DAYMARK® ENERGY ADVISORS

CASE NO 18-1618-EL-RDR

AEP OHIO GRIDSMART® DEPLOYMENT AUDIT: REVIEW OF THE PHASE 1 AND PHASE 2 OPERATIONAL BENEFITS

FINAL REPORT

APRIL 12, 2019

PREPARED FOR

The Staff of the Public Utilities Commission of Ohio

PREPARED BY

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LIST OF ACRONYMS

AEP Ohio	American Electric Power Ohio
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading (Radio Frequency Meters)
ANSI	Annual National Standards Institute
AP	access point
CAIDI	Customer Average Interruption Duration Index
CIS	Customer Information System
CMI	Customer Minutes of Interruption
CSR	Customer Service Representative
DAC	Distribution Automation Controllers
DACR	Distribution Automation Circuit Reconfiguration
Daymark	Daymark Energy Advisors, Inc.
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FTE	Full-Time Equivalent
GHG	Greenhouse Gas
IEEE	Institute of Electrical and Electronics Engineers
LBNL	Lawrence Berkeley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MDM	Meter Data Management
MOPS	Meter Outage Processing System
MRO	Meter Revenue Operations
O&M	Operations and Maintenance
OMS	Outage Management System
OSHA	Occupational Safety and Health Administration
PIPP	Percentage of Income Payment Plan Plus
PUCO	Public Utilities Commission of Ohio
RFP	Request for Proposal
Rider	gridSMART® Phase 2 Rider
RPM	Reliability Pricing Model
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGDP	Smart Grid Demonstration Project
TERS	Trouble Entry Reporting System
VVO	Volt VAR Optimization

1. EXECUTIVE SUMMARY

1.1 Evaluation Background

As part of American Electric Power Ohio's ("AEP Ohio", "AEP", or "the Company") first electric security plan proceeding, the Company proposed and was granted approval for gridSMART® Phase 1, a smart grid deployment project within AEP Ohio's service territory, which included the deployment of Advanced Meter Infrastructure ("AMI"), Distribution Automation Circuit Reconfiguration ("DACR") and Volt VAR Optimization ("VVO") technologies.[1] AEP's gridSMART® Phase 1 was approved by the Public Utilities Commission of Ohio ("PUCO" or "the Commission") in Case No. 08-918-EL-SSo, et al., Opinion and Order, at 37-38 (March 18, 2009).

In its order in AEP Ohio's second electric security plan proceeding, the Commission approved AEP Ohio's request to continue the gridSMART® Phase 1 project, as well as the gridSMART® Phase 1 Rider as a mechanism to recover its prudently-incurred costs associated with Phase 1, subject to annual true-up and reconciliation. The Commission also directed the Company to file an application to initiate Phase 2 of the gridSMART® project.[2]

Through application in Commission Case No. 13-1939-EL-RDR, AEP Ohio presented its proposed expansion of the gridSMART® project ("gridSMART® Phase 2"). The Commission subsequently modified and approved a Joint Stipulation and Recommendation ("Stipulation") regarding AEP Ohio's application to implement gridSMART® Phase 2.[3] The Stipulation provides that costs incurred for gridSMART® Phase 2 will be recovered through a gridSMART® Phase 2 Rider ("Rider"), to be adjusted on a quarterly basis and subject to an annual audit for prudency.[4] As part of the quarterly Rider adjustment, the Commission ordered that a credit reflecting projected operational cost savings would be incorporated to offset costs otherwise recovered through the Rider. The Stipulation also authorizes the PUCO Staff to retain an external consultant through a Request for Proposal ("RFP") to review the Phase 1 and Phase 2 operational benefits of AEP Ohio's gridSMART® project. The Stipulation provides that

[1] Commission Case No. 08-918-EL-SSO, et al., Opinion and Order, at 37-38 (March 18, 2009), Entry on Rehearing (July 23, 2009) at 18-24.

[2] Case No. 11-346-EL-SSO, et al., Opinion and Order, at 62-63 (August 8, 2012), Entry on Rehearing at 53 (January 20, 2013).

[3] Case No. 13-1939-EL-RDR, Opinion and Order, at ¶¶33-35 (February 1, 2017).

[4] Case No. 13-1939-EL-RDR, Opinion and Order, at ¶¶34 (February 1, 2017).

the consultant will evaluate and recommend an ongoing level of operational benefits to be achieved and recognized in rates, to the extent such operational savings are not already reflected in rates.

Daymark Energy Advisors ("Daymark") was retained to assist the PUCO staff in its evaluation and recommendation of the Phase 1 and Phase 2 operational benefits of AEP Ohio's gridSMART® project to be achieved and recognized in rates as required under the Commission's modified and approved Joint Stipulation and Recommendation in Case No. 13-1939-EL-RDR. For this audit, the Phase 1 pilot learnings were used to inform the Phase 2 evaluation. If Phase 1 deployment contributed to operational benefits in Phase 2, and those Phase 1 benefits could not be separately identified, then the combined impact of both Phase 1 and Phase 2 were included in the estimation of benefits in our analysis.

Daymark provides electric and natural gas economic planning and strategic consulting services. Our team's experience includes working with executives to provide organization-wide management reviews of business functionality and process improvement opportunities, advising utilities and commission staff in utility rate case filings and reviewing utility plans for capital investment in electric and gas system improvement cases. In performing this audit, we applied our specialized knowledge and understanding of the design and operation of power systems and utility operations and expertise in evaluating the economics of power markets and energy policies under current and potential future market conditions.

1.2 Evaluation Scope

Our audit scope is comprised of the following four components:

- **Operational Benefits** – Evaluate AEP's originally-filed Phase 2 operational benefit savings and quantify the operational benefits achieved to date by AEP's deployments of AMI, DACR, and VVO investments. Estimate operational benefits that are reasonably achievable through full deployment of Phase 2 for each of the programs that are collectively AEP's gridSMART® project. Recommend an amount of benefit savings each year that should be credited against the gridSMART® Phase 2 Rider and where additional data tracking is necessary to quantify future benefits, recommend what data AEP should be tracking.
- **Reliability and Energy Efficiency** – Examine the reliability impacts associated with the deployment of DACR, including review of annual performance reports on circuits with

and without DACR. Examine the energy efficiency improvements (including energy and demand reductions) associated with the deployed of VVO that have resulted in reduced greenhouse gas ("GHG") emissions.

- **Non-Financial Metrics** - These metrics track deployment status and potential operating efficiencies for which financial benefit is difficult to ascribe or that may result in increased customer satisfaction. Review the non-financial metrics that AEP Ohio reported to the PUCO as of December 31, 2018. Based on findings, recommend changes to the current metrics beings tracked and identify additional metrics that should be tracked.

- **System Integration Assessment** – Evaluate AEP's end to end system integration efforts and plans as part of gridSMART® Phase 1 and Phase 2. Provide deeper insights into drivers associated with variances in actual versus planned operating benefits, as well as timing and reasonableness of achieving future operational benefits.

1.3 Audit Approach

Daymark was charged with auditing the operational and reliability benefits achieved through the gridSMART® Phase 2 deployment. The audit focused on comparing actual to expected benefits based on available industry data and based on AEP Ohio's own data. We reviewed case history, Commission precedent, and Company data. Targeted interviews were conducted with AEP Ohio personnel to assess operational efficiencies and calibrate data consistency. Company data was analyzed to determine or confirm operational benefits or changes in operations that result in savings or efficiencies.

1.4 Summary of Findings and Recommendations

Daymark's recommendations fall in the following four categories.

- ***Operational benefits*** –estimation of operational benefits that are reasonably achievable through full deployment of Phase 2 that can be credited against the Rider for 2019 through 2021 (or the conclusion of the Company's next base rate case) as well as those that will flow through to customers in other riders.[5]
- ***Data tracking*** – to improve the measurement of future operational savings.
- ***Non-financial metrics*** – to improve transparency of ongoing Phase 2 deployment and the effectiveness and operational, reliability, and energy efficiency value of AMI, DACR, and VVO technologies.

[5] The nominal dollars each year in Table 1 are from the Daymark Analysis Lower Case estimated savings.

- ***Systems integration and operational business process improvement*** – opportunities to deliver the full range of benefits from the deployed technologies.

Operational Benefits:

Daymark's evaluation of AEP's originally-filed Phase 2 operational benefit savings and estimation of operational benefits that are reasonably achievable through full deployment of Phase 2 leads us to recommend the following operational benefit savings be credited against the Rider for 2019 through 2021 (or the conclusion of the Company's next base rate case).[6]

Table 1: Operations Benefit Savings (Nominal $)

	2019	2020	2021
BENEFITS NETTED AGAINST RIDER ($M)	$6.8	$9.1	$9.4

Benefits that are defined as "Rider eligible" are operational savings enabled by AEP's deployment of gridSMART® technologies. These savings can be directly netted against the system deployment and ongoing O&M costs included in the Rider. Other benefits discussed in Section 3 are "not Rider eligible" because they are direct customer benefits or will flow through to customers in other Riders. Some of these other benefits, which were identified by AEP Ohio in its original business case, such as customer benefits (e.g., time-differentiated rates and reliability) or societal benefits (e.g., environmental) were not part of the scope of work as defined by the RFP and are therefore not included in this scope of work. We specifically define in Section 3 which operational benefits are classified as "Rider eligible" versus "not Rider eligible".

Prior to the effective date of the Company's next base rate case, most, if not all, AMI and VVO technology investments are expected to be deployed. Additionally, deployment of DACR circuits will be much further along. At that point, AEP can shift its focus from deployment to a more complete integration of systems and processes. If the real-time data reported from these technologies are better incorporated into current Company systems and potential future advanced systems (e.g., Advanced Distribution Management System), AEP will have the ability to identify more operational benefits. Therefore, we recommend that for years 2022 through 2031 the following operational benefit savings be credited against the Rider or successor recovery mechanism approved

[6] The nominal dollars each year in Table 1 are from the Daymark Analysis Lower Case estimated savings.

by the PUCO until such time that they are rolled into new base rates and the new base rates are in effect. [7]

Table 2: Operational Benefit Savings (Nominal $)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
BENEFITS NETTED AGAINST RIDER ($M)	$11.6	$11.9	$12.2	$12.5	$12.9	$13.2	$13.6	$14.0	$14.3	$14.7

In addition to the operational benefits originally identified by AEP Ohio in its original filing, our analysis includes the following measurable operational benefits not previously identified by the Company, which are explained in more detail in Section 3:

- ***Remote meter diagnostics (avoided O&M cost)*** – labor and non-labor (e.g., truck rolls) savings associated with AMI capability to conduct real-time remote meter diagnostics. "Rider eligible."
- ***Meter salvage value (increased revenue)*** – savings obtained by refurbishing and redeploying analog and AMR ("Traditional"[8]) meters across AEP corporate's operating companies or by salvaging scrap metal from meters that cannot be redeployed. "Not Rider eligible."
- ***System fine tuning (capacity deferral and avoided fuel cost)*** – the installation of VVO across distribution circuits helps to reduce the reactive power requirements at the customer-level by flattening the voltage profile of these circuits. This in turn helps to reduce distribution losses across these circuits. "Not Rider eligible."

Our analysis also includes the following additional operational benefits not previously identified by the Company, which we were not able to measure based on the information provided by the Company. These operational benefits are also explained in more detail in Section 3:

- ***Meter accuracy improvements (increased revenue)*** - analog meters are likely to under- or over-report usage, which will lead to inaccurate billing. Smart meters will lead to more accurate billing. "Not Rider eligible."
- ***Outage reduction – revenue impact (increased revenue)*** – implementation of gridSMART® investments will enable AEP to increase revenue collected from customers

[7] The nominal dollars each year in Table 2 are from the Daymark Analysis Upper Case estimated savings.

[8] Ohio Administrative Code, Chapter 4901:1-10-01(FF). "Traditional meter" means any meter with an analog or digital display that does not have the capability to communicate with the utility using two-way communications.

that would have otherwise been left without service due to outage events. "Not Rider eligible."

- ***Outage detection and verification (avoided O&M cost)*** – as AMI and DACR are deployed throughout the Phase 2 area, AEP will have a better ability to detect the extent of a customer outage and more quickly determine areas still experiencing an outage and areas where power has been restored, which reduces assessment time and therefore labor hours. Similarly, maintenance and outage crews can more quickly identify and verify failures, which reduces labor and other associated costs (e.g., vehicle costs). "Rider eligible."
- ***Continuous voltage monitoring (avoided O&M cost)*** – as more circuits become VVO-enabled, AEP will have improved ability to automate voltage monitoring for low voltage situations. This will reduce employee field time associated with performing this function. "Rider eligible."
- ***Capacitor inspection costs (avoided O&M cost)*** – capacitor banks are typically inspected annually on a rotating basis. Technology deployed through gridSMART® should lead to reduced visual inspections, as the new capacitor bank controllers and communication modems can be leveraged to produce alarms and reports when issues arise. "Rider eligible."
- ***Circuit breaker inspections costs (avoided O&M cost)*** – circuit breaker inspections are needed on modern circuit breakers because they are located inside substations without the ability to communicate. As these old reclosers are replaced, remote analysis of these circuit breakers will eliminate the need for physical inspections. "Rider eligible."

In addition, due to inherent challenges in isolating the operational benefits of AMI, DACR, and VVO pre- and post-Phase 2 deployment, when comparing pre- and post-operational budgets as proposed by AEP Ohio as a verification method and where the Company noted no verification method possible, Daymark has recommended the use of alternative calculations for estimating benefits which formed the basis for calculating the operational benefits savings summarized above. Our alternative calculation recommendations, including details of specific data limitations by operational benefit, are provided in Section 3.

Data Tracking:

In Section 3, Daymark has also provided specific data tracking recommendations by operational benefit, which if implemented will provide the necessary data to measure and verify operational benefits in the future. A full summary of our data tracking recommendations is provided in Section 3.4 for convenience.

Non-financial Metrics:

In order to improve transparency of ongoing deployment progress as well as the impact and value of AMI, DACR, and VVO, we recommend a number of enhancements to the set of Phase 2 non-financial metrics that AEP Ohio tracks and reports to the PUCO Staff on a monthly basis. These, along with our review of the existing metrics, is provided in Section 5 of this report. A full summary of our non-financial metric recommendations is provided in Section 5.3 for convenience.

Systems Integration:

Finally, as it relates to AMI, DACR, and VVO, these technologies have demonstrated the ability to achieve substantial positive impacts on the grid in addition to providing significant benefits to utilities. The great majority (estimated at 90%[9]) of these benefits relate to automation of meter reading to cash activities (AMI) or will accrue directly to customers in the form of fewer and shorter power outages as well as decreased energy consumption (DACR/VVO). As a result, the Company's focus throughout Phase 2 has been more on implementation and execution of the technologies to capture these benefits. Going forward, we recommend AEP Ohio shift from deployment to further system integration and business process improvement in order to position itself to capture the full suite of benefits derived from existing and future gridSMART® technology investments. Specific system integration and operational business process improvement recommendations are provided in Section 6.

1.5 Structure of this Report

This report contains one section for each of the main audit scope items. Each of these sections is designed to address the following outline:

- An **Introduction** providing general background information on each specific component in the audit
- A detailed explanation of the **Methodologies** Daymark used to complete each specific audit component
- **Findings** from our analysis

As described in Section 1.4, our recommendations fall into 4 categories – each of those are shown at the left in Table 3 and where to find summary recommendations and benefit details is noted in the right-two columns.

[9] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

Table 3: Mapping to audit recommendations

TYPE OF RECOMMENDATION	TECHNOLOGY	SUMMARY OF RECOMMENDATIONS	BENEFIT DETAILS
Operational benefits	AMI	Section 3.5	Section 3
Data tracking	AMI, DACR, VVO	Section 3.4	Section 3
Non-financial metrics	AMI, DACR, VVO	Section 5.3	Section 5
Systems integration and operational business process improvement	AMI	Section 6.3 and 6.6	Section 6
	DACR	Section 6.4.3 and 6.6	
	VVO	Section 6.5.3 and 6.6	

2. GRIDSMART® TECHNOLOGY OVERVIEW AND STATUS

The gridSMART® technologies adopted by AEP Ohio include Advanced Meter Infrastructure, Distributed Automation-Circuit Reconfiguration, and Volt-Var Optimization. These advanced grid technologies are integrated into the Company's electric distribution system with the goal of improving service quality and reliability, reducing energy consumption, and providing operational and customer savings.

2.1 AMI

AMI is an integrated system of smart meters, communications networks, and data management systems that provide near real-time meter readings and allow two-way communications between the utility and the customer. Integrated with utility systems, AMI can drive significant operational improvements such as eliminating the need for meter readers, improving billing accuracy, improving credit and collections, and allowing for greater real-time visibility of power flows and outages across the distribution system. A full analysis of operational benefits associated with AEP Ohio's gridSMART® program is provided in Section 3 of this report.

AEP Ohio currently has approximately 1.5 million meters installed throughout its service territory. As part of gridSMART® Phase 1, AEP Ohio installed 110,000 AMI meters in Northeast Central Ohio, all with two-way communication enabled across a radio frequency mesh network with wireless carrier backhaul communications. In addition to AMI meters, the infrastructure included network interface cards for each meter, 64 relays and access points ("AP"s) across the communications network and supporting information systems technology. Single phase residential meters included remote connect/disconnect switch capability.[10]

AEP Ohio's gridSMART® Phase 2 expansion plan included deploying an additional 894,000 AMI meters and 1,449 network communication devices (relays and APs) across 89 urban and suburban cities and towns in AEP Ohio's service territory. The Phase 2 expansion replaces virtually all of AEP Ohio's existing analog meters as well as some

[10] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy ("DOE") Smart Grid Demonstration Project ("SGDP") Contract Award Number DE-OE000193, June 2014. Image from p. 14.

Automatic Meter Reading ("AMR") meters that fall within the deployment area. Once Phase 2 is complete, nearly two thirds of AEP Ohio's installed meters will be AMI meters.

Phase 2 AMI network infrastructure development began on April 19, 2017 and was completed in early August 2017. Meter installations began on August 21, 2017 and were accelerated to address manual meter reading completion concerns.[11] As of March 4, 2019, the Company had completed installation of 619,025 meters, or 68% of the meters in the Phase 2 deployment area.[12] The Company expects to complete the Phase 2 AMI meter roll-out by the end of 2019 with a total deployment of 910,004 meters.[13] . The higher number of meters reflects a net growth of meters in the Phase 2 deployment area.[14]

2.2 DACR

DACR is an electrical process illustrated in the figure below that includes remote sensors, monitors, switches, digital relays and Distribution Automation Controllers ("DAC") with embedded intelligence to automatically detect faulted line sections and reconfigure circuits to quickly restore electricity to customers in the other unaffected sections of the affected circuit. In AEP's system, the DAC is integrated with AEP Ohio's Supervisory Control and Data Acquisition ("SCADA") system to leverage communications and coordinated control to improve reliability. With DACR, "*AEP Ohio can monitor for potential electrical faults and isolate portions of its network when a fault occurs, strategically re-routing electric loads to available circuits to maintain energy delivery to the majority of customers*."[15]

[11] Staff DR1-001 – Attachment 1

[12] *Building a Better Smarter Grid*. AEP Ohio Smart Grid Phase 2 Newsletter Volume 2, Issue 2, March 2019.

[13] The total meter installation number (910,004 meters) is calculated using the monthly count of certified meters installed during the period of 2016 – 2018 (Staff DR 02-02 Appendix A) and the monthly deployment plan for 2019 (Staff DR 04-004).

[14] AEP Ohio response to Staff DR 01-001 – Attachment 1.

[15] AEP Ohio gridSMART® Phase 2 FAQ's.

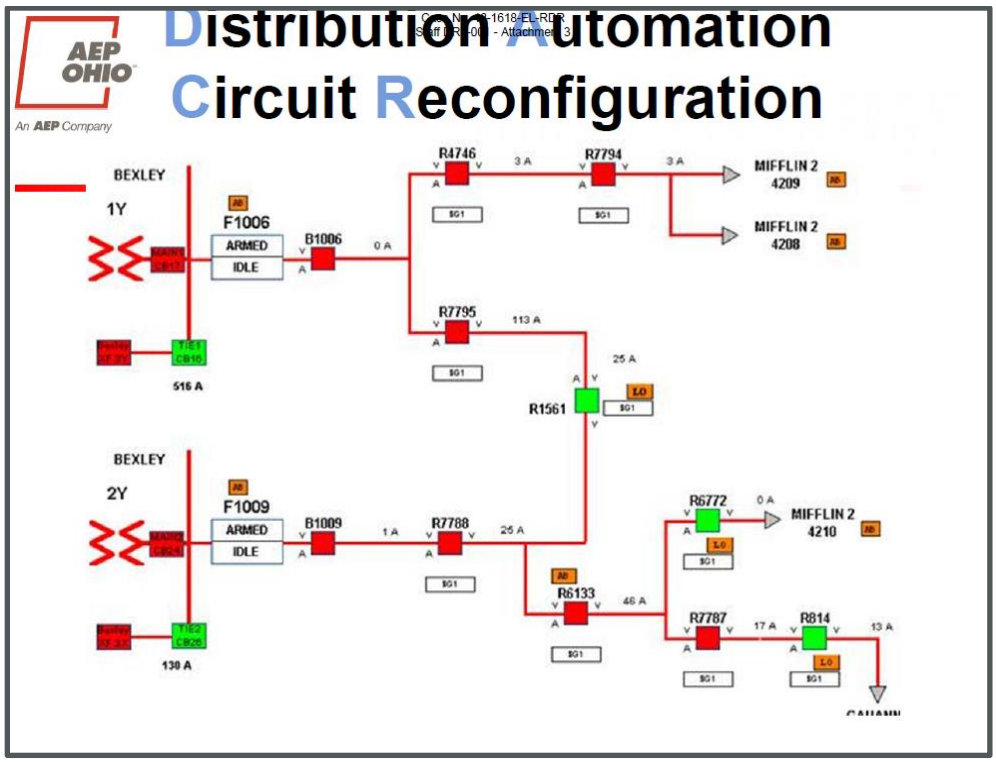

Figure 1: DACR Process

AEP Ohio's Phase 2 expansion plan involves installing 250 DACR circuits across their service territory.[16] Deployment is focused in areas providing the greatest outage reduction benefits to customers, consisting of 13 kV and 34.5 kV distribution circuits. Upon complete installation, AEP Ohio expects to see the System Average Interruption Frequency Index reliability metric decrease by 15.8%[17].

The first of the Phase 2 DACR circuits were installed in October 2018. At the time of this report only 2 of the Phase 2 planned 250 DACR circuits had been deployed. Currently, there is a focused, ongoing effort by AEP Ohio to meet their planned deployment of DACR circuits by 2023 at which point, theoretically at least, more data would be available to support a more meaningful analysis.[18]

[16] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy (DOE) Smart Grid Demonstration Project (SGDP) Contract Award Number DE-OE000193, June 2014. Image from p. 14.

[17] AEP Ohio response to Staff DR 01-001 – Attachment 1.

[18] AEP Ohio response to Staff DR 02-052.

2.3 VVO

VVO is a process, illustrated in the figure below, of optimizing voltage levels and reactive power in real-time to reduce system losses, peak demand, and energy consumption on the electric grid. VVO is an advanced application that runs periodically or in response to operator demand, at the control center for distribution systems or in substation automation systems. Combined with two-way communication infrastructure and remote-control capable capacitor banks and voltage regulating transformers, VVO makes it possible to optimize the energy delivery efficiency on distribution systems using real-time information. By operating the system with voltages closer to the lower end of the Annual National Standards Institute ("ANSI") Standard acceptable range, energy efficiency benefits can be achieved while maintaining the same level of comfort and service level.[19]

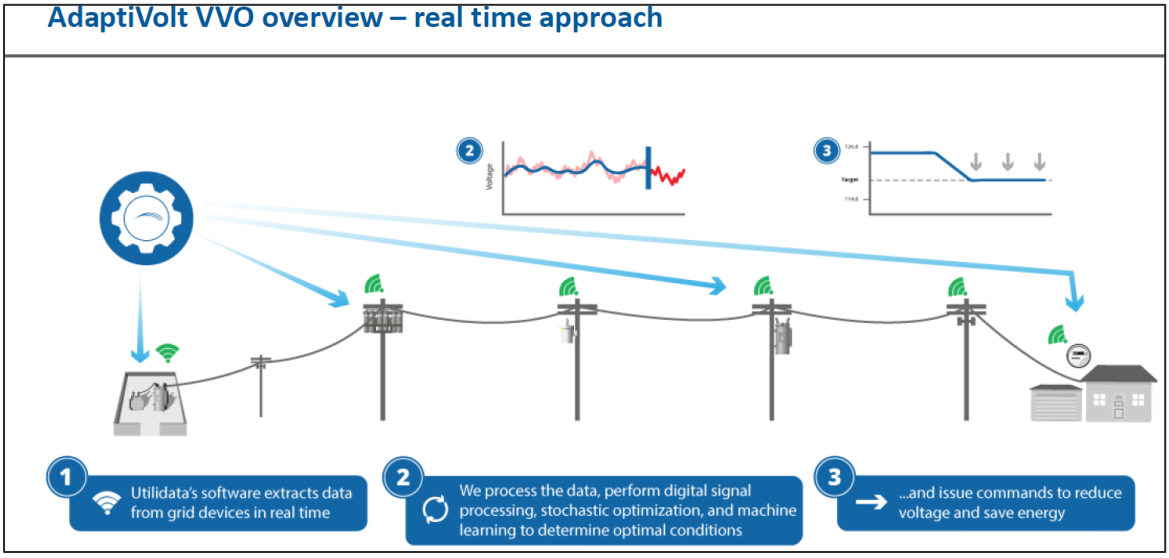

Figure 2: VVO Process

AEP Ohio's Phase 2 expansion plan includes installing VVO on 160 distribution circuits (13 kV and 34.5 kV) across their service territory. Upon complete installation of the VVO and integrated AMI modules, the Company believes an average energy efficiency improvement of 4%[20] is achievable.

[19] AEP Ohio response to Staff DR 02-008, Attachment, p. 3.

[20] AEP Ohio response to Staff DR 01-001 – Attachment 1.

The first of the VVO circuits were installed in November 2018. At the time of this report only 24 of the 160 VVO circuits had been deployed in Phase 2. As is the case with DACR, there is a focused ongoing effort by AEP Ohio to accelerate the deployment of VVO in 2019 at which point, more data would be available to support a more meaningful analysis.[21]

[21] AEP Ohio response to Staff DR 02-006.

3. OPERATIONAL BENEFITS

3.1 Introduction

As part of this audit Daymark reviewed a number of individual approaches to calculate operational benefits. These benefits are directly accessible to the Company through the deployment of AMI, DACR, and VVO. This section explains the operational benefits in detail, including an explanation of the operating benefit. The summary details the specific estimated savings that Daymark calculated, the calculation methodology, and additional data that Daymark recommends AEP track to better enable calculation of future savings.

After discussions with AEP and propounding ten sets of data requests, data gaps still remain related to missing or untracked information. There was only limited information provided prior to 2016 and the aggregated information available cannot be easily disaggregated. As a result, several assumptions were made throughout the analysis using available data and learnings from Phase 1 to estimate operational benefits for Phase 2. To help with future evaluations, Daymark identified data that could be used to better monitor and identify operational benefits going forward.

3.2 Identified Benefits Summary

Table 4 summarizes the operational benefits (and type of benefit) identified and quantified, where possible, in the course of this audit. The values in the table are the 15-year cash basis (total of nominal yearly savings) savings per operational benefit in millions of dollars. A comparison of each column to the Company's original Phase 2 application is also provided to show the differences from the application. The columns are defined as:

- **Per Company Filing** – Operational benefit value from AEP Attachment C of the Phase 2 Filing (Case No. 13-1939-EL-RDR). Due to rounding from yearly data provided by AEP some numbers will not tie out to Attachment C from the Filing.
- **Daymark Analysis Upper Case** – Where Daymark was able to complete an analysis of the operational benefit, this column shows the Upper Case calculations for the period 2017-2031. When this was not possible, AEP's original Filing value was updated to reflect the period from 2017to2031 by shifting the yearly value forward three years based on inflation and adjusting for updated deployment plans.

- **Daymark Analysis Lower Case** – Where Daymark was able to complete an analysis of the operational benefit, this column shows the Lower Case of those calculations for the period 2017-2031. If an analysis only generated one case or the if the AEP initial Filing value was updated, this case is equal to Daymark's Upper Case. In cases where the benefit value is equal to zero, this represents a redeployment of labor by AEP that will not lead to Rider savings.

- **Industry Benchmark** – Operational benefits savings estimates provided by AEP were compared to other utilities in Ohio. Additional operational benefits added by Daymark and evaluated by Daymark were also compared to these same Ohio utilities. It is important to note that the other utilities experienced different levels of system deployment and used different types of AMI, DACR, and VVO devices. This limits the direct comparability to AEP's and Daymark's estimated savings but helps provide a guide for additional data tracking recommendations to enable calculation of future operational benefits.

The benefits listed in the following table are either netted against the Rider or captured outside the Rider. Benefits defined as "Rider eligible" are (1) operational savings that AEP experiences through deployment of gridSMART® technologies, (2) netted against the Rider, and (3) not direct customer benefits and do not otherwise flow through to customers in other riders. Each benefit discussed in this table and this section is classified as "Rider eligible" or "not Rider eligible". The last three rows of the table show the total savings calculated for each benefit over the 15-year period that are (1) netted against the Rider, (2) captured outside of the Rider, and (3) the total operational benefit savings, for each of the columns defined above.

Please note that the "*Customer Savings Associated with Participating in TOU Programs*" is included in Table 1 below but was not analyzed by Daymark as part of this audit because it is a customer benefit that is not netted against the Phase 2 Rider. We did provide an update to for it, for consistency, by shifting the benefits out to start in 2017 and by adjusting for inflation.[22]

[22] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from the Federal Reserve Bank of Minneapolis.

Table 4: Phase 2 Operational Benefits Savings

AEP Ohio Phase 2 Benefits	Benefit Type	Cash Basis				Change from Original Filing		
		Per Company Filing (2014-2028)	Daymark Analysis Upper Case (2017-2031)	Daymark Analysis Lower Case (2017-2031)	Industry Benchmark (2017-2031)	Daymark Analysis Upper Case	Daymark Analysis Lower Case	Industry Benchmark
		15-Yr Total ($M)				15-Yr Total ($M)		
Benefits included in the Benefit / Cost Analysis - Netted against the Rider								
Meter Reading and Meter Operational Labor Savings	Avoided O&M Cost	82.7	120.6	94.7	134.5	37.9	12.0	51.8
Credit and Collections Operational Labor Savings	Avoided O&M Cost	20.5	38.9	38.9	NA	18.4	18.4	NA
Other Benefits - Netted against the Rider								
Billing Labor Benefits	Avoided O&M Cost	1.7	3.7	2.4	0.8	2.0	0.7	(0.9)
Call Center Labor Benefits	Avoided O&M Cost	0.8	0.9	0.0	1.2	0.1	(0.8)	0.4
Capacity Planning O&M Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.2	0.2	0.0	NA	(0.0)	(0.2)	NA
Benefits included in the Benefit / Cost Analysis - Benefit Captured outside of the Rider								
Reduction in Uncollectible Revenue Through Use of Remote Disconnect	Increased Revenue	49.6	52.1	52.1	NA	2.5	2.5	NA
Reduction in Theft	Increased Revenue	35.5	37.8	37.8	17.6	2.3	2.3	(17.8)
Reduction in Consumption on Inactive Meters	Increased Revenue	6.1	6.5	6.5	NA	0.4	0.4	NA
Customer Savings associated with VVO benefits	Customer Benefit	115.4	245.2	120.1	NA	129.8	4.7	NA
Distribution Automation Circuit Reconfiguration Outage Reduction	Customer Benefit	1,015.9	1,763.5	1,083.7	NA	747.6	67.9	NA
Other Benefits - Benefit Captured outside of the Rider								
Customer Savings Associated with Participating in TOU Programs	Customer Benefit	62.9	67.0	67.0	NA	4.1	4.1	NA
Capacity Planning Capital Savings Due to Superior AMI Data Quality	Cap Defer	10.8	11.0	0.0	NA	0.2	(10.8)	NA
Injury Reduction - Reduction in liability / lost work days	Avoided O&M Cost	1.0	0.9	0.9	1.0	(0.0)	(0.0)	0.0
Other Benefits - Captured by Daymark - Netted against Rider								
Remote Meter Diagnostics	Avoided O&M Cost	0.0	0.2	0.2	11.8	0.2	0.2	11.8
Outage Detection and Verification	Avoided O&M Cost	0.0	0.0	0.0	6.5	0.0	0.0	6.5
Continuous Voltage Monitoring	Avoided O&M Cost	0.0	0.0	0.0	3.2	0.0	0.0	3.2
Capacitor Inspection Costs	Avoided O&M Cost	0.0	0.0	0.0	2.6	0.0	0.0	2.6
Circuit Breaker Inspection Costs	Avoided O&M Cost	0.0	0.0	0.0	1.4	0.0	0.0	1.4
Other Benefits - Captured by Daymark outside of the Rider								
Meter Salvage Value	Increased Revenue	0.0	0.5	0.5	1.1	0.5	0.5	1.1
Meter Accuracy Improvement	Increased Revenue	0.0	0.0	0.0	19.0	0.0	0.0	19.0
Outage Reduction - Revenue Impact	Increased Revenue	0.0	0.0	0.0	9.0	0.0	0.0	9.0
System Fine Tuning	Cap Defer & Avoided Fuel Cost	0.0	45.1	45.1	13.3	45.1	45.1	13.3
Operational Benefits (Benefits Netted against the Rider)		106.0	164.5	136.3	162.1	58.5	30.3	76.8
Operational Benefits (Benefits Captured outside of the Rider)		1,297.1	2,229.7	1,413.8	61.1	932.6	116.7	24.6
Total Operational Benefits		1,403.1	2,394.2	1,550.1	223.2	991.1	147.0	101.5

3.3 Operational Benefits Summary

In this section, we provide our analysis of each operational benefit. Each benefit is referenced to the applicable line number in Table 4 where we indicate whether it is a Rider eligible benefit, and if not, why not. The format for our analysis of each operational benefit is the following:

- **AEP Proposed Calculation** – We first identify the verification method for operational savings that AEP provided in its Phase 2 application. Then we explain whether we were able or not to reasonably audit that original savings estimate using the verification method and data proposed by AEP.
- **Daymark Analysis** – We identify the data that was used to calculate the estimated savings. Then we explain how we arrived at each datum used in the estimated savings calculation, including the related assumptions. For some of the benefits, we provided an Upper Case and Lower Case. The cases are a function of one of the following three approaches: Top-Down, Bottom-Up, or AEP Filing Update.
  - *Top-Down Approach* uses higher level data available, i.e., operating budget level, to estimate savings.
  - *Bottom-Up Approach* parses out the operational benefit out into sub-benefits that were separately calculated and then were combined into one set of estimated savings.
- **Industry Benchmark** – As explained previously and throughout this section, we reviewed other utilities in Ohio with grid modernization programs in place and used these as reasonableness checks against the estimated savings provided by AEP and calculated by Daymark. Since these other utilities experienced different levels of deployment and used different technology types, it would not be appropriate to use instead of AEP data as a basis for savings against the Phase 2 Rider. However, they do demonstrate the potential for further savings yet to be realized by AEP.

The following benefits are discussed in the remainder of this section:

- Meter Reading and Operational Labor Savings
- Credit and Collections Operational Labor Savings
- Reduction in Uncollectible Revenue Through Use of Remote Disconnect
- Reduction in Theft
- Reduction in Consumption on Inactive Meters

- Customer Savings Associated with VVO
- Distribution Automation Circuit Reconfiguration Outage Reduction
- Billing Labor Benefits
- Call Center Labor Benefits
- Capacity Planning Labor / Non-Labor Operations and Maintenance ("O&M") Savings Due to Superior Data Quality
- Long-Term Planning Labor / Non-Labor Capital Savings Due to Superior Data Quality
- Short-Term Planning Labor / Non-Labor Capital Savings Due to Superior Data Quality
- Injury Reduction (Reduction in liability / lost work days)
- Remote Meter Diagnostics
- Meter Salvage Value
- Meter Accuracy Improvement
- Outage Reduction (Increased Revenue)
- Outage Detection and Verification
- Continuous Voltage Monitoring
- Capacitor Inspection Costs
- Circuit Breaker Inspection Costs
- System Fine Tuning

3.3.1 Meter Reading and Operational Labor Savings

Deployment of AMI technology in the Phase 2 area (or footprint) will reduce or eliminate meter reading routes and other operational activities, which will lead to reductions in personnel (including Meter Readers, Meter Servicers, and Meter Specialists). This labor reduction from the Meter Revenue Operations ("MRO") department is the largest benefit value identified in this audit. Benefits accrued from reducing truck rolls for meter reading activities are captured in the loaded labor costs of the reduced employees. Additionally, AEP has not renewed the most recent meter reading contractor contract and will be able to reduce or eliminate most of the contracted meter readers. This benefit shown in Line 1, Table 4 is "Rider eligible".

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

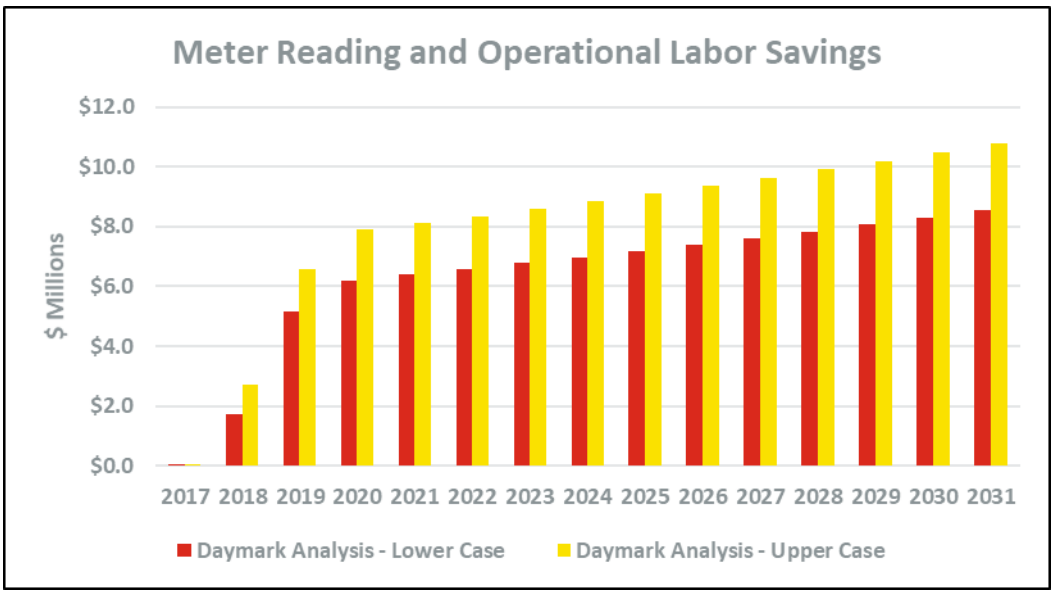

Figure 3: Meter Reading and Operational Savings – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare the Annual Meter Reading and Operational Budgets to the Pre-deployment Budget.[23]
  - Daymark tried to compare the MRO actual budgets[24] over time, but there is a lot of noise[25] in the budgets and actual spend that did not allow for a proper evaluation and estimation of benefits as suggested by the AEP proposed calculation. While we were not able to use the MRO actual budgets, MRO operational savings data associated with AMI was provided to support AEP's Phase 2 initial Filing. Along with explanations provided for the data by AEP, Daymark was able to confirm the reasonableness of the original estimates.
- **Daymark Analysis (Lower Case)** – Savings for this benefit are a function of annual Full-Time Equivalent ("FTE") planned reductions, loaded labor rate, labor rate increase, and annual hours worked. We also note the potential savings due to reduction in meter reading contract labor, although this is not directly included in the estimated savings at this time.

[23] AEP Ohio Phase 2 Application, Attachment C.

[24] AEP Ohio response to Staff DR 02-030, Attachment.

[25] Examples of this include re-organization and an AMR deployment project.

- *Annual FTE reductions* provided by AEP were reduced by the percent of AMI actually deployed compared to the original plan.[26] Using AEP's Phase 2 AMI deployment plan,[27] we reduced the annual FTE reductions applicable to 2017-2019 and used 100% from 2020 forward.
- The *loaded labor rate* used in the calculations is the weighted average loaded labor rate for the Meter Reader, Meter Servicer, and Meter Specialist positions in 2018.[28] Daymark used the average loaded labor rate instead of the loaded labor rate of any one position because there was no clear indication on the specific numbers of each position that would be eliminated.
- The *labor rate increase* is based on the annual average negotiated increase for the Meter Reader, Meter Servicer, and Meter Specialist positions for the 2014 – 2018 period.[29] This rate increase is applied to the loaded labor rate each year to inflate the loaded labor rate into future year dollars through the forecast period.
- *Annual hours worked* is an assumption taken from AEP's analysis of labor savings for annual hours worked by meter operations staff.[30]
- In addition, the Company indicated that it would be eliminating 100% of its meter reading contract labor after Phase 2 deployment is complete. We evaluated the previous level of contract labor, but it was unclear whether the staff reduction analysis considered the benefits associated with reduction in contract labor cost.[31] Therefore, additional contract labor in the range of $0 - $2.2M per year[32] has not been included in our calculated benefits. To the extent this value can be confirmed with the Company, additional benefits could be realized through the Rider.

- **Daymark Analysis (Upper Case)** – Compared to our Lower Case, which is based on AEP Ohio's planned staff reduction levels, this case is based on what we believe is achievable based on a cost reduction buildup of specific activities that are being eliminated.[33] We

[26] AEP Ohio response to Staff DR 04-017.

[27] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004.

[28] AEP Ohio response to Staff DR 02-026, Confidential Attachment 3.

[29] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[30] AEP Ohio response to Staff DR 02-026, Attachment 1.

[31] Staff DR 04-017.

[32] AEP Ohio response to Staff DR 04-014b, Confidential Attachment 1. Value range determined in our workpapers based on the contract value reported in this response.

[33] We believe AEP's numbers likely have a level of conservatism built into them.

estimated Meter Reading and Operations Labor savings benefit based on three sub-categories: Regular Meter Reads, Meter Operations Costs, and Off-cycle/Off-Season Meter Reads. The benefits estimated for each sub-category were then aggregated to form this Upper Case.

- ***Regular Meter Reads*** **-** This benefit captures the elimination of on-cycle meter reading as smart meters are deployed. The primary benefit value is from avoided labor and other associated costs required for meter reading due to the installation of smart meters. Savings are a function of avoided labor hours for meter reading, meter reader loaded labor rate, and labor rate increase.
  - *Avoided labor hours* are determined by the following process:
    - Daymark used the Phase 1 results from the Columbus area to estimate number of avoided meter readings per meter reading route.[34] Specifically, total meter reading routes and avoided meter reading routes from Phase 1 and the number of non-AMI meters in the Columbus area at the beginning of Phase 2 were used to calculate an assumed number of meters reads per route prior to Phase 2. The use of the Columbus area Phase 1 results to estimate avoided meter reading routes for Phase 2 provides a conservative reference because Phase 2 includes sub-urban areas where meter density is less and consequently the number of meter reads completed per meter reading route is less than for a route in the Columbus area.
    - Average avoided monthly meter reads were calculated using the annual number of certified AMI meters installed per year.[35]
    - Daymark assumed 8 hours of meter reader's time to complete each meter reading route. This assumption is based on the Company's Phase 1 Report.[36]
    - The monthly avoided meter reading labor hours were then estimated by multiplying average monthly avoided meter reads, meter reads per meter reading routes, and assumed number of hours required to complete each

[34] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy ("DOE") Smart Grid Demonstration Project ("SGDP") Contract Award Number DE-OE000193, June 2014. See from p. 23.

[35] AEP Ohio response to Staff DR-02-002, Attachment, Appendix A.

[36] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy ("DOE") Smart Grid Demonstration Project ("SGDP") Contract Award Number DE-OE000193, June 2014. See from p. 23.

meter reading route. Daymark then estimated avoided labor hours for regular meter reads for each year by multiplying the monthly number by 12.

- *Meter reader loaded labor rate* for 2018 was provided by AEP and includes all labor and vehicle costs associated with meter reading.[37]
- The meter reader *labor rate increase* was used to inflate the loaded labor rate each future year and was based on the average annual rate increases for a Meter Reader/Meter Servicer during the 2014 to 2018 period.[38]

- ***Meter Operations Costs*** **-** This benefit captures reduced labor costs due to smart meters requiring less frequent testing and refurbishment than analog meters. When smart meters fail, they are replaced upon failure or after minimal testing. Analog meters will decrease in accuracy over time, as well as experience speed changes impacting reading integrity, which requires routine testing and occasional refurbishment to ensure proper functionality. This benefit is a function of avoided O&M meter testing and refurbishment cost per AMI meter installed, deployment of AMI meters, and inflation.
  - *Avoided O&M meter testing and refurbishment cost per AMI meter installed* during Phase 2 was determined by:
    - Calculating a baseline, pre-AMI Phase 2 deployment, O&M meter testing and refurbishment cost, which was the average combined O&M costs for 2014 through 2016.[39]
    - Avoided meter testing and refurbishment cost in 2018 was then calculated by subtracting the O&M meter testing and refurbishment combined costs for 2018 from the baseline, which assumes the reduction in O&M costs are associated with deployment of AMI meters.
    - Average annual Phase 2 AMI meters deployed was calculated by averaging the monthly deployments for each year.[40]

[37] AEP Ohio response to Staff DR 02-026, Confidential Attachment 3.

[38] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[39] AEP Ohio responses to Staff DR 04-002a, Attachments 1 and 2, and Staff DR 04-002b Attachment.

[40] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004.

- The O&M meter testing and refurbishment avoided cost per AMI meter installed was then calculated by dividing the avoided meter testing and refurbishment cost in 2018 by the average number of Phase 2 AMI meters installed in 2018.

– *Deployment of AMI meters* for Phase 2 was determined based on the deployment plan for the AMI meters, which as noted above is the average annual Phase 2 AMI meters deployed that was calculated by averaging the monthly deployments, and planned deployments, each year.

– O&M meter testing and refurbishment avoided cost per AMI meter installed was escalated each year by *inflation* from the base cost year (2018).[41]

- ***Off-Cycle / Off-Season Meter Reads*** **-** This benefit captures the labor costs associated with the elimination of additional meter reads (i.e., those not associated with regular monthly reads, or those outside of a normal billing cycle). These reads will include, for example, customer move-ins and move-outs, customer requested service additions, and cancellations. Remote disconnects for non-payment could also be included here but are valued in the Daymark analysis as part of the Credit and Collections Operational Labor Savings benefit. Off-Cycle / Off-Season Meter Reads benefits are a function of annual avoided field visits due to remote open/close ability, meter read time, loaded labor rate, and labor rate increase.

– *Annual avoided field visits due to remote open/close* meter reads was determined by:

- Estimating the number of avoided field visits for off-cycle and off-season meter reads as a result of smart meters. Daymark used monthly data from the pre-AMI deployment period (February 2016 through June 2017) to estimate average manual open/close visits; this was used as a baseline for quantifying the number of avoided monthly field visits for open/close in the Phase 2 area once smart meters are installed. Use of pre-AMI deployment data will help avoid overcounting any open/close reads, which may have increased due to the ability of smart meters to do so remotely.[42]

[41] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[42] AEP Ohio response to Staff DR 04-003.

- Daymark used the following methodologies to estimate avoided field visits for open/close for different years.
  - For 2017 and 2018, Daymark used actual open/close meter read numbers[43] adjusting for any increase in open/close reads due to the remote ability of smart meters. Daymark adjusted for any possible increase in open/close numbers after AMI meter installation by using the percent of remote open/close reads as a portion of total open/close visits July 2017 through December 2018.
  - For 2019 and beyond, Daymark used average monthly avoided manual meter reads for open/close visits of pre-AMI installation period to estimate annual avoided off-season/off-cycle meter reads. Moreover, for 2019, Daymark further adjusted avoided off-season/off-cycle meter reads to account for phased-in meter deployment.

- The off-season/off-cycle *meter read time* is assumed to be one hour per read. This was determined from our review of industry data and confirmed as reasonable in discussion with the Commission Staff.
- *Loaded labor rate*, using 2018 as the base cost year, for a Meter Specialist is used under the assumption that meter readers are responsible for regular meter reads. Note that this value includes vehicle costs.[44]
- *Labor rate increase* was assumed to be the historical average annual rate increase for a Meter Specialist during the 2014 to 2018 period.[45]

- **Industry Benchmark** – We reviewed grid modernization programs for other utilities in Ohio[46] to compare those against AEP's values and against our analysis, as a reasonableness check. The industry benchmark came out higher, possibly due to differences in system deployment, devices used, or aggressiveness in driving or estimating savings. However, as a reasonability check, our analysis shows benefits

[43] AEP Ohio response to Staff DR 04-006.

[44] AEP Ohio response to Staff DR 02-026, Confidential Attachment 3.

[45] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[46] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

within a rational range. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

While Daymark was able to analyze and determine benefits of Meter Reading and Operational Labor Savings, several assumptions were used because of limitations in the data available. Going forward, Daymark recommends that AEP track the following information to better capture the operational benefits through the Phase 2 deployment period.

- Monthly and yearly meter reading routes per meter reader, per district, as well as the number of meter reads per route, per district.

3.3.2 Credit and Collections Operational Labor Savings

Deployment of AMI technology will reduce labor costs related to credit and collections, and more specifically will lead to labor savings through the use of remote disconnect when customers fail to pay (referred to as credit or non-payment disconnects). Previously, AEP would have had to manually disconnect customers for non-payment. Now, after getting approval to remotely disconnect customers for non-payment, AEP can avoid sending someone out to disconnect a customer, which will also lead to reduction in injuries related to truck rolls (benefit captured separately). Additionally, AEP will be able to reduce uncollectible revenue by completing remote credit disconnects. This benefit, shown in Line 2 of Table 4, is “Rider eligible”.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

Figure 4: Credit and Collections Operational Labor Savings – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare the Annual Credit and Collections Operational Budgets to the Pre-deployment Budget.[47]
  - Daymark tried to compare the Credit and Collections actual budgets[48] (AEP indicated these were specific to Accounts 252 and 253) over time, but there is a lot of noise in the budgets, including the fact that Phase 2 program eligibility[49] for remote disconnects has not been enabled for a majority of customers yet. This is the result of the required waiver[50] for remote disconnect for non-payment not having been approved until June 2018. This did not allow for a proper evaluation and estimation of benefits. We were able to determine that the budget actuals were generally trending down over time, which is the expectation following AMI deployment.

[47] AEP Ohio Phase 2 Application, Attachment C.

[48] AEP Ohio response to Staff DR 05-002a, Attachment.

[49] AEP Ohio response to Staff DR 02-042. The Company explained that they are implementing program eligibility as customers are switched over to AMI and that they are adding them to the next wave of customers to be notified under the waiver.

[50] AEP Ohio response to Staff DR 02-042. AEP Ohio stated in June 2018, the "*Phase 2 disconnect waiver was approved and AEP Ohio started the process to provide required notifications and system changes to support the Phase 2 disconnect waiver.*"

- **Daymark Analysis** – This benefit is a function of annual avoided truck rolls for credit disconnects, meter disconnect time, loaded labor rate, and labor rate increase.
  - *Annual avoided truck rolls* due to remote credit disconnects was determined by:
    - Estimating the number of avoided remote credit disconnects as a result of smart meter deployment and disconnect waiver granted by the Commission for the Phase 2 area.[51] Daymark used customers disconnected for non-payment in 2016 as a baseline for determining Phase 2 avoided truck rolls for credit disconnects. Use of pre-AMI deployment data will help avoid overcounting any remote credit disconnects, especially early in the AMI meter deployment.
    - Daymark used the following methodologies to estimate avoided field visits for remote credit disconnects for different years.
      - For 2017 and 2018, Daymark conservatively assumed there were no customers remotely disconnected for non-payment because AMI meter deployment was still ramping up at that time and the remote disconnect waivers were not being granted until mid-summer 2018.
      - For 2019, Daymark started with the 2016 remote customer disconnects. We assumed that only a percentage were feasible due to program eligibility. We used AEP's Phase 2 eligibility plan to calculate the percent of customers that would be program eligible for remote disconnect by taking a ratio of those expected to be eligible by 4/4/2019 compared to the total eligible by early 2020. This ratio was then applied to the 2016 remote customer credit disconnects.
      - For 2020 and beyond, Daymark assumed that all customers remotely disconnected in 2016 for non-payment would be a conservative total of customers that were remotely disconnected for non-payment each year. We are using a conservative total since the same customers disconnected for non-payment in one year may or may not be disconnected again in that same year or in the following year. Additionally, AEP may still have to send someone out occasionally, depending on the circumstances.

[51] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix K, Staff 02-018, Attachment, and Staff DR 08-001.

- The *meter disconnect time* is assumed to be one hour per meter. This was determined from review of industry data and confirmed in discussion with the Commission Staff.
- *Loaded labor rate*, using 2018 as the base cost year, for a Meter Specialist. Meter Specialist is used under the assumption that meter readers are responsible for regular meter reads. Note that this value includes vehicle costs.[52]
- *Labor rate increase* was assumed to be the historical average annual rate increase for a meter specialist over the 2014 to 2018 period.[53]

- Daymark analyzed an alternative approach based on AEP's explanation of the disconnect/reconnect fee calculated from the Test Year for its last rate case (Case No. 11-351-EL-AIR). AEP explained that the fee would be reduced as AMI installations increased as a percentage of total system meters.[54]
  - We completed a similar calculation using Phase 2 AMI deployment as a percent of total system meters multiplied by the current $53 fee to calculate the fee each year from 2017 through 2020, when all Phase 2 meters are expected to be deployed. The difference between the calculated fee each year and the current fee was then multiplied by the number of customers disconnected for non-payment in 2016. After 2020, each year's savings was the previous year plus inflation.[55] Under this approach, estimated savings over the 15-year period were reasonably close to our main analysis where we calculate savings resulting from avoided truck rolls for credit disconnects.

Data Tracking Recommendations:

Daymark was able to analyze and determine the benefits of Credit and Collections Operational Labor Savings, under two different approaches. We don't have additional data tracking recommendations. However, we discuss additional non-financial metric recommendations in Section 5 related to non-payment remote disconnects that will improve transparency of the effectiveness and value AMI as it relates to uncollectable activities.

[52] AEP Ohio response to Staff DR 02-006, Confidential Attachment 3.

[53] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[54] AEP Ohio responses to Staff DR 02-075 and Staff DR 04-010, Attachment 1.

[55] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

3.3.3 Reduction in Uncollectible Revenue Through Remote Disconnect

Not only will deployment of AMI technology reduce labor costs related to credit and collections, it will also lead to increased revenue through the use of remote disconnect when customers fail to pay. The increase in revenue would be attributed to a lower amount of uncollectible expense due to the accelerated ability to disconnect customer meters as Phase 2 AMI meters are deployed. This benefit, shown in Line 6 of Table 4, is "not Rider eligible". AEP explains that the savings for this operational benefit will *"[f]low back to customers through a future Uncollectible Revenue Rider that the Company plans to file separate from the gridSMART Phase 2 filing."*[56]

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

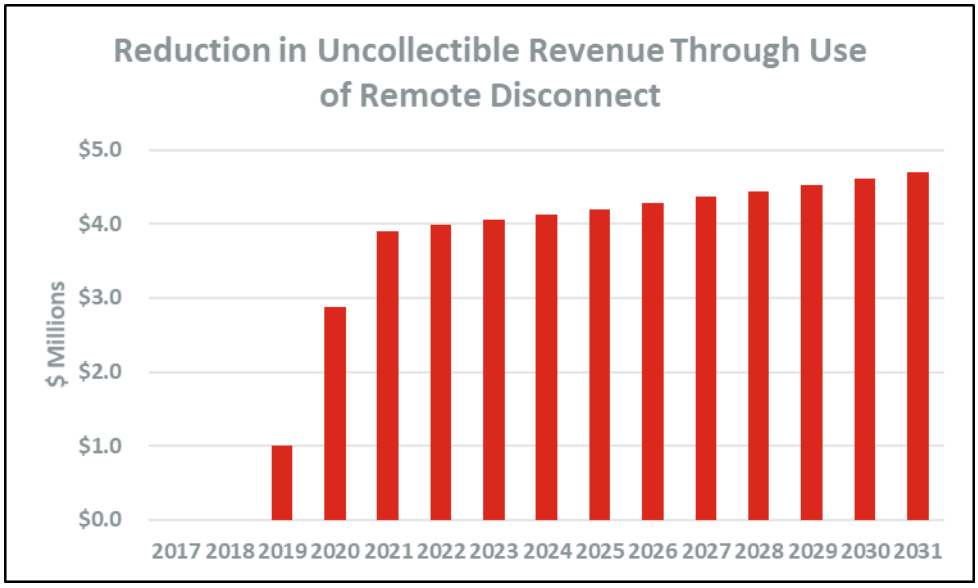

Figure 5: Reduction in Uncollectible Revenue Through Use of Remote Disconnect – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare the Annual Uncollectible Revenue Write-Off to the pre-deployment data. AEP noted that "*performance is prone to other economic factors that will not allow for pure measure.*"[57]

[56] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[57] *Id*.

- Daymark reviewed uncollectible revenue from the period 2008 through 2018, which AEP indicated was "*based on a rolling 12 month average of net charge offs and is not tracked by PIPP*[58] *and non-PIPP*", which changed during the period reviewed.[59] Since the remote credit disconnect program is still in its infancy, the uncollectible revenues provided by AEP do not allow for identification of a trend. This benefit will begin showing up as AMI is more fully deployed in 2019 and as more customers become eligible for remote credit disconnect both at a program level and based on receiving the initial notifications from AEP.[60]

- **Daymark Analysis** – This benefit is a function of realigning AEP's original savings estimates following the delayed deployment of AMI, the remote credit disconnect program start, and inflation.
  - AEP provided Phase 2 timelines for *AMI deployment* and the *remote credit disconnect program eligibility*.[61] Using these timelines, we determined that 2018 should be zeroed out because (1) there were few customers eligible by the time AEP was granted the remote credit disconnect waiver, (2) the timing of providing customers the required notifications, and (3) the system changes to support the Phase 2 disconnect waiver. For 2019, we reduced the savings based on the ratio of customers that were program eligible by early 2019 compared to the total planned AMI installs and adjusted for *inflation*.[62] For 2020 and beyond, the original savings estimates were adjusted for *inflation*.

[58] Percentage of Income Payment Plan Plus ("PIPP") enables people in Ohio to pay a consistent energy bill that is based on percentage of household income. https://www.development.ohio.gov/is/is_pipp.htm.

[59] AEP response to Staff-08-007.

[60] AEP Ohio response to Staff DR 02-042. AEP Ohio stated in June 2018, the "*Phase 2 disconnect waiver was approved and AEP Ohio started the process to provide required notifications and system changes to support the Phase 2 disconnect waiver*."

[61] AEP Ohio responses to Staff DR 08-001, Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004.

[62] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

Data Tracking Recommendations:

Daymark was unable to analyze and determine benefits for Reduction in Uncollectible Revenue Through Use of Remote Disconnect and settled for adjusting AEP's original estimates to realign them with AMI deployment and the delayed start of the remote credit disconnect program. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- Monthly and yearly uncollectible amount (uncollectible expense from factored receivables, which are based on a 12-month rolling average of net charge offs). This data should include uncollectible revenue associated with each rate class and should be tracked with and without the PIPP program by district.

In addition, as discussed in Section 3.2.2, Section 5 contains additional non-financial metric recommendations related to non-payment remote disconnects that will improve transparency of the effectiveness and value AMI as it relates to uncollectable activities.

3.3.4 Reduction in Theft

Reduction in power theft is a hard benefit to quantify because Traditional utility meters do not have the capability of detecting tampering, incorrect installation, bypassing, or mis-wiring. AMI technology enables MRO to more quickly identify and mitigate meter theft, which will lead to increased revenues. This benefit, shown in Line 7 of Table 4, is "not Rider eligible". AEP explains that the increased revenue from reduction in theft will "*naturally flow through to customers as they [savings] occur based on the base distribution amounts being trued up to the test year expenses through the Pilot Throughput Adjustment Rider as well as other Riders being subject to true up.*"[63] Basically, increased revenues from lower theft will lower the amount of revenue that will need to be collected from all other customers.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

[63] AEP response to Staff-04-010, Attachment 1.

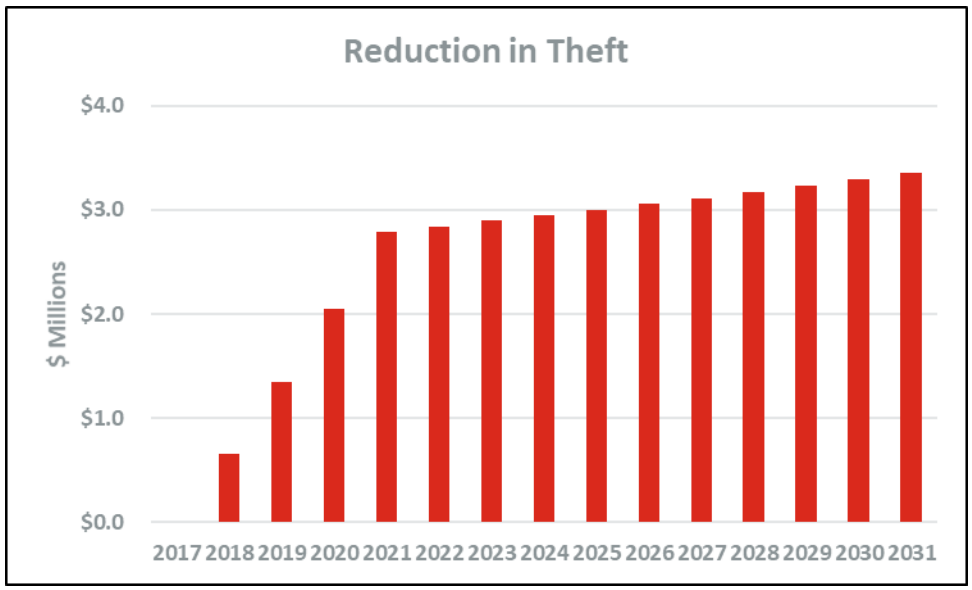

Figure 6: Reduction in Theft – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare Annual Theft of Energy revenue savings; some savings will not be identifiable.[64]
  - As part of the non-financial metrics, AEP is tracking the number and monetary value of power theft cases found each month throughout the system.[65] Additionally, AEP provided Phase 2 area power theft case numbers and values each month for 2016 through early 2019 by each type of meter.[66] Daymark analyzed the power theft case data, unaccounted for energy[67] for 2014 through 2018, and investigation costs related to power theft. Since AEP used available industry data at the time of its Phase 2 Filing (data that is no longer readily available), we were not able to use the Company's power theft related data to verify the original estimated reduction in theft benefits.
- **Daymark Analysis** – Due to a lack of adequate data to calculate reduction in theft savings, as well as delayed deployment of AMI, which will delay potential savings until

[64] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[65] AEP Ohio response to Staff DR 02-002, Attachment, Appendices L and M.

[66] AEP Ohio response to Staff DR 08-005, Attachment.

[67] AEP Ohio response to Staff DR 08-006.

future years, the savings for this benefit were just a function of realigning AEP's original savings estimates due to the delayed *deployment of AMI* and *inflation*.[68] We did not find it necessary to delay initial savings until AMI deployment reaches 100% because it is evident in the 2018 and early 2019 Phase 2 area data regarding power theft cases that AMI meters are having an impact on theft identification and mitigation.[69]

- **Industry Benchmark** – Since AEP explained that industry data was used at the time of the Phase 2 Filing to estimate reduction of theft, we analyzed other utilities in Ohio[70] as a reasonableness check and found that they assumed about half of AEP's original estimate when compared over a similar 15-year period. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was unable to analyze and determine benefits for Reduction in Theft and settled for adjusting AEP's original estimates to realign them with AMI deployment. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- Monthly and yearly power theft cases and monetary value per case. Breakout power theft cases by meter type in the Phase 2 area. Track the investigation costs associated with each case separately. Track case timelines, i.e., from when case was opened for investigation to when it was closed and customer was invoiced.

3.3.5 Reduction in Consumption on Inactive Meters

Reduction in consumption on inactive meters is another benefit that will lead to increased revenue because AMI meters that are connected to inactive accounts can be disconnected remotely. The capability to remotely disconnect meters will lead to increased revenue by not having active meters on closed accounts (until they can be manually disconnected, or until a new account associated with the meter is opened). AEP explained that increased revenue associated with eliminating consumption on inactive meters flows back to customers like increased revenue associated with

[68] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[69] AEP Ohio response to Staff DR 08-005.

[70] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

reduction in theft, as explained above. As such, this benefit, shown in Line 8 of Table 4, is "not Rider eligible."[71]

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

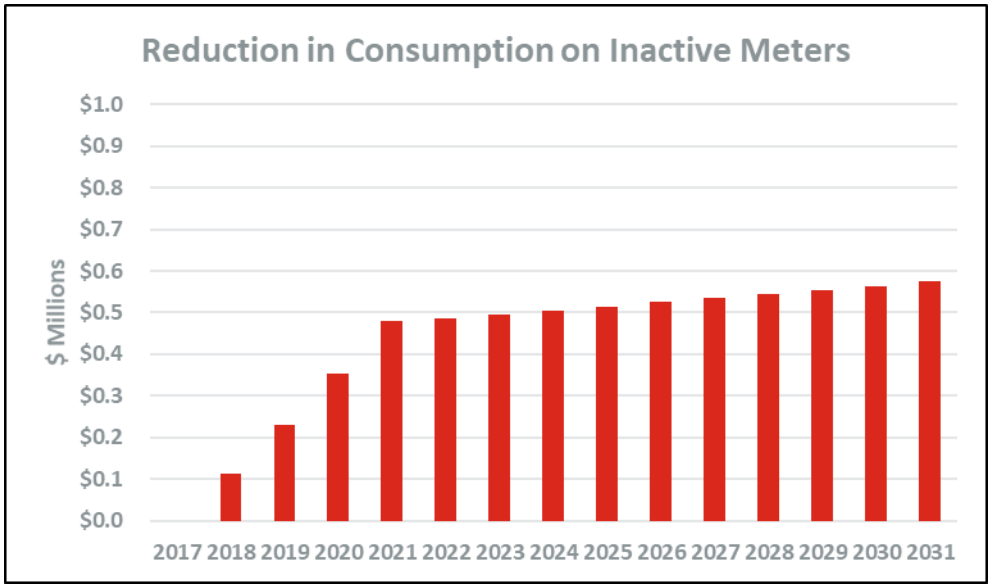

Figure 7: Reduction in Consumption on Inactive Meters – AEP Filing Update

Calculation:

- **AEP Proposed Calculation** – No measurable verification method was provided by AEP.[72]
  - AEP used available industry data at the time of its Phase 2 Filing, which was not retained and is therefore is no longer available for review. AEP was able to provide kWh consumption data for connected meters on inactive accounts from its Consumption Reports for 2016 through 2018.[73] Daymark analyzed the data, but with such a small amount of data available, no discernable trend could be determined. As more AMI meters are deployed, we expect to see a decline in consumption from connected meters on inactive accounts. This is supported by AEP explaining that revenue protection efforts were refocused in late 2018 and that it is using additional

[71] AEP explains that "*[a]ny savings for reduction in in consumption of inactive meters will flow through to customers as they occur due to the same reasons as the theft reduction*." AEP response to Staff-04-010, Attachment 1.

[72] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[73] AEP Ohio response to Staff DR 09-014, Attachment.

resources to help identify theft and develop reports on findings.[74] However, due to current AMI deployment levels, we are not able to use the Company's Consumption Report data to verify the original estimated benefit of reduction in consumption on inactive meters.

- **Daymark Analysis** – Due to a lack of adequate data to calculate reduction in consumption on inactive meter savings, as well as delayed deployment of AMI, which will delay potential savings until future years, the savings for this benefit were just a function of realigning AEP's original savings estimates due to the delayed *deployment of AMI* and *inflation*.[75] We did not find it necessary to delay initial savings until AMI deployment reaches 100%, so the original estimates were simply shifted to start in 2017 and inflated through the rest of the period.

Data Tracking Recommendations:

Daymark was unable to analyze and determine benefits for Reduction in Consumption on Inactive Meters and settled for adjusting AEP's original estimates to realign them with AMI deployment. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- Monthly and yearly consumption for connected meters on inactive accounts. Breakout consumption by meter type in the Phase 2 area.

3.3.6 Customer Savings Associated with VVO Benefits

VVO helps to maintain optimal lower voltages across distribution circuits at desired standards through voltage flattening. VVO is a demand-side management tool that does not require customer participation. VVO-enabled circuits also assist in reducing reactive power support across the distribution system. Customer savings associated with VVO are due to reductions in energy consumption (kWh) and peak load (kW) resulting in energy and capacity savings. This benefit, shown in Line 9 of Table 4, is "not Rider eligible". AEP explains that this is a customer benefit,[76] which does not accrue to AEP as an operational savings.

[74] AEP Ohio response to Staff DR 03-002 PT.

[75] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[76] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

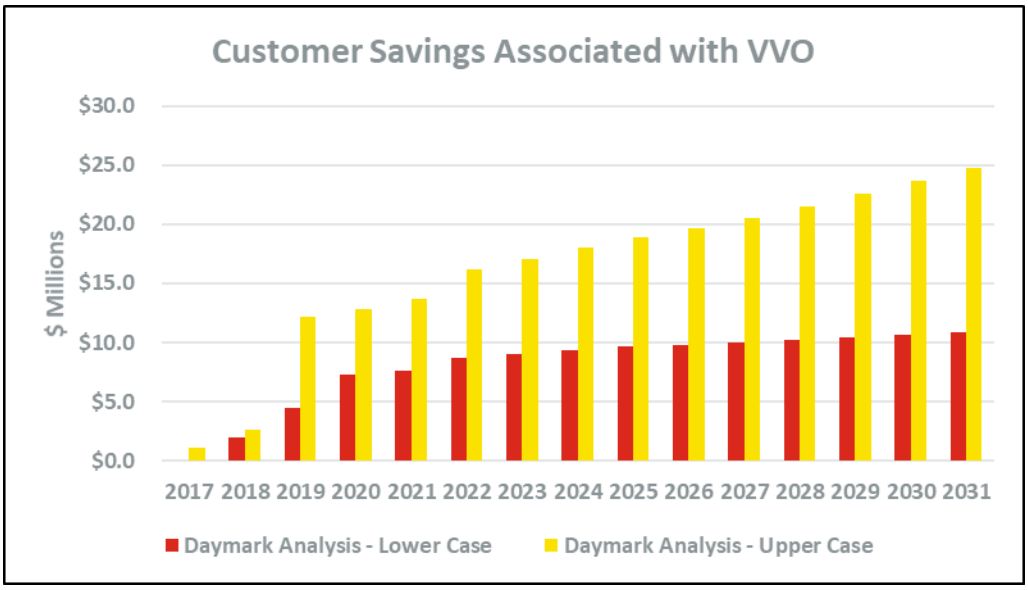

Figure 8: Customer Savings Associated with VVO – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare the annual average percent voltage reduction per circuit to pre-VVO deployment levels.[77]
  - This involves applying a 3% (based on AEP's experience) reduction in energy and capacity values to baseline assumptions. For pricing, AEP assumed the energy and capacity prices for the 'AEP Gen Hub'[78] from PJM Interconnection LLC data. The capacity prices were forecasted by the Company using 2012 data. While Daymark did not have access to how the prices and consumption were specifically determined, the calculations AEP used based on those estimations and our own experience were reasonable.
- **Daymark Analysis (Upper Case)** – This benefit is a function of the difference between average kWh and peak kW on VVO-enabled circuits under a scenario where VVO had been installed compared to a scenario where VVO was not installed. These differences

[77] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[78] The AEP Gen Hub is the AEP Generation Hub, which is a trading hub, represents the aggregated Locational Marginal Price generation nodes defined by PJM Interconnection, LLC.

in energy and peak were then valued by applying an estimated per unit value for both energy and capacity prices and then escalated for inflation after 2018, as follows:

- Daymark analyzed circuits that AEP identified for VVO-enablement[79] under two scenarios: (1) *If VVO was not installed*, and (2) *If VVO was installed*. Using AEP's Phase 1 experience of 3% reduction per VVO-enabled circuit for both energy and capacity savings, we calculated the total average kWh and peak kW for all VVO-enabled or to be enabled circuits and either applied a 3% reduction[80] or added 3% back depending on the scenario.
- Energy and capacity prices were the AEP assumed prices for the 'AEP Gen Hub'[81], escalated for *inflation*[82] at the end of the forecast, due to shifting the start date to 2017.[83]
- Energy and capacity savings benefits were calculated as the difference between each scenario multiplied by the energy prices for kWh consumption benefits and capacity prices for kW peak benefits.

- **Daymark Analysis (Lower Case)** – As a reasonableness check, Daymark shifted AEP's original estimates out three years to account for the delayed *deployment of VVO* and applied *inflation*.[84] Since we were not able to verify AEP's original energy and capacity prices, we did not otherwise adjust AEP's forecasted prices, except for inflation.

Data Tracking Recommendations:

Under AEP's methodology, for future assessments, AEP should update the energy price forecasts for 'AEP Gen Hub' with each report. Additionally, the capacity prices should be updated using a robust capacity market pricing model and the most recent PJM Reliability Price Model ("RPM").

[79] AEP Ohio response to Staff DR 04-022e, Attachment.

[80] Case No. 13-1939-EL-RDR, AEP Initial Application, p. 9.

[81] Capacity prices were determined at this hub by using recent PJM capacity market auction clearing prices that were then forecasted through the rest of the period.

[82] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[83] AEP Ohio response to Staff DR 02-006, Attachment.

[84] AEP Ohio response to Staff DR 02-006, Attachment. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

To identify the impact of VVO specifically it would be necessary to identify each of the various energy-saving drivers, including demand-side (i.e., time-of-use) measures implemented by customers.

Verification of the benefits of VVO optimization is difficult. Load changes occur for many reasons and are hard to separate from power flow changes due to VVO exclusively. One verification approach described in the literature[85] would be to compare feeders or circuits with strongly-correlated load patterns using one as the baseline control while VVO is added to the other.

Alternatively, and at a minimum, more explicit weather-adjusted accounting needs to be taken of hourly circuit voltages and power factor corrections both before and after VVO deployment.

3.3.7 DACR Outage Reduction

DACR-enabled circuits are capable of reconfiguring the distribution system quickly to help restore power to de-energized customers. DACR also helps in remote system monitoring, coordination, and operation of distribution circuit equipment to keep the power on. DACR automatically detects fault conditions and outages and strategically reroutes the paths of electricity within the electrical grid. This section focuses on quantifying the outage reduction benefits that result from DACR deployment and accrue to customers. DACR-enabled circuits will reduce customer minutes of interruption, which is a direct benefit to customers. This benefit, shown in Line 10 of Table 4, is "not Rider eligible". AEP explains that this is a customer benefit,[86] and not an operational benefit to AEP.

The figure below shows the expected annual value for this benefit calculated using the methodology described below and an assumed level of deployment.

[85] Sunderman, W. G. 2012."Conservation Voltage Reduction System Modeling, Measurement, and Verification." Transmission and Distribution Conference and Exposition (T&D), IEEE PES.

[86] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

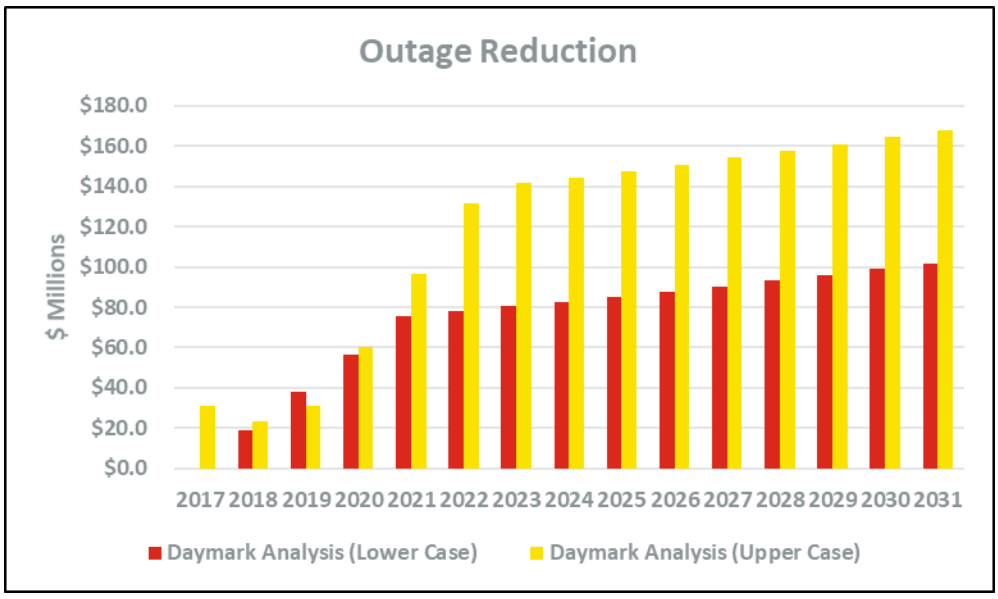

Figure 9: Outage Reduction – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare annual customer minutes of interruption for DACR circuits to pre-deployment data.[87]
  - AEP estimated the customer benefit to be $77 million per year from increased reliability. Through discovery, Daymark identified that the Company calculated this number by multiplying the cost of a sustained outage[88] by the number of customers affected by an outage. Using the Company's data, we were able to verify AEP's savings estimate.
- **Daymark Analysis (Upper Case)** – This customer benefit is a function of the avoided number of interrupted customers, the cost to a customer of a sustained outage, and inflation.
  - Using the Company's data, Daymark determined the *number of customers* that were affected by an outage, historically. We then used an updated Lawrence Berkley

[87] *Id*.

[88] Cost of Power Interruptions to Electricity Consumers in the United States (U.S.), Lawrence Berkeley National Lab, 2006. https://emp.lbl.gov/publications/cost-power-interruptions-electricity.

National Labs ("LBNL") study[89] that estimated the *cost of a sustained outage* for the various customer classes. Outage reduction benefits were determined by multiplying the cost of a sustained outage per class by the number of customers affected by an outage. The number of customers were allocated to each customer class based on the Company-wide percentage of 2017 AEP Ohio customers per class. For future years, we assumed an average benefit per DACR circuit, which was calculated by averaging the outage reduction benefits in 2017 and 2018 divided by the number of active DACR circuits. This average benefit was applied to the DACR deployment schedule and adjusted for *inflation*.[90]

- **Daymark Analysis (Lower Case)** – As part of a reasonableness check, Daymark shifted AEP's original estimates out three years to account for the delayed *deployment of DACR* and applied *inflation*.[91]

***Data Tracking Recommendations**:*

Daymark was able to analyze and determine DACR Outage Reduction benefits to customers based on Company data and industry data on customer costs related to outages. Outside of having data that better captures the estimated cost impact to each type of customer, Daymark does not have any recommendations for AEP to better capture future customer savings. There are however several concerns addressed elsewhere in this report regarding the need for the Company to evolve its internal processes to fully realize Company-related savings.

3.3.8 Billing Labor Benefits

AMI deployment will benefit the billing department because smart meters are able to provide billing data on the scheduled reading day, which allows bills to be available on the first day of the billing cycle. Analog meters need to be read manually, which delays billing and leads to more estimated bills. Additionally, smart meters will provide more accurate bills than Traditional meters, which will eliminate the need for rebills. By reducing estimated bills and the number of bills issued, AEP will be able to accelerate collections and reduce interest expense. It is important to note that the billing

[89] Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers, Lawrence Berkeley National Lab, 2018. https://emp.lbl.gov/publications/improving-estimated-cost-sustained.

[90] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[91] AEP Ohio response to Staff DR 02-052, Revised Attachment. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

department is a shared service where labor is allocated partly on direct costs associated with the operating company where billing occurs, and partly on the number of retail customers, which happens on a volume of bills basis.[92] This benefit, shown in Line 3 of Table 4, is "Rider eligible".

The figure below shows the expected value for this benefit calculated using the methodology described below.

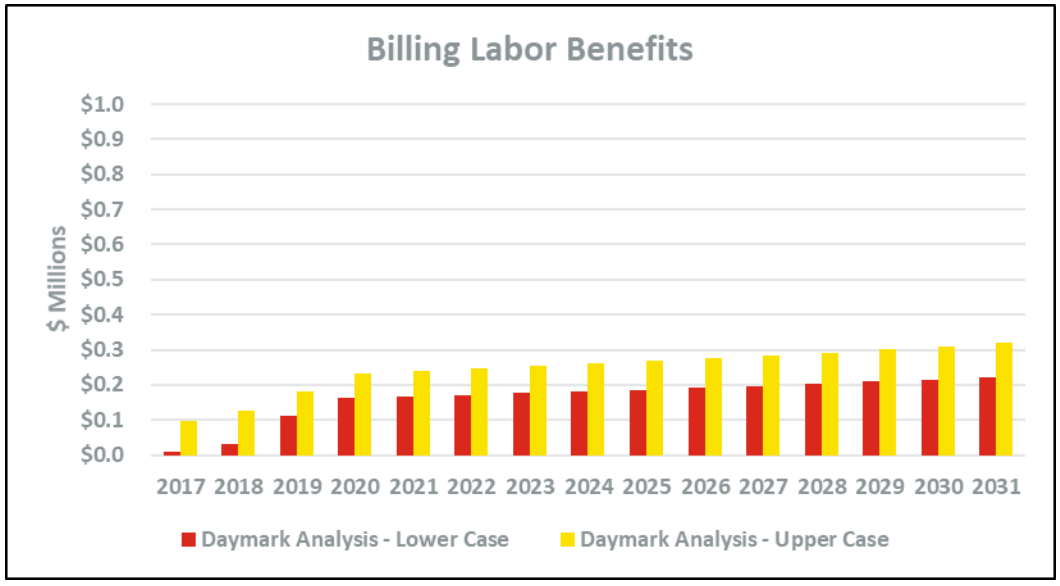

Figure 10: Billing Labor Benefits – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare the number of annual No-Bill Workflows created for AMI customers and compare to the pre-deployment quantity.[93]
  - AEP provided data on No-Bill Workflows (accounts that did not bill because of an issue with the previous or present meter reading, or a larger issue) and Bill Warning Workflows (accounts that were billed but may have an issue the biller will need to review) for at least 2013 through 2018 (data for No-Bill Workflows was available back to 2010).[94] Daymark analyzed the data, but there appears to be a mix of trends occurring in the data that does not correlate to the expectations of AMI meter

[92] AEP response to Staff-02-081.

[93] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[94] AEP Ohio response to Staff DR 09-009, Attachment.

benefits. More granular data by meter type may help reduce some of the noise. Even without the granular data though, AEP does not track labor hours at a granular level, which prevents association of a dollar value to reduction of either type of workflow.

- **Daymark Analysis (Upper Case)** – In addition to the No-Bill and Bill Warning Workflows, Daymark reviewed the annual billing department costs from 2011 through 2018.[95] There has been a lot of downward cost reduction in the billing department, which AEP has described as reductions to associates used for billing because they were needed on phones, higher paid "Billers" retiring and being replaced by less tenured, lower paid employees, and other efficiencies like use of macros and shifting of employees from billing to phones when there is a high call volume. Further, AEP expects to see increased training time needed for its Groveport Customer Operations Billing group.[96] While these changes have impacted earlier years, we believe that more recent trends in billing department costs are more highly correlated to AMI deployment. Therefore, we calculate the savings for this benefit as a function of annual billing costs adjusted through the analysis period and the labor rate increase.
  - *Annual billing cost* differences are used in the early years (2017 and 2018) to determine savings, which are cumulative until full deployment in 2020. Annual billing costs for 2019 and 2020 were calculated by applying a reduction trend in costs, which was determined by calculating a compound annual growth rate between 2016 and 2018. Using 2016 as a base year is reasonable because it was the first full year before Phase 2 AMI deployment. After 2020, the savings each year are the previous year's savings plus the merit wage rate increase.
  - *Labor rate increase* is an average of the merit wage rate over the period 2014-2018. This rate was used because it represents labor rate changes, which directly impact billing department costs.[97]
- **Daymark Analysis (Lower Case)** – We analyzed an additional case that discounts 2017 through 2020 by the *ratio of AMI currently deployed each year* from Phase 1 and Phase 2 to total system meters (calculated as Phase 1 AMI deployed plus Phase 2 AMI currently deployed each year and Phase 3 meters planned to be deployed in the future). As the percentage of AMI meters on the system increases, the more savings the billing

[95] AEP Ohio response to Staff DR 02-083, Attachment 1.

[96] AEP Ohio responses to Staff DR 09-008 and Staff DR 09-010.

[97] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

department will be able to realize. After 2020, when full Phase 2 AMI deployment has been completed, the savings each year are the previous year's savings plus the *merit wage rate increase*.

- **Industry Benchmark** – In addition to analyzing AEP's data, we analyzed other utilities in Ohio[98] as a reasonableness check against AEP's estimate and against our analysis. We found that other Ohio utilities assumed benefits that were lower than our and AEP's original estimates when compared over a similar 15-year period. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison. Additionally, the utility data used in the benchmark only considered benefits from a shortened billing cycle.

Data Tracking Recommendations:

While Daymark was able to analyze and determine Billing Labor Benefits, there were assumptions made due to lack of granularity in the billing department data. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- Hourly rate and time data for billing department employees that indicates time spent on calls, No-Bill Workflows, Bill Warning Workflows (data is needed by type – i.e., Zero Use Workflows, Excess Use Workflows, Budget Workflows, and Seasonal Use Workflows), and any other types of activity codes that apply to the billing department. Staff should include Core Billers, Non-Core Billers, Billing trainees, supervisors, and any other staff not included here.

3.3.9 Call Center Labor Benefits

AMI deployment will benefit the call center because over time smart meters will reduce the number of customer calls, especially those related to credit and billing issues, move-ins and move-outs, and trouble calls. Smart meters will provide AEP staff with the remote capability of reading meters and diagnosing meter issues, as well as providing more granular historical data. To the extent that call center employees have access to more granular historical data than just a monthly meter read, as well as the capability of remote diagnostic meter reads, call center employees can better resolve questions and complaints. It is important to note that the call center, like the billing department, is a

[98] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

shared service, which allocates costs based on call volume per operating company. This benefit, shown in Line 4 of Table 4, is "Rider eligible".

The figure below shows the expected value for this benefit calculated using the methodology described below.

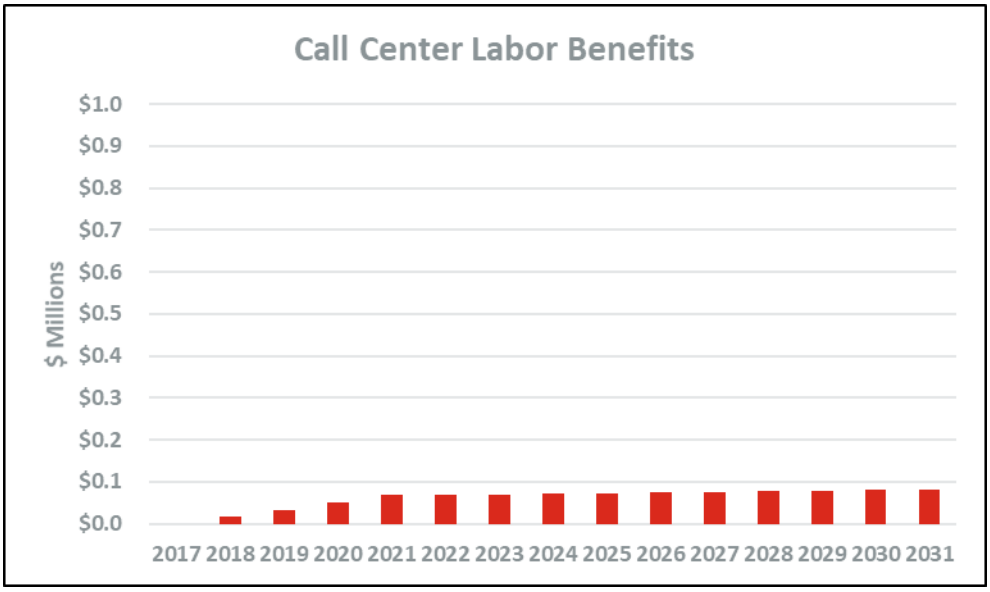

Figure 11: Call Center Labor Benefits – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – No measurable verification method was provided by AEP due to savings deemed difficult to quantify because work is shifted to a different focus.[99]
  - Daymark reviewed the call center annual costs[100] and determined that there is too much noise in the data to properly calculate benefits of AMI. Additionally, we analyzed the number of total calls, calls related to meter reading and billing complaints, and other types of calls provided for the internal AEP call center.[101] Just looking at internal call center total calls, the data shows a downward trend in call volume since 2015. Some of this reduction could be due to Phase 1 AMI, and some could be due to Phase 2 AMI, especially in 2018. However, without more granular

[99] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[100] AEP Ohio response to Staff DR 02-050, Attachment 1.

[101] AEP Ohio responses to Staff DR 04-008a, Attachment A and Staff DR 04-016, Attachment 1.

data that tracks calls by type and length, as well as cost per call, for all internal and external call center calls, a proper benefit calculation cannot be completed.

- **Daymark Analysis** – Due to a lack of adequate data to calculate call center labor benefit savings, as well as delayed deployment of AMI, which will delay potential savings until future years, the savings for this benefit were just a function of realigning AEP's original savings estimates due to the delayed *deployment of AMI* and labor rate increase. We did not find it necessary to delay initial savings until AMI deployment reaches 100% because the total AEP internal call center calls are showing a downward trend after 2016 and non-financial metrics tracked calls related to meter reading are showing a decrease after 2017. Both of these trends appear to indicate a reduction of calls due to installation of AMI meters, so the original estimates were just shifted to start in 2017 and inflated through the rest of the period by the average labor rate increase. The *labor rate increase* is an average of the merit wage rate over the period 2014-2018.[102] This rate was used because it represents labor rate changes, which directly impact call center costs.

- **Industry Benchmark** – In addition to analyzing AEP's data, we analyzed other utilities in Ohio[103] as a reasonableness check against AEP's estimate and against our analysis. We found that over a similar 15-year period the benefit estimates are reasonable. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was not able to analyze and determine Call Center Labor Benefits due to lack of granular call center data. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- Hourly rate and time data for call center employees that indicates time spent on calls, type of call, customer meter type, non-AEP Ohio call center calls, and any other types of activity codes that apply to the call center. Staff should include all call center employees, including supervisors. Data collected should include AEP call centers and outsourced call centers.

[102] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[103] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

3.3.10 Injury Reduction

AMI technology deployment will lead to reductions in staff in MRO, as discussed under the Meter Reading and Operational Labor Savings benefit. As the labor costs drop, so will worker's compensation costs, which are most-directly captured in long-term disability cost savings. Insurance rates will also likely be reduced, but will be more difficult to quantify. As VVO and DACR are also deployed, there will be a reduction in maintenance and inspection of distribution field equipment thanks to remote monitoring capabilities. Over time, AEP should see a reduction in the frequency of safety incidents, which will also reduce liability and lost work days. This benefit, shown in Line 13 of Table 4, is "not Rider eligible". AEP does not explicitly explain why. However, as we explain below, the data needed to meaningfully analyze the estimated savings for this benefit are not available, so for now this is not included as a "Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

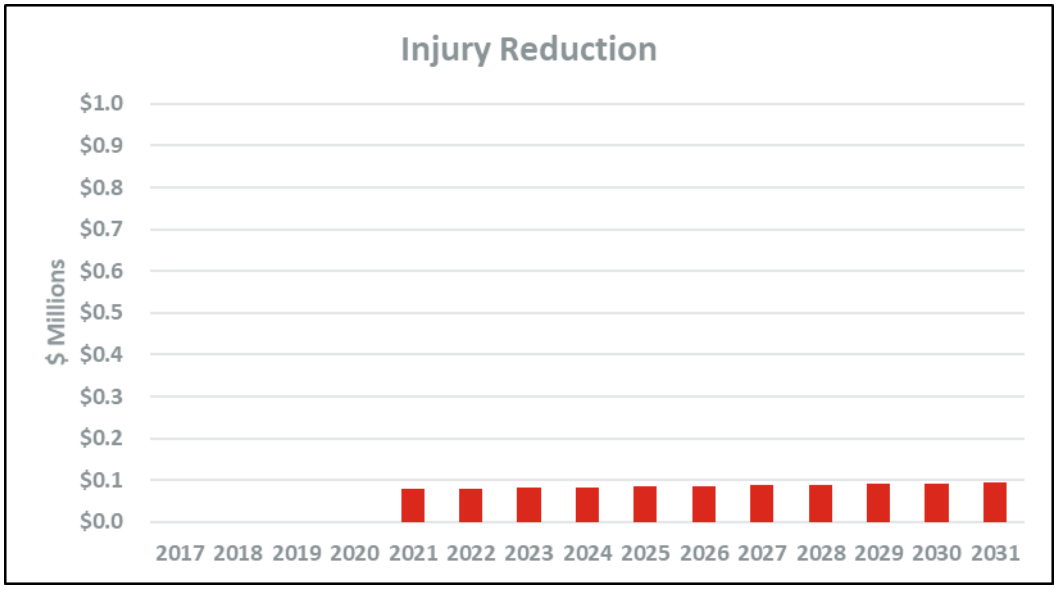

Figure 12: Injury Reduction – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – Compare Occupational Safety and Health Administration ("OSHA") recordable and severity rates to pre-deployment data.[104]
  - AEP provided detailed data on OSHA incidents, including costs.[105] This data contained a lot of noise because it included every incident. We further asked for and received data on just long-term disability OSHA incidents.[106] At a high level of review, there is not enough data to properly audit AEP's original saving estimate.
- **Daymark Analysis** – This benefit should be a function of OSHA data on long-term disability incidents, vehicle accident costs, and inflation. However, the data on *OSHA long-term disability incidents* and *vehicle accident costs* provided by AEP does not properly capture injury reduction benefits.[107] This is likely due to the delay in deployment, especially for DACR and VVO. Once AMI is fully deployed in 2020, and once most if not all VVO is deployed in parallel, the number and cost of OSHA incidents and vehicle accidents should be reduced. Therefore, we calculated the savings for this benefit as a function of realigning AEP's original savings estimates due to the delayed deployment of AMI, DACR, and VVO and *inflation*.[108] We found that it was necessary to zero out benefits from 2017 through 2020 because AEP is currently focused on AMI and VVO deployment and savings will not really be possible until most of the technology is deployed. For all years after 2020, the savings from the previous year are increased by inflation.
- **Industry Benchmark** – In addition to analyzing AEP's data, we analyzed other utilities in Ohio[109] as a reasonableness check against AEP's estimate and against our analysis. We found that over a similar 15-year period the benefit estimates are reasonable. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

[104] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[105] AEP Ohio response to Staff DR 02-078, Attachment.

[106] AEP Ohio response to Staff DR 06-004, Attachment.

[107] AEP Ohio responses to Staff DR 06-004, Attachment, and Staff 04-023, Attachment.

[108] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[109] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

Data Tracking Recommendations:

Daymark was not able to analyze and determine Injury Reduction due to delayed AMI, DACR, and VVO deployment, and due to a lack of granular data on vehicle accident costs. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- AEP should track vehicle accident and OSHA incident cost details based on labor activity. Additionally, the Company should track insurance cost reductions for labor and vehicles before and after AMI deployment. Costs should include the full cost of managing a safety incident (e.g. lost wages, vehicle loss/repair cost, internal review of incident, legal fees, insurance premium adjustments, etc.)

3.3.11 Remote Meter Diagnostics

AMI deployment provides AEP the ability to conduct real-time remote diagnostics of smart meters. Several departments will benefit from remote meter diagnostics, including system dispatchers that can reduce trouble truck dispatches when an issue is determined to relate to a specific customer meter. The Customer Service Representatives ("CSRs") also benefit from smart meters as they diagnose customer complaints not easily addressed by the call center. These typical issues include high/low bills, incorrect billing parameters (tariffs, taxes, third party, name change, address change, etc.), and inspection or site visits that result in CSRs going to the customer's property to check for an issue. AEP further explained that many of the issues they deal with are related to power quality. Since Traditional meters do not have the same capability as AMI meters to provide CSRs more information about an issue, they would previously have to physically investigate problems, and in many cases, they would also send a trouble truck to investigate the issue as part of the investigation process. AMI meters allow for real-time remote diagnostics that can help CSRs determine if a meter is operating normally, which reduces the need to send a trouble truck or a CSR to investigate. This benefit, shown in Line 14 of Table 4, is a Daymark added "Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

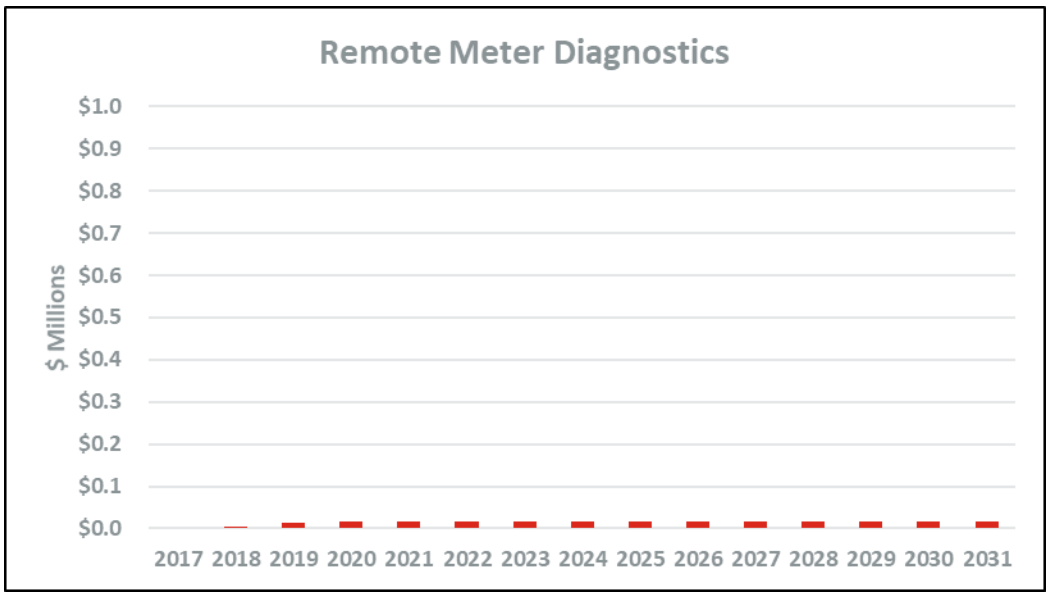

Figure 13: Remote Meter Diagnostics – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing benefits detailed in Attachment C. If it was included, AEP would have likely compared the annual department budget against pre-deployment budget. We did a similar analysis and found a lot of noise in the budgets, especially in recent years.
- **Daymark Analysis** – This benefit captures labor costs associated with the elimination of some investigation orders for inspection or site visits. Remote Meter Diagnostics is a function of avoided site inspections, site inspection time, loaded labor rate, and labor rate increase.
  - Annual *avoided site inspections* due to remote meter diagnostics were determined by estimating the number of avoided site inspections by CSRs. Daymark used monthly data from 2017 to estimate a typical year's site inspections before AMI (data prior to October 2016 was not available).[110] This is a reasonable baseline because Phase 2 AMI installations in 2017 started occurring in July and were still ramping up during the rest of the year. After establishing the baseline, the 2018 site inspections were compared to it and the reduced amount was assumed to be due to smart meters. The avoided site inspection annual total was used for each year of the

[110] AEP Ohio response to Staff DR 10-001a, Confidential Attachment.

forecast, which is a conservative approach as it would likely increase with full deployment. For 2017 the value was assumed to be zero, since this was the baseline year. For 2018 and 2019, the rate of AMI was multiplied by the avoided site inspections to provide a discount until full deployment. For 2020 and after, the full amount of avoided site inspections was used.

- The *site inspection time* spent is assumed to be one hour per visit. This was determined from review of industry data and confirmed in discussion with the Commission Staff. This may be a conservative view though because the reason for the site visit will have a major impact on the time spent there, in addition to any travel time.
- *Loaded labor rate*, using 2018 as the base cost year, a Meter Specialist fully loaded labor rate was used as a proxy for the CSR loaded labor rate.[111] Note that this value includes vehicle costs.
- *Labor rate increase* was assumed to be the historical average annual rate increase for a Meter Specialist for the 2014 to 2018 period.[112]

- **Industry Benchmark** – In addition to analyzing AEP's data, we analyzed other utilities in Ohio[113] as a reasonableness check against our analysis. We found that over a similar 15-year period the benefit estimates developed by other Ohio utilities were much higher than ours. Part of the reason is because of the delay in deployment, which means current data is not sufficient and is conservative for use in projecting future benefits. We also note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was able to analyze and determine a conservative savings estimate for Remote Meter Diagnostics. However, the savings estimate was conservative due to delayed AMI deployment and lack of more granular data regarding site inspections. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

[111] AEP Ohio response to Staff DR 02-026, Confidential Attachment 3.

[112] AEP Ohio response to Staff DR 04-002c, Confidential Attachment.

[113] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

- CSR investigation coding should be more detailed to include accounting for different reasons for a site inspection. CSR hours (time on-site and opening and closing the ticket related to the visit) and miles related to each site inspection should be tracked. Labor and time (time on-site and opening and closing the ticket related to the visit) per site inspection for trouble trucks sent out by CSRs should be tracked.

3.3.12 Meter Salvage Value

When Traditional meters are exchanged for smart meters, some of them can be refurbished and redeployed, albeit in another operating company's footprint, as indicated by AEP. The remaining Traditional meters will be scrapped and salvaged for scrap metal, which will increase AEP's revenues. This is only a benefit following the deployment of smart meters and will end after all smart meters have been deployed. This benefit, shown in Line 19 of Table 4, is a Daymark added "not Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

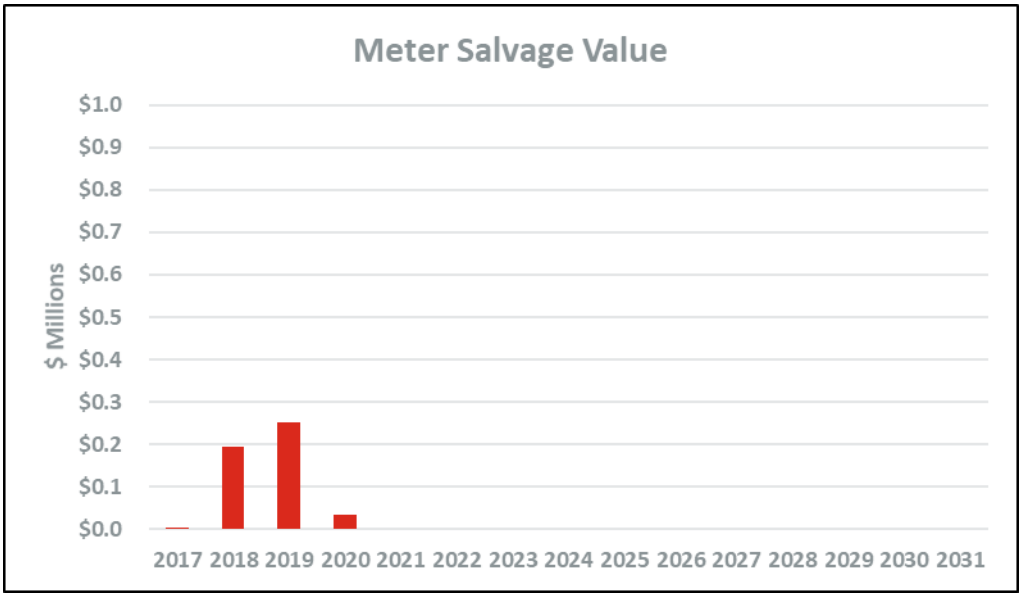

Figure 14: Meter Salvage Value – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing detailed in Attachment C. In the non-financial metrics that AEP and the Commission

Staff agreed upon, AEP is tracking the monthly and yearly number and dollar value for meters salvaged and transferred to other AEP operating companies outside of Ohio.

- **Daymark Analysis** – This benefit captures meter salvage and transfer revenues. Meter Salvage Value is a function of meters removed from Phase 2 premises and sent to salvage, dollar value of meters removed from Phase 2 premises, meters transferred from Phase 2 premises to other AEP operating companies, and dollar value of the meters transferred to other AEP operating companies.
  - AEP provided monthly data from 2016 through 2018 for *meters sent to salvage* and the *dollar value of those salvage meters*.[114] The original salvage value for the Phase 2 meters was $0.86 per meter, but the value was reduced to $0.45 per meter in October 2018 by the scrap vendor.
    - For 2019 and 2020, the only years where calculating a meter salvage value is possible, we used the difference in percent of AMI meters left to deploy each year from 2018 through 2020 to calculate an escalator to the number of meters that would be salvaged in 2019 and 2020. The $0.45 salvage value was multiplied by the number of salvaged meters to estimate the revenue increase to AEP each year.
  - AEP provided monthly data from 2016 through 2018 for *meters transferred from Phase 2 premises* to other AEP operating companies and the *dollar value associated with those transferred meters*.[115] The transfer value was determined by analyzing the dollar per meter values each month. Over time the value has fluctuated a bit, but at the end of 2018, the value was about $73 per meter.
    - For 2019 and 2020, the only years when calculating a meter transfer value is possible, we used the difference in the percent of AMI meters left to deploy each year from 2018 through 2020 to calculate an escalator to the number of meters that would be transferred in 2019 and 2020. The $73 transfer value was multiplied by the number of transferred meters to estimate the revenue increase to AEP each year.
  - Together these increased revenues were totaled each year for actuals in 2017 and 2018 and forecast in 2019 and 2020.

[114] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix D and Staff DR 02-031, Attachment 1.

[115] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix E and Staff DR 02-031, Attachment 1.

- **Industry Benchmark** – In addition to analyzing AEP's data, we analyzed other utilities in Ohio[116] as a reasonableness check against our analysis. We found that over a similar 15-year period the benefit estimates were a bit higher at the other utilities. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was able to analyze and determine a savings estimate for Meter Salvage Value. As this benefit will go away once AEP reaches full deployment, we do not recommend that AEP track any additional data to better capture the future benefits of Phase 2 deployment.

3.3.13 Meter Accuracy Improvement

Smart meters are more accurate than analog meters because they do not have moving parts and they can correct for temperature-related errors using algorithms. Analog meters are likely to under- or over-report usage, which will lead to inaccurate billing. Smart meters will lead to more accurate billing, including reduction in estimated bills and No-Bill Workflows, as discussed earlier under Billing Labor Benefits. This benefit, shown in Line 20 of Table 4, is a Daymark added "not Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

[116] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

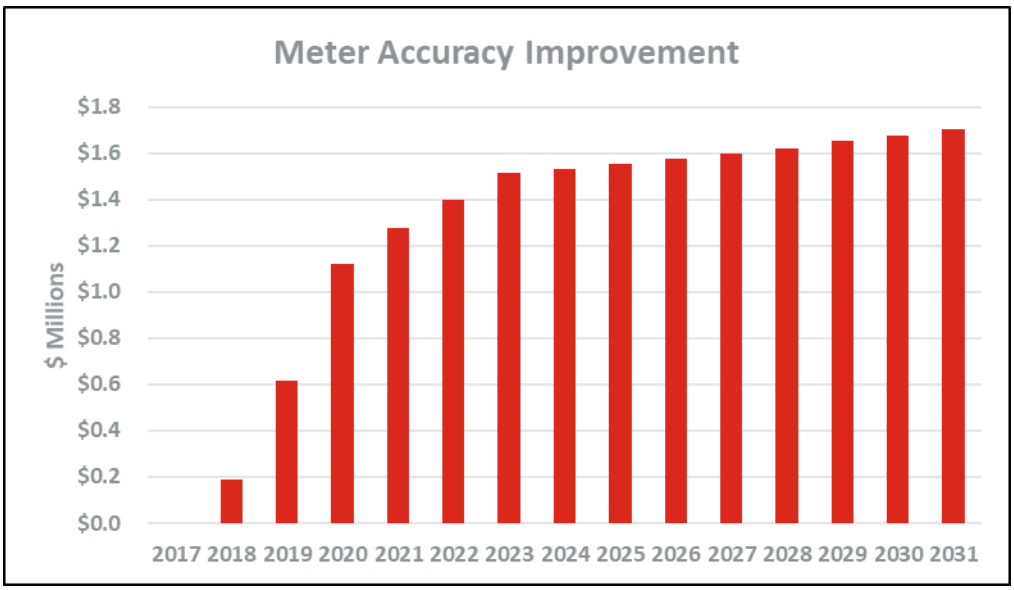

Figure 15: Meter Accuracy Improvement – Industry Benchmark

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing of benefits detailed in Attachment C. In the non-financial metrics that AEP and the Commission Staff agreed upon, AEP is tracking some data on certified meter failures for Phase 1 and Phase 2, which is the number of certified AMI meters that are removed due to defect, and successful AMI meter reads, which are actual meter reads within the Phase 2 area. This information is helpful for tracking meter accuracy improvement but could be additionally supplemented.
- **Industry Benchmark** – While we did not have specific analysis for this benefit, we analyzed other utilities in Ohio[117] to understand the expected benefit. Based on our review, with the completion of a meter accuracy study as discussed below, AEP is likely to find a significant future savings due to increased revenue. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

[117] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

Data Tracking Recommendations:

Daymark was not able to analyze and determine a savings estimate for Meter Accuracy Improvement. Additionally, these savings may be tied to Billing Labor Benefits. Therefore, Daymark recommends the following study be performed to allow for estimation of the benefits of Phase 2 deployment.

- The Company should have their meters independently tested to determine the expected improvement in the accuracy of AMI meters over the Company's Traditional meters. Then it should apply the results of this testing to the aggregate monthly usage by original meter type since post-AMI deployment to estimate of the value of meter accuracy improvements.

3.3.14 Outage Reductions – Revenue Impact

Implementation of gridSMART® investments will enable AEP to increase revenue collected from customers that would have otherwise been left without service due to outage events. When DACR is successful, customer minutes of interruption will be reduced or even eliminated for some customers. This occurs through fault isolation from the reclosers reducing the number of customers impacted by an outage. This benefit, shown in Line 21 of Table 4, is a Daymark added "not Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

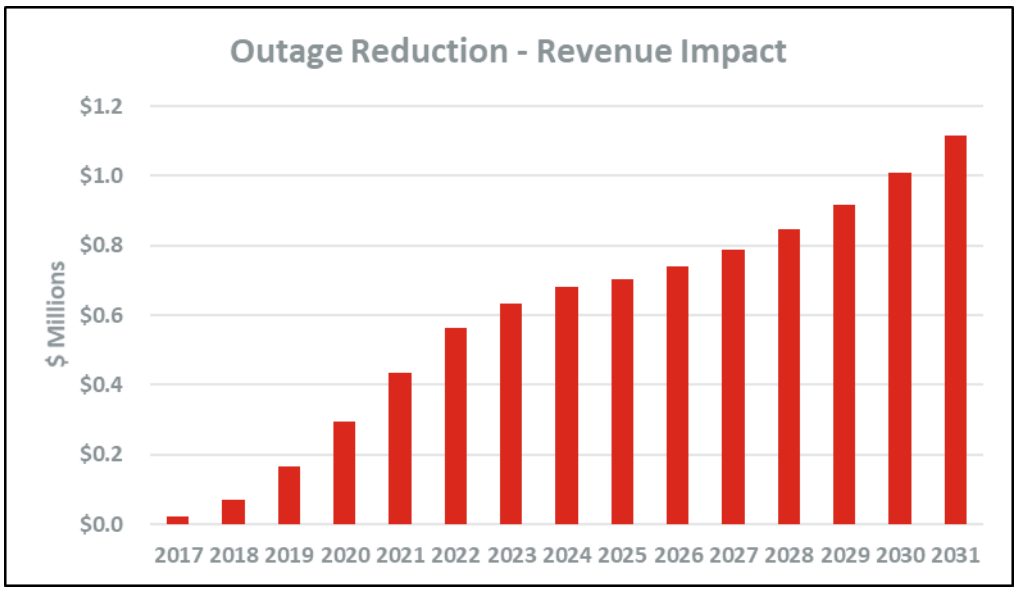

Figure 16: Outage Reductions – Revenue Impact – Industry Benchmark

Calculation:

- **Industry Benchmark** – AEP only includes a customer benefit driven by industry averages for outage costs for customers. They do not include the benefit from increased revenue driven by reduced outage minutes. We were not able to calculate this benefit because AEP is not tracking the granular data needed to determine the revenue impacts. Additionally, DACR deployment for Phase 2 has been delayed, as AEP has been more focused on VVO installations. Future revenue benefits from DACR-enabled circuits will be further delayed until AEP ramps up deployment. While we did not have Company specific data for this benefit, we analyzed other utilities in Ohio[118] to get a sense of the potential value. Based on our review, AEP is likely to find a significant future savings due to increased revenue once they are tracking the data necessary to calculate this benefit. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

AEP is currently tracking data on DACR circuits related to successes and failures when DACR had the opportunity to work. Additionally, the Company tracks data for Phase 1

[118] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

DACR circuits including the number of customers and outages that have been avoided due to DACR. In some of our other analysis on outage reductions, we made some assumptions about the cost impact of an outage to customers. While this analysis looked at the customer perspective, if AEP were to track avoided outage data by customer class and other restoration time data per outage event on DACR circuits, they could calculate the revenue impacts associated with those avoided customer outages.

3.3.15 Outage Detection and Verification

As AMI and DACR are deployed throughout the Phase 2 area, AEP will have a better ability to detect the extent of a customer outage. Using smart meters to provide real-time readings and real-time sensing technology on circuits, assessors can more quickly determine areas still experiencing an outage and areas where power has been restored, which reduces assessment time and therefore labor hours. Similarly, with the deployment of DACR, maintenance and outage crews can more quickly identify and verify failures, which reduces labor and other associated costs (e.g., vehicle costs). This benefit, shown in Line 15 of Table 4, is a Daymark added "Rider eligible" benefit. However, because there is currently not enough meaningful data available to calculate all the estimated savings associated with this benefit, it will not impact the Rider until AEP implements the recommendations below.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

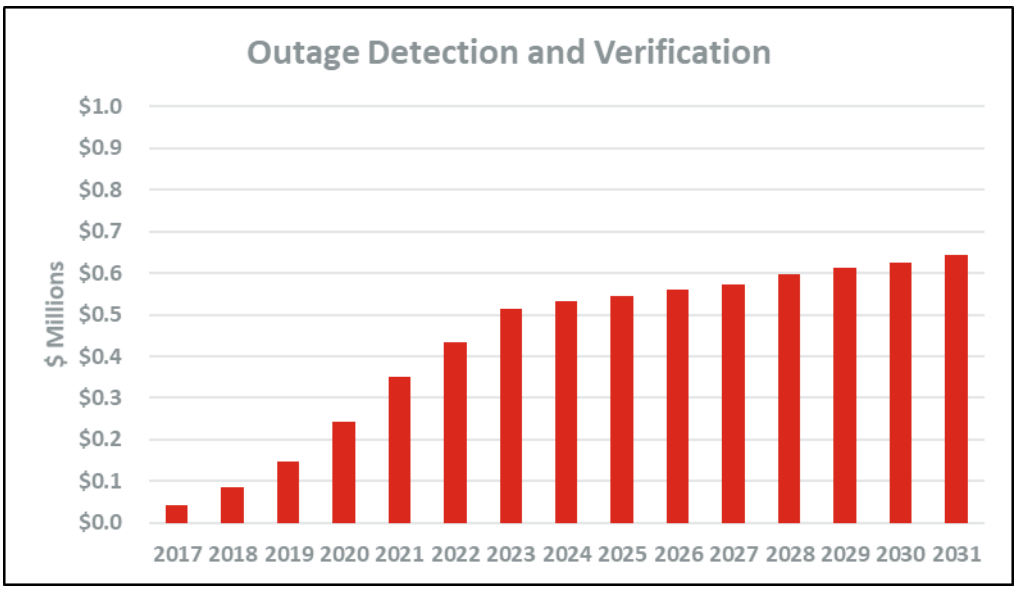

Figure 17: Outage Detection and Verification – Industry Benchmark

Calculation:

- **AEP Proposed Calculation** – AEP only includes a customer benefit for outage reduction in the Phase 2 gridSMART® application. Outage detection and verification savings are not considered. DACRs can assist in fault isolation by automatically detecting fault conditions and strategically rerouting the paths of electricity within the electrical grid. With this implementation, sustained outages (outages lasting greater than five minutes) can be reduced across distribution circuits, while utilities can directly address the isolated outages.

- **Daymark Analysis** – Daymark recommends recognizing the cost savings associated with labor and truck rolls for outage assessments (detection and verification) and restoration phases. Daymark defines the outage assessment phase as the initial phase in an outage response. Utilities without distribution automation require utility personnel to identify, detect, and verify outages across their circuits. Additional personnel are deployed depending on the magnitude of the outage event. With automation, in the presence of DACR across some distribution circuits, utilities like AEP can reduce or eliminate this phase and hence avoid labor and vehicle costs associated with outage assessments. Though outage restoration is the central focus of an outage response, with DACR, the Company can determine the avoided labor costs for restoration of circuits due to

automatic switching. To determine outage reductions and savings associated with truck rolls, Daymark used the following process.

- Daymark used data collected from AEP to isolate the number of switching events that were involved in all outages identified on DACR-enabled circuits.[119]
- Using this post-DACR implementation outage data, Daymark classified the switching events as *'with DACR'* and *'without DACR'* scenarios. The 'with DACR' scenario considered actual outages and remote switching. The 'without DACR' scenario assumed individual outages due to no automatic switching. This scenario assumed the absence of DACR on deployed circuits.
- AEP's Phase 1 DOE report stated that the Company was quantifying the number of truck rolls avoided by "*counting the number of remote switching operations and assigning each as either a short or standard truck roll*."[120] Standard truck rolls represent a crew traveling from the service center to the outage location, while short truck rolls represent a crew traveling from one switching location to another.
  - Since the outage events data provided by the Company did not include more granular data on outages (e.g., timestamp surrounding the recloser switching events), Daymark assumed that all avoided truck rolls would be attributed to short truck rolls.
- Daymark quantified the *vehicle and labor costs* associated with the truck rolls in both the 'with DACR' and 'without DACR' scenarios. Labor and vehicle costs for standard and short truck rolls were taken from the Phase 1 DOE Report and escalated for *inflation*.[121]
- The savings between the two scenarios was calculated historically for the years 2017 and 2018. For future years, Daymark assumed an average benefit per DACR circuit, which was calculated by averaging the outage reduction benefits in 2017 and 2018 after they were divided by the number of active DACR circuits. This average benefit was applied to the DACR deployment schedule and adjusted for inflation.

[119] AEP Ohio responses to Staff DR 02-061, Attachment, and Staff DR 04-026a, Attachment A.

[120] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy ("DOE") Smart Grid Demonstration Project ("SGDP") Contract Award Number DE-OE000193, June 2014, p. 185.

[121] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

- Our calculated yearly benefits came out lower than would reasonably be expected. There is likely insufficient data available for this assessment and that is impacting the results; with better granular data, future benefits related to avoided truck rolls can be calculated.

- **Industry Benchmark** – We analyzed other utilities in Ohio[122] to better understand the expected benefit from Outage Detection and Verification. Based on our review, AEP is likely to find some future savings from avoiding outage-related truck rolls once they are tracking the data necessary to calculate this benefit. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

With respect to Daymark's approach to estimating benefits, calculation of truck roll savings would be an added benefit to the overall operational savings. By specifically monitoring the actions performed in automatic switching across DACR-enabled circuits, the Company can evaluate the potential savings in dispatching additional outage restoration crews.

Additionally, for each outage event, by accurately sub-classifying the outage response time and outage restoration time, the Company can include the labor cost savings associated with elimination of outage restoration with DACR. The labor cost savings in addition to the above-described truck roll savings could provide significant additional benefits to the Company with respect to outage reductions from DACR installations.

Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- In its data collection for each outage event, the Company should sub-classify the time and personnel required under both the outage assessment phase and outage restoration phase.

- AEP should examine outage events on DACR-enabled circuits, by comparing the pre-DACR outage assessment and restoration durations with post-DACR durations.

[122] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

3.3.16 Continuous Voltage Monitoring

As more circuits become VVO-enabled, AEP will have improved ability to automate voltage monitoring for low voltage situations. This will reduce employee field time associated with performing this function. This benefit, shown in Line 16 of Table 4, is a Daymark added "Rider eligible" benefit. However, because there is currently not enough meaningful data available to calculate all the estimated savings associated with this benefit, it will not impact the Rider until AEP implements the recommendations below.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

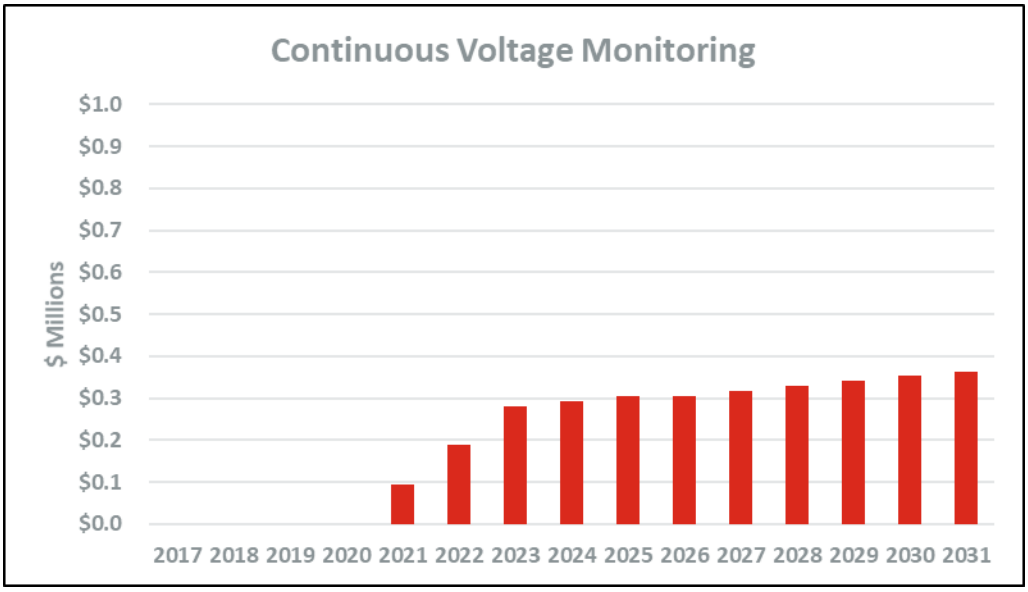

Figure 18: Continuous Voltage Monitoring – Industry Benchmark

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing of benefits detailed in Attachment C, which only included customer benefits from VVO. This operational benefit is a function of field time associated with low voltage monitoring, labor rate, and labor inflation rate. AEP does not sufficiently track employee activity related to this function and would likely explain that any savings would just be a shift to other required work.

- **Industry Benchmark** – While we did not have specific analysis for this benefit, we analyzed other utilities in Ohio[123] to understand the expected benefit. Based on our review, AEP is likely to find some future savings due to continuous voltage monitoring once they are tracking the data necessary to calculate this benefit. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was not able to analyze and determine a savings estimate for Continuous Voltage Monitoring. Therefore, Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

The Company should track time and labor costs associated with voltage monitoring that would be reduced due to automation.

3.3.17 Capacitor Inspection Costs

Capacitor banks are typically inspected annually on a rotating basis. Technology deployed through gridSMART® should lead to reduced visual inspections, as the new capacitor bank controllers and communication modems can be leveraged to produce alarms and reports when issues arise. Since these alarms can be generated in close to real-time, on-site inspection costs should be reduced. This benefit, shown in Line 17 of Table 4, is a Daymark added "Rider eligible" benefit. However, because there is currently not enough meaningful data available to calculate all the estimated savings associated with this benefit, it will not impact the Rider until AEP implements the recommendations below. It should be noted that in order to capture this benefit, which is avoiding physical inspections of capacitors, a modification of the Ohio Administrative Code Rule 27 may be necessary.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

[123] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

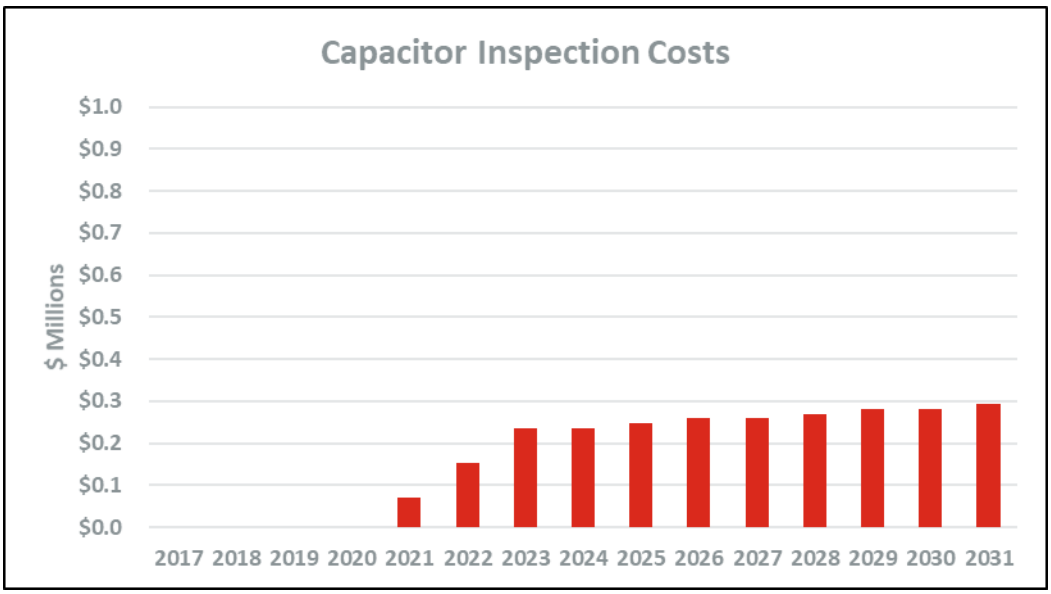

Figure 19: Capacitor Inspection Costs – Industry Benchmark

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing detailed in Attachment C. This benefit is a function of field time associated with on-site capacitor inspections, labor rate, and labor inflation rate. The only data related to these costs that AEP was able to provide us showed stable inspection costs year over year from 2008 through 2018.[124] These budget level costs should be reduced over time as more circuits are equipped with near real-time monitoring. Currently though, there is no discernable budget reduction outside of the early years (2008 and 2009) actual costs related to capacitor inspections. AEP, however, did provide a list of alarms[125] that have been added to the SCADA to improve visibility of the system to the system operators.
- **Industry Benchmark** – While we did not have specific analysis for this benefit, we analyzed other utilities in Ohio[126] to understand the expected benefit. Based on our review, AEP is likely to find some future savings due to reduced capacitor inspection costs once they are tracking the data necessary to calculate this benefit. We note that

[124] AEP Ohio response to Staff DR 09-007.

[125] AEP Ohio response to Staff DR 08-003.

[126] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

Daymark was not able to analyze and determine a savings estimate for Capacitor Inspection Costs. Therefore, Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- AEP should continue tracking detailed budget level data regarding capacitor inspections, and report them on an annual basis, separate from the detailed budgets and grossed up for all costs that should be reviewed for savings. While the project identifier in the budgets appears to be clear, the activity codes are not as clear for how this benefit would be calculated.

3.3.18 Circuit Breaker Inspection Costs

Circuit breaker inspections are needed on modern circuit breakers because they are located inside substations without the ability to communicate. As these old breakers are replaced, remote analysis of these circuit breakers will eliminate the need for physical inspections. This benefit, shown in Line 18 of Table 4, is a Daymark added "Rider eligible" benefit. However, because there is currently not enough meaningful data available to calculate all the estimated savings associated with this benefit, it will not impact the Rider until AEP implements the recommendations below.

The figure below shows the expected value for this benefit calculated using the Industry Benchmark methodology described below.

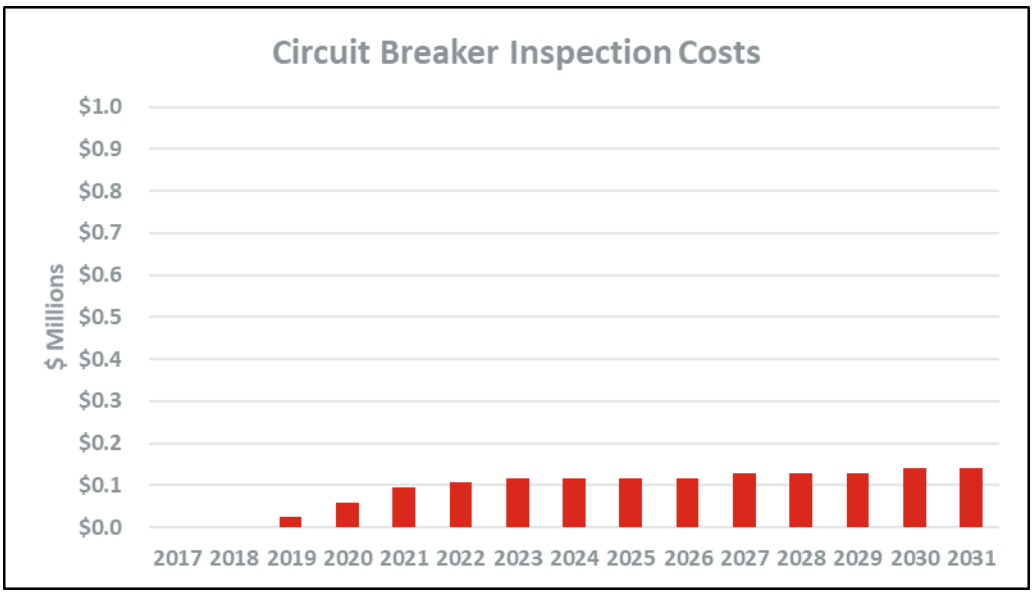

Figure 20: Circuit Breaker Inspection Costs – Industry Benchmark

Calculation:

- **AEP Proposed Calculation** – This benefit was not included in AEP's Phase 2 Filing of benefits detailed in Attachment C. This benefit is a function of field time associated with on-site circuit inspections, labor rate, and labor inflation rate. When asked to provide these costs, AEP did not provide any data and did not indicate that these costs are available. It is possible that these costs are included in the capacitor inspection costs.
- **Industry Benchmark** – While we did not have specific analysis for this benefit, we analyzed other utilities in Ohio[127] to understand the expected benefit. Based on our review, AEP is likely to find some future savings due to reduction in circuit break inspection costs once they are tracking the data necessary to calculate this benefit. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

[127] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

Data Tracking Recommendations:

Daymark was not able to analyze and determine a savings estimate for Circuit Breaker Inspection Costs. Therefore, Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- The Company should track detailed budget-level data regarding circuit breaker inspections and report them on an annual basis, separate from the detailed budgets and grossed up for all costs that should be reviewed for savings.

3.3.19 System Fine Tuning

Transmission and distribution losses contribute to a measurable portion of energy lost between electric generation and utility customer consumption. The installation of VVO across distribution circuits helps to reduce the reactive power requirements at the customer-level by flattening the voltage profile of these circuits. This in turn helps to reduce distribution losses across these circuits. This benefit, shown in Line 22 of Table 4, is a Daymark added "not Rider eligible" benefit.

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

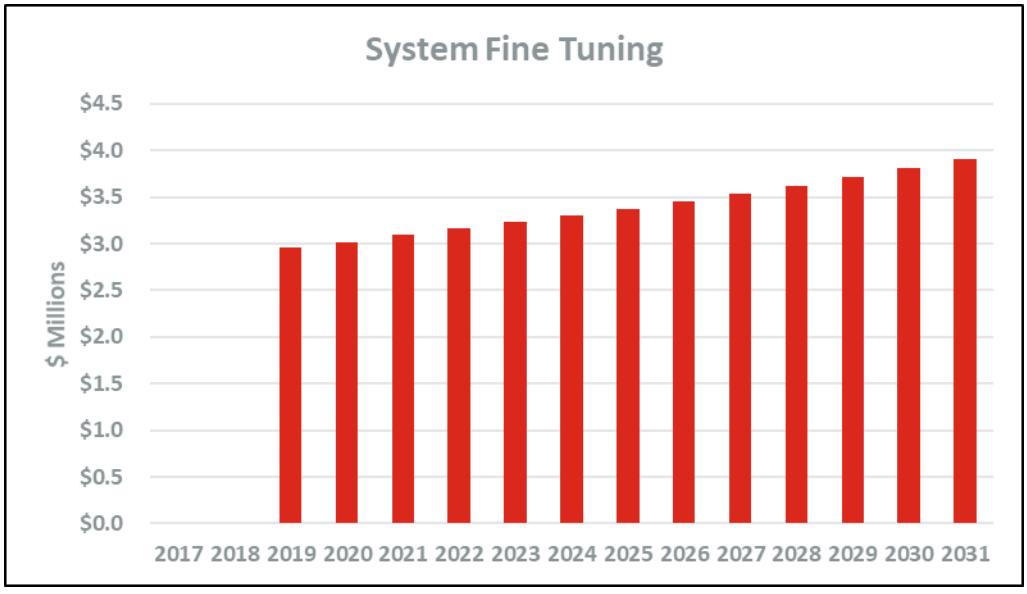

Figure 21: System Fine Tuning – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** - This benefit was not included in AEP's Phase 2 Filing detailed in Attachment C. However, Daymark recommends calculation of System Fine Tuning benefits to determine the savings associated with loss reduction and the O&M circuit monitoring costs.

- **Daymark Analysis** – This benefit is a function of energy savings resulting from VVO (measured by comparing a 'with VVO' scenario to a 'without VVO' scenario), system loss factor, and inflation. Daymark performed the following high-level steps to determine System Fine Tuning benefits.

  - Daymark reviewed the circuit performance data provided by the Company.[128] The data included average and peak active power (kW) and apparent power (kVA) flows across VVO-enabled circuits between 2015 and 2018. The average circuit flows were used to estimate energy flows on these VVO-enabled circuits for the given time period (2015-2018). These energy flows were used to create a 'with VVO' scenario.

  - From the Company's data on losses across its transmission and distribution system, Daymark assumed a 5.52% *loss factor* on distribution circuits.[129] Daymark used this loss factor assumption to calculate *losses on VVO-enabled circuits for the 'with VVO'* scenario.

  - The Company provided a 3% energy savings estimate from its workpapers for Phase 1 VVO installation and from the Phase 1 DOE Report. To create a 'without VVO' scenario, Daymark back-estimated energy flows by removing this 3% energy savings from the data for these VVO-enabled circuits.

  - Similar to the previous scenario, using the back-estimated energy flows and the 5.52% loss factor on distribution circuits, Daymark calculated the *losses on VVO-enabled circuits for the 'without-VVO'* scenario.

  - Using the marginal loss component data provided by the Company, Daymark calculated the cost of line losses under 'with VVO' and 'without-VVO' scenarios.

  - For future years, Daymark assumed that the energy flows on the Company's system follow the system demand growth trend as forecasted by the Company in the

[128] AEP Ohio response to Staff DR 04-022e, Attachment.

[129] AEP Ohio – Ohio Power Rate Zone, Delivery Loss Factors, Effective 8-8-2018. https://www.aepohio.com/account/service/choice/cres/tariffs.aspx.

System Forecast Study.[130] Loss savings were determined as described-above for future years and included an escalator for *inflation*.[131]

- **Industry Benchmark** – As a check against our analysis, we analyzed other utilities in Ohio[132] to understand the expected benefit. Daymark's estimate comes in higher than the other benchmark utilities, but we still find it reasonable using the data AEP provided and applying the assumptions and formula discussed above. We note that the utilities reviewed had different deployment amounts and technologies, which impacts the comparison.

Data Tracking Recommendations:

While Daymark was able to analyze and determine a savings estimate for System Fine Tuning, the calculations relied on a 3% reduction estimate from Phase 1. Daymark recommends that AEP track the following information to better capture the future benefits of Phase 2 deployment.

- AEP should review assumptions, and update where necessary, for the energy savings estimate on VVO-enabled circuits to determine the loss savings associated with Phase 2 VVO installations.

3.4 Audit Findings

As it relates to AMI, DACR, and VVO, these technologies have demonstrated the ability to achieve substantial positive impacts on the grid in addition to providing significant benefits to utilities. Over the course of this audit, estimating the operational benefits portion was hampered by the limited number of actual DACR and VVO deployments and by the difficulty of extracting meaningful information from the Company's accounting and operational databases. As a result, not all operational benefits evaluated by Daymark were able to be quantified in this audit. Many of the benefits quantified by Daymark for DACR and VVO either accrue as customer benefits ("not Rider eligible") or are "Rider eligible", but without meaningful data to calculate the benefits.

[130] AEP Ohio response to Staff DR 05-003.

[131] Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

[132] Duke Energy Ohio Grid Smart Audit and Assessment, prepared by MetaVu, Inc., June 30, 2011. First Energy Companies, Operational Benefits of the Smart Grid, Confidential – Prepared for Settlement Purposes Only, September 11, 2018.

Consistent with regulatory guidance and the expectation that the great majority (estimated at 90%[133]) of the benefits will accrue directly to customers in the form of fewer and shorter power outages as well as decreased energy consumption, the Company's focus throughout Phase 2 has been more on implementation and execution rather than measuring the operational benefits achieved. This is especially true for both DACR and VVO. Going forward, Daymark recommends the following data tracking improvements for the Company to be better positioned to measure the full suite of benefits derived from gridSMART® technology investments.

- ***Meter Reading and Operational Labor Savings***. Monthly and yearly meter reading routes per meter reader, per district, as well as the number of meter reads per route, per district.
- ***Reduction in Uncollectible Revenue Through Use of Remote Disconnect.*** Monthly and yearly uncollectible amount (uncollectible expense from factored receivables, which are based on a 12-month rolling average of net charge offs). This data should include uncollectible revenue associated with each rate class and should be tracked with and without the PIPP program by district.
- ***Reduction in Theft***. Monthly and yearly power theft cases and monetary value per case. Breakout power theft cases by meter type in the Phase 2 area. Track the investigation costs associated with each case separately. Track case timelines, i.e., from when case was opened for investigation to when it was closed and customer was invoiced.
- ***Reduction in Consumption on Inactive Meters***. Monthly and yearly consumption for connected meters on inactive accounts. Breakout consumption by meter type in the Phase 2 area.
- ***Customer Savings Associated with VVO***. Update energy price and capacity price forecasts for the 'AEP Gen Hub' for future assessments. Identify drivers of energy savings, including their contributions to energy usage on given circuits and classify all factors that drive peak load reductions across circuits, including demand-side measures implemented by customers. Additionally, to verify the benefits of VVO, AEP could compare feeders or circuits with strongly-correlated load patterns using one as the baseline control while VVO is added to the other. Alternatively, and at a

[133] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

minimum, more explicit weather-adjusted accounting needs to be taken of hourly circuit voltages and power factor correction both before and after VVO deployment.

- ***Billing Labor Benefits***. Hourly rate and time data for billing department employees that indicates time spent on calls, No-Bill Workflows, Bill Warning Workflows (data is needed by type – i.e., Zero Use Workflows, Excess Use Workflows, Budget Workflows, and Seasonal Use Workflows), and any other types of activity codes that apply to the billing department. Staff should include Core Billers, Non-Core Billers, Billing trainees, supervisors, and any other staff not included here.

- ***Call Center Labor Benefits***. Hourly rate and time data for call center employees that indicates time spent on calls, type of call, customer meter type, non-AEP Ohio call center calls, and any other types of activity codes that apply to the call center. Staff should include all call center employees, including supervisors. Data collected should include AEP call centers and outsourced call centers.

- ***Injury Reduction***. AEP should track vehicle accident and OSHA incident cost details based on labor activity. Additionally, the Company should track insurance cost reductions for labor and vehicles before and after AMI deployment. Costs should include the full cost of managing a safety incident (e.g. lost wages, vehicle loss/repair cost, internal review of incident, legal fees, insurance premium adjustments, etc.)

- ***Remote Meter Diagnostics***. CSR investigation coding should be more detailed to include accounting for different reasons for a site inspection. CSR hours (time on-site and opening and closing the ticket related to the visit) and miles related to each site inspection should be tracked. Labor and time (time on-site and opening and closing the ticket related to the visit) per site inspection for trouble trucks sent out by CSRs should be tracked.

- ***Meter Accuracy Improvement***. The Company should have their meters independently tested to determine the expected improvement in the accuracy of AMI meters over the Company's Traditional meters. Then it should apply the results of this testing study to the aggregate monthly usage by original meter type since post-AMI deployment to estimate of the value of meter accuracy improvements.

- ***Outage Reduction – Revenue Impact and Detection and Verification.*** In its data collection for each outage event, the Company should sub-classify the time and personnel required to assess outages and restore service. Additionally, the

Company should examine outage events on DACR-enabled circuits, by comparing the pre-DACR outage assessment and restoration durations with post-DACR durations and tracking avoided outages by customer class.

- ***Continuous Voltage Monitoring***. The Company should track time and labor costs associated with voltage monitoring that would be reduced due to automation.
- ***Capacitor Inspection Costs***. AEP should track detailed budget-level data regarding capacitor inspections and report them on an annual basis, separate from the detailed budgets and grossed up for all costs that should be reviewed for savings. While the project identifier in the budgets appears to be clear, the activity codes are not as clear for how this benefit would be calculated.
- ***Circuit Breaker Inspection Costs***. The Company should track detailed budget-level data regarding circuit breaker inspections and report them on an annual basis, separate from the detailed budgets and grossed up for all costs that should be reviewed for savings.
- ***System Fine Tuning***. AEP should review assumptions, and update where necessary, for the energy savings estimate on VVO-enabled circuits to determine the loss savings associated with Phase 2 VVO installations.

3.5 Audit Recommendations

Daymark's evaluation of AEP's originally-filed Phase 2 operational benefit savings and estimation of operational benefits that are reasonably achievable through full deployment of Phase 2 leads us to recommend the following operational benefit savings be credited against the Rider for 2019 through 2021 (or the conclusion of the Company's next base rate case).[134]

Table 5: Operations Benefit Savings (Nominal $)

	2019	2020	2021
BENEFITS NETTED AGAINST RIDER ($M)	$6.8	$9.1	$9.4

Benefits that are defined as "Rider eligible" are operational savings that AEP experiences by deployment of gridSMART® technologies that are netted against the Rider. Other benefits discussed in Section 3 are "not Rider eligible" because they are direct customer benefits or will flow through to customers in other riders. Some of these other benefits,

[134] The nominal dollars each year in Table 5 are from the Daymark Analysis Lower Case estimated savings.

which were identified by AEP Ohio in its original business case, such as customer benefits (e.g., time-differentiated rates and reliability) or societal benefits (e.g., environmental) were not part of the scope of work as defined by the RFP and are therefore not included in this scope of work. We specifically define throughout Section 3 which operational benefits are classified as "Rider eligible" versus "not Rider eligible".

Prior to the effective date of the Company's next base rate case, most, if not all, AMI and VVO technology investments are expected to be deployed. Additionally, deployment of DACR circuits will be much further along. At that point, AEP can shift its focus from deployment to a more complete integration of systems and processes. If the real-time data reported from these technologies are better incorporated into current Company systems and potential future advanced systems (e.g., Advanced Distribution Management System), AEP will have the ability to identify more operational benefits. Therefore, we recommend that for years 2022 through 2031 the following operational benefit savings be credited against the Rider or successor recovery mechanism approved by the PUCO until such time that they are rolled into new base rates and the new base rates are in effect.[135]

Table 6: Operational Benefit Savings (Nominal $)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
BENEFITS NETTED AGAINST RIDER ($M)	$11.6	$11.9	$12.2	$12.5	$12.9	$13.2	$13.6	$14.0	$14.3	$14.7

In the Appendix, we provide additional tables that detail the yearly estimated savings by methodology type for each operational benefit.

In addition to the operational benefits originally identified by AEP Ohio in its original filing, our analysis includes the following measurable operational benefits not previously identified by the Company, which are explained in more detail in Section 3:

- ***Remote meter diagnostics (avoided O&M cost)*** – labor and non-labor (e.g., truck rolls) savings associated with AMI capability to conduct real-time remote meter diagnostics. "Rider eligible."
- ***Meter salvage value (increased revenue)*** – savings obtained by refurbishing and redeploying Traditional meters across AEP corporate's operating companies or by salvaging scrap metal from meters that cannot be redeployed. "Not Rider eligible."

[135] The nominal dollars each year in Table 6 are from the Daymark Analysis Upper Case estimated savings.

- ***System fine tuning (capacity deferral and avoided fuel cost)*** – the installation of VVO across distribution circuits helps to reduce the reactive power requirements at the customer-level by flattening the voltage profile of these circuits. This in turn helps to reduce distribution losses across these circuits. "Not Rider eligible."

Our analysis also includes the following additional operational benefits not previously identified by the Company, which we were not able to measure based on the information provided by the Company. These operational benefits are also explained in more detail in Section 3:

- ***Meter accuracy improvements (increased revenue)*** - analog meters are likely to under- or over-report usage, which will lead to inaccurate billing. Smart meters will lead to more accurate billing. "Not Rider eligible."
- ***Outage reduction – revenue impact (increased revenue)*** – implementation of gridSMART® investments will enable AEP to increase revenue collected from customers that would have otherwise been left without service due to outage events. "Not Rider eligible."
- ***Outage detection and verification (avoided O&M cost)*** – as AMI and DACR are deployed throughout the Phase 2 area, AEP will have a better ability to detect the extent of a customer outage and more quickly determine areas still experiencing an outage and areas where power has been restored, which reduces assessment time and therefore labor hours. Similarly, maintenance and outage crews can more quickly identify and verify failures, which reduces labor and other associated costs (e.g., vehicle costs). "Rider eligible."
- ***Continuous voltage monitoring (avoided O&M cost)*** – as more circuits become VVO-enabled, AEP will have improved ability to automate voltage monitoring for low voltage situations. This will reduce employee field time associated with performing this function. "Rider eligible."
- ***Capacitor inspection costs (avoided O&M cost)*** – capacitor banks are typically inspected annually on a rotating basis. Technology deployed through gridSMART® should lead to reduced visual inspections, as the new capacitor bank controllers and communication modems can be leveraged to produce alarms and reports when issues arise. "Rider eligible."
- ***Circuit breaker inspections costs (avoided O&M cost)*** – circuit breaker inspections are needed on modern circuit breakers because they are located inside substations without the ability to communicate. As these old reclosers are replaced, remote analysis of these circuit breakers will eliminate the need for physical inspections. "Rider eligible."

In addition, due to inherent challenges in isolating the operational benefits of AMI, DACR, and VVO pre- and post-Phase 2 deployment, when comparing pre- and post-operational budgets as proposed by AEP Ohio as a verification method and where the Company noted no verification method possible, Daymark has recommended the use of alternative calculations for estimating benefits which formed the basis for calculating the operational benefits savings summarized above. Our alternative calculation recommendations, including details of specific data limitations by operational benefit, are provided in Section 3.

4. RELIABILITY AND ENERGY EFFICIENCY

4.1 Introduction

As part of the gridSMART® Phase 2 audit, Daymark examined reliability impacts associated with the deployment of DACR, which included review of annual reports that provide performance metrics on circuits that have DACR and circuits that do not. Additionally, we examined energy efficiency improvements associated with the development of VVO, and estimated reductions in greenhouse gas emissions, energy, and demand.

4.1.1 Reliability

Electric system reliability is impacted by factors that can be classified as internal or external. Internal factors include design, planning criteria, maintenance, and construction practices. External factors include weather, physical characteristics of the service territory (i.e., topography, geology, and geography), and the reliability of neighboring electrical systems. Internal factors are those that can be controlled by the utility and, if problems are identified, corrective actions taken. External factors are, by and large, beyond the control of the utility. These external factors are also a significant limiting factor to the usefulness of developing utility reliability comparisons. In general, each utility has a somewhat unique set of external factors that it must face in providing reliable electric service. For example, a utility that serves a sparsely populated area is likely to experience average outage durations that would be longer than a utility that serves a compact or densely-populated area. Conversely, each outage in a densely populated utility is likely to impact a greater number of customers than an outage on a rural system. In either case, the facility age, type of construction (especially overhead vs. underground), or engineering design practices significantly affect outage frequency and duration.

To minimize distortions from factors unrelated to DACR deployment, this audit focused on the reliability impacts before and after DACR deployment on both an overall average and individual circuit basis. Reliability benefits were assessed by reviewing the performance of key reliability metrics used by the Company to evaluate the reliability performance. These metrics include System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), Customer Average Interruption Duration Index ("CAIDI"), and Customer Minutes of Interruption ("CMI"). These types of metrics, albeit with some degree of variation in interpretation, are defined in the Institute of Electrical and Electronics Engineers ("IEEE") standard P1366

and are used by many utilities to measure the reliability of local or sub-transmission and distribution systems.[136] It is interesting to note that IEEE P1366 outlines more than 20 variations of reliability metrics, indicating a wide variety of possibilities when measuring reliability, however, the ones used by the Company and reviewed in this audit are among the most widely-used in the industry.

- **SAIFI** – Designed to give information about the average frequency of sustained interruptions per customer over a predefined area. It is computed by dividing the total number of customers interrupted in a year by the total number of customers served. It does not measure the number of times a particular customer or group of customers was interrupted but represents a system average.
- **SAIDI** – Designed to provide information about the average time that the customers are interrupted. This index is commonly referred to as Customer Minutes of Interruption or Customer Hours. It is a measure of the response time or restoration time when outages occur and is computed by dividing the sum of all customer interruption durations by the total number of customers served.
- **CAIDI** – Represents the average time required to restore service to the average customer per sustained interruption. It is computed by dividing the sum of the customer interruption durations by the total number of customer interruptions. Alternatively, it can also be calculated by dividing SAIDI by SAIFI.
- **CMI** – Represents the total number minutes of outage duration multiplied by the number of customers impacted by the outage.

4.1.2 Energy Efficiency

VVO is designed to realize a reduction in energy consumption and peak demand on circuits where it is deployed. Voltage standards exist in the electric utility industry, such as ANSI C84.1, that mandate an acceptable voltage range at the secondary or the distribution transformer.[137] VVO enables a reduction of the average voltage that each customer on the circuit receives, thereby reducing the annual energy consumption of the feeder while maintaining the quality of service to the end-use customer. Based on results obtained through field demonstrations, AEP Ohio estimates that a 3% reduction

[136] IEEE 1366-2012 – IEEE Guide for Electric Power Distribution Reliability Indices. https://standards.ieee.org/standard/1366-2012.html.

[137] American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz). https://www.nema.org/Standards/Pages/American-National-Standard-for-Electric-Power-Systems-and-Equipment-Voltage-Ratings.aspx.

in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on the circuits where the technology is deployed.

The Company has identified the impact of VVO deployment on energy efficiency under three metrics – capacity savings (peak demand reduction), energy savings, and system voltage reduction. Daymark performed a review of the data provided by the Company on each of these metrics. Detailed review of Daymark's analysis is available in the Non-Financial Metrics discussion of this report.

Our review of a number of industry studies performed by organizations like the Electric Power Research Institute ("EPRI"),[138] Environmental Protection Agency ("EPA"),[139] and the US Department of Energy[140] on VVO impacts indicated that on average, with VVO deployed, for every percent voltage reduction, energy consumption decreased 0.4 to 0.7 percent. The DOE study also identified an approximate 3.04% annual energy consumption reduction at the national level and around a 2.4% annual energy consumption reduction across high-value distribution feeders.

By monitoring the system voltage reduction with VVO installations, the Company can reasonably quantify the average energy and capacity reductions for the system.

To determine greenhouse gas emissions savings, AEP used the EPA Emissions & Generation Resource Integrated Database ("eGRID") study findings.[141] Daymark reviewed the data provided by the Company and updated our findings based on the most-recent EPA study.[142] The detailed review of Daymark's GHG analysis and recommendations are available in the Non-Financial Metrics discussion of this report.

[138] EPRI Study: https://www.smartgrid.gov/files/EPRI_Smart_Grid_Demonstration_Initiative_Three_Year_Update_201110.pdf

[139] EPA Study: https://www.energystar.gov/sites/default/files/asset/document/Volt%20Var%20and%20CVR%20EMV%20Best%20Practice%2006-01-17clean%20-%20508%20PASSED.PDF

[140] DOE Study: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf

[141] https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.

[142] AEP Ohio Response to Staff DR 04-022e.

4.2 Audit Methodology

This section describes Daymark's analysis of AEP's reliability metrics.

DACR Metrics

Generally, as is the case with AEP, major storm events are not included in reliability metrics; this is consistent with prevalent industry practice and storm events are therefore excluded from the computation of reliability benefits presented here. The Company had provided their outage records on a yearly basis for their Phase 1 DACR candidate circuits and included information such as: the number of customers served by that circuit, the number of outage records, the number of customers who were interrupted, and the Customer Minutes of Interruption.[143]

SAIFI

To replicate circuit performance without the installation of DACR, Daymark re-engineered the Company's approach by recording the avoided number of customers interrupted, the number of avoided occurrences, and the avoided Customer Minutes of Interruption data from the Company's outage records.[144] This data was then added on to the Company's reported reliability data and the circuit's reliability metrics were recalculated. SAIFI was determined using the following equation:

$$SAIFI = \frac{Number\ of\ Customers\ Interrupted}{Total\ Number\ of\ Customers\ Served}$$

Daymark observed an overall reduction in SAIFI, reduced by an average of 15% from 2011 to 2018.

[143] AEP Ohio response to Staff DR 02-057 and Staff 04-026.

[144] AEP Ohio response to Staff DR 02-061.

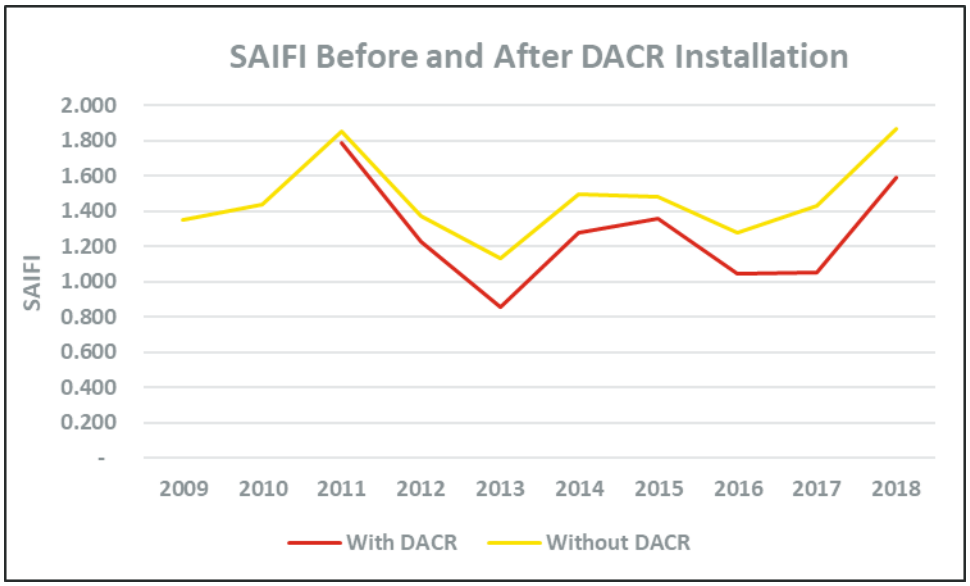

Figure 22: SAIFI Before and After DACR Installation

CAIDI

To replicate circuit performance without the installation of DACR, Daymark re-engineered the Company's approach by recording the avoided number of customers interrupted, the number of avoided occurrences, and the avoided Customer Minutes of Interruption data from the Company's outage records.[145] This data was then added on to the Company's reported reliability data and the circuit's reliability metrics were calculated again. CAIDI was calculated using the following equation:

$$CAIDI = \frac{Customer\ Minutes\ of\ Interruption}{Total\ Number\ of\ Interrupted\ Customers}$$

Daymark observed an overall increase in CAIDI, increasing by an average of 5% from 2011 to 2018.

[145] AEP Ohio response to Staff DR 02-061.

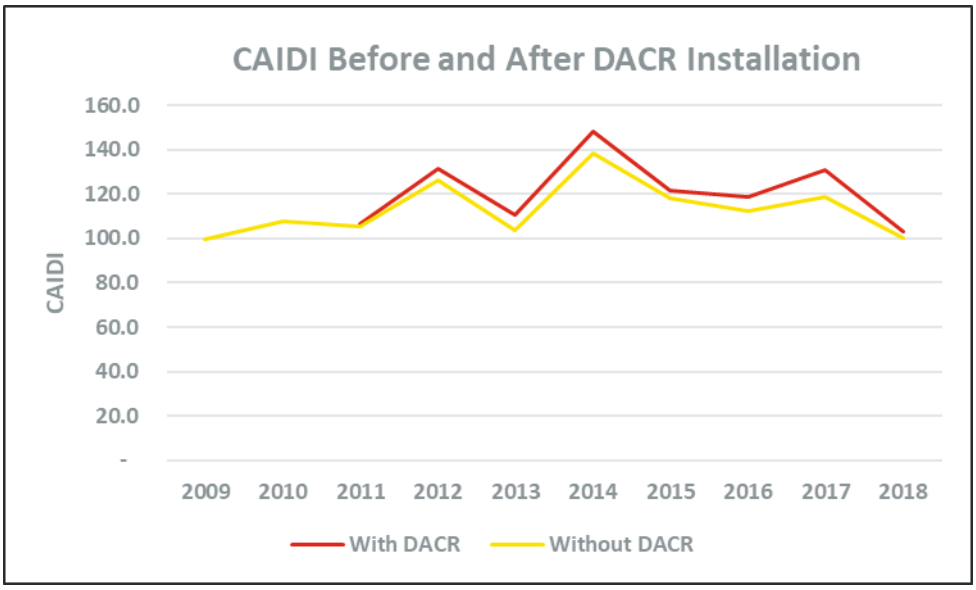

Figure 23: CAIDI Before and After DACR Installation

SAIDI

SAIDI was calculated using the following equation:

$$SAIDI = \frac{Customer\ Minutes\ of\ Interruption}{Total\ Number\ of\ Customers\ Served}$$

Daymark performed a similar analysis as before by comparing the data provided in the Company's Filing to the data from the Company's outage records.[146] The data from the outage records was then added on to the Company's reported reliability data and the circuit's reliability metrics were calculated again to get a measure of what SAIDI would be in a case where no DACR was present. Daymark observed an overall reduction in SAIDI by an average of 11% from 2011 to 2018.

[146] AEP Ohio response to Staff DR 02-057, Staff DR 02-061 and Staff DR 04-026.

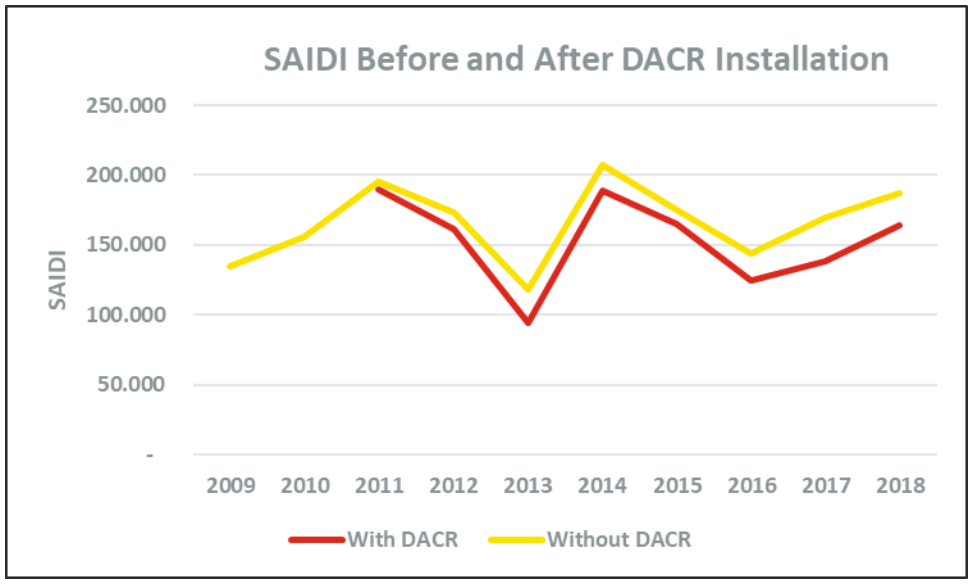

Figure 24: SAIDI Before and After Installation

CMI

CMI represents the total number minutes of outage duration multiplied by the number of customers impacted by the outage.

$$CMI = Total\ Outage\ Duration\ (in\ minutes) * Number\ of\ Interrupted\ Customers$$

To replicate circuit performance without the installation of DACR, Daymark re-engineered the Company's approach by recording the avoided number of customers interrupted, the number of avoided occurrences, and the avoided Customer Minutes of Interruption data from the Company's outage records.[147] This data was then added on to the Company's reported reliability data and the circuit's reliability metrics were calculated again. Daymark observed the CMI decreased overall by an average of 11% from 2011 to 2018.

[147] AEP Ohio response to Staff DR 02-061.

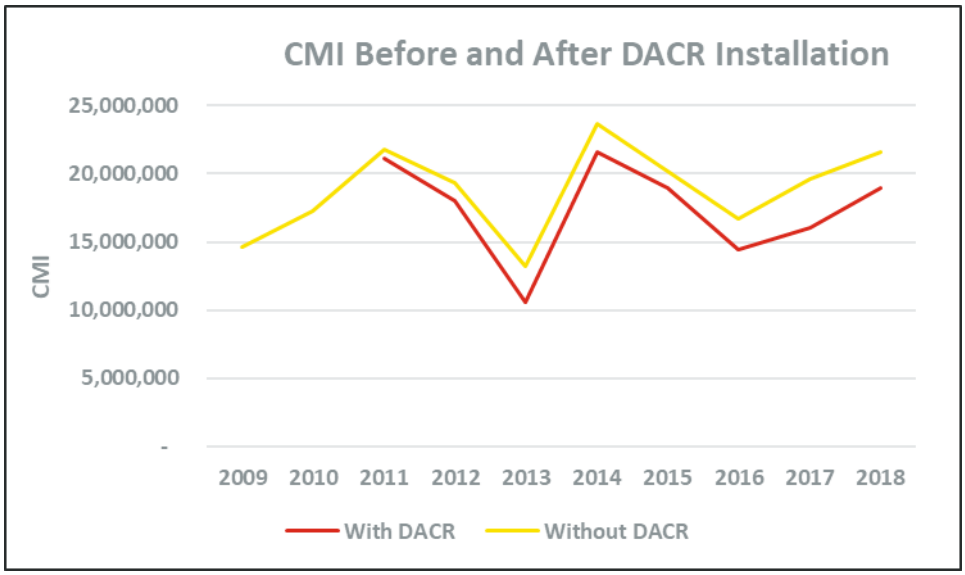

Figure 25: CMI Before and After DACR Installation

4.3 Reliability and Energy Efficiency Audit Findings

Overall, with only a few exceptions, reliability as measured improved with the deployment of DACR. Circuits where DACR was deployed showed a consistent, measurable reliability benefit in SAIDI, SAIFI and CMI, however, CAIDI did not improve in like fashion. SAIDI improved by 11%, SAIFI improved by 15%, and CMI improved by 11%. The only exceptions were circuits in Bexley, Genoa, and Jug Street where reliability, as measured by SAIDI and SAIFI, did not improve. A specific investigation into why was treated as beyond the scope of this audit. However, the limited nature of this contrary result suggests mitigating external factors as likely drivers.

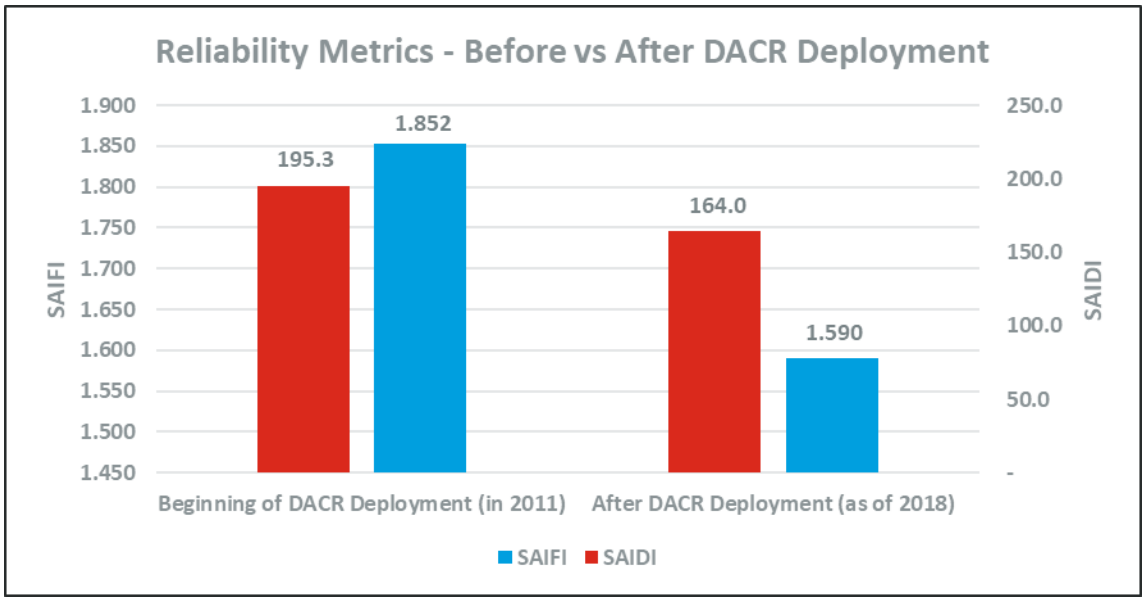

Figure 26: Reliability Metrics Before and After DACR Deployment

The lack of CAIDI improvement is understandable. DACR essentially all but eliminates the shorter-duration outages that would have previously (prior to DACR) been restored with manual switching, thereby leaving only the longer-duration outages, which would result in higher average durations for customers interrupted. As mentioned previously, of all the metrics tracked, CAIDI is the one most indicative of length of time customers who are interrupted are out of service. By eliminating the shorter outages, the overall average increases.

Noticeable by its absence, the Company does not track any reliability-based measures of power quality. One such metric from IEEE P1366 that merits consideration for future monitoring is the Momentary Average Interruption Frequency Index ("MAIFI").[148]

- **MAIFI** – This index is very similar to SAIFI, except that it measures the frequency of momentary interruptions instead of sustained interruptions. Momentary interruptions are those that result in zero voltage and are less than five minutes in duration. For example, two breaker or recloser operations equal two momentary interruptions. It is calculated by dividing the total number of customer momentary interruptions by the total number of customers served.

[148] IEEE 1366-2012 – IEEE Guide for Electric Power Distribution Reliability Indices. https://standards.ieee.org/standard/1366-2012.html.

Momentary interruptions can be as troublesome to customers as longer duration sustained outages and should be monitored. One unavoidable consequence of automated switching like DACR is an increase in momentary outage frequency. While generally trading a longer outage for a shorter one is a trade worth making, this may not hold in the extreme. If there is a significant increase in momentary outages, action needs to be taken to remedy the root cause of the problem. Monitoring a metric like MAIFI would help ensure persistent problems are identified before they become a longer duration outage.

4.4 Reliability and Energy Efficiency Audit Recommendations

In addition to the operational benefits identified in the previous section, Daymark identified a few valuable reliability-based metrics that could be used to monitor and identify benefits to the Company through the deployment of DACR and VVO across its circuits through Phase 2 of the gridSMART® program. The additional operational reliability metrics that Daymark suggests be monitored for future evaluations include:

- Reactive Support Device Status
- Circuit Voltage and Power Factor
- Transformer Health

Each of these are described in the remainder of this section.

Reactive Support Device Status

Reactive support devices such as capacitors and reactors are integral to the distribution system and help to maintain desired voltage profiles across various circuits. In a traditional system without VVO, reactive device control is not feasible and voltage control across each capacitor/reactor-enabled circuit is independent.

With implementation of VVO across its distribution circuits, the Company can dynamically control these reactive support devices and help to efficiently maintain system voltage. Optimized operation of these reactive support devices can improve system performance, increase life-expectancy of these devices, and more efficiently identify device-faults.

By tracking the health of various reactive support devices across its system near VVO installations, the Company can evaluate the following benefits.

- **Reactive power improvement** – the level of improvement in reactive power consumption across each distribution circuit after VVO installation due to optimization of reactive support device control.
- **Asset replacement** – comparison of the number of reactive support devices that need to be replaced before and after VVO installation, depending on the potential increase in operational life expectancy of these devices.
- **Equipment maintenance for reactive support devices** – evaluation of the potential decrease in the number of maintenance-related incidences for the Company with optimization of reactive support device control after VVO installation.

Circuit Voltage and Power Factor

As VVO is primarily designed to flatten and lower voltage fluctuations in circuits and maintain power factors within defined limits, it is critical for the Company to monitor circuit voltages and power factor changes. A comparison of these metrics before and after VVO deployment measures the improvements achieved by VVO and helps identity and diagnose external issues that might be affecting voltage and power factor improvements.

The Company can evaluate the following non-financial benefits by monitoring circuit voltage and power factor changes.

- **Equipment maintenance for reactive support devices** – evaluation of the potential decrease in the number of maintenance-related incidences for the Company with optimization of reactive support device control after VVO installation.
- **Power quality improvements** – comparison of voltage variations (short-term voltage sag variations, long-term under voltage/over voltage fluctuations) as an indicator of power quality improvement.

Transformer Health

The operating efficiency of distribution transformers is largely affected by accelerated thermal degradation of both the insulating paper and oil. As demand increases on a distribution circuit, the utilization of transformers consequently increases. Additionally,

harmonics and voltage deviations directly affect the oil temperature within distribution transformers.

With implementation of DACR and VVO across its distribution circuits, the Company can reduce the insulation and oil degradation of distribution transformers and prolong their useful life. The Company can evaluate the following financial benefit by monitoring the health (oil levels) of distribution transformers:

- **Asset replacement** – comparison of distribution transformers that need to be replaced before and after VVO installation, depending on the potential increase in operational life expectancy of these devices.

5. NON-FINANCIAL METRICS

5.1 Introduction

Non-financial metrics are those that track deployment status, potential operating efficiencies for which financial benefit is difficult to ascribe, or that may result in increased customer satisfaction. This section explains our evaluation of these metrics in detail, including:

- The definition and objective of the reported metrics
- The methodology for how we evaluated each metric
- Our findings and recommendations including additional metrics AEP should consider tracking to provide more insights on the progress and impact of gridSMART® deployments

Non-financial metrics currently monitored by AEP Ohio include the following.

- **AMI / Meter Metrics**, which include ***physical meter information*** such as the number of certified meters installed, meters installed but not certified, certified meter failures, and the number and value of meters salvaged and transferred; ***meter reading*** such as number of manual meter reads, successful meter reads for billing, and number of meter readers; ***billing-related metrics*** such as number of residential bills issued, number of estimated residential bills, disconnects, and theft cases; and ***customer impact metrics*** such as call center calls in total, those associated with meter reads, and those associated with billing complaints.
- **DACR Metrics**, which include ***circuit metrics*** such as those equipped with DACR and DACR opportunities, successes, and failures; ***operational efficiency gains*** such as truck rolls related to an outage and avoided truck rolls; and ***direct customer benefits*** such as customer minutes and customer interruptions saved by self-healing events.
- **VVO Metrics**, which include ***energy efficiency metrics*** such as demand (MW) and energy (MWh) saved as a result of VVO and average system voltage; and ***greenhouse gas impact metric*** such as reduction in greenhouse gases due to VVO.

The following sections describe each of the gridSMART® non-financial metrics, as reported by AEP Ohio as of December 31, 2018, along with our assessment.

5.2 Non-Financial Metrics Evaluation

5.2.1 AMI / Meter Metrics, Physical Meter Information

PHYSICAL METERS	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Number of Certified Meters Installed	The number of AMI meters installed, communicating, and available for billing within the Phase 1 and Phase 2 deployment area.	133,975	151,091	671,305
Number of meters installed, but not certified	The number of AMI meters installed, but not communicating and considered Active within the Phase 2 deployment area.	0	0	0
Certified smart meter failures	The number of certified AMI Meters that are removed due to defect. Includes Phase 1 and Phase 2 areas.	3,087	2,056	1,720
Meters salvaged (number)	The number of meters removed from Phase 2 premises and sent to salvage.	0	0	106,489
Meters salvaged (dollars)	The dollar value of meters removed from Phase 2 premises and sent to salvage.	$0	$0	$81,292
Meters transferred (number)	The number of meters removed from Phase 2 premises and transferred between AEP operating companies outside of Ohio.	16	5	1,550
Meters transferred (dollars)	The dollar value of meters removed from Phase 2 premises and transferred between AEP operating companies outside of Ohio.	$3,522	$337	$114,214

Objective: AMI physical meter metrics provide insight on the progress and success of AMI meter deployment as well as the value captured through transfer or recycling of pre-AMI meters. The physical meter metrics also form the basis for evaluating the operational benefits achieved to date. Our review of these metrics consisted of comparing monthly supporting data provided by AEP Ohio[149] to other relevant data either provided by the Company or from industry sources to confirm the reasonableness

[149] AEP Ohio response to Staff DR 02-002.

of the reported metrics. Our review methodology as well as our findings and recommendations are provided for each metric below.

Number of Certified Meters Installed

There have been 671,305 AMI meters deployed as of year-end 2018 (134,631 meters in Phase 1 and 536,674 meters in Phase 2). Though AEP's gridSMART® application included a plan to deploy 894,000 AMI meters in the Phase 2 deployment area, a list of all meters to be replaced in the Phase 2 deployment area provided by AEP Ohio included a total of 910,004 meters, a 1.8% increase.[150] Similarly, we saw growth in the Phase I meter deployments from the original plan of 110,000 meters to a total of 134,631 meters (a 22.4% increase) as of year-end 2018. In discussions, AEP Ohio indicated that the number of certified Phase 1 and Phase 2 meters has increased primarily due to growth in the number of customer meters in the respective deployment areas. We confirmed the reasonableness of the reported number of certified meters installed in Phase 2 to date as follows.

- We compared the 910,004 AMI meters to the sum of (1) the number of certified meters as of year-end 2018, and (2) the number of AMI meters to be deployed as reported in the Company's deployment plan as of February 11, 2018.[151] This confirmed a plan for 888,927 meters to be deployed through 2019 leaving 21,077 meters for future deployment. Based on discussions with the Company, we understand that AEP Ohio is targeting full deployment by the end of 2019 and that it updates its deployment plan regularly to adjust for changes in the schedule and changes in meter counts. This seems reasonable, however for our analysis of financial benefits, we conservatively assumed that the remaining 21,077 meters will be deployed in 2020.
- We also compared AEP's monthly total certified meters to the total AMI meter reads for Phase 1 and Phase 2 to verify that the certified meters are translating to billings. Though there is not a one-for-one relationship between meters and bills, the figure below demonstrates a high correlation between the two, which provides further evidence of the reasonableness of the reported metrics. We observed a significant divergence in March - May 2016 related to Phase 1 which corrected itself by June 2016. We did not investigate this further because it

[150] AEP Ohio response to Staff DR 02-18, Attachment 1.

[151] AEP Ohio response to Staff DR 04-004.

appeared to be an issue on the billing side, unrelated to the number of certified meters, which is the purpose of this comparison.

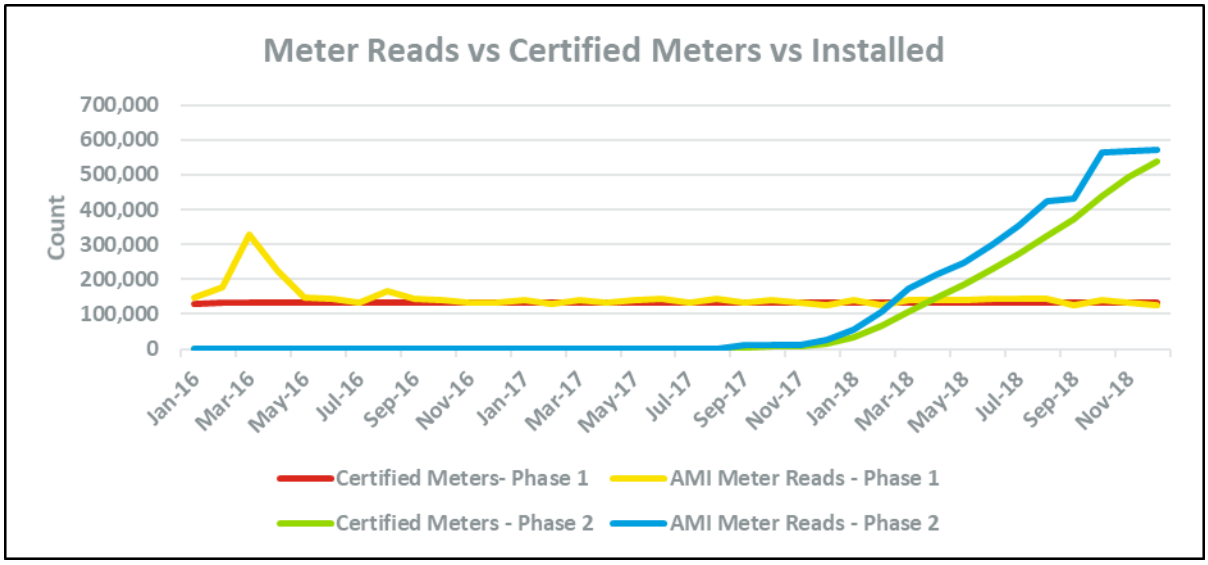

Figure 27: Meter Reads vs Certified Meters for Phase 1 and 2

Recommendations: Maintaining full deployment of AMI meters in the AMI deployment areas is critical to ensuring realization of the operational benefits discussed in Section 3. To improve visibility of changes in total AMI meters deployment expectations, we recommend AEP Ohio break out the existing metric into Phase 1 and Phase 2 and add a metric that provides the total number of remaining meters to be deployed in the Phase 2 areas.

Number of Meters Installed, but not Certified

This metric is intended to measure the number of AMI meters installed but not actively communicating with the system due to a defect. In discussion with the Company, it was confirmed that meters generally only stay in the "Installed not Certified" state for a few days. The Company does not have monthly data to support this metric. We also confirmed with the Company that they do not track the actual time meters stay in this status, so we could not audit the reported numbers or provide evidence for how long meters stay in this "Installed not Certified" state. However, as discussed in the number of certified meters installed section just above, we observed a high correlation between installed AMI meters and the number of actual AMI meter reads, which supports the

reported metric values and a conclusion that there are no material issues or delays in moving meters from installed to active status.

Recommendation: If the PUCO Staff is concerned about this issue going forward, we recommend adding a metric to measure the average time a meter sits in the installed, but not certified state. Since the data doesn't currently exist to support such a metric, we further recommend discussion with the Company on the effort required to improve its data tracking to support the metric before requiring the metric to be reported.

Certified Smart Meter Failures

To evaluate this metric, we compared meter failure rates to the total number of meters installed.[152] Below are the graphical results of that comparison. We didn't see anything alarming in the number of failures.

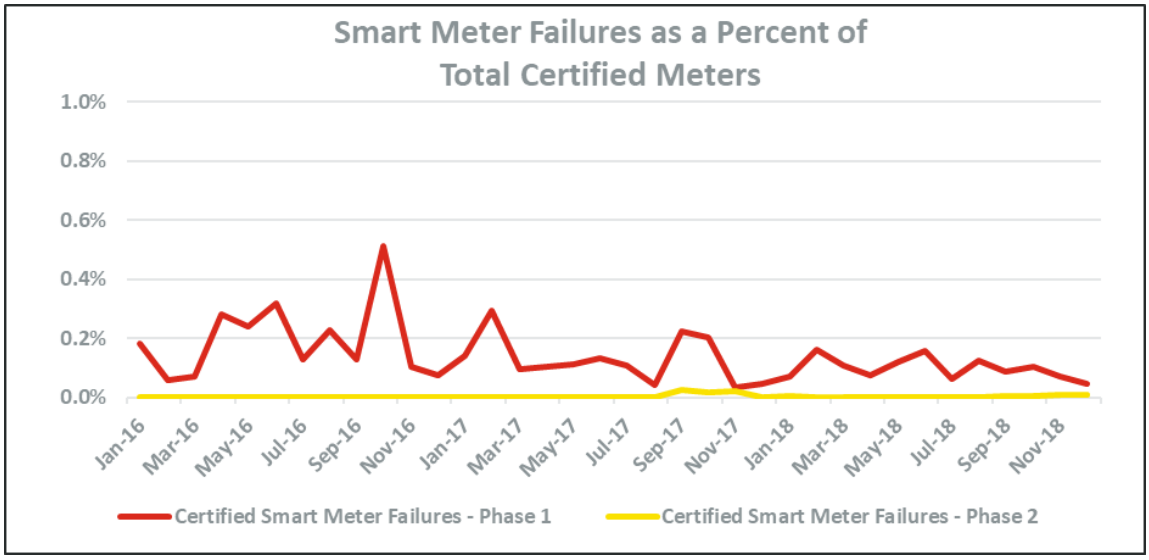

Figure 28: Smart Meter Failures as a Percent of Total Certified Meters

Recommendation: Going forward, AEP Ohio may start to see an increased number of failures of Phase 1 meters that are now approaching 10 years of life. This is worth tracking to understand life expectancy of AMI technology. The parties agreed in Joint Stipulation and Recommendation in Case No. 13-1939-EL-RDR to a 15-year depreciable life on AMI meters. We recommend the Company track and perform a study on realized life of AMI meters for future input on AMI depreciation life assumptions.

[152] AEP Ohio response to Staff DR 02-002.

Meters Salvaged (number and dollar value)

We compared the monthly number of meters salvaged to the monthly dollar value of meters salvaged, over the Phase 2 deployment period, to determine the average monthly salvage value per meter salvaged. We observed that the monthly salvage value per meter dropped from $0.86 to $0.45 in October 2018.[153] In discussions, the Company indicated that this was a result of a price renegotiation with their vendor after realizing that there was more plastic in the meters than originally anticipated. We benchmarked salvage rates with a meter salvage company serving the greater Ohio area and confirmed that the current salvage rate of $0.45 per meter is on the high side of the market, indicating AEP Ohio is receiving a fair market value for the meters it is salvaging.[154]

Meters Transferred (number and dollar value)

We compared the monthly number of meters transferred to the monthly dollar value of meters transferred, over the Phase 2 deployment period, to determine the average monthly transfer value per meter transferred. We calculated monthly transfer values per meter in the range of $67.33 to $297.00.[155] The overall Phase 2 average transfer value per meter was $75.16 as of December 31, 2018. We confirmed in discussions with the Company that the internal transfer price is based on the remaining book value of the meter. In discussion, the Company explained that the low transfer values are due to both the age of the meters and the high deployment of AMI and AMR meters within AEP's other subsidiaries' electric distribution utility service territories. We did not investigate this further given the number of transfers to date is very low (1,571 meter transfers as of December 31, 2018).

[153] AEP Ohio response to Staff DR 02-002 Appendix D.

[154] Meter salvage company we spoke to quoted us a range of $0.10 to $0.40 per meter depending on the year, make, and model.

[155] AEP Ohio response to Staff DR 02-002 Appendix E.

5.2.2 AMI / Meter Metrics, Meter Reading

METER READING	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Manual Meter Reads	Within the Phase 2 deployment area, the number of meter reads conducted by an individual onsite for monthly billing.	7,742,540	7,815,196	6,123,030
Successful ("actual" for the purpose of billing) AMI meter reads	Within the Phase 2 deployment area, the total number of "actual" reads recorded from AMI meters.	0	60,501	4,010,456
Successful ("actual" for the purpose of billing) AMR meter reads	Within the Phase 2 deployment area, the total number of "actual" reads recorded from AMR meters.	1,857,526	2,077,401	1,786,444
Meter readers employed by AEP Ohio, expressed in FTEs	Number of meter readers (expressed in FTE) employed by AEP Ohio each month.	86	84	48
Meter readers employed by an external contractor, expressed in FTEs	Number of meter readers (expressed in FTE) employed by contractor each month.	25	18	18

Objective: AMI Meter Reading metrics provide insight into the progress and success of AMI meter deployment in driving operational savings through the elimination of manual meter reading activities. Our review of these metrics consisted of comparing monthly supporting data provided by AEP Ohio[156] to other relevant data provided by the Company to confirm the reasonableness of the reported metrics. Our review methodology, findings, and recommendations are provided for each metric below.

Number of Manual Meter Reads

We compared the reported annual number of meter reads to the annual sum of monthly manual meter reads provided by the AEP Ohio from their Customer Service System. We observed no discrepancies in the data.

[156] AEP Ohio response to Staff DR 02-002.

Successful ("actual" for the purpose of billing) AMI Meter Reads & AMR Meter Reads

We compared the reported number of annual successful meter reads (AMI and AMR) to the annual sum of monthly Digital and Radio meter reads provided by AEP Ohio from their Customer Service System.[157] We observed no discrepancies in the data.

The figure below shows a strong correlation between the number of manual meter reads, successful meter reads, and certified AMI units deployed, indicating a well-functioning system integration from meter to bill.

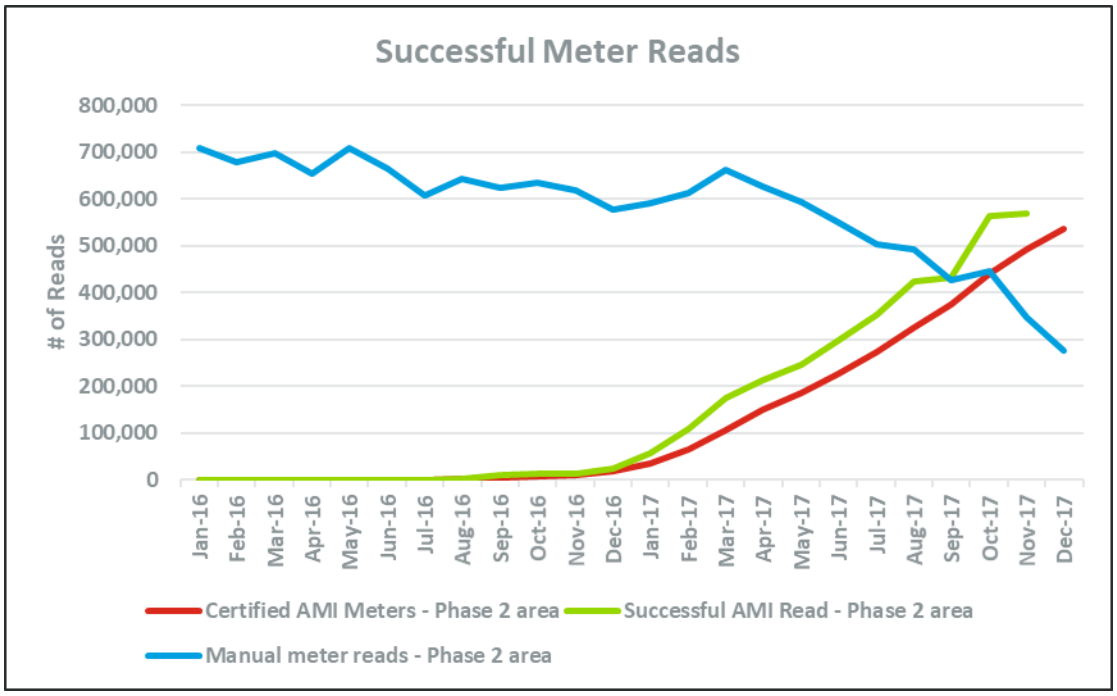

Figure 29: Successful Meter Reads

Meter Readers Employed by AEP Ohio and Employed by an External Contractor (expressed in FTEs)

The combined meter reader metrics reported (both meter readers employed by AEP Ohio and those employed by an external contractor) show an overall decline in total meter readers (expressed in FTEs) from 111 FTEs as of year-end 2016 to 56 FTEs as of year-end 2018. We reviewed monthly FTE data and observed some monthly fluctuations in the total number of meter readers over the deployment period as well as shifts

[157] AEP Ohio response to Staff DR 02-032.

between AEP-employed meter readers and contracted meter readers. In discussions, the Company explained that the monthly fluctuations are primarily due to a combination of reduced routes and employee vacancies resulting from terminations and job changes. The Company further explained that where possible they use contract staff to manage interim staffing needs that could be temporary as meter routes are eliminated. The Company also shared future estimates of planned reductions based on full deployment across the full MRO department (not just the meter reader job classification). An analysis of the operational savings associated with staff reductions in the MRO department is included in the operational benefits section (Section 3) above.

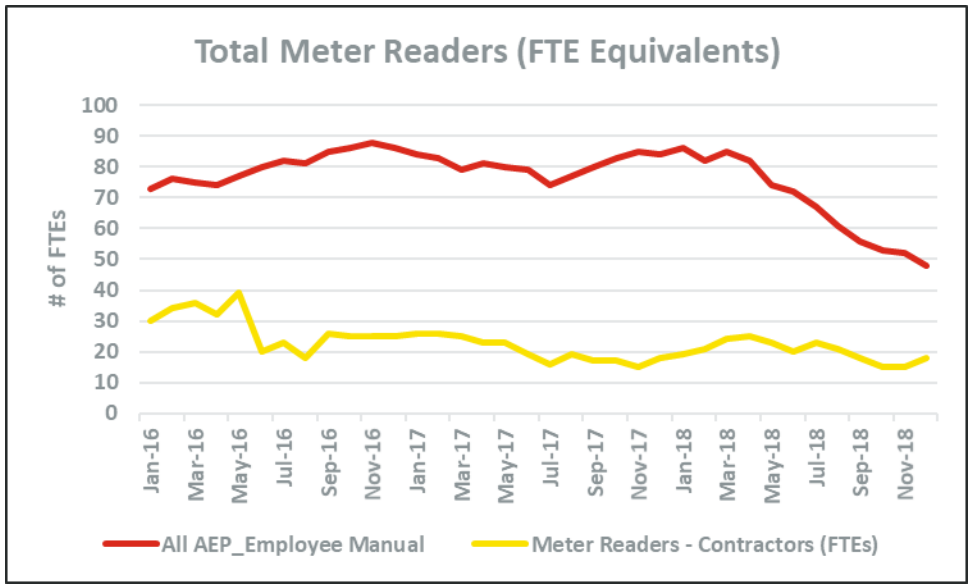

Figure 30: Total Meter Readers (FTE Equivalents)

5.2.3 AMI / Meter Metrics, Billing-Related

BILLING RELATED	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Residential bills issued	Number of residential bills issued each month, system-wide.	15,655,613	15,698,375	15,818,321
Residential bills based upon estimated read	Number of estimated residential bills issued each month, system-wide.	1,366,651	1,025,230	751,374
Customers eligible for disconnect due to non-payment (System)	Number of customers eligible for disconnection each month, system-wide.	884,286	793,293	817,573
Customers eligible for disconnect due to non-payment (Phase 2)	Number of customers eligible for disconnection each month, Phase 2 deployment area only.	541,956	495,898	508,118
Non-Payment Disconnects (System)	Number of customers disconnected due to non-payment each month, system-wide.	131,388	104,541	123,050
Non-Payment Disconnects (Phase 2)	Number of customers disconnected due to non-payment each month, Phase 2 only.	68,029	52,349	68,177
Power theft cases (number)	Number of power theft cases found each month, system-wide.	139 cases per month	129 cases per month	137 cases per month
Power theft cases (dollar value)	Monetary value of power theft cases found each month, system-wide.	$222 per case per month $30,925 total per month	$211 per case per month $27,205 total per month	$221 per case per month $30,374 total per month

Objective: Billing-related metrics track improvement in the accuracy of bills (resulting from decreased estimated readings), indicators of increased revenues associated with improvements in credit and collections, and reductions in theft resulting from the deployment of AMI meters.[158]

Residential Bills Issued and Residential Bills based upon Estimated Reads

We compared the monthly number of residential bills based on estimated reads to the total number of residential bills and observed a steady decline since 2016 following in-line with the deployment of Phase 2 meters (6.7% in 2016 declining to 6.5% in 2017 and

[158] AEP Ohio response to Staff DR 02-002.

5.8% in 2018).[159] This is consistent with the increase in digital reads noted in the Manual Meter Reads metric discussed earlier in this section. The monthly data showed significant improvement in the early part of 2017, which was prior to the rollout of Phase 2 meters (1st half of the 2017 averaged 5%), indicating there were other factors related to manual meter reads that impacted the total number of estimated reads. Nevertheless, based on our analysis and discussion with the Company, we expect the decline to continue and be sustained as Phase 2 AMI meter deployment continues.

Customers Eligible for Disconnect Due to Non-Payment (system-wide and Phase 2) and Non-Payment Disconnects (system-wide and Phase 2)

Eligibility for disconnect is determined by creation of a collection order for non-payment. However, for a customer to be remotely disconnected for non-payment, the customer's AMI meter has to be flagged in AEP Ohio's systems as eligible for remote disconnect, which requires a multi-step customer notification process to be completed per AEP Ohio's remote disconnect waiver approved on June 2018.[160] The Company explained that they are implementing program eligibility – as customers are switched over to AMI the Company is adding those customers to the next wave of customers to be notified under the waiver.[161] The schedule of program eligibility for remote disconnect is based on the install date of the AMI meter. For example, customers of the 210,052 AMI meters (23% of total Phase 2 installation) installed through June 2018 were program eligible for remote disconnect on October 3, 2018. Similarly, an additional 284,447 premises that had AMI meters installed through December 2018 are scheduled to be eligible for remote disconnect on April 4, 2019. The Company mentioned that any premises installing AMI meters between January and May 2019 will have remote disconnect eligibility by September 4, 2019. The remaining premises installing AMI meters after May 2019 will obtain remote disconnect eligibility in March/April 2020.[162]

Additionally, just because a customer is program-eligible and non-payment eligible for disconnect, it does not mean that they will be disconnected. For example, customers can pay prior to the collection order being implemented, go on a budget, establish a

[159] AEP Ohio response to Staff DR 02-002 and Staff DR 02-043.

[160] AEP Ohio response to Staff DR 02-042. AEP Ohio stated in June 2018, the "*Phase 2 disconnect waiver was approved and AEP Ohio started the process to provide required notifications and system changes to support the Phase 2 disconnect waiver*."

[161] Response to Staff-2-42.

[162] Response to Staff-8-1.

payment plan, etc. The Company explained that as a policy, they do no remotely disconnect for non-payment during- upon first occurrence during peak periods.

For the above reasons, there are always a lot fewer disconnections than eligible disconnections as observed in the reported metrics.

In addition, the Company identified a reporting issue in the eligibility metric which caused duplicate collection orders on the same meter to be counted as separate instances resulting in the reporting of an inflated number of customers eligible for disconnect.[163] An old process still causes multiple orders to be created for a single non-payment event. Also, the Eligible for Disconnect metric and Disconnection metric used different dates to determine the reporting month. Eligible for Disconnect used the collection activity date and Disconnection used the order complete date.

Recommendation: Daymark supports recommendation provided to us by the Company to improve the accuracy of its reporting of customers eligible for disconnect by removing duplicate orders. In addition, to provide better visibility around the impact and implementation of the remote disconnect waiver, we recommend that the Company report for the Phase 2 area: (1) the number of meters that are program-eligible for disconnect, and (2) the number of customers that are eligible for disconnect that are not disconnected due to not yet being program eligible. We also recommend that the Company track, separately, the number of remote and manual disconnects in the Phase 2 area. These additional metrics would provide further visibility into the effectiveness and value of non-payment-related remote disconnects on customers with AMI meters. Currently, the Company only reports actual non-payment disconnects but doesn't report the breakdown by manual and remote disconnect methods.

Power Theft Cases (number and dollar value)

We reviewed monthly data for the number of power theft cases and the dollar value of those cases for the period 2016 through 2018. To date, we did not observe a meaningful correlation between either of these metrics and the deployment of AMI meters. However, in reviewing specific data provided by the Company that identified theft cases by meter type for the period January 2016 to February 2018[164] in the Phase 2 area, we noted that nearly all theft cases for this period were identified on AMI meters. The

[163] The Company indicated that an old process still causes multiple orders to be created for a single non-payment event.

[164] The Company provided data through March 2019. March 2019 was not included in our analysis since it did not represent a full month of data.

figure below shows the number of cases identified on AMI, non-metered, and all other meters, which includes Traditional meters.[165]

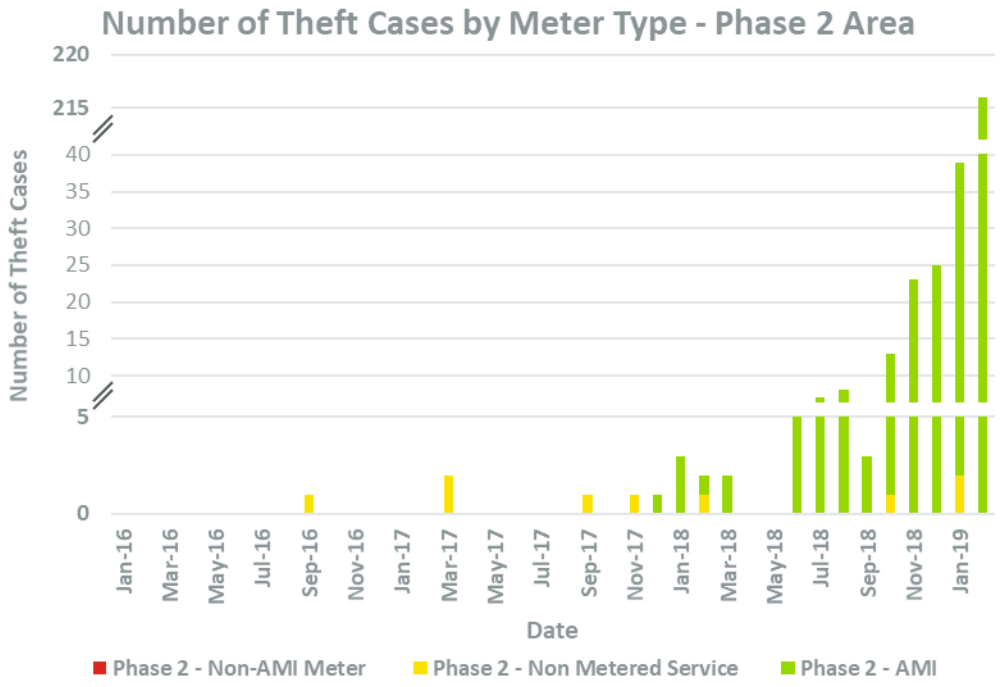

Figure 31: Number of Theft Cases Identified by Meter Type – Phase 2 Area

As can be observed in the chart above, there was a significant increase in the number of theft cases identified on AMI meters in the month of February 2019. This could be driven by a number of factors including an enhancement in the AMI system and/or Company processes to allow for better automated theft detection on AMI meters.

Recommendation: To further enhance the understanding of the value of AMI meters in identifying theft cases, Daymark recommends that AEP track and report the number and dollar value of theft cases by meter type in the Phase 2 area. We would expect that as the Company's remote theft detection capabilities improve, the number of cases will go up and the average dollar value will go down, both as a result of early detection.

[165] AEP Ohio response to Staff DR 08-001.

5.2.4 AMI / Meter Metrics, Customer Impact Metrics

CUSTOMERS IMPACT MEASURES	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Total call center calls	Number of call center calls received each month, system-wide. Total of monthly data.	5,447,623	5,481,173	5,594,456
Call center calls related to meter reading (IO40 Check Read Orders initiated at call center)	Number of call center calls related to meter reading received each month, system-wide. Metric is being tracked as total of Check Read Orders (IO40s) issued by the call center.	15,400	25,713	20,625
Call center calls related to billing complaints (IO04 HI/LO Bill Orders initiated at call center)	Number of call center calls related to billing complaints received each month, system-wide. Metric is being tracked as total of High/Low Bill complaint orders (IO04s) issued by the call center.	3,317	2,655	3,892

Objective: Customer impact measures attempt to measure improved efficiency in call center activity as a result of AMI deployment.

Total Call Center Calls

Total call center calls system-wide increased 0.06% in 2017 and 2.1% in 2018. However, as described further below, we found the customer impact metrics reported and the call center data being captured by AEP Ohio to be insufficient to conclude whether call center efficiencies have been achieved to date as a result of AMI and whether these efficiencies (to the extent achieved) are resulting in improved value to customers.

In AEP Ohio's initial gridSMART® Phase 2 Filing, the Company attributed an estimated $1 million (15-year cash view[166]) in soft savings benefit related to call center efficiencies as a result of lower meter and bill complaints, which the Company would reallocate to higher priority tasks.[167] As part of our audit of the customer impact metrics, we attempted to verify call center efficiencies realized to date and measure the related benefits realized by the call center staff being able to focus on other activities (e.g., reduced wait times, increased customer service). Though AEP Ohio was able to provide us the number of calls by call type, the information was limited to only those calls

[166] 15-year cash basis (total of nominal yearly savings) savings per operational benefit in millions of dollars.

[167] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

answered by AEP internal call centers, which only represents approximately 21% of the reported 5,594,456 calls in 2018.[168] We also found that the Company does not track call center data with enough granularity to measure the specific types of call center efficiencies that may be achieved through the deployment of AMI or how those efficiencies translate to the customer through reallocation of call center staff to higher priority tasks.

Recommendation: Daymark recommends that AEP Ohio consider how it can improve its call center tracking to set the stage for a better understanding of how programs like AMI are impacting call center efficiencies and more specifically work with the PUCO Staff to improve call center metrics reporting related to gridSMART® deployment. To the extent material call center efficiencies are achieved through the deployment of gridSMART® technologies like AMI and redeployed to "higher value" work as proposed by the Company, we further recommend that the Company, in consultation with the PUCO Staff, identify the high priority work to be achieved and set appropriate metrics that will verify the resulting customer benefit (e.g., reduced wait times, improved customer satisfaction rating).

Call Center Calls Related to Meter Readings

Through discovery and discussion with the Company, we learned that the number of call center calls related to meter readings received each month is limited to "check read orders" (IO40) issued by the call center to the MRO department. Although this metric could be an indication of efficiencies in the MRO department (i.e., fewer meter investigations/off-cycle meter reads), it is inconclusive regarding efficiencies in the call center because it does not include meter reading inquiries that are resolved by the call center service representatives and therefore does not provide insight as to how this number has changed with AMI rollout.

As it relates to MRO investigations, although there was a drop in total check read orders in 2018 versus 2017, 2018 was still higher than 2016. This may be driven by other factors. The data by itself is inconclusive and would require further analysis to determine the reason for the calls.

[168] In response to Staff DR 04-016, AEP Ohio confirmed that the Company does not categorize all calls. In follow-up discussion, the Company explained that it only categorized calls received by its internal call centers.

Recommendation: Daymark recommends that AEP Ohio track the reasons for check read orders in more detail to enable the PUCO Staff to further understand trends in check read orders driven by AMI that could lead to further operational benefits.

Call Center Calls Related to Billing Complaints

Similar to the prior section on meter readings-related calls, the number of calls related to billing complaint was limited to billing complaints that resulted in a "high/low bill complaint order" (IO04) issued by the call center to the billing department. These represent only 1-2% of internal bill complaint calls received by AEP's internal call center and we would expect that it would be an even lower percentage of total bill complaint calls. Although this metric could be an indication of efficiencies in the billing department (i.e., fewer investigations, billing adjustments), it is inconclusive regarding efficiencies in the call center because it does not include bill complaints that are resolved by the call center service representative and therefore does not provide insight as to how this number has changed with AMI rollout.

As it relates to billing complaint investigations, although there was a drop in total billing complaints in 2017 versus 2016, 2018 was higher than both 2016 and 2017. This may be driven by several factors unrelated to AMI. The data by itself is inconclusive and would require further analysis to determine the reason for the calls.

Recommendation: Daymark recommends that AEP Ohio track the reasons for billing complaints in more detail to enable the PUCO Staff to understand trends in billing complaints driven by AMI that could lead to further operational benefits.

5.2.5 DACR Metrics, Circuit Metrics

DACR CIRCUIT METRICS	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Circuits equipped with DACR	Number of Phase 2 circuits newly equipped with DACR each month	n/a	0	2
DACR opportunities	For Phase 2 circuits, number of opportunities for DACR to operate each month	n/a	0	0
DACR successes	For Phase 2 circuits, number opportunities when DACR operated as intended each month	n/a	0	0
DACR failures	For Phase 2 circuits, number of opportunities when DACR did not operate as intended each month	n/a	0	0

Objective: DACR circuit metrics attempt to measure how well DACR works each month as a result of circuits being equipped with DACR.

Circuits Equipped with DACR

There had been 72 DACR circuits deployed as of year-end 2018 (70 circuits in Phase 1 and 2 circuits in Phase 2). The Company's plan involves installing around 327 circuits by 2023.[169] After speaking with the Company, Daymark has learned that the Company intends to expedite DACR installation (potentially completing installation for all DACR circuits by 2023.

Daymark finds the Company's tracking of DACR deployments to be reasonable and proceeding according to plan. The Company reports its DACR and VVO installation progress in its monthly newsletter.

[169] AEP Ohio response to Staff DR 02-052.

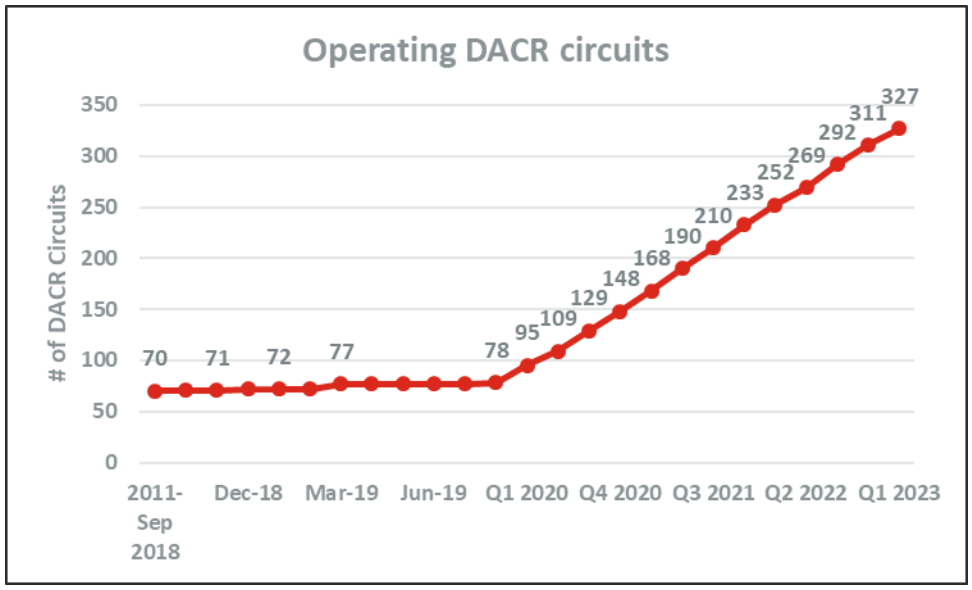

Figure 32: DACR and VVO Installation Progress and Deployment Schedule

Recommendation: Daymark recommends that the Company report its 'scheduled' versus 'actual' DACR deployment for Phase 2 circuits separately. This will help the PUCO Staff in examining the progress related to Phase 2 DACR deployment in the coming months.

DACR Opportunities

This metric is tracked by recording the number of times where DACR circuits were called into action over the course of an outage. The Company keeps a record of all outages that occur on DACR enabled circuits.[170] In the data provided, the Company records whether a DACR reconfiguration was available for that outage or not. This provides a reasonable tracking metric to estimate the number of DACR opportunities available to the Company.

Currently, the Company has no data pertaining to Phase 2 DACR circuits because there have not been any events yet on the circuits in question. As a result, Daymark was unable to track the number of DACR opportunities for Phase 2 circuits, specifically. For Phase 1 circuits, Daymark observed a total of 355 opportunities for DACR circuits to function during outages from 2011 to 2018.

[170] AEP Ohio response to Staff DR 02-061.

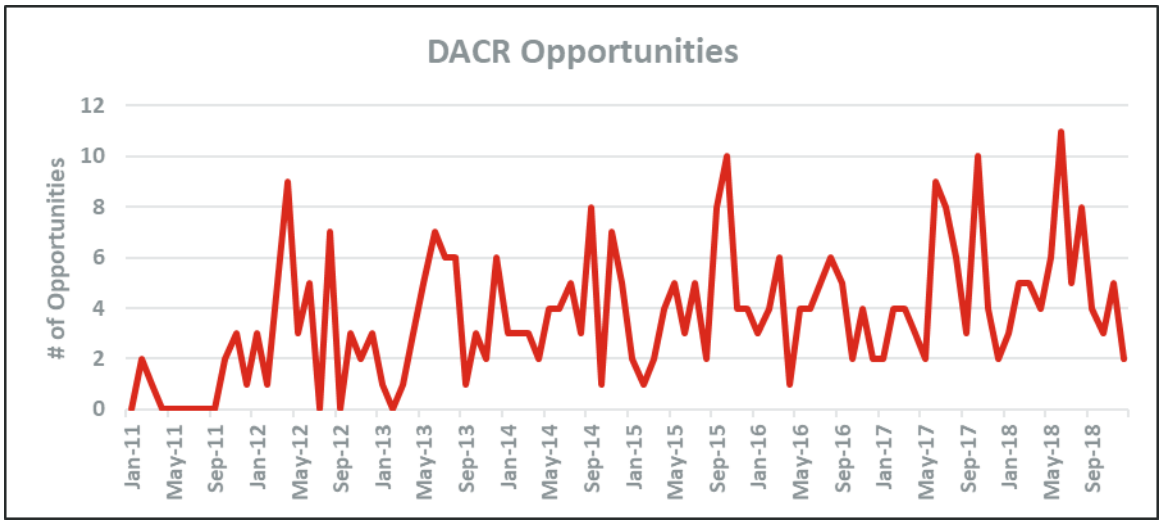

Figure 33: DACR Opportunities for Phase 1 Circuits

Recommendation: Daymark recommends that the Company report its DACR opportunities for Phase 2 circuits separately, instead of rolling them into their outage records. This will provide a clearer view to the PUCO Staff on DACR effectiveness.

DACR Successes and Failures

The Company tracks these metrics by recording the number of instances where the DACR circuits either functioned as expected or did not function; these metrics are measured across AEP's system each month. Daymark finds this to be an acceptable way to track DACR successes and failures. However, the Company does not possess data for Phase 2 circuits since there have not been any events yet on the two circuits that were installed in 2018.

Daymark looked at the DACR outage records provided by the Company for Phase 1 circuits. In these records, the Company keeps track of whether the DACR circuit functioned as expected, or not, for every single outage record on their system. Daymark used this data to estimate the Phase 1 DACR successes and failures to be 83% and 17%, respectively.[171]

[171] AEP Ohio response to Staff DR 02-061.

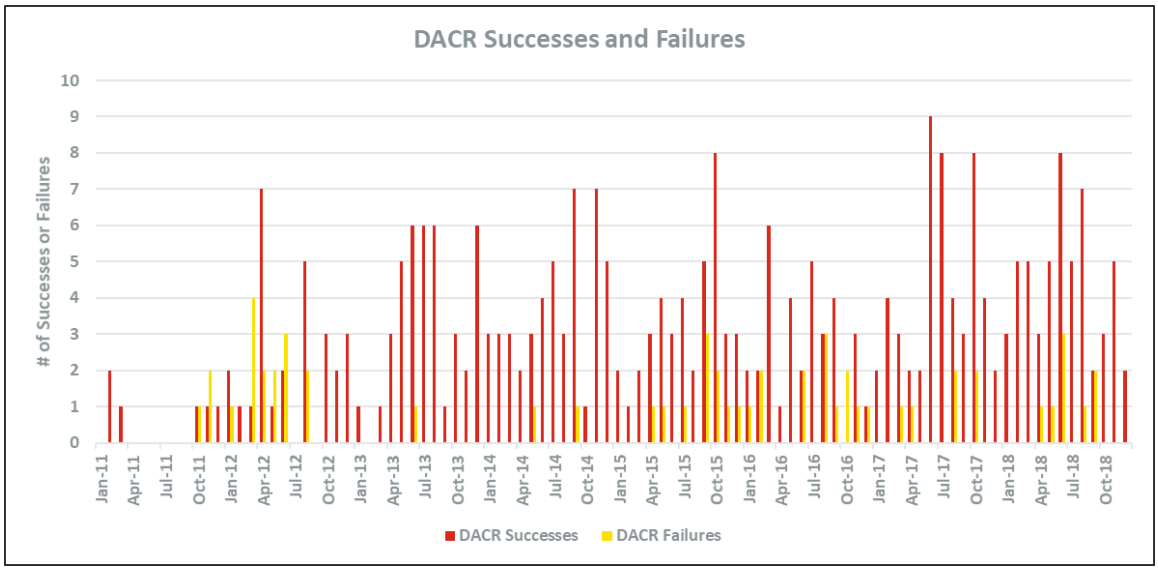

Figure 34: DACR Successes and Failures

Recommendation: Daymark recommends that the Company report specific metrics on its DACR successes and failures for Phase 2 circuits (which are already tracked). These should be reported separately, in addition to rolling them into their outage records. This will provide a clearer view to the PUCO Staff on DACR effectiveness, similar to Figure 34.

5.2.6 DACR Metrics, Operational Efficiency Gains

DACR CIRCUIT METRICS	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Truck rolls related to an outage	For Phase 2 circuits, number of truck rolls related to an outage each month.	n/a	0	0
Outage-related truck rolls avoided	For Phase 2 circuits, number of avoided truck rolls related to an outage each month.	n/a	0	0

Objective: Operational efficiency gains metrics attempt to measure avoided truck rolls that occur as a result of circuits being equipped with DACR.

Truck Rolls related to an Outage

The Company tracks outage events, each of which typically involves at least one truck roll (standard or short[172]). After speaking with the Company, Daymark understands that the Company sends a truck roll for every outage that occurs on their circuits, irrespective of whether the DACR circuit functioned as expected or not.

Since the Company does not report the specific number of truck rolls, Daymark assumed that the number of truck rolls equals the number of outages that occurred on DACR-enabled circuits.[173] This methodology was only applied to Phase 1 circuits, since no events have occurred yet (as of year-end 2018) on Phase 2 deployed circuits.

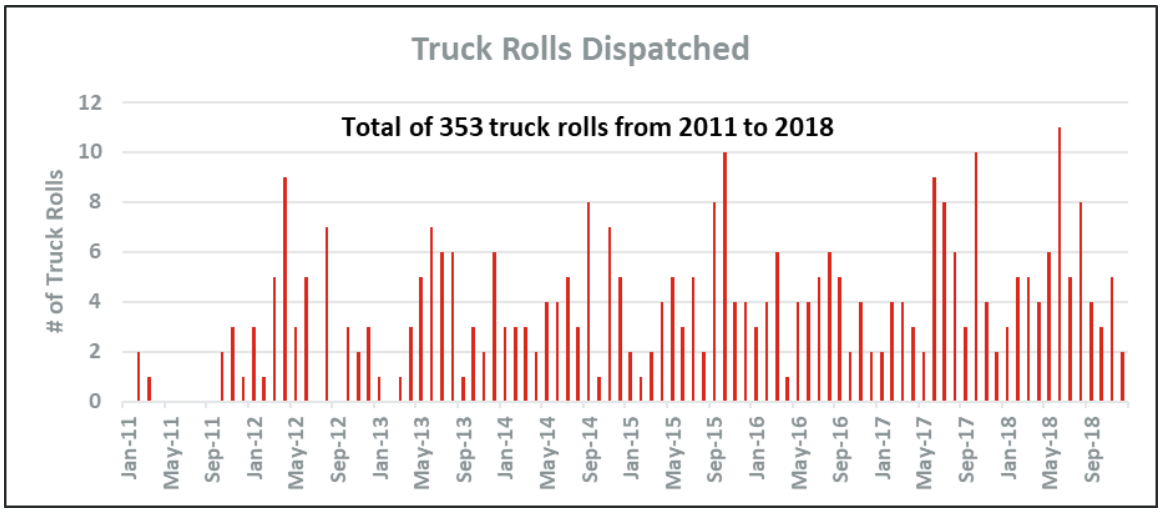

Figure 35: Number of Truck Rolls Dispatched

Recommendation: Daymark recommends the Company explicitly report the number of truck rolls that were dispatched during an outage. Since more than one truck roll could be dispatched for one outage event, it will make more sense to report the truck rolls dispatched explicitly. Daymark discovered that the Company possesses this data in their outage tickets, which are generated after every outage event. Going forward, Daymark recommends that the Company explicitly separate and track data from the outage tickets that occur on Phase 2 DACR-enabled circuits and report the number of truck rolls (standard and short) that are dispatched as a result.

[172] Standard truck rolls represent a crew traveling from the service center to the outage location, while short truck rolls represent a crew traveling from one switching location to another.

[173] AEP Ohio response to Staff DR 02-061.

Outage-related Truck Rolls Avoided

The Company tracks this metric by tracking the number of truck rolls that were avoided due to DACR deployment on a monthly basis. Daymark learned from the Company that no reduction in dispatched truck rolls had occurred as a result of DACR deployment. The Company sends a truck to the outage location irrespective of whether the DACR functioned as expected or not.

Recommendation: Daymark recommends that the Company use the same methodology that was used to quantify avoided truck rolls in its Phase 1 DOE study. The Company's Phase 1 DOE report stated that the Company was quantifying the number of truck rolls avoided by "*counting the number of remote switching operations and assigning each as either a short or standard truck roll*."[174] Standard truck rolls represent a crew traveling from the service center to the outage location, while short truck rolls represent a crew traveling from one switching location to another.

5.2.7 DACR Metrics, Direct Customer Benefits

DACR CIRCUIT METRICS	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Customer minutes saved by self-healing events	For Phase 2 circuits, the customer minutes interrupted avoided monthly due to successful self-healing events.	n/a	0	0
Customer interruptions saved by self-healing events	Number of customers interruptions avoided by DACR multiplied by an estimated outage duration.	n/a	0	0

Objective: Direct customer benefits metrics attempt to measure customer benefits that occur as a result of circuits being equipped with DACR.

Customer Minutes Saved by Self-Healing Events

This metric is used to track the effectiveness of DACR-enabled circuits in reducing outages experienced by customers. By successful reconfiguration of DACR circuits during an outage, customers would experience lower interruption times. The Customer

[174] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy ("DOE") Smart Grid Demonstration Project ("SGDP") Contract Award Number DE-OE000193, June 2014, p. 185.

Minutes of Interruption avoided due to successful DACR operation allows the Company to potentially estimate significant savings that would pass on to AEP's customers.

The Company tracks this metric by recording the number of customers that were brought back online during an outage as a result of successful DACR operations. This number is then multiplied by an estimated duration of 83 minutes to derive the customer minutes saved during every DACR event. AEP derives the 83 minutes by taking an average of the historical first step of restoration durations for outages in impacted areas in Columbus (Phase 1 area). For Phase 2, the Company uses the same methodology to arrive at the estimated outage duration, but this figure varies for AEP Ohio's service districts.[175] While conducting the analysis, Daymark used the Company's DACR outage records to keep track of the number of customers that were automatically restored by successful DACR operations. In its non-financial metrics filing, the Company stated that their baseline value is calculated by taking the cumulative sum of customers that were restored automatically for a 12-month period ending on 2/1/2017 and then multiplying that by the estimated duration value. Upon conducting the analysis on Phase 1 circuits, Daymark arrived in the same ballpark as the Company in setting this baseline (Daymark calculated 2,578,810 avoided CMI versus 2,602,115 avoided CMI calculated by the Company). From the data provided to us by the Company, over the Phase 2 time period (starting Jan 2017), the Company avoided an overall CMI of 6,772,136 between January 2017 to December 2018.[176]

[175] AEP Ohio response to Staff DR 08-013

[176] AEP Ohio response to Staff DR 02-061.

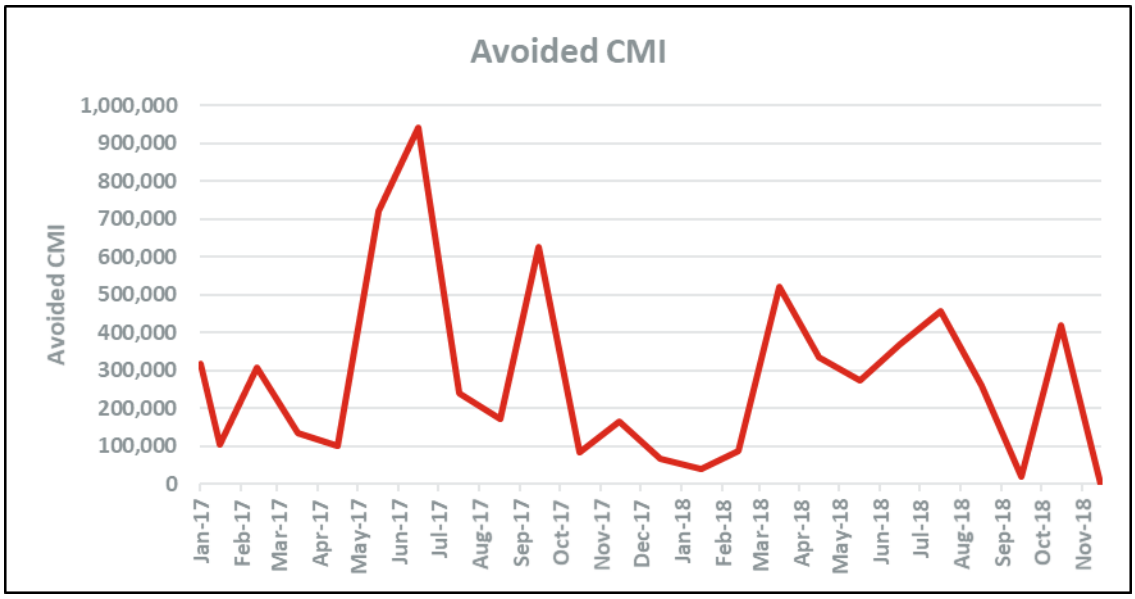

Figure 36: Avoided CMI from January 2017 to December 2018

Recommendation: Daymark finds the methodology that the Company used to track the avoided CMI as reasonable. Daymark recommends that the Company explicitly report their avoided customer minutes of interruption for Phase 2 circuits along with the other non-financial metrics that are related to DACR outages.

Customer Interruptions Saved by Self-Healing Events

Due to successful reconfiguration of DACR circuits during an outage, more customers would be restored immediately and would therefore not be impacted by an extended outage. The number of avoided customer interruptions due to a successful DACR operation allows the Company to track the avoided customer minutes of interruption and the subsequent benefits that pass on to customers.

The Company tracks this metric by recording the number of customers that were brought back online by successful DACR operations during an outage. While conducting the analysis, Daymark used the Company's DACR outage records to keep track of the number of occurrences where customers were automatically restored by successful DACR operations. From the Company's Phase 1 data, we observed an increase in the

number of customer interruptions avoided, ranging from 3 interruptions in 2012 to 29 interruptions in 2018.[177]

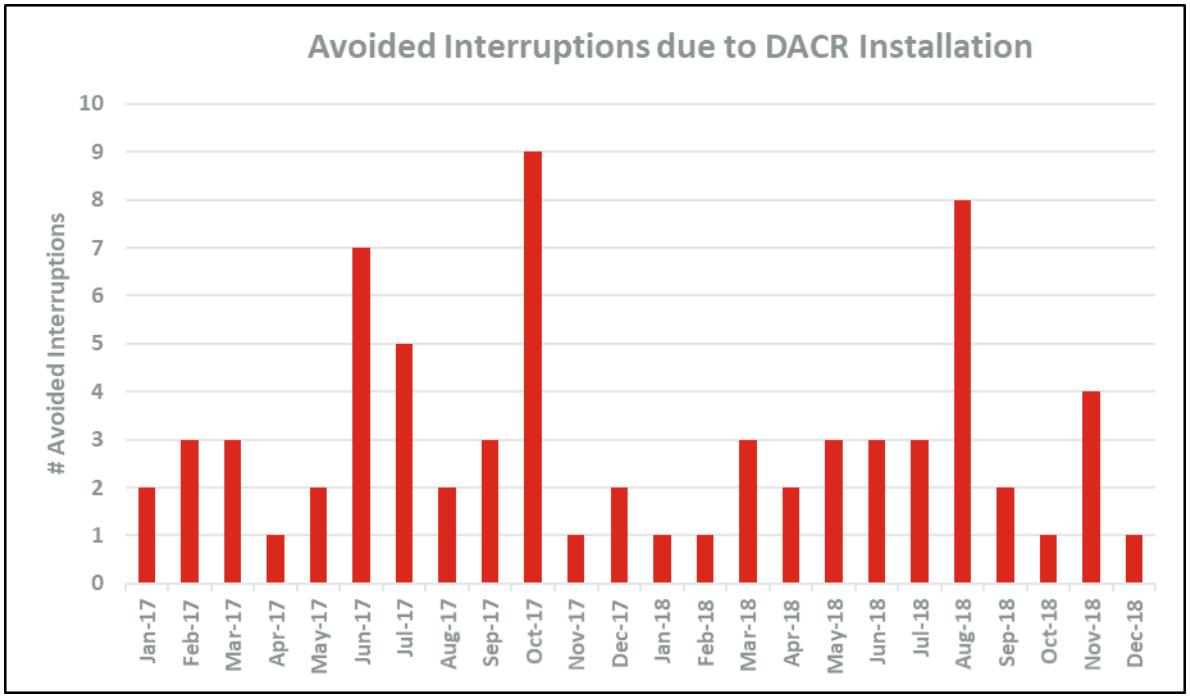

Figure 37: Monthly Avoided Customer Interruption Occurrences

Recommendation: Daymark finds the methodology that the Company used to track the avoided customer interruptions as reasonable. Going forward, Daymark recommends that the Company explicitly report their avoided customer interruption for Phase 2 circuits along with the other non-financial metrics that are related to DACR circuit outages.

[177] AEP Ohio response to Staff DR 02-061.

5.2.8 VVO Metrics, Energy Efficiency

VVO ENERGY EFFICIENCY	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Megawatts saved by VVO	Provided by Utilidata from M&V data; Phase 2. VVO circuits only. Total MW saved by VVO per month, system-wide.	n/a	0	0
Megawatt-hours saved by VVO	Provided by Utilidata from M&V data; Phase 2. VVO circuits only. Total MWh saved by VVO per month, system-wide.	n/a	0	0
Average system voltage	For Phase 2 VVO circuits only, the average of the voltage at the substation on the secondary side of regulation. This an average of all 3 Phases over the entire month.	n/a	0	0

Objective: VVO energy efficiency metrics provide insight into the progress and success of VVO deployment as well as the value captured through energy and capacity savings on AEP's distribution system. It also forms the basis for evaluating the operational benefits achieved to date. Our review of these metrics consisted of comparing monthly supporting data provided by AEP Ohio to other relevant data either provided by the Company or from industry sources to confirm the reasonableness of the reported metrics. Since VVO deployment for Phase 2 did not occur until November 2018, any data displayed in the following sections refers to Phase 1 deployment data and recommendations are made for tracking these appropriate metrics in Phase 2. Our review methodology as well as our findings and recommendations are provided for each metric below.

Megawatts Saved by VVO

Around 40 VVO circuits had been deployed as of year-end 2018 (17 circuits in Phase 1 and 23 circuits in Phase 2).[178] The Company noted in their non-financial metrics that there were no MW savings as a result of these VVO deployments. This is because Phase 2 VVO deployment did not occur until the end of 2018 (8 circuits in November 2018 and 15 circuits in December 2018). Since the Company is currently undergoing testing of

[178] AEP Ohio response to Staff DR 02-006.

their Phase 2 VVO deployments, it was not possible for Daymark to quantify the MWs saved.

The Company did, however, provide useful data on their candidate circuits for VVO.[179] This data included the average and peak power on the VVO candidate circuits reported on an hourly basis from 2015 to February 2019. Since there was no pre-2011 data available for these circuits (i.e., data prior to VVO deployments), Daymark assumed that the 3% capacity savings that AEP reported on their Phase 1 circuits was reasonable. Based on the circuit performance data provided by the Company, the VVO candidate circuits experienced peak capacity savings of 67 MW from January 2017 to December 2018.

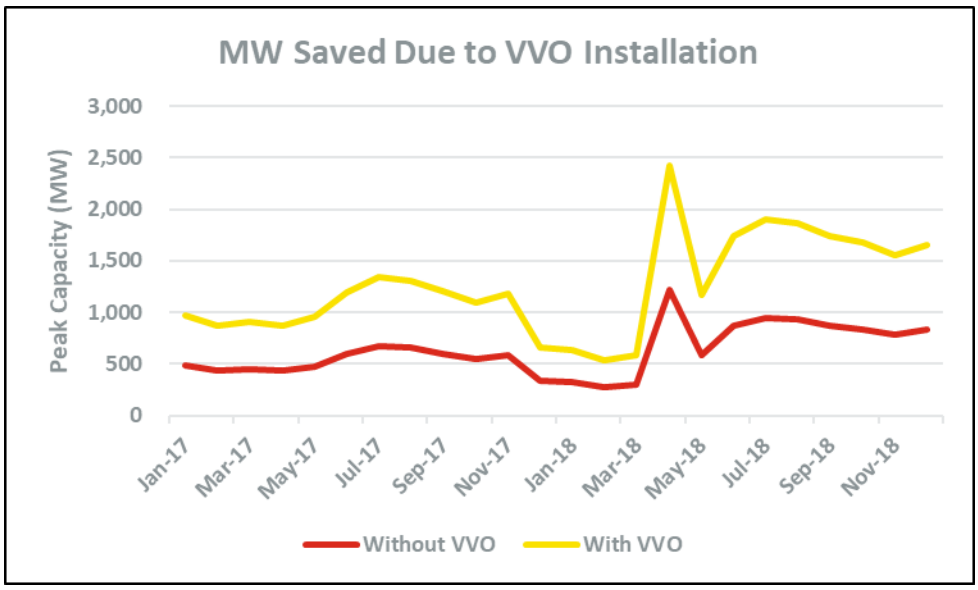

Figure 38: Capacity Savings on VVO Circuits from January 2017 to December 2018

Recommendation: Accurate tracking of energy and capacity savings on VVO circuits is critical in estimating operational benefits. To improve visibility related to the capacity savings on VVO circuits, we recommend that AEP track Phase 1 and Phase 2 circuit performance data separately, in addition to maintaining a pre versus post circuit performance metric per month for the circuits in question.

[179] AEP Ohio response to Staff DR 04-022e, Attachment.

Megawatt-hours Saved by VVO

This metric is intended to gauge the effectiveness of VVO deployment. The installation of VVO across distribution circuits reduces voltage and energy at the customer-level by flattening and lowering the voltage profile of these circuits. Daymark was unable to track this metric at a monthly level for Phase 2 circuits because the deployment occurred at the end of 2018. However, Daymark was able to use the hourly circuit performance data (as mentioned in the previous section) to estimate the energy savings for VVO candidate circuits.

The data provided by the Company included the average and peak power on the VVO candidate circuits reported on an hourly basis from 2015 to February 2019. The energy served by these circuits was determined by multiplying the average circuit power by the number of hours in a year. Since there was no pre-2011 data available for these circuits (i.e., data prior to VVO deployments), Daymark assumed that the 3% capacity savings that AEP reported on their Phase 1 circuits was reasonable. From the Company-provided circuit data, the VVO candidate circuits experienced energy savings totaling 596,874 MWh from January 2017 to December 2018.[180]

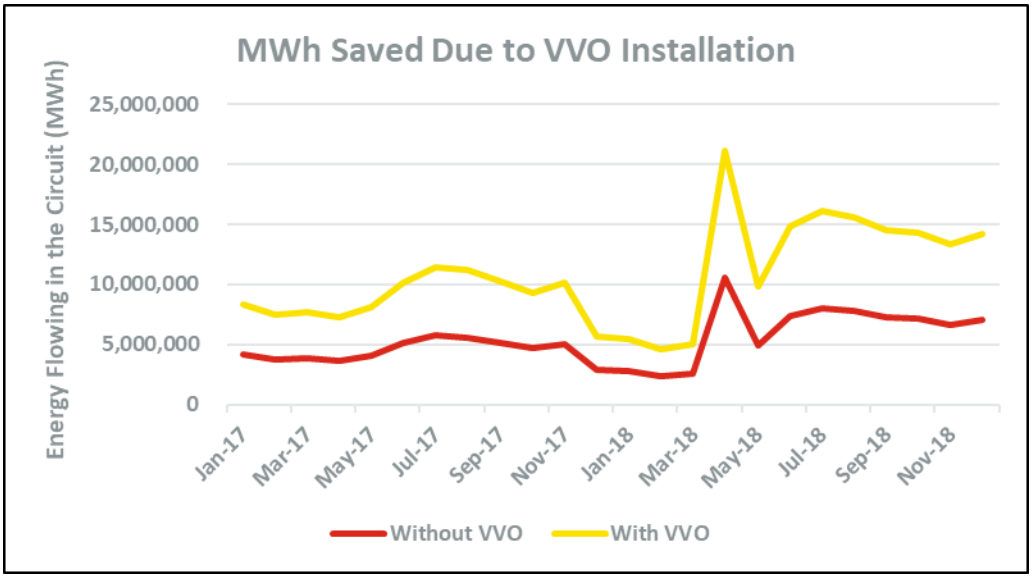

Figure 39: Energy Savings Due to VVO Installation from January 2017 to December 2018

[180] AEP Ohio response to Staff DR 04-022e.

Recommendation: Accurate tracking of energy and capacity savings on VVO circuits is critical in estimating operational benefits. To improve visibility related to the capacity savings on VVO circuits (which also drives energy savings), we recommend that AEP track Phase 1 and Phase 2 circuit performance data separately, in addition to maintaining a pre versus post circuit performance metric per month for the circuits in question.

Average System Voltage

With the advent of VVO, utilities can install these devices on their substations or feeders to adjust the voltage at specific points, thereby reducing energy, capacity, and resulting line losses on the system. The Company has proposed to track this metric by measuring the average of the voltage at the substation on the secondary side of the voltage regulation for all 3 phases over a month. However, the Company does not possess the monthly data required to support this metric. We have also confirmed with the Company that they currently do not track this metric but have plans to track this metric for Phase 2.

Recommendation: This metric is currently not used as a basis in estimating energy or capacity savings. However, going forward, we recommend tracking as a basis for refining the Company's Phase 1 estimates (3%) of capacity and energy value associated with VVO.

5.2.9 VVO Metrics / GHG Impact

VVO GHG IMPACT	METRIC DEFINITION	2016 YE VALUE	2017 YE VALUE	2018 YE VALUE
Reduction in greenhouse gases due to VVO (estimate)	For Phase 2 circuits, the estimated reduction in greenhouse gases due to VVO per month. This represents the number of MWh saved by VVO on Phase 2 circuits, multiplied by 0.88442, which is based on 2014 EPA eGRID number for RFC West subregion of 1,949.8 lbs of CO_2 per MWh, converted to metric tons per MWh.	n/a	0	0

Objective: Greenhouse gas impacts attempts to measure reduction in emissions as a result of VVO deployment.

Reduction in Greenhouse Gases Due to VVO (Estimate)

The rationale behind this metric is that by reducing energy usage with VVO deployment, the greenhouse gas emissions will also reduce accordingly. The Company, in their non-financial metrics planning, has suggested that the greenhouse gas emission reductions would be estimated by multiplying the energy savings by 0.88442 metric tons of carbon dioxide. This number is based on an EPA eGRID study that was conducted in 2014 for the RFC West subregion.

Daymark finds this a reasonable approach. However, while conducting the analysis, Daymark identified an update to the EPA eGRID study that was conducted in 2016 (this changed the number to 0.5640 metric tons per MWh).[181] Based on the Company's provided data and the updated 2016 EPA EGrid study, Daymark observed a reduction of 1.5 million metric tons of CO_2 from January 2017 to December 2018. We note that there is a significant increase in peak capacity and average load served by AEP's circuits in April 2018. This led to our analysis showing higher savings, which led to a higher reduction of GHG emissions.

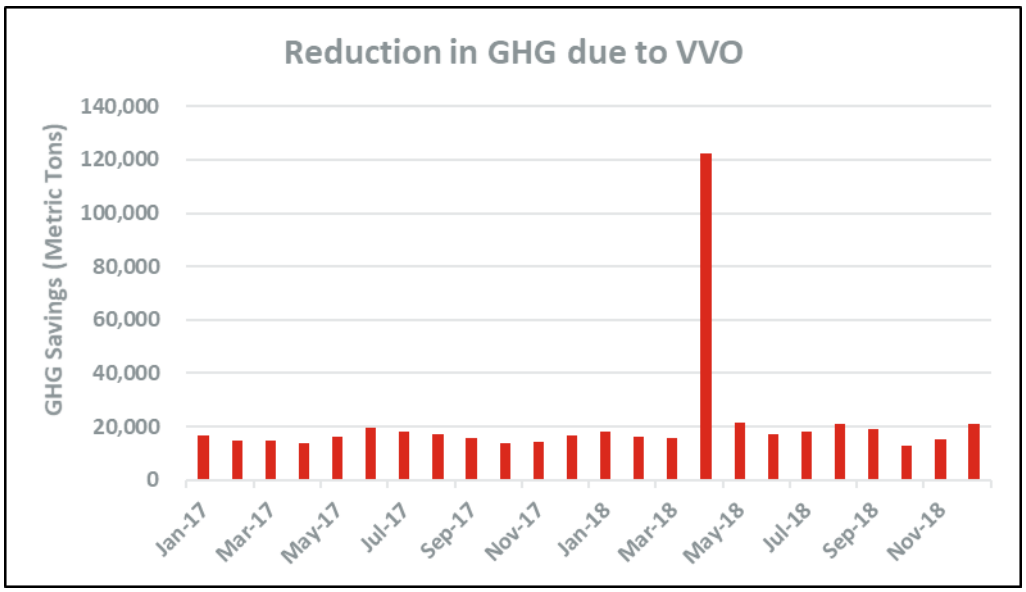

Figure 40: Reductions in GHG Due to VVO Installation from January 2017 to December 2018

[181] Emissions & Generation Resource Integrated Database ("eGRID"). https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.

Recommendation: Daymark suggests that the Company use the updated 2016 eGrid study values to estimate the reductions in greenhouse gases. Furthermore, the Company should be reporting the estimated greenhouse gas reductions for Phase 1 and Phase 2 VVO circuits separately.

5.3 Summary of Non-financial Audit Findings and Recommendations

Daymark's evaluation of the non-financial metrics reports associated with Phase 2 of AEP Ohio's gridSMART® project, which included a review of the installed equipment and systems, an analysis of their functionality, and a mapping of deployment status against implementation plans, led us to the following set of recommendations:

- **Number of Certified Meters**. Maintaining full deployment of AMI meters in the AMI deployment areas is critical to ensuring the realization of the operational benefits discussed in Section 3. To improve visibility of the total expected AMI meter deployments, we recommend AEP Ohio break out the existing metric into Phase 1 and Phase 2 and add a metric that provides the total number of remaining meters to be deployed in the Phase 2 areas.
- **AMI Meters Installed, but not Certified**. If the PUCO Staff is concerned about this issue going forward, we recommend adding a metric to measure the average time a meter sits in the active, but not certified state. Since the data doesn't currently exist to support such a metric, we further recommend discussion with the Company on the effort required to improve its data tracking to support the metric before requiring the metric to be reported.
- **Certified Smart Meter Failures**. Going forward, AEP Ohio may start to see an increased number of failures on Phase 1 meters that are now approaching 10 years of life. This is worth tracking to understand life expectancy of AMI technology. The parties agreed, in Joint Stipulation and Recommendation in Case 13-1939-EL-RDR, to a 15-year depreciable life on AMI meters. We recommend the Company track and perform a study on realized life of AMI meters for future input on AMI depreciation life assumptions.
- **Customers Eligible for Disconnect Due to Non-payment (system-wide an Phase 2) and Non-payment Disconnects (system-wide and Phase 2)**. Daymark supports recommendation provided to us by the Company to improve the accuracy of its reporting of customers eligible for disconnect by removing duplicate orders. In addition, to provide better visibility around the impact and implementation of the remote

disconnect waiver, we recommend that the Company report for the Phase 2 area: (1) the number of meters that are program-eligible for disconnect, and (2) the number of customers that are eligible for disconnect that are not disconnected due to not yet being program eligible. We also recommend that the Company track, separately, the number of remote and manual disconnects in the Phase 2 area. These additional metrics would provide further visibility on the effectiveness and value of non-payment-related remote disconnects on customers with AMI meters. Currently, the Company only reports actual non-payment disconnects but doesn't report the breakdown by manual and remote disconnect methods.

- **Power Theft Cases (number and dollar value).** To further enhance the understanding of the value of AMI meters in identifying theft cases, Daymark recommends that AEP track and report the number and dollar value of theft cases by meter type in the Phase 2 area. We would expect that as the Company's remote theft detection capabilities improve, the number of cases will go up and the average dollar value will go down, both as a result of early detection.

- **Total Call Center Calls**. Daymark recommends that AEP Ohio consider how it can improve its call center tracking to set the stage for a better understanding of how programs like AMI are impacting call center efficiencies and more specifically work with the PUCO staff to improve call center metrics reporting related to gridSMART® deployment. To the extent material call center efficiencies are achieved through the deployment of gridSMART® technologies like AMI and redeployed to "higher value" work as proposed by the Company, we further recommend that the Company, in consultation with the PUCO Staff, identify the high priority tasks to be achieved and set appropriate metrics that will verify the resulting customer benefit (e.g., reduced wait times, improved customer satisfaction rating).

- **Call Center Calls Related to Meter Readings.** Daymark recommends that AEP Ohio track the reasons for check read orders in more detail to enable the PUCO Staff to further understand trends in check read orders driven by AMI that could lead to further operational benefits.
- **Call Center Calls Related to Billing Complaints.** Daymark recommends that AEP Ohio track the reasons for billing complaints in more detail to enable the PUCO Staff to further understand trends in billing complaints driven by AMI that could lead to further operational benefits.

- **Circuits Equipped with DACR**. Daymark recommends that the Company report its 'scheduled' versus 'actual' DACR deployment for Phase 2 circuits separately. This will help the PUCO Staff in examining the progress related to Phase 2 DACR deployment in the coming months.
- **DACR Opportunities**. Daymark recommends that the Company report its DACR opportunities for Phase 2 circuits separately, instead of rolling them into their outage records. This will provide the PUCO Staff with a clearer view of DACR effectiveness.
- **DACR Successes and Failures**. Daymark recommends that the Company report specific metrics on its DACR successes and failures for Phase 2 circuits (which are already tracked). These should be reported separately, in addition to rolling them into their outage records. This will provide the PUCO Staff with a clearer view of DACR effectiveness.
- **Truck rolls Related to an Outage**. Daymark recommends the Company explicitly report the number of truck rolls that were dispatched during an outage. Since more than one truck roll could be dispatched for one outage event, it will make more sense to report the truck rolls dispatched explicitly. Daymark discovered that the Company possesses this data in their outage tickets, which are generated after every outage event. Daymark recommends that the Company explicitly separate and track data from the outage tickets that occurred on Phase 2 DACR-enabled circuits and report the number of truck rolls (standard and short) that were dispatched as a result.
- **Outage-related Truck Rolls Avoided**. Daymark recommends that the Company use the same methodology that was used to quantify avoided truck rolls in its Phase 1 DOE study. The Company's Phase 1 DOE report stated that the Company was quantifying the number of truck rolls avoided by "*counting the number of remote switching operations and assigning each as either a short or standard truck roll*." Standard truck rolls represent a crew traveling from the service center to the outage location, while short truck rolls represent a crew traveling from one switching location to another.
- **Customer Minutes Saved by Self-healing Events**. Daymark finds the methodology that the Company used to track the avoided CMI as reasonable. However, the Company provided no data as to how they got to an estimated standard duration of 83 minutes for an outage. Daymark recommends that the Company explicitly report their avoided customer minutes of interruption for Phase 2 circuits along with the other non-financial metrics that are related to DACR outages.

- **Customer Interruptions Saved by Self-healing Events**. Daymark finds the methodology that the Company used to track the avoided customer interruptions as reasonable. Going forward, Daymark recommends that the Company explicitly report their avoided customer interruption for Phase 2 circuits along with the other non-financial metrics that are related to DACR circuit outages.
- **Megawatts Saved by VVO**. Accurate tracking of energy and capacity savings on VVO circuits is critical in estimating operational benefits. To improve visibility related to the capacity savings on VVO circuits, we recommend that AEP track Phase 1 and Phase 2 circuit performance data separately, in addition to maintaining a pre versus post circuit performance metric per month for the circuits in question.
- **Megawatt-hours Saved by VVO**. Accurate tracking of energy and capacity savings on VVO circuits is critical in estimating operational benefits. To improve visibility related to the capacity savings on VVO circuits (which also drive energy savings), we recommend that AEP track Phase 1 and Phase 2 circuit performance data separately, in addition to maintaining a pre versus post circuit performance metric per month for the circuits in question.
- **System Average Voltage**. This metric is currently not used as a basis in estimating energy or capacity savings. However, going forward, we recommend tracking as a basis for refining the Company's Phase 1 estimates (3%) of capacity and energy value associated with VVO.
- **Reduction in Greenhouse Gases Due to VVO (Estimate).** Daymark suggests that the Company use the updated 2016 eGrid study values to estimate the reductions in greenhouse gases. Furthermore, the Company should be reporting the estimated greenhouse gas reductions for Phase 1 and Phase 2 VVO circuits separately.

6. SYSTEMS INTEGRATION ASSESSMENT

6.1 Introduction

The level of benefits achievable through the deployment of "smart" technologies like AMI, DACR, and VVO are dependent on the level of "smart" integration of the technologies into the utilities system operations and business processes. For example, the benefit of reducing meter reading costs with AMI is only achieved by integrating the AMI systems with the utility's billing system. AMI data and communications functionality can be further leveraged to improve utility operations and decision making as well as improve the overall customer experience through integration with other internal and external facing utility systems. Likewise, the benefits of DACR and VVO installed throughout the distribution system can be enhanced when integrated with operations and planning software and new business processes.

Each utility's solution implementation and integration strategy will be different based on factors such as the topology, age, and design of its existing infrastructure, the profile of its customers, and the state of its core operating and business systems. Regardless of the strategy, realizing benefits by increasing access to real-time information and enabling remote and/or automated operational control and communication through the implementation of smart devices requires smart integration of these technologies with its core operational and business systems.

As part of its efforts, Daymark performed a high-level assessment of AEP Ohio's system integration efforts to inform the identification and quantification of operational benefits as well as provide deeper insights into some of the drivers associated with variances in (1) actual versus planned operating benefits, and (2) the timing and reasonableness of achieving future savings. It is not intended to be a detailed architectural system review or an assessment of the Company's integration or systems choices. It also does not cover all operational benefits, but rather focuses on system integrations that are driving the highest value operational benefits.

This section focuses on our approach and findings related to our system integration assessment.

6.2 System Integration Audit Methodology

Our systems integration data collection and evaluation efforts specifically included the following steps:

- Review reliability metrics for the AMI, DACR, and VVO hardware and communications infrastructure.
- Identify and evaluate specific gridSMART® integration use cases that rely on data generated by or communication with the deployed gridSMART® field hardware to drive operational benefits as follows:
  - Identify and review performance metrics that confirm integration is functioning adequately.
  - Verified metrics, where possible, by performing an end-to-end test on a sample of deployments further confirming the level of end to end integration achieved to date. A similar approach was considered for DACR and VVO but ultimately dismissed due to early findings through discovery and discussions with the Company indicating very little integration with AEP operations and business systems was planned or implemented for these technologies. See further discussion in DACR and VVO section below.
  - Assess the integration solution's effectiveness in driving operational benefits and identify any systems integration gaps, limitations, or timing issues that are impacting AEP's ability to achieve benefits.
  - Review information systems' implementation plans to determine status of new and planned integrations not yet fully implemented.

Our assessment relied on metrics and other data collected through written information requests and focused interviews with AEP Ohio staff to walk through the Company's system integration diagrams, data flows, and business process changes. These guided discussions provided our team with a deeper understanding of the Company's approach to integration and how operational, reliability, and energy savings benefits are impacted by the Company's integration plan.

The results of our systems integration assessment are broken out by technology below.

6.3 AMI System Integration

As part of Phase 1, AEP Ohio integrated its AMI meter infrastructure with its back-office systems to collect, meter, and manage meter data, and to leverage two-way meter functionality to improve its billing, collection, connect/disconnects, outage detection, and meter monitoring activities. Other than expanding its communications network, there were no additional system integration projects associated with AMI meters as part of Phase 2.[182] The Company further indicated that there are no budgeted plans to implement any additional system integration projects associated with AMI meters.[183]

6.3.1 AMI System Reliability Metrics

Component and communications failures are the primary reasons for unavailability of AMI data. Component failure can be a result of a hardware or software malfunction, or human tampering with the meter. Communication failure can be caused by a variety of things such as interference, cut cables, network traffic, etc. To test the reliability of the system, we reviewed the number of meter failures and uptime of the AMI communication network.

Meter Failure Rate: AEP Ohio tracks and reports the number of meter failures on a monthly basis. The cumulative failure rates[184] are approximately 0.025% for Phase 2 meters and 5.0% for Phase 1 meters. The low rates experienced to date paired with the early detection capability provided by near real time meter monitoring (discussed further below) gives us confidence that meter performance is not impeding the Company's ability to derive value from the investment.

Communication Infrastructure: AEP Ohio's communications network has built in redundancy such that if a relay or AP goes down, data will automatically be redirected to another relay or AP. Once the network is fully optimized (which won't occur until full deployment of Phase 2), AEP Ohio has a contractual Service Level Agreement with its communication vendor. Optimization is an effort at the final stage of deployment that optimizes the routing and number of meters assigned to a relay and/or AP to improve performance of the system. AEP Ohio has been tracking availability of the communications network (as a measure of uptime) through deployment; for example,

[182] AEP Ohio response to Staff DR 05-010.

[183] AEP Ohio response to Staff DR 05-010 and Staff DR 05-011.

[184] Total failures since inception divided by the total number of meters installed.

2018 monthly aggregated average performance was consistently above 97%, indicating a strong performing system.

6.3.2 AMI Business Use Cases

In AEP Ohio's Final Technical Report submitted to the DOE for Phase 1, the Company identified the following use cases for the AMI system.[185]

- Remote connect/disconnect
- Outage reporting
- Interval data collection
- Calc of billing determinants
- Power quality monitoring
- Consumer programs facilitation

Based on our discussion with the Company, we narrowed the list down to the following three integration use cases that are driving the bulk of operational benefits for AEP Ohio.[186]

Meter to Bill – Integration of AMI meter data with AEP Ohio's Meter Data Management ("MDM") system for billing system access to billing determinants thus eliminating the need for manual meter reading and improving the billing process.

Remote Connect/Disconnect - Integration of UtilityIQ AMI meter software with the Company's billing systems to enable remote connect/disconnects for routine requests, non-payment, and theft.

Meter and System Outage Monitoring - Integration of AMI meters with the Company's Meter Outage Processing System ("MOPS") to enable remote pings to confirm meter is functioning properly.

In addition to the use cases above, AEP has implemented a UtilityIQ Data Store to capture meter events for power quality reporting and interval data for PJM settlements and to feed its business partner portal and customer web portal. This system was not considered as part of our integration assessment work given its low impact on driving operational benefits as implemented at this time.

[185] Final Technical Report, AEP Ohio gridSMART® Demonstration Project, A Community Based Approach to Leading the Nation in Smart Energy Use Department of Energy (DOE) Smart Grid Demonstration Project (SGDP) Contract Award Number DE-OE000193, June 2014.

[186] Consumer programs facilitation and related technology systems integrations are out of scope for purposes of this audit.

AEP Ohio also has plans to integrate AMI and VVO through implementation of the VVO AMI module to drive further energy efficiency savings from its VVO deployment. We will cover this effort in the VVO section below.

The following table identifies how the three use cases identified above contribute to the operational benefits discussed earlier in Section 3 of this report.

Table 7: AMI Integration Use Cases

USE CASE	BENEFITS IMPACTED	BENEFIT CATEGORY
METER TO BILL	• Reduced meter operations cost –meter reading routes	• Avoided cost
	• Reduced billing labor costs	• Avoided cost
	• Reduced call center costs related to bill complaints	• Avoided cost • Improved customer service
	• Increased safety	• Avoided cost • Improved employee safety
CONNECT/DISCONNECT	• Reduced meter operations cost –off-cycle meter reads for routine connect/disconnects	• Avoided cost
	• Reduced consumption on inactive meters	• Increased revenue
	• Reduced bad debt	• Increased revenue
METER AND SYSTEM OUTAGE MONITORING	• Reduced meter operations cost – labor and vehicle management	• Avoided cost
	• Reduced theft	• Increased revenue
	• Remote meter diagnostics	• Avoided cost
	• Reduced outages	• Increased revenue • Reliability
	• Optimized restoration dispatch	• Avoided cost

For each business use case, identified, we reviewed the performance metrics that confirm integration is functioning sufficiently to drive operational benefits. A discussion of each integration use case and our findings is provided below.

Meter to Bill:

Analog meters require meter readers on assigned routes to physically walk up to each meter, inspect the seal, read the meter, and re-seal the meter if necessary. Where analog meters have been replaced by radio frequency meters, meters can be automatically read by driving by the premises, which has resulted in operational savings by increasing the number of meter reads that can be accomplished per meter reader and per route. In either case, when the assigned route is complete, the meter reader returns to the office and downloads the reads back into the Company's FieldNet system. Reads are then routed to AEP Ohio's Customer Information System ("CIS"), and bills are produced overnight and mailed the following day. If the meter is not read before the billing cycle, the customer is issued an estimated bill.[187]

Through deployment of AMI, AEP Ohio's goal is to displace 100% of routine meter reads in the Phase 1 and Phase 2 deployment areas. Instead of manual reads, an automated daily register read and 15-minute interval data is collected from meters via the AMI network and transmitted to the AEP Ohio's legacy back office billing and CIS systems via the AMI Meter Head-End UtilityIQ systems as shown in Figure 41, below. This occurs every 4 hours for interval data and once daily for billing determinants. Customers are billed with the registered read collected on the billing date. In the event of a communication outage, registered reads within a window (1 day before or 2 days after the bill date) can be used for billing, effectively negating the need for estimated bills.[188]

[187] AEP Ohio response to Staff DR 02-085b.

[188] AEP Ohio response to Staff DR 05-009.

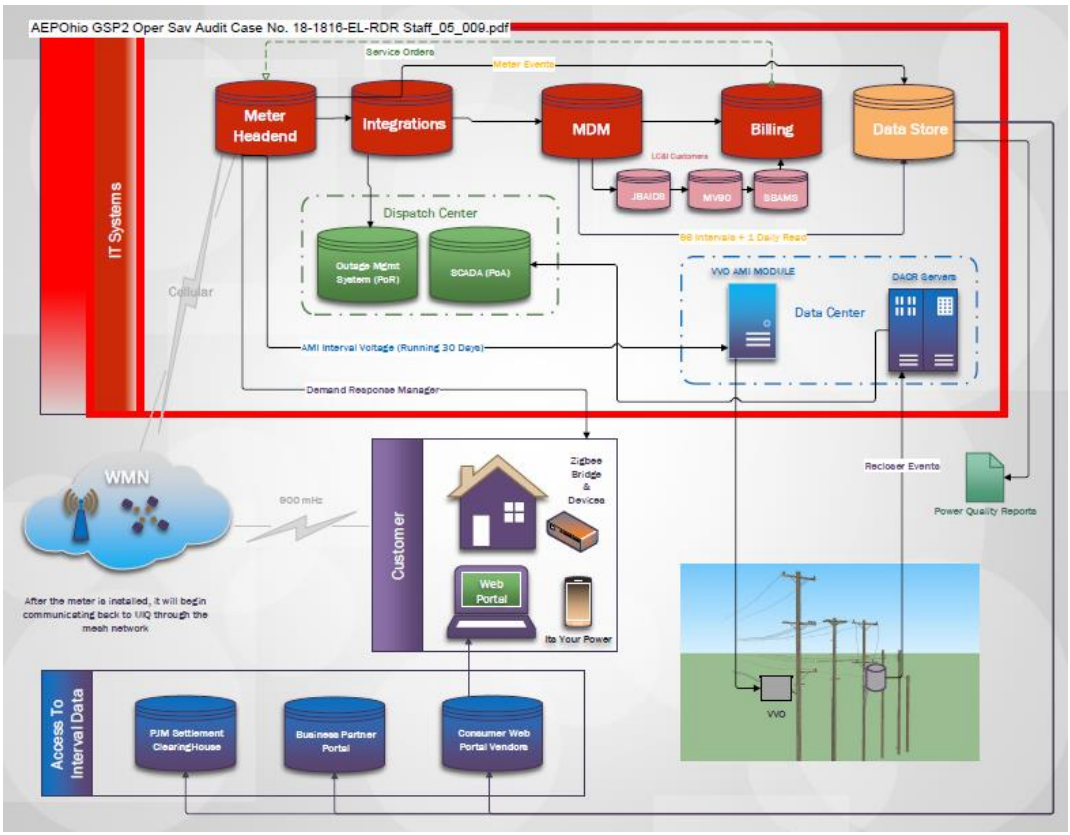

Figure 41: AEP Integration Diagram

As discussed in Section 5, our assessment of the Manual Meter Reads metric indicated a strong correlation between the number of successful meter reads and the number of certified AMI meters deployed indicating a well-functioning system integration from meter to bill. This was further evidenced in our sample data testing described below.[189]

[189] AEP Ohio response to Staff DR 02-002.

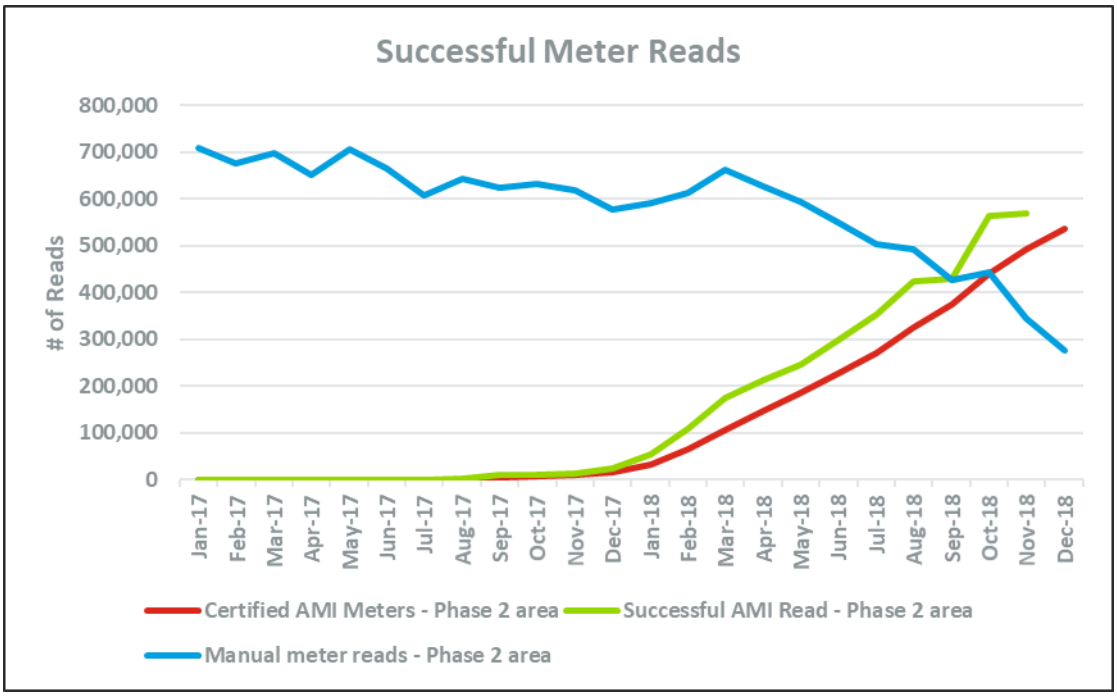

Figure 42: Successful Meter Reads

Connects/Disconnects

Traditional meters require that AEP Ohio send a meter specialist out to the meter to open/close the meter for routine events such as moves, failure to pay, and theft cases. In some cases, the Company may not have time or may elect not to send someone out to read the meter off-cycle. For example, in the case of a tenant moving out and a new tenant moving in a few days later, the Company may simply close the account and reopen a new account in the billing system. This saves the cost of the truck roll, but can result in consumption on an inactive account, which adds to the amount of unaccounted for energy that all customers ultimately pay for through rates.

With AMI, customer service reps can remotely open or close the meters over the AMI network via service order generated by the Customer Service Representative or billing specialist. Remote meter connects can occur in minutes versus the days that it might take to schedule an off-cycle meter reading manually. This capability contributes to improved customer service, reduced cost from avoided off-cycle truck rolls, and higher revenue associated with reduced theft and timely disconnect for non-payment.

For the reasons discussed previously in Section 3, the implementation of disconnects for non-payment was delayed.

Meter Monitoring & System Outage Detection

The AEP Operations department would typically learn about an outage only after someone calls into the AEP call center to report a power outage. With AMI, the system provides AEP Ohio with the ability to monitor meters and notify Operations of consumer power outages in near real-time This monitoring capability is enabled through meters sending a "last gasp" notification to the MOPS systems prior to an outage. The MOPS then sends regular pings (approximately every 5 minutes) to the AMI meter through the Meter Head-End (UtilityIQ) system to detect a sustained outage. To avoid false positives (momentary outages), the MOPS system identifies outages lasting more than 20 minutes and reports these to the AEP Dispatch Center through the existing Trouble Entry Reporting System ("TERS"). TERS is the same system that AEP Ohio's call center uses to report outages received by customer via phone call. There is no change to this process and customers with AMI meters can still call in to report an outage as they could before.

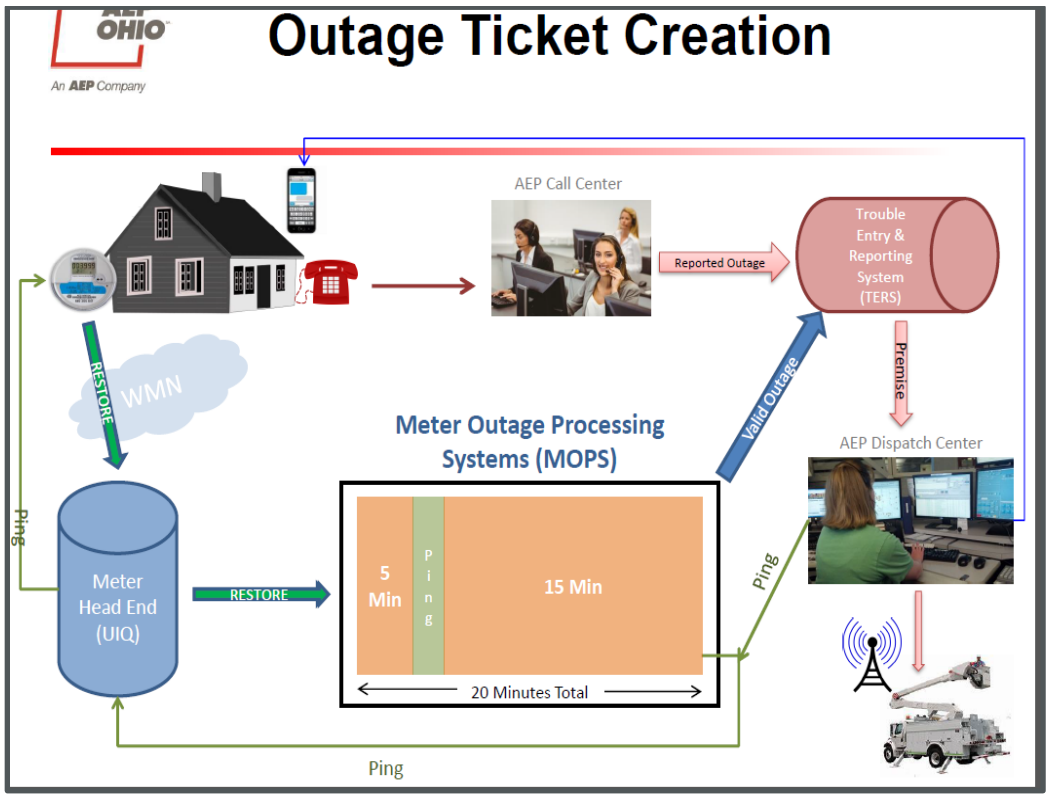

Figure 43: Outage Ticket Creation[190]

Since implementation of MOPS in Phase 1, logic enhancements have continued to improve its value. For example, AEP Ohio has adjusted logic and settings in MOPS to reduce false positives that would otherwise increase cost associated with falsely investigating outage events. In addition, outage enhancements were placed into production on February 28th, 2019, to allow the dispatch center to customize MOPS settings based on the time of day. Storm Mode was also added, which allows the dispatch center to quickly-enable pre-determined storm settings for each district.[191]

AEP Ohio's meter monitoring and system monitoring integration to date is rather elementary, essentially plugging outage data into the current outage management systems and processes. In addition, there is a built-in delay of 20 minutes (the time built into MOPS to confirm a meter outage) or longer once you consider the information then

[190] AEP Ohio response to Staff DR 01-001.

[191] *Building a Better Smarter Grid*. AEP Ohio Smart Grid Phase 2 Newsletter Volume 2, Issue 2, March 2019.

needs to pass through the Company's TERS system and be processed by the AEP dispatch center before an order for action is taken.

6.3.3 Systems Integration Sample Testing

As part of our system integration assessment, Daymark analyzed monthly data for a sample of Phase 2 premises with AMI meters ("Sample"). Specifically, Daymark requested meter and billing account information such as meter read types, AMI meter installation dates, meter read dates and bill issue dates, and eligibilities for non-payment-related disconnect and remote disconnect for the randomly-selected premises. The purpose of this analysis was to assess the trends observed in the Sample taken and compare them with the population trends reported in the non-financial AMI metrics.

6.3.3.1 Sample Premises Considered

Daymark randomly selected 400 premises from the population of premises in the gridSMART® Phase 2 deployment area that had AMI meters installed during the period October 2017 to September 2018. Daymark limited premise selection to September 2018 to allow for monthly meter read information for post-AMI installation of all premises in the considered Sample. Daymark employed a stratified sampling methodology to randomly select 200 premises each from 2017 and 2018. The 200 premises from each AMI installation year were then randomly selected. Daymark chose stratified random sampling to make sure that there would be enough post-AMI installation information to consider in the assessment.

For the randomly-selected 400 premises, Daymark requested the same information (meter read types, AMI meter installation dates, meter read dates and bill issue dates, and eligibilities for non-payment related disconnect and remote disconnect). The Company provided the requested information for 397 premises out of the 400 requested premises.[192] Out of 397 premises with installed AMI meters, 198 premises had AMI meters installed in 2017 and the remaining 199 premises had AMI meters installed in 2018. Figure 44 shows the monthly count of premises with AMI meters installed that were included in the Sample.

[192] The 400 premises selected in the Sample developed by Daymark included one duplicate premise .and two premises that did not have AMI meters installed during September 2017 – December 2018 period.

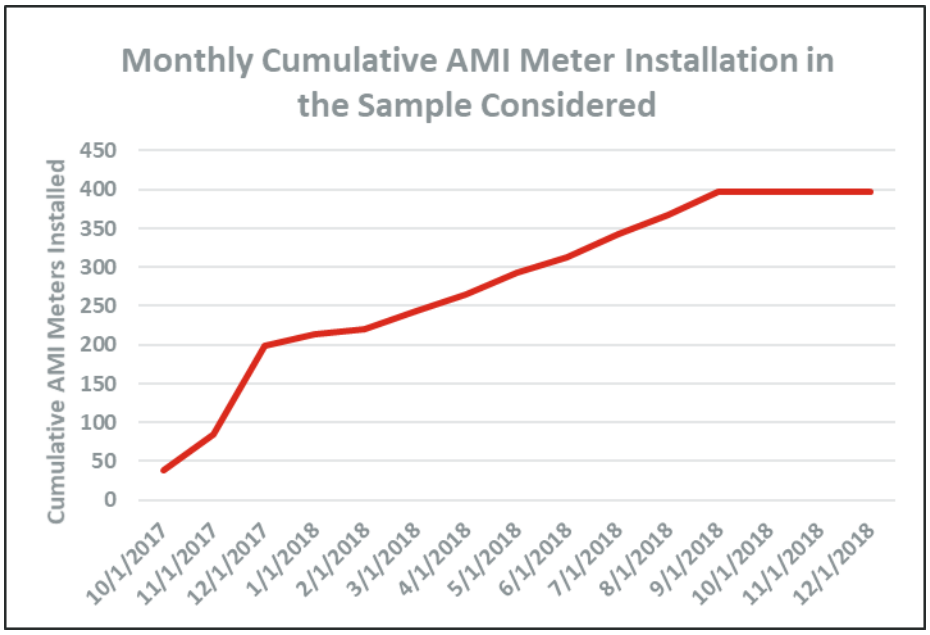

Figure 44: Premises included in the Sample with cumulative monthly AMI meter installation[193]

6.3.3.2 Data Analysis and Findings

Meter Reading Types

As a further review of the meter-to-bill integration, Daymark analyzed the Sample meter reading type data for all bills issued in the study period to determine the percentage of bills that were based on digital meter readings post-AMI deployment. This data was then compared to the same percentage calculated from data provided by AEP Ohio in support of the monthly non-financial metrics for the Phase 2 population.[194] Although our Sample included AMI meters being installed starting in the fall of 2017, we compared actual monthly meter reads beginning in January 2018 to make sure that we had enough meter read data for the post-AMI installation period on the premises included in the Sample. Our analysis of the Sample shows that 99.2% of the meter readings used for billing were based on digital meter reads post-AMI deployment. This compares closely with the 99.6% for the Phase 2 population post-AMI deployment. Figure 45 below shows a comparison of the monthly percentage of actual meter reads for the sampled and population of AMI meters installed in Phase 2. The consistently

[193] AEP Ohio response to Staff DR 07-001.

[194] AEP Ohio response to Staff DR 02-043.

high percentage of actual-digital meter readings in the Sample as well as in the population provides supporting evidence that the AMI meter system integration with the billing system is functioning as intended.

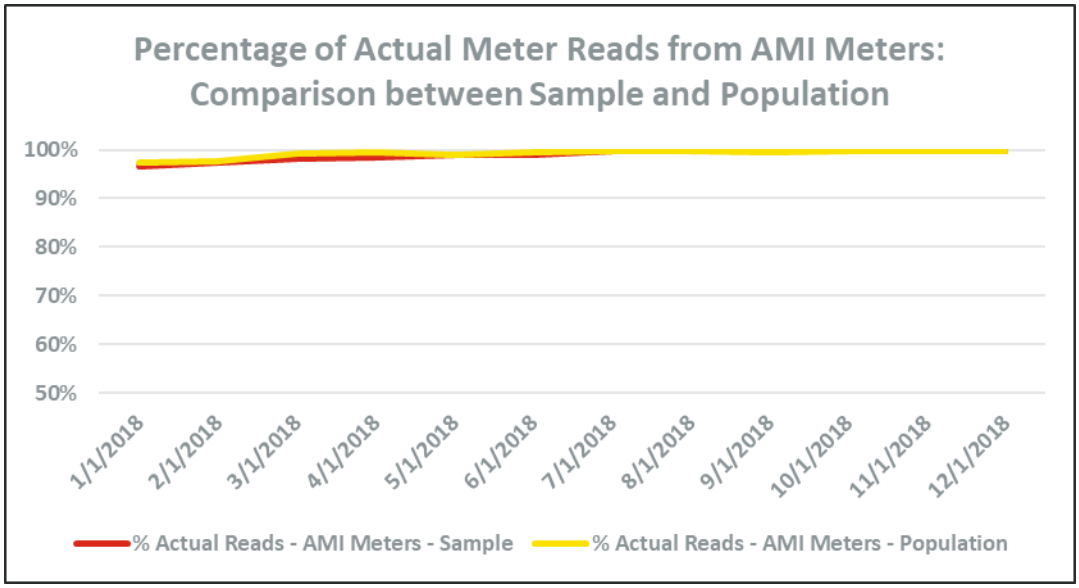

Figure 45: Monthly percentage of actual meter reads of AMI meters installed in Sample and Phase 2 premises

Daymark also compared the percentage of actual meter reads[195] for the period before and after AMI installation within the Sample. Daymark observed that the installation of AMI meters has significantly increased the proportion of actual meter reads. Prior to the installation of AMI, actual reads within the Sample averaged 81.9% of the total meter reads. However, after AMI meters were installed, the percentage of actual meter reads included in the Sample increased to 99.2%.

Remote Disconnects for Non-Payment Eligible Disconnects

As discussed in Section 5, AEP Ohio is still in the process of rolling out program eligibility for remote disconnect for non-payment under its remote disconnect waiver approved in June 2018.[196] Nevertheless, Daymark observed that about 75% of the premises considered in the Sample were program-eligible for remote disconnect starting October 1, 2018, which we felt was enough of the population to analyze for insights.

[195] Which would include digital, radio (AMR), or manual reads.

[196] AEP Ohio response to Staff DR 02-042.

Daymark assessed whether remote non-payment related disconnects occurred for any non-payment eligible customers included in the Sample premises that were also program-eligible for remote disconnect. For this purpose, Daymark simultaneously looked at the remote disconnect and non-payment disconnect eligibilities along with bill period and meter turn-on and turn-off dates using the monthly data provided by the Company to identify any remote non-payment related disconnects.

Daymark did not observe any non-payment remote disconnects in the Sample. There were 33 instances where a premise with an AMI meter installed was both eligible for remote disconnect and non-payment eligible for disconnect. Out of the observed 33 instances, 18 instances occurred during the shoulder months and could have been remotely disconnected.[197] We were not able to discern from the dataset whether this was related to a systems integration issue or any number of valid reasons a customer may not be disconnected for non-payment (i.e., customer made a payment, agreed to a payment plan, etc.).

Daymark anticipates that there will be an increase in remote disconnects once the Company has completed the process of establishing remote disconnect eligibility for non-payment. Currently, the Company reports monthly customers eligible for non-payment disconnect and actual disconnects, but doesn't report on non-payment-related disconnects. We recommend that the PUCO staff continue to monitor the implementation of remote disconnects for non-payment through current metrics. In addition, we recommend that the Company track the number of remote and manual disconnects in the Phase 2 area separately, as additional metrics, to provide further visibility into the effectiveness and value of non-payment related remote disconnects on customers with AMI meters. Currently, the Company only reports non-payment disconnects but does not report the breakdown by manual versus remote disconnect methods.

Because the reason for lack of disconnection was unclear from the data provided on the 33 observed instances, we recommend that the Company review these instances to ensure that there is a valid reason and that the lack of disconnects is not an indication of a system integration or process failure.

[197] Per AEP Ohio, the Company's policy is not to initiate a remote during a peak period.

Meter Failures

Daymark also compared the meter failure rates between the meters installed in the Sample and the AMI meters installed as part of Phase 2. In the Sample of 397 premises, Daymark observed there were two instances where an AMI meter was replaced with a new AMI meter. The replacement of AMI meters could occur due to meter malfunction. We assume that there were two failures out of 397 AMI meters resulting in a 0.5% failure rate for the Sample considered. For the population of premises that had AMI meters installed during Phase 2, as of December 2018, the meter failure rate was 0.02%.[198] Even though the meter failure rates observed in the Sample was higher than that of the population, the failure rate is still very small and did not raise any significant concerns.

6.4 DACR Systems Integration

DACR integration is key to extracting the full value of DACR investment. In this section we will detail the areas where increased integration would drive value for the Company.

6.4.1 DACR System Reliability Metrics

The Company currently tracks the reliability of the DACR integration as a non-financial metric based on the success of DACR operation when afforded the opportunity. Recent history shows an 85% success rate, which is expected to improve as more experience is gained.

6.4.2 DACR Business Use Cases

As listed in the following table, the following business use case was identified as critical to delivering the broader benefits of DACR. Currently, the Company's focus is on operationally integrating DACR with SCADA and the OMS, thereby reducing the frequency and duration of outages experienced by customers. Beyond operational integration there is a need to fundamentally integrate the data and functionality provided by DACR into the Company's daily work processes. The following table lists just a couple of areas where increased focus on integration is necessary to extract the full value of DACR implementation.

[198] There were 129 certified system failures out of 536,674 meters installed in 2018. Source: AEP response to Staff 02-002, Appendix C.

Table 8: DACR Integration Use Cases

USE CASE	BENEFITS IMPACTED	BENEFIT CATEGORY
MAINTENANCE PLANNING	• Reduced O&M costs • Reduced capital associated with equipment replacement	• O&M • Capital

6.4.3 Findings & Recommendations

The Company needs to focus more on better integrating the data and functionality provided by DACR into their everyday work processes in order to enhance business process efficiencies.

- ***Legacy databases need to evolve.*** The Outage Management System ("OMS"), which currently receives outage notifications from both customer call-ins and the DACR system where deployed, needs to be modified to track all the steps involved in outage restoration; notification, assignment, cause identification, and lastly, restoration.

6.5 VVO Systems Integration

VVO integration is key to extracting the full value of the VVO the investment. In this section we will detail the areas where increased integration would drive value for the Company.

6.5.1 VVO System Reliability Metrics

Integration is key to realizing the full value from VVO deployment. VVO integration is limited to SCADA and remote operation of select voltage regulating devices. The Company is in the process of expanding the integration to include AMI as a means of extracting additional efficiency savings, increasing the total estimated benefit by an additional 1% to an overall 4% savings in energy requirements.

As is the case with DACR, there is a need to go beyond operational integration to fundamentally integrate the data and functionality provided by VVO into the Company's daily work processes. Table 9 lists just a few of the areas where increased focus on integration is necessary to extract the full value of DACR implementation.

6.5.2 VVO Business Use Cases

Table 9 lists the business use case that were identified as critical to delivering the broader benefits of VVO and AMI technologies combined.

Table 9: VVO Integration Use Cases

USE CASE	BENEFITS IMPACTED	BENEFIT CATEGORY
SYSTEM PLANNING	• Delayed or eliminated need for capital investment	• Capital
MAINTENANCE PLANNING	• Reduced O&M costs • Reduced capital associated with equipment replacement	• O&M • Capital
VVO OPTIMIZATION WITH AMI MODULE	• Reduced energy requirements	• Fuel cost • Billing

6.5.3 Findings & Recommendations

The Company needs to focus more on better integrating the data and functionality provided by VVO into their everyday work processes.

- ***Distribution planning practices need to evolve.*** One of the well-documented benefits of VVO deployment is the potential for capacity investment deferrals based on reductions in peak demand. It is generally accepted in the industry that an optimized lower voltage level leads to a lower peak demand, which reduces the need for capacity. Several case studies were reported by the U.S. Department of Energy ("DOE") where VVO's capabilities were instrumental in providing significant operational savings by deferring capacity additions in a utility's asset class. For instance, Con Edison used the voltage control and reactive power management capabilities of VVO to increase its substation capability, saving $15.7 million in the process.[199] As of this report, the Company has indicated that no capital projects have been deferred as a result of VVO deployment. Going forward the Company needs to specifically address the capacity value of VVO in its distribution planning whenever there is a need for capacity expansion.

- ***Maintenance practices need to evolve.*** Another benefit of VVO deployment cited in industry studies relates to reduced operating cycles and associated "wear and tear" for legacy voltage regulators and tap changing substation transformers. To-date this has not been the Company's experience. Going forward, a greater emphasis placed on monitoring existing voltage regulating equipment cycles would help to better inform future maintenance activities.

[199] Distribution Automation: Results from the Smart Grid Investment Grant Program, U.S. Department of Energy, September 2016, p. 6.

6.6 Combined Systems Integration

This section highlights the potential benefits that the Company could realize after integrating Phase 2 deployments of AMI, DACR and VVO. By using advanced real-time meter data and superior AMI data quality from deployed AMI, along with real-time system data available from deployed DACR and VVO systems, the Company could identify O&M and capital savings.

6.6.1 Capacity Planning O&M Savings Due to Superior AMI Data Quality

Deployment of AMI over the Phase 2 area will enable AEP to have access to more granular historical meter data in real time. Access to smart meter data in real time will enable AEP's remote diagnostics capability and over time the ability to transform the way load is forecasted, which will benefit the distribution planning process. This specific benefit will capture labor savings related to capacity planning deferral.

Load values used in the planning process are typically measured and recorded by the SCADA system, which mainly gathers data at a substation level. Amount of load on line equipment during a given period is typically estimated using customer monthly consumption data (collected from Traditional meters) and feeder loading throughout a day can be shown using aggregate level data at the substation. Line equipment loading can be predicted using models and monthly customer consumption data. As real time metering becomes available at the substation level or along the circuit, estimated load flow will not match actual loading. However, with AMI meter deployment, more granular, real-time customer data can be integrated with the SCADA data to produce feeder or other specific equipment load curves. Analysis of these load curves and detailed time series load data will enable AEP to identify opportunities for deferral of projects. As AEP develops more advanced system modeling and planning tools, the distribution system can be modeled in a way that ties more closely to actual conditions and projects can be built closer to the time they are actually needed, due to reduced planning margins. This will allow AEP to prioritize labor to more pressing tasks, thereby leading to savings in the process.

Additional future benefits of AMI data include transformer and line equipment optimal sizing, proactive power quality assessment including momentary data analysis, and proactive replacement of overloaded equipment. These future benefits are attained through AMI data providing more real-time data points that can be used in more advanced system modeling and planning tools that will lead to better utilization of existing infrastructure, proactive equipment replacement, and earlier detection and

remediation of power quality issues in poorer performing areas of the system. This benefit, shown in Line 5 of Table 4, is "Rider eligible".

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

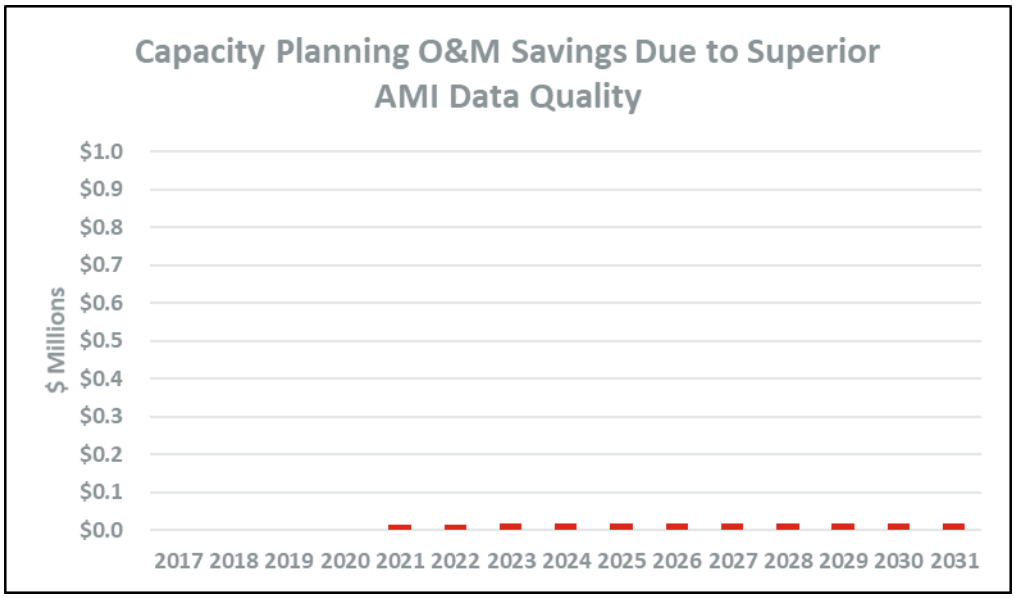

Figure 46: Capacity Planning O&M Savings Due to Superior AMI – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – No measurable verification method was provided by AEP due to savings deemed to be a shifting of resources to other required work.[200] AEP based this saving on industry models to provide a reasonable estimate of expected results.[201] These industry models were not available for our review and therefore we were not able to verify the estimated savings for this benefit.
- **Daymark Analysis** – Due to a lack of adequate data to calculate Capacity Planning O&M Savings Due to Superior AMI Data Quality, as well as delayed deployment of AMI, which will delay potential savings until future years, the savings for this benefit were simply a function of realigning AEP's original savings estimates due to the delayed *deployment of*

[200] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[201] AEP response to Staff-04-010, Attachment 1.

AMI and *inflation*.[202] We found that it was necessary to zero out benefits from 2017 through 2020, as AEP is currently focused on AMI deployment. For all years after, the savings from the previous year are increased by inflation.

Recommendations:

Daymark was unable to analyze and determine Capacity Planning O&M Savings driven by the Availability of Superior AMI Data Quality due to the lack of integration.

Once AMI deployment is complete, AEP should focus on developing advanced system modeling and planning tools to take advantage of this additional, real-time meter data. It is important to note that for the analysis from these models and tools to be the most useful, AEP needs to better integrate their systems and leverage real-time data available from VVO and DACR being installed on circuits where the AMI meters are being deployed.

6.6.2 Capacity Planning Capital Savings Due to Superior AMI Data Quality

This operational benefit is similar to the Capacity Planning O&M Savings Due to Superior AMI Data Quality benefit explained above. The main difference is that this is focused on the capital aspects of capacity planning. This benefit shown, in Line 12 of Table 4, is "not Rider eligible."

The figure below shows the expected value for this benefit calculated using the Daymark Analysis methodology described below.

[202] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

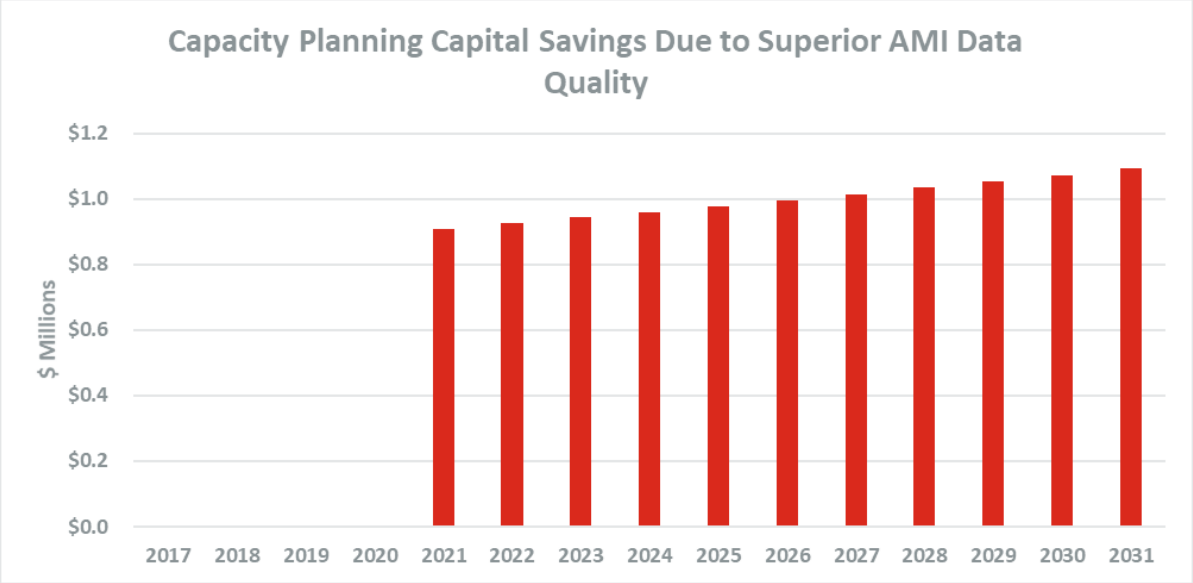

Figure 47: Capacity Planning Capital Savings Due to Superior AMI – Daymark Analysis

Calculation:

- **AEP Proposed Calculation** – No measurable verification method was provided by AEP due to savings deemed to be a shifting of resources to other required work. [203] AEP based these savings on industry models to provide a reasonable estimate of expected results.[204] These industry models were not available for our review and therefore we were not able to verify the estimated savings for this benefit.
- **Daymark Analysis** – Due to a lack of adequate data to calculate Capacity Planning Capital Savings Due to Superior AMI Data Quality, as well as delayed deployment of AMI, which will delay potential savings until future years, the savings for this benefit were simply a function of realigning AEP's original savings estimates due to the *deployment of AMI* and *inflation*.[205] We found that it was necessary to zero out benefits from 2017 through 2020 because AEP is currently focused on AMI deployment. For all years after, the savings from the previous year are increased by inflation.

[203] Case No. 13-1939-EL-RDR, AEP Initial Application, Attachment C.

[204] AEP response to Staff-04-010, Attachment 1.

[205] AEP Ohio responses to Staff DR 02-002, Attachment, Appendix A, Staff DR 02-018, Attachment, and Staff DR 04-004. Inflation is based on a 20-year annual percentage average during the 2000 through 2018 period using annual data from Federal Reserve Bank of Minneapolis.

Recommendations:

Daymark was unable to analyze and determine Capacity Planning Capital Savings driven by the Availability of Superior AMI Data Quality due to the lack of integration. See our recommendation for the Capacity Planning O&M Savings Due to Superior AMI Data Quality benefit in the prior section.

6.7 Other Recommendations

As AEP Ohio expands its deployment of gridSMART® technologies and other "smart" devices, access to granular real-time information will create large amounts of data and log files that have the potential to provide data analytics opportunities to improve business processes and decision making by the utility, customers, and third-party providers. This includes system operation and equipment performance data as well as information about customer use and behavior. In order to manage the vast amount of data available through smart technologies and turn it into actionable knowledge, AEP Ohio will need to continue to invest in its IT reporting, data mining applications, and data analytics capabilities.

APPENDIX A

Additional Supporting Tables

The tables below provide our initial evaluation details for each category of non-financial metrics that were analyzed, including data from AEP that was analyzed, the methodology used to analyze the data, and the deliverable or findings from the analysis.

Table 10: AMI Metrics

CATEGORY	DATA	METHODOLOGY	DELIVERABLE
Meters	• Number of certified meters • AMI meters installed but not certified • Certified AMI meter failures • Meters salvaged (quantity and monetary value)	• Review a small sample of meters in each category to confirm that they are being accounted for accurately • Evaluate installation, certification, and failure rates against plan assumptions	Identify and explain findings in meter installation, quality, and inventory levels that have the potential to materially-impact the benefits and/or cost of the program.
Meter reads	• Manual meter reads • Successful AMI meter reads • Successful AMR meter reads • Number of estimated meter reads • Number of meter readers employed by AEP Ohio and by external contractors (expressed as full-time equivalent)	• Review a small sample of automated AMI meter reads for process automation success • Compare as a percent against total meter reads for AMI group and non-AMI group • Evaluate against planned improvement	Identify and explain findings in meter data and functionality used to capture operational efficiency improvements that have the potential to materially-impact the benefits and/or cost of the program.
Bills issued	• Residential bills issued • Residential bills based on estimated meter reads	• Compare as a percent against total meter reads for AMI group and non-AMI group • Evaluate against planned improvement	Identify and explain findings in meter data quality, billing data accuracy, and operational efficiency improvements that have the potential to materially-impact the benefits and/or cost of the program.

CATEGORY	DATA	METHODOLOGY	DELIVERABLE
Disconnects	• Customers eligible for disconnect due to non-payment (entire service territory and Phase 2 footprint) • Disconnects due to non-payment (entire service territory and Phase 2 footprint)	• Compare as a percent against total metered customer for AMI group and non-AMI group • Evaluate against planned improvement	Identify and explain findings in improved identification of customers eligible for disconnect and automation of routine connect/disconnects that have the potential to materially-impact the benefits and/or cost of the program.[206]
Power theft cases	• Quantity • Monetary value	• Compare as a percent against total meter reads for AMI group and non-AMI group • Evaluate against planned improvement	Identify and explain findings in improved identification of theft that have the potential to materially-impact the benefits and/or cost of the program.
Call center	• Call Center Calls (total) • Call Center Calls (related to meter reading) • Call Center Calls (related to billing complaints)	• Compare against total customers for AMI group and non-AMI group • Evaluate against planned improvement	Identify and explain findings in reductions in calls and efficiency of call center activities that have the potential to materially-impact the benefits and/or cost of the program.

Table 11: DACR Metrics

CATEGORY	DATA	METHODOLOGY	DELIVERABLE
DACR equipment	• Circuits equipped • DACR opportunities to operate • DACR successes • DACR failures	• Evaluation of a sample of DACR successes to estimate the potential outage impact avoided • Evaluation of DACR failures for patterns that could be addressed to improve performance • Evaluate against plan assumptions	Identify and explain findings in DACR equipment operating results that have the potential to materially-impact the benefits and/or cost of the program.

[206] It's important to note that disconnects require a PUCO waiver of the current process that requires an on-site customer interaction. Factors related to social equity, customer medical concerns, and electrical safety must also be considered.

CATEGORY	DATA	METHODOLOGY	DELIVERABLE
Reliability	• System Average Interruption Frequency Index ("SAIFI") statistics • Customer Average Interruption Duration Index ("CAIDI") statistics • Customer Minutes of Interruption ("CMI") statistics	• Comparison of SAIFI, CAIDI and CMI statistics for upgraded circuits vs non-upgraded circuits • Evaluate against plan assumptions	Identify and explain findings related to reliability improvements including reduced frequency and duration of interruptions achieved via DACR investments.

Table 12: VVO Metrics

CATEGORY	DATA	METHODOLOGY	DELIVERABLE
VVO equipment	• Average system voltage • MWhs saved • MWs saved	• End-to-end evaluation of the system integration of upgraded circuits to determine how circuit data is being used and analyzed to improve reliability • Evaluate against plan assumptions	Identify and explain findings in VVO operating results that have the potential to materially impact the benefits and/or costs of the program.
Greenhouse gases	• Estimated reduction in greenhouse gas from VVO	• Review Company's analysis of the estimated reduction in greenhouse gas from VVO	Identify and explain findings related to the Company's estimated reduction in greenhouse gas from VVO.

Table 13: AEP Phase 2 Operational Benefits Filed in Case No. 13-1939-EL-RDR– Year Details

AEP Ohio Phase 2 Benefits		2014	2015	2016	2017	2018	2019	2020	2021
		$M	$M	$M	$M	$M	$M	$M	$M
Benefits included in the Benefit / Cost Analysis - Netted against the Rider									
Meter Reading and Meter Operational Labor Savings	Avoided O&M Cost	0.000	1.447	2.961	4.544	6.197	6.295	6.395	6.495
Credit and Collections Operational Labor Savings	Avoided O&M Cost	0.000	0.359	0.718	1.077	1.436	1.479	1.524	1.569
Other Benefits - Netted against the Rider									
Billing Labor Benefits	Avoided O&M Cost	0.000	0.029	0.060	0.092	0.125	0.127	0.129	0.132
Call Center Labor Benefits	Avoided O&M Cost	0.000	0.015	0.030	0.046	0.062	0.063	0.065	0.066
Capacity Planning Labor / Non-Labor O&M Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.000	0.003	0.007	0.011	0.015	0.015	0.015	0.016
Benefits included in the Benefit / Cost Analysis - Benefit Captured outside of the Rider									
Reduction in Uncollectible Revenue Through Use of Remote Disconnect	Increased Revenue	0.000	0.868	1.768	2.701	3.668	3.736	3.805	3.875
Reduction in Theft	Increased Revenue	0.000	0.620	1.263	1.929	2.620	2.668	2.718	2.768
Reduction in Consumption on Inactive Meters	Increased Revenue	0.000	0.106	0.216	0.331	0.449	0.457	0.466	0.475
Customer Savings associated with VVO benefits	Customer Benefit	0.000	1.852	4.794	7.293	7.105	7.400	7.729	8.095
Distribution Automation Circuit Reconfiguration Outage Reduction	Customer Benefit	0.000	17.750	35.500	53.250	71.000	73.130	75.324	77.584
Other Benefits - Benefit Captured outside of the Rider									
Customer savings associated with participating in TOU programs	Customer Benefit	0.000	0.893	1.673	2.260	2.794	3.554	4.098	4.762
Long-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.000	0.185	0.376	0.574	0.780	0.794	0.809	0.824
Short-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.000	0.003	0.007	0.011	0.015	0.015	0.015	0.016
Injury Reduction - Reduction in liability / lost work days	Avoided O&M Cost	0.000	0.017	0.035	0.054	0.074	0.075	0.076	0.078
Total		0.000	24.148	49.409	74.174	96.339	99.809	103.168	106.754
Operational Benefits (netted against Rider)		0.000	1.854	3.776	5.769	7.835	7.980	8.127	8.278
Operational Benefits (captured outside of the Rider)		0.000	1.800	3.666	5.601	7.606	7.746	7.890	8.036
Customer Benefits (captured outside of the Rider)		0.000	20.495	41.967	62.804	80.899	84.083	87.151	90.441
Total Operational Benefits		0.000	24.148	49.409	74.174	96.339	99.809	103.168	106.754

AEP Ohio Phase 2 Benefits		2022	2023	2024	2025	2026	2027	2028	
		$M	$M	$M	$M	$M	$M	$M	15-Yr Total
Benefits included in the Benefit / Cost Analysis - Netted against the Rider									
Meter Reading and Meter Operational Labor Savings	Avoided O&M Cost	6.598	6.701	6.806	6.912	7.020	7.129	7.239	82.7
Credit and Collections Operational Labor Savings	Avoided O&M Cost	1.616	1.665	1.715	1.766	1.819	1.874	1.930	20.5
Other Benefits - Netted against the Rider									
Billing Labor Benefits	Avoided O&M Cost	0.134	0.136	0.139	0.142	0.144	0.147	0.150	1.7
Call Center Labor Benefits	Avoided O&M Cost	0.067	0.068	0.070	0.071	0.072	0.073	0.075	0.8
Capacity Planning Labor / Non-Labor O&M Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.016	0.016	0.016	0.017	0.017	0.017	0.018	0.2
Benefits included in the Benefit / Cost Analysis - Benefit Captured outside of the Rider									
Reduction in Uncollectible Revenue Through Use of Remote Disconnect	Increased Revenue	3.947	4.020	4.094	4.170	4.247	4.326	4.406	49.6
Reduction in Theft	Increased Revenue	2.819	2.872	2.925	2.979	3.034	3.090	3.147	35.5
Reduction in Consumption on Inactive Meters	Increased Revenue	0.483	0.492	0.501	0.511	0.520	0.530	0.540	6.1
Customer Savings associated with VVO benefits	Customer Benefit	9.294	9.595	9.956	10.260	10.455	10.687	10.900	115.4
Distribution Automation Circuit Reconfiguration Outage Reduction	Customer Benefit	79.911	82.308	84.778	87.321	89.941	92.639	95.418	1,015.9
Other Benefits - Benefit Captured outside of the Rider									
Customer savings associated with participating in TOU programs	Customer Benefit	5.823	6.509	5.770	5.967	6.093	6.282	6.417	62.9
Long-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.839	0.855	0.871	0.887	0.903	0.920	0.937	10.6
Short-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality	Avoided O&M Cost	0.016	0.016	0.016	0.017	0.017	0.017	0.018	0.2
Injury Reduction - Reduction in liability / lost work days	Avoided O&M Cost	0.079	0.081	0.082	0.084	0.085	0.087	0.088	1.0
Total		111.643	115.335	117.740	121.103	124.368	127.818	131.282	1,403.1
Operational Benefits (netted against Rider)		8.431	8.587	8.746	8.907	9.072	9.240	9.411	106.0
Operational Benefits (captured outside of the Rider)		8.184	8.336	8.490	8.647	8.807	8.970	9.136	102.9
Customer Benefits (captured outside of the Rider)		95.028	98.412	100.504	103.549	106.489	109.608	112.735	1,194.2
Total Operational Benefits		111.643	115.335	117.740	121.103	124.368	127.818	131.282	1,403.1

Table 14: AEP Phase 2 Operational Benefits – Daymark Benefits Valuation Summary by Year

Benefits Valuation		2017	2018	2019	2020	2021	2022	2023	2024
		$M	$M	$M	$M	$M	$M	$M	$M
Benefits included in the Benefit / Cost Analysis - Netted against the Rider									
Meter Reading and Meter Operational Labor Savings	Avoided O&M Cost								
Daymark Analysis - Upper Case		0.033	2.715	6.591	7.889	8.117	8.351	8.592	8.840
Daymark Analysis - Lower Case		0.020	1.721	5.182	6.206	6.389	6.578	6.772	6.971
Industry Benchmark		0.000	1.071	2.898	5.580	7.910	9.352	10.532	11.098
Regular Meter Reads	Avoided O&M Cost								
Daymark Analysis		0.012	1.067	3.248	3.877	3.977	4.081	4.187	4.296
Industry Benchmark		0.000	0.443	1.421	2.910	3.969	4.597	5.136	5.500
Meter Operations Costs	Avoided O&M Cost								
Daymark Analysis		0.002	0.143	0.428	0.509	0.520	0.531	0.543	0.555
Industry Benchmark		0.000	0.017	0.080	0.187	0.249	0.284	0.314	0.320
Off-Cycle / Off-Season Meter Reads	Avoided O&M Cost								
Daymark Analysis		0.020	1.505	2.916	3.504	3.619	3.739	3.862	3.990
Industry Benchmark		0.000	0.612	1.398	2.483	3.691	4.470	5.082	5.279
Credit and Collections Operational Labor Savings	Avoided O&M Cost								
Daymark Analysis		0.000	0.000	1.474	2.763	2.823	2.885	2.947	3.012
Other Benefits - Netted against the Rider									
Billing Labor Benefits	Avoided O&M Cost								
Daymark Analysis - Upper Case		0.098	0.126	0.182	0.233	0.240	0.247	0.254	0.261
Daymark Analysis - Lower Case		0.008	0.032	0.110	0.162	0.166	0.171	0.176	0.181
Industry Benchmark		0.000	0.007	0.022	0.036	0.051	0.058	0.058	0.066
Call Center Labor Benefits	Avoided O&M Cost								
Daymark Analysis - Upper Case		0.000	0.016	0.033	0.050	0.068	0.069	0.070	0.072
Daymark Analysis - Lower Case		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Industry Benchmark		0.000	0.006	0.018	0.052	0.070	0.088	0.099	0.105
Capacity Planning O&M Savings Due to Superior AMI Data Quality	Avoided O&M Cost								
Daymark Analysis		0.000	0.000	0.000	0.000	0.016	0.016	0.016	0.017
Staff Redployment		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Benefits Valuation		2017	2018	2019	2020	2021	2022	2023	2024
		$M	$M	$M	$M	$M	$M	$M	$M
Benefits included in the Benefit / Cost Analysis - Benefit Captured outside of the Rider									
Reduction in Uncollectible Revenue Through Use of Remote Disconnect	Increased Revenue								
Daymark Analysis		0.000	0.000	1.903	3.805	3.875	3.947	4.020	4.094
Reduction in Theft	Increased Revenue								
Daymark Analysis		0.000	0.660	1.345	2.055	2.791	2.843	2.896	2.949
Industry Benchmark		0.000	0.172	0.570	1.043	1.183	1.295	1.401	1.418
Reduction in Consumption on Inactive Meters	Increased Revenue								
Daymark Analysis		0.000	0.113	0.231	0.352	0.479	0.487	0.496	0.506
Customer Savings associated with VVO benefits	Customer Benefit								
Daymark Analysis - Lower Case		0.000	1.987	4.461	7.254	7.598	8.724	9.006	9.346
Daymark Analysis - Upper Case		1.084	2.644	12.213	12.859	13.703	16.222	17.029	17.995
Distribution Automation Circuit Reconfiguration Outage Reduction	Customer Benefit								
Daymark Analysis - Lower Case		0.000	18.936	37.872	56.807	75.743	78.015	80.356	82.766
Daymark Analysis - Upper Case		31.020	23.329	30.956	60.017	96.544	131.672	141.462	144.545
Other Benefits - Benefit Captured outside of the Rider									
Customer Savings Associated with Participating in TOU Programs	Customer Benefit								
Update to Filing		0.000	0.951	1.782	2.408	2.977	3.786	4.366	5.074
Capacity Planning Capital Savings Due to Superior AMI Data Quality	Cap Defer								
Daymark Analysis		0.000	0.000	0.000	0.000	0.909	0.926	0.943	0.961
Staff Redployment		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Injury Reduction - Reduction in liability / lost work days	Avoided O&M Cost								
Daymark Analysis		0.000	0.000	0.000	0.000	0.078	0.080	0.081	0.083
Industry Benchmark		0.000	0.007	0.015	0.029	0.051	0.073	0.080	0.087

Benefits Valuation		2017	2018	2019	2020	2021	2022	2023	2024
		$M	$M	$M	$M	$M	$M	$M	$M
Other Benefits - Captured by Daymark - Netted against Rider									
Remote Meter Diagnostics	Avoided O&M Cost								
Daymark Analysis		0.000	0.004	0.014	0.016	0.016	0.016	0.016	0.016
Industry Benchmark		0.000	0.059	0.164	0.364	0.587	0.799	0.939	0.975
Outage Detection and Verification	Avoided O&M Cost								
Industry Benchmark		0.043	0.087	0.148	0.244	0.351	0.435	0.513	0.532
Continuous Voltage Monitoring	Avoided O&M Cost								
Industry Benchmark		0.000	0.000	0.000	0.000	0.094	0.188	0.282	0.294
Capacitor Inspection Costs	Avoided O&M Cost								
Industry Benchmark		0.000	0.000	0.000	0.000	0.070	0.153	0.235	0.235
Circuit Breaker Inspection Costs	Avoided O&M Cost								
Industry Benchmark		0.000	0.000	0.023	0.059	0.094	0.106	0.117	0.117
Other Benefits - Captured by Daymark outside the Rider									
Meter Salvage Value	Increased Revenue								
Daymark Analysis		0.000	0.196	0.253	0.036	0.000	0.000	0.000	0.000
Industry Benchmark		0.059	0.012	0.117	0.247	0.258	0.200	0.188	0.000
Meter Accuracy Improvement	Increased Revenue								
Industry Benchmark		0.000	0.189	0.614	1.123	1.275	1.399	1.516	1.534
Outage Reduction - Revenue Impact	Increased Revenue								
Industry Benchmark		0.023	0.070	0.164	0.294	0.434	0.564	0.634	0.681
System Fine Tuning	Cap Defer & Avoided Fuel Cost								
Daymark Analysis		0.146	0.472	2.983	3.038	3.115	3.186	3.257	3.326
Industry Benchmark		0.000	0.012	0.012	0.012	0.012	0.599	1.221	1.292
Total									
All Upper Bound									
Operational Benefits (netted against Rider)		0.1	2.9	8.3	11.0	11.3	11.6	11.9	12.2
Operational Benefits (captured outside of the Rider)		32.3	27.4	49.9	82.2	121.5	159.4	170.2	174.5
Total Operational Benefits		32.382	30.277	58.177	93.113	132.773	170.947	182.080	186.675
All Lower Bound									
Operational Benefits (netted against Rider)		0.0	1.8	6.8	9.1	9.4	9.6	9.9	10.2
Operational Benefits (captured outside of the Rider)		0.1	22.4	49.0	73.3	93.7	97.3	100.1	103.1
Total Operational Benefits		0.175	24.123	55.827	82.495	103.074	106.932	110.023	113.250

Benefits Valuation		2025	2026	2027	2028	2029	2030	2031	
		$M	$M	$M	$M	$M	$M	$M	15-Yr Total
Benefits included in the Benefit / Cost Analysis - Netted against the Rider									
Meter Reading and Meter Operational Labor Savings	Avoided O&M Cost								
Daymark Analysis - Upper Case		9.095	9.358	9.629	9.908	10.194	10.490	10.794	120.6
Daymark Analysis - Lower Case		7.177	7.389	7.607	7.831	8.062	8.300	8.545	94.7
Industry Benchmark		11.377	11.671	11.971	12.279	12.602	12.932	13.269	134.5
Regular Meter Reads	Avoided O&M Cost								
Daymark Analysis		4.408	4.522	4.640	4.760	4.884	5.011	5.141	58.1
Industry Benchmark		5.576	5.653	5.737	5.820	5.904	5.995	6.086	64.7
Meter Operations Costs	Avoided O&M Cost								
Daymark Analysis		0.567	0.579	0.592	0.604	0.618	0.631	0.645	7.5
Industry Benchmark		0.326	0.331	0.337	0.343	0.349	0.355	0.361	3.9
Off-Cycle / Off-Season Meter Reads	Avoided O&M Cost								
Daymark Analysis		4.121	4.257	4.398	4.543	4.693	4.848	5.008	55.0
Industry Benchmark		5.475	5.686	5.897	6.116	6.349	6.582	6.822	65.9
Credit and Collections Operational Labor Savings	Avoided O&M Cost								
Daymark Analysis		3.077	3.144	3.213	3.283	3.354	3.427	3.502	38.9
Other Benefits - Netted against the Rider									
Billing Labor Benefits	Avoided O&M Cost								
Daymark Analysis - Upper Case		0.269	0.276	0.284	0.293	0.301	0.310	0.319	3.7
Daymark Analysis - Lower Case		0.186	0.192	0.197	0.203	0.209	0.215	0.221	2.4
Industry Benchmark		0.066	0.066	0.073	0.073	0.080	0.080	0.080	0.8
Call Center Labor Benefits	Avoided O&M Cost								
Daymark Analysis - Upper Case		0.073	0.074	0.076	0.077	0.078	0.080	0.081	0.9
Daymark Analysis - Lower Case		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0
Industry Benchmark		0.105	0.111	0.111	0.117	0.117	0.123	0.123	1.2
Capacity Planning O&M Savings Due to Superior AMI Data Quality	Avoided O&M Cost								
Daymark Analysis		0.017	0.017	0.018	0.018	0.018	0.019	0.019	0.2
Staff Redployment		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0

Benefits Valuation

		2025	2026	2027	2028	2029	2030	2031	
		$M	$M	$M	$M	$M	$M	$M	15-Yr Total
Benefits included in the Benefit / Cost Analysis - Benefit Captured outside of the Rider									
Reduction in Uncollectible Revenue Through Use of Remote Disconnect	Increased Revenue								
Daymark Analysis		4.170	4.247	4.326	4.406	4.428	4.450	4.471	52.1
Reduction in Theft	Increased Revenue								
Daymark Analysis		3.004	3.059	3.116	3.173	3.232	3.292	3.353	37.8
Industry Benchmark		1.436	1.459	1.483	1.506	1.530	1.553	1.583	17.6
Reduction in Consumption on Inactive Meters	Increased Revenue								
Daymark Analysis		0.515	0.524	0.534	0.544	0.554	0.564	0.575	6.5
Customer Savings associated with VVO benefits	Customer Benefit								
Daymark Analysis - Lower Case		9.631	9.814	10.032	10.232	10.455	10.682	10.915	120.1
Daymark Analysis - Upper Case		18.905	19.651	20.541	21.490	22.535	23.610	24.761	245.2
Distribution Automation Circuit Reconfiguration Outage Reduction	Customer Benefit								
Daymark Analysis - Lower Case		85.249	87.807	90.441	93.154	95.949	98.827	101.792	1,083.7
Daymark Analysis - Upper Case		147.694	150.913	154.201	157.561	160.994	164.502	168.086	1,763.5
Other Benefits - Benefit Captured outside of the Rider									
Customer Savings Associated with Participating in TOU Programs	Customer Benefit								
Update to Filing		6.204	6.934	6.147	6.357	6.492	6.692	6.836	67.0
Capacity Planning Capital Savings Due to Superior AMI Data Quality	Cap Defer								
Daymark Analysis		0.979	0.997	1.015	1.034	1.053	1.073	1.092	11.0
Staff Redployment		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0
Injury Reduction - Reduction in liability / lost work days	Avoided O&M Cost								
Daymark Analysis		0.084	0.086	0.088	0.089	0.091	0.093	0.094	0.9
Industry Benchmark		0.087	0.095	0.095	0.102	0.102	0.109	0.109	1.0

Benefits Valuation		2025	2026	2027	2028	2029	2030	2031	
		$M	$M	$M	$M	$M	$M	$M	15-Yr Total
Other Benefits - Captured by Daymark - Netted against Rider									
Remote Meter Diagnostics	Avoided O&M Cost								
Daymark Analysis		0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.2
Industry Benchmark		1.010	1.045	1.092	1.127	1.174	1.221	1.257	11.8
Outage Detection and Verification	Avoided O&M Cost								
Industry Benchmark		0.545	0.559	0.572	0.598	0.611	0.625	0.645	6.5
Continuous Voltage Monitoring	Avoided O&M Cost								
Industry Benchmark		0.305	0.305	0.317	0.329	0.341	0.352	0.364	3.2
Capacitor Inspection Costs	Avoided O&M Cost								
Industry Benchmark		0.247	0.258	0.258	0.270	0.282	0.282	0.294	2.6
Circuit Breaker Inspection Costs	Avoided O&M Cost								
Industry Benchmark		0.117	0.117	0.129	0.129	0.129	0.141	0.141	1.4
Other Benefits - Captured by Daymark outside the Rider									
Meter Salvage Value	Increased Revenue								
Daymark Analysis		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.5
Industry Benchmark		0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.1
Meter Accuracy Improvement	Increased Revenue								
Industry Benchmark		1.551	1.575	1.598	1.622	1.651	1.675	1.704	19.0
Outage Reduction - Revenue Impact	Increased Revenue								
Industry Benchmark		0.705	0.740	0.787	0.846	0.916	1.010	1.116	9.0
System Fine Tuning	Cap Defer & Avoided Fuel Cost								
Daymark Analysis		3.398	3.475	3.556	3.646	3.742	3.837	3.938	45.1
Industry Benchmark		1.327	1.362	1.409	1.444	1.491	1.538	1.585	13.3
Total									
All Upper Bound									
Operational Benefits (netted against Rider)		12.5	12.9	13.2	13.6	14.0	14.3	14.7	164.5
Operational Benefits (captured outside of the Rider)		178.7	183.0	187.4	191.9	196.6	201.4	206.4	2162.7
Total Operational Benefits		191.296	195.839	200.611	205.537	210.592	215.761	221.102	2,327.2
All Lower Bound									
Operational Benefits (netted against Rider)		10.5	10.7	11.0	11.3	11.6	12.0	12.3	136.3
Operational Benefits (captured outside of the Rider)		106.1	109.0	112.1	115.2	118.5	121.7	125.1	1346.8
Total Operational Benefits		116.508	119.753	123.125	126.577	130.091	133.703	137.423	1,483.1

Summary: Audit "AEP Ohio gridSMART Deployment Audit: Review of the Operational Benefits", prepared for PUCO Staff by Daymark Energy Advisors electronically filed by Ms. Krystina M Schaefer on behalf of PUCO Staff