and the associated communication system infrastructure would be installed.	$ 60	$ 45	$ 45	$ 150
SCADA	This project includes installation of approximately 2,600 additional SCADA devices in substations and on circuits.	$ 5	$ 10	$ 15	$ 30
ADMS	This project includes installation of ADMS, a software platform that integrates all the SCADA information into one centralized software system.	$ 5	$ 10	$ 15	$ 30
Total Capital		$ 100	$ 150	$ 200	$ 450
O&M Expense[8]		$ 6	$ 9	$ 12	$ 27
Capital + O&M		$ 106	$ 159	$ 212	$ 477

Attachments B, C, and D to the Application provide the estimated revenue requirements, rate calculations, and customer rate impacts, respectively, associated with the proposed DPM Plan.

[8] O&M Expense estimated to be $13 million per year starting in year four.

ESTIMATED CUSTOMER BENEFITS

The DPM Plan is expected to provide meaningful benefits to customers, both qualitative and quantitative. These benefits are summarized below.

Improved Reliability and Storm Restoration Benefits

Through implementation of the proposed DPM Plan, the Companies expect reliability enhancements in terms of System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") on the circuits that are included in the DPM Plan. SAIDI represents the average outage duration for a customer, as measured in minutes. SAIFI represents the average number of interruptions experienced per customer, typically measured on an annual basis.

The Electric Power Research Institute (EPRI) published a report entitled "Quantifying Distribution Reliability Benefits"[9] that provides guidance on calculating expected reliability improvements upon installation of certain types of distribution system investments, including those in the DPM Plan. As discussed above, the Companies analyzed the historical outage information of each of the circuits estimated to benefit the most from the DPM Plan work. Using the EPRI methodology and the historical outage information, the Companies conservatively estimated the reduction in the number of customers affected by outages and the outage durations that would have occurred if the investments from the DPM Plan were in place. These results were used to conservatively estimate the improvements in SAIDI and SAIFI performance on the circuits estimated to be included in the DPM Plan.

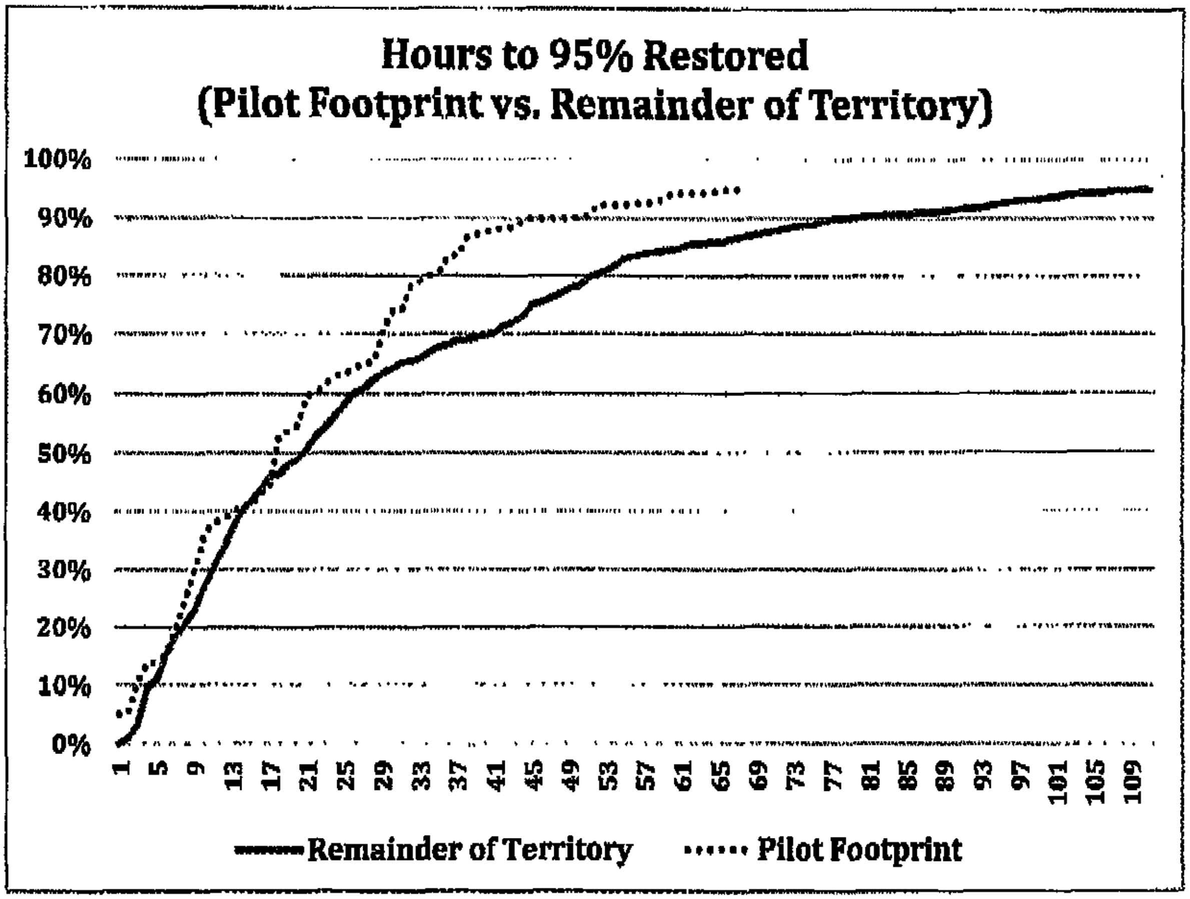
The table below shows the estimated improvements in SAIDI and SAIFI on the circuits estimated to be included in the DPM Plan, assuming the same historical outage conditions occur and the DPM Plan is fully implemented. The impact of transmission outages is included in the analysis below in order to capture all benefits to customers, but major storms are excluded consistent with the Companies' reliability standards reporting.

	SAIDI			SAIFI		
	Current	Estimated	up to % Improve	Current	Estimated	up to % Improve
CEI	225.3	157.5	30%	1.41	0.82	42%
OE	225.0	165.6	26%	1.43	0.89	38%
TE	196.2	149.0	24%	1.20	0.80	33%

* The table above includes the impact of transmission outages but excludes major storms.

[9] EPRI, "Quantifying Distribution Reliability Benefits", Final Report, December 2008.

In addition to the reliability improvements discussed above, the DPM Plan also provides benefits by improving the Companies' ability to restore power following a major storm or other adverse weather event. In order to estimate the storm restoration benefits to customers from the DPM Plan, the Companies relied upon data from the SGMI Project area in CEI's service territory. Specifically, the Companies analyzed major storm event data in this area from January 1, 2012 through May 31, 2014. During this period the SGMI Pilot area included circuit ties, reclosers, and SCADA. The more advanced technologies that are part of the SGMI Project, such as distribution automation and IVVC, had not yet been installed during this period, so the data analyzed by the Companies provides a direct analog for the Companies' DPM Plan. During this period there were eight major storm events producing 424 outages within the SGMI Project area and 4,094 outages outside the SGMI Project area. The chart below shows the average number of hours to restore service to 95% of the affected customers during these eight events, both inside the SGMI Project area and outside.



This chart shows that customers located within the SGMI Project area experienced significantly shorter restoration times after these major storms than other customers. On average, service was restored to 95% of customers within the SGMI Project area within 67 hours, compared to 110 hours for customers outside of the SGMI Project area. Since restoration time is measured during major storm events, there is no change in the frequency of outages. Therefore, storm restoration benefits to customers are best measured by analyzing the improvement in the average outage duration time per customer during these major events, or Customer Average Interruption Duration Index ("CAIDI"). For all events over the period, the average CAIDI was 829 minutes in the SGMI Project area versus 1,341 minutes for customers outside the SGMI Project area, representing a 38.2% improvement in CAIDI. For outages lasting less than 16 hours the average CAIDI was 239 minutes in the SGMI Project area versus 309 minutes for customers outside the SGMI Project area, representing a 22.6% improvement in CAIDI.

In addition to the measurable reliability and storm restoration improvements above, there are additional non-quantifiable benefits from the DPM Plan. These include, but are not limited to, increased public safety and improved customer satisfaction. Enhanced reliability should result in increased public safety due to fewer non-functioning traffic lights and streetlights, as well as improvements in safety for the Companies' personnel. Also, while the DPM Plan includes work on only a subset of the Companies' circuits, all customers benefit. With fewer outages and shorter restoration times expected to be experienced on the circuits included in the DPM Plan, the Companies will be able to more quickly direct restoration resources to other areas.

Quantitative Benefits

The estimated reliability and storm restoration enhancements discussed above translate to quantitative benefits to customers as fewer and shorter outages result in the avoidance of economic losses that otherwise would occur. To quantify the benefits to customers associated with the DPM Plan, the Companies used the Interruptible Cost Estimate (ICE) tool available from the U.S. Department of Energy ("DOE"). This tool was developed by Nexant and the Lawrence Berkeley National Laboratory to estimate the benefits associated with reliability improvements, and is based on extensive research on the cost of service interruption in the United States.[10] The tool uses inputs that are specific to the Companies, such as number of customers and average annual energy usage by customer class, as well as state specific inputs determined by the DOE, such as number of commercial and industrial customers in certain industries, median household income, and time of day outage information, to determine the average cost to customers of service interruptions. This tool can be used to quantify the estimated benefits to customers from the improvements in reliability and storm restoration times associated with the DPM Plan.

Using this tool, the Companies conservatively estimate nominal benefits to customers from improved reliability of $2.257 billion over the estimated average life of the equipment installed as part of the DPM Plan, or $838 million on a net present value basis. The estimated nominal benefits to customers from improved storm restoration on the Companies' system is $592 million over the estimated average life of the equipment installed as part of the DPM Plan, or $220 million on a net present value basis.

ESTIMATED COSTS VS. BENEFITS

The DPM Plan is expected to result in significant net benefits to customers. Specifically, the estimated quantitative benefits to customers over the estimated average life of the investments

[10] A report on this research is available at www.icecalculator.com (Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, January 2015).

made as part of the DPM Plan are $2.8 billion, compared to estimated nominal costs of $0.8 billion, which yields estimated net benefits of $2.0 billion and a benefit-to-cost ratio of 3.4. On a net present value basis, the estimated net benefits to customers are $0.5 billion, which is a benefit-to-cost ratio of 2.0.

($ in millions)	Nominal	Net Present
Estimated Benefits		
Reliability	$2,257	$838
Storm Restoration	$592	$220
Total	$2,849	$1,058
Estimated Costs		
Capital	$450	$386
O&M	$378	$147
Total	$828	$533
Net Benefits	$2,021	$525
Benefit-to-Cost Ratio	3.4	2.0

CONCLUSION

Customers expect reliable service. They also are likely going to be adopting new technologies that will change the way electric service is provided and consumed, requiring changes to modernize and transform the Companies' grid. The projects included in the DPM Plan will provide immediate customer benefits, including fewer outages and quicker restoration, and a more safe and resilient system. These customer benefits will continue independent of any additional grid modernization investments that may be undertaken by the Companies. The DPM Plan investments also will modernize the Companies' distribution system to better support and enable the grid of the future and the outcome of the Commission's PowerForward initiative. Approval of the DPM Plan will accelerate these reliability and resiliency benefits to customers.

Distribution Platform Modernization

Estimated Revenue Requirement Calculation

*Estimates are across all three operating companies (OE, CEI and TE)

Assumptions		
O&M	6%	of Capital Spend
Debt	51%	6.54%
Equity	49%	10.38%
Income Tax	36%	
CAT Tax	0.26%	

*Assumptions are weighted averages across OE, CEI and TE

	Circuit Work	Reclosers	SCADA	ADMS	
Book Life	30	30	30	7	Years
Tax Life	20	20	20	3	Years
In-Service Lag	0.5	0.5	0.5	1.5	Years
AFUDC	0.8%	0.8%	0.8%	2.5%	
Property Tax	9.7%	9.7%	9.7%	0.0%	
Capital - Yr 1	$30.0	$60.0	$5.0	$5.0	$100.0
Capital - Yr 2	$85.0	$45.0	$10.0	$10.0	$150.0
Capital - Yr 3	$125.0	$45.0	$15.0	$15.0	$200.0

*Assumptions are weighted averages across OE, CEI and TE

(A)	(B)	(C)	(D)	(E) = (C) + (D)	(F)	(G) = (E) + (F)	(H) = -(D) + Prev (D)	(I)	(J) = (G) x 49% x 10.38%	(K) = (G) x 51% x 6.54%	(L) = (J) x (1/(1 - 36%) - 1)	(M) = (B) x 12%	(N) = Sum((H)-(M)) x 0.26%	(O) = Sum ((H) - (N))
Year	Capital Spend	Gross Plant In-Service	Reserve	Net Plant	ADIT	Rate Base	Depreciation Expense	Property Tax	Equity Return	Interest Expense	Income Tax	O&M Expense	CAT Tax	Revenue Requirement
1	$ 100.0	$ 47.9	$ (0.8)	$ 47.1	$ (7.0)	$ 40.1	$ 0.8	$ 3.9	$ 2.0	$ 1.3	$ 1.1	$ 6.0	$ 0.0	$ 15.2
2	$ 150.0	$ 168.9	$ (4.5)	$ 164.4	$ (20.7)	$ 143.7	$ 3.7	$ 13.3	$ 7.3	$ 4.8	$ 4.1	$ 9.0	$ 0.1	$ 42.3
3	$ 200.0	$ 340.4	$ (13.5)	$ 326.9	$ (23.2)	$ 303.7	$ 9.1	$ 25.9	$ 15.4	$ 10.1	$ 8.7	$ 12.0	$ 0.2	$ 81.4
4	$ -	$ 446.5	$ (28.3)	$ 418.2	$ (27.9)	$ 390.3	$ 14.7	$ 32.4	$ 19.8	$ 13.0	$ 11.2	$ 13.0	$ 0.3	$ 104.4
5	$ -	$ 454.2	$ (46.0)	$ 408.2	$ (33.4)	$ 374.8	$ 17.7	$ 31.0	$ 19.1	$ 12.5	$ 10.7	$ 13.0	$ 0.3	$ 104.2

Notes

(C) Gross plant in-serviced on a half-year convention and grossed up for the capitalization Allowable Funds Used During Construction (AFUDC)

(C) Circuit ties, Reconductoring, Reclosers and SCADA are capitalized after 6 months; ADMS is capitalized after 18 months

(D) Book Life - Circuit Ties, Reconductoring, Reclosers, SCADA - approx. 30 years; ADMS - 7 years

(F) ADIT: Tax Depreciation - Three-year straight-line for ADMS and MACRS 20 for all remaining. Bonus Depreciation - Year 1 - 40%, Year 2 - 30%;

(I) Property Tax: Annual Property True Value x Property Tax Rate

(L) Then current composite tax rate

Estimated Rate Calculations

$/Customer/Month

Rate Schedule Allocation of Annual Revenue Requirement							
	RS	GS	GP	GSU	ESIP & STL	TRF	POL
Allocation	56.69%	34.25%	3.59%	1.69%	2.64%	0.05%	1.09%
No. of Cust.	1,906,135	220,332	1,760	723	390,963	1,874	25,784

Notes

1) Revenue Requirement allocations per Schedule A from Case 07-551-EL-AIR

2) Current Number of Monthly Customers

Year	RS	GS	GP	GSU	ESIP & STL	TRF	POL
1	$0.38	$1.97	$25.84	$29.66	$0.09	$0.32	$0.54
2	$1.05	$5.48	$71.83	$82.42	$0.24	$0.89	$1.49
3	$2.04	$10.68	$140.09	$160.75	$0.46	$1.73	$2.91
4	$2.59	$13.52	$177.37	$203.52	$0.59	$2.19	$3.69
5	$2.58	$13.50	$177.12	$203.24	$0.59	$2.19	$3.68

Notes

1) Monthly Charge = (Annual Revenue Requirement x Rate Schedule Allocation) / Customer Count / 12

*Rates are weighted averages across all operating companies (OE, CEI, TE)

Distribution Platform Modernization
Estimated Non-Shopping Customer Bill Impacts

Rate Schedule	Level of Demand *(kw/kVa)*	Level of Usage *(kWh)*	Current vs Year 1 *Increase (%)*	Year 1 vs Year 2 *Increase (%)*	Year 2 vs Year 3 *Increase (%)*
RS		500	0.5%	1.0%	1.4%
RS		750	0.4%	0.7%	1.0%
RS		1,000	0.3%	0.5%	0.7%
RS		1,250	0.2%	0.4%	0.6%
RS		1,500	0.2%	0.3%	0.5%
RS		2,000	0.1%	0.3%	0.4%
GS	10	500	1.3%	2.2%	3.2%
GS	10	1,000	1.0%	1.8%	2.6%
GS	10	3,000	0.6%	1.0%	1.5%
GS	1,000	50,000	0.0%	0.0%	0.0%
GS	1,000	100,000	0.0%	0.0%	0.0%
GS	1,000	300,000	0.0%	0.0%	0.0%
GP	500	25,000	0.4%	0.7%	1.1%
GP	500	100,000	0.2%	0.4%	0.6%
GP	500	200,000	0.1%	0.3%	0.4%
GP	5,000	250,000	0.0%	0.1%	0.1%
GP	5,000	1,000,000	0.0%	0.0%	0.1%
GP	5,000	2,000,000	0.0%	0.0%	0.0%
GSU	1,000	50,000	0.3%	0.5%	0.8%
GSU	1,000	200,000	0.2%	0.3%	0.4%
GSU	1,000	400,000	0.1%	0.2%	0.2%
GSU	10,000	500,000	0.0%	0.1%	0.1%
GSU	10,000	2,000,000	0.0%	0.0%	0.0%
GSU	10,000	4,000,000	0.0%	0.0%	0.0%

**Estimated bill impacts are displayed for a typical customer. Actual customer impacts may be higher or lower based on customer specific usage characteristics.*

***Rates effective October 1, 2017*

TOTAL OHIO COMPANIES (OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY & THE TOLEDO EDISON COMPANY)
Advanced Metering Infrastructure Rider (Rider AMI) - Rate Design
Rate Calculation

Line No.	Description	Source	RS Residential	GS Secondary	GP Primary	GSU Subtransmission	ESIP & STL Street Lighting	TRF Traffic Lighting	POL Private Outdoor Lighting	Total
A	B	C	D	E	F	G	H	I	J	K
	CEI									
1	Revenue Requirement	Revenue Requirement L14								$ -
2	Revenue Requirement Allocation % per Schedule A (Excluding GT) from D Rate Case	Stip & Recommendation dated 2/11/08	56.69%	34.25%	3.59%	1.69%	2.64%	0.05%	1.09%	100.00%
3	Total Revenue Requirement per Rate Schedule (Excluding GT)	KL1 x L2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Annual Customer Counts	Forecast								
5	CEI Monthly Customer Charge	(L3/L4)								
	OE									
6	Revenue Requirement	Revenue Requirement L15								$ -
7	Revenue Requirement Allocation % per Schedule A (Excluding GT) from D Rate Case	Stip & Recommendation dated 2/11/08	63.85%	27.71%	5.32%	0.87%	1.42%	0.06%	0.78%	100.00%
8	Total Revenue Requirement per Rate Schedule (Excluding GT)	KL6 x L7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Annual Customer Counts	Forecast								
10	OE Monthly Customer Charge	(L8/L9)								
	[illegible]									
11	Revenue Requirement	Revenue Requirement L16								$ -
12	Revenue Requirement Allocation % per Schedule A (Excluding GT) from D Rate Case	Stip & Recommendation dated 2/11/08	58.74%	32.58%	4.87%	0.11%	2.95%	0.03%	0.70%	100.00%
13	Total Revenue Requirement per Rate Schedule (Excluding GT)	KL11 x L12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Annual Customer Counts	Forecast								
15	TE Monthly Customer Charge	(L13/L14)								

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

Rider AMI
Revenue Requirement Calculation

	($ millions)	CEI	OE	TE	Total	Source
(1)	Gross Plant	$ -	$ -	$ -	$ -	Net Plant
(2)	Reserve	$ -	$ -	$ -	$ -	Net Plant
(3)	Net Plant	$ -	$ -	$ -	$ -	(1) + (2)
(4)	ADIT	$ -	$ -	$ -	$ -	- ADIT Balances
(5)	Rate Base	$ -	$ -	$ -	$ -	(3) + (4)
(6)	Depreciation Expense	$ -	$ -	$ -	$ -	Depr. Exp. Calc.
(7)	Property Tax Expense	$ -	$ -	$ -	$ -	Property Tax Exp. Calc.
(8)	O&M Expense	$ -	$ -	$ -	$ -	Estimated O&M Exp
(9)	Return @ 8.42%	$ -	$ -	$ -	$ -	(5) x (13)
(10)	Reconciliation	$ -	$ -	$ -	$ -	
(11)	Revenue Requirement	$ -	$ -	$ -	$ -	(6) + (7) + (8) + (9) + (10)

	Capital Structure & Returns	% mix	rate	wtd rate
(12)	Debt	51%	6.64%	3.3%
(13)	Equity	49%	10.38%	5.1%
(14)				8.42%

		(a)	(b)	(c)	(d)	(e)	(f)
	Revenue Requirement with Tax	Equity Return	Tax Rate	Income Tax	CAT 0.26%	Taxes	
(15)	CEI	$ -		$ -	$ -	$ -	
(16)	OE	$ -		$ -	$ -	$ -	
(17)	TE	$ -		$ -	$ -	$ -	
	Total	$ -		$ -	$ -	$ -	

(a) = Weighted Cost of Equity x Rate Base
(b) = Current composite income tax rates
(c) = (a) x (1 / (1-(b)) - 1)
(d) = (Rev. Req. + (c)) x (1/(1-.26%) - 1)
(e) = (c) + (d)
(f) = (e) + Rev. Req. from Line 11

Facsimile Cover

CALFEE

Calfee, Halter & Griswold LLP

The Calfee Building
1405 East Sixth Street
Cleveland, Ohio 44114-1607
216.622.8200 Phone
216.241.0816 Fax

1200 Huntington Center
41 South High Street
Columbus, Ohio 43215-3465
614.621.1500 Phone
614.621.0010 Fax

2800 First Financial Center
255 East Fifth Street
Cincinnati, Ohio 45202-4728
513.693.4880 Phone
513.842.7028 Fax
www.calfee.com

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