OCC EXHIBIT_______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan.	)))	Case No. 16-0395-EL-SSO
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs.	)))	Case No. 16-0396-EL-ATA
In the Matter of the Application of The Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code § 4905.13.	))))	Case No. 16-0397-EL-AAM

DIRECT TESTIMONY
OF
JAMES D. WILLIAMS

On Behalf of
The Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

November 21, 2016

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ATTACHMENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A1. My name is James D. Williams. My business address is 10 West Broad Street, 18th Floor, Columbus, Ohio 43215-3485. I am employed by the Office of the Ohio Consumers' Counsel ("OCC") as a Senior Utility Consumer Policy Analyst.

Q2. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE

A2. I am a 1994 graduate of Webster University, in St. Louis, Missouri, with a Master's in Business Administration, and a 1978 graduate of Franklin University, in Columbus, Ohio, with a Bachelor of Science, Engineering Technology. My professional experience includes a career in the United States Air Force and over 20 years of utility regulatory experience with the OCC.

Initially, I served as a compliance specialist with the OCC and my duties included the development of compliance programs for electric, natural gas, and water industries. Later, I was designated to manage all of the agency's specialists who were developing compliance programs in each of the utility industries. My role evolved into the management of OCC's consumer hotline, the direct service provided to consumers to resolve complaints and inquiries that involved Ohio utilities. More recently, following a stint as a Consumer Protection Research Analyst, I was promoted to a Senior Utility Consumer Policy Analyst. In this role, I am responsible for developing and recommending policy positions on utility issues that affect residential consumers.

I have been directly involved in the development of comments in various rulemaking proceedings at the Public Utilities Commission of Ohio ("PUCO") and the Ohio Development Services Agency. Those comments included advocacy for consumer protections, affordability of utility rates, service quality and the provision of reasonable access to essential utility services for residential consumers. I have assisted in the development of OCC policies and positions in a number of proceedings involving the Ohio Electric Service and Safety Standards Ohio Adm. Code 4901:1-10,[1] distribution system reliability standards,[2] and the provision of utility services and consumer protections for residential consumers, including low-income Ohioans.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY OR TESTIFIED BEFORE THE PUCO?

A3. Yes. The cases that I have submitted testimony and/or have testified before the PUCO can be found in Attachment JDW-1.

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[1] *In the Matter of the Commission's Review of Chapter 4901:1-10, Ohio Administrative Code, Regarding Electric Companies.,* Case No. 12-2050-EL-ORD. *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code,* Case No. 06-653-EL-ORD.

[2] Including DP&L reliability standard cases (*In the Matter of the Application of The Dayton Power and Light Company for Establishing New Reliability Targets.,* Case 12-1832-EL-ESS) and (*In the Matter of the Application of The Dayton Power and Light Company For Establishing New Reliability Targets*., Case No. 09-754-EL-ESS).

II. PURPOSE OF MY TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

***A4*.** The purpose of my testimony is to address certain consumer issues related to the Dayton Power and Light Company's ("DP&L" or "Utility") proposed Distribution Investment Rider ("DIR"). In addition, I address DP&L's proposal to include in its electric security plan other riders that DP&L also proposed in its on-going rate case 15-1830-EL-AIR. These additional riders include a Regulatory Compliance Rider ("RCR"), an Uncollectible Rider, and a Storm Cost Recovery Rider.[3] I also address DP&L's request for a new yet to be named rider during the term of the ESP "to the extent there are changes in law, rule, or regulatory ruling."[4]

Q5*. *PLEASE SUMMARIZE YOUR CONCLUSIONS.

A5. I recommend that the PUCO not approve DP&L's request for a Distribution Investment Rider ("DIR"). If approved by the PUCO, the

[3] Amended Application at page 7.

[4] Id.

DIR will result in charges to customers[5], including residential customers, which are unreasonable and contrary to Ohio regulatory policy. DP&L has not shown a need for the charge, nor has it shown that current distribution rates do not provide it with an opportunity to collect those same costs from customers. Approving DP&L's DIR charge may in fact cause customers to pay twice for the same expenses. The DIR also does not comply with the provisions of an infrastructure modernization program that is permitted under a utility's electric security plan.[6]

I also recommend that the PUCO not approve the Regulatory Compliance Rider, the Uncollectible Rider, and the Storm Cost Recovery Rider.[7] And I recommend that DP&L not be allowed the broad authority to request a new yet to be named rider during the ESP term to address changes in rules or laws. These riders seek to impose significant rate increases upon customers. Since the riders are not capped, customers could be burdened with unlimited cost increases. The PUCO should protect DP&L customers from these potentially costly increases.

[5] Direct Testimony of Robert Adams at 2. DP&L claims that the DIR proposal requests tariff approval at a rate of zero (See DP&L response to OCC INT-274 (attached herein as JDW-2). But it is disingenuous to represent to the public that DIR is not going to cost customers anything. Ultimately, the DIR and other riders will be used to increase the cost of electric bills by potentially hundreds of millions of dollars over many years to the detriment of the many impoverished Ohioans in the DP&L service territory. The projected costs are staggering. The DIR proposal alone will cost hundreds of millions of dollars over a five-year time frame (see Direct Testimony of Kevin Hall at 11).

[6] R.C. 4928.143(B)(2)(h).

[7] Amended Application at page 7.

Q6. WHY IS IT NECESSARY FOR THE PUCO TO PROTECT CUSTOMERS FROM THE COSTLY INCREASES THAT DP&L PROPOSES?

A6. One of the policies of the state is to ensure that customers are provided access to reasonably priced retail electric service. The PUCO has the duty to implement that state policy.

Residential consumers in the DP&L service territory live within some of the highest poverty areas in Ohio. For example, DP&L serves the city of Dayton that has a poverty level of 35.3 percent.[8] At the county level, 18.5 percent of the residents live in poverty.[9] More telling, 18.4 percent of the population of Montgomery County is living in an environment where they have insecure access to food.[10] Insecure access to food is directly related to hunger and it represents household members not obtaining sufficient nutrition for their well-being.

But, hunger in Ohio is not limited to just Montgomery County. DP&L also serves customers in Fayette and Clinton Counties where the food insecurity rate is 16.1 and 16.3 percent, respectively.[11] Disturbingly, the

[8] The Ohio Poverty Report, February 2016, Table A6.

[9] Id. at A4.

[10] Map the Meal Gap 2016. Feeding America (attached herein as JDW-3). http://www.feedingamerica.org/hunger-in-america/our-research/map-the-meal-gap/data-by-county-in-each-state.html?referrer=https://www.google.com/

[11] Id.

lack of access to sufficient food extends to approximately 25.0 percent of the children[12] residing in Montgomery County.[13] Food insecurity rates for children in Fayette and Clinton Counties are 25.9 percent and 26.0 percent, respectively.[14] Yet, despite the fact that many of DP&L's consumers are lacking in the most basic of life sustaining needs, the Utility has chosen to pursue a costly and unreasonable charges. To protect consumers, and further state policy in allowing customers reasonably priced electric service, the PUCO should not approve DP&L's proposed riders.

III. DISTRIBUTION INVESTMENT RIDER (DIR)

Q7. PLEASE DESCRIBE THE PROPOSED DIR.

A7. If approved by the PUCO, the proposed DIR would provide DP&L with the ability to expedite recovery of certain capital costs and incremental operations and maintenance expenses.[15] DP&L explains, the DIR is "a mechanism to implement incremental capital investment as well as the O&M necessary to address its aging distribution infrastructure along with supporting additional key technical resources for the future of DP&L."[16] DP&L claims that the DIR is an infrastructure modernization plan

[12] Id.

[13] Id.

[14] Id.

[15] DP&L Direct Testimony of Robert J. Adams at 2.

[16] DP&L Direct Testimony of Kevin L. Hall at 3.

consistent with Ohio Revised Code 4928.143(B)(2)(h).[17] Finally, DP&L claims that the proposed DIR represents a "balanced approach" to addressing infrastructure needs and vulnerabilities while also providing safe and affordable service to customers.[18]

Q8. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A8. I recommend that the PUCO reject DP&L's proposed DIR. Approval of the DIR can result in double recovery since many of these costs have and are already being collected from customers. The DIR as proposed does not qualify as an infrastructure modernization initiative. DP&L has a pending rate case where all matters related to the just and reasonableness of DP&L distribution rates will be considered. Any request for an infrastructure modernization initiative should be made in the context of the overall distribution rates. Utility bill increases associated with the DIR contribute to unreasonably priced retail electric service and fail to protect at-risk consumers. This violates Ohio policy as stated in Ohio Revised Code 4928.02(A) and (L), respectively. Finally, DP&L has not provided support justifying the need for a DIR.

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[17] Id.

[18] Id at 4.

Q9. DOES THE PROPOSED DIR QUALIFY AS A DISTRIBUTION INFRASTRUCTURE MODERNIZATION PLAN?

A9. No. DP&L claims that the proposed DIR Rider is an infrastructure modernization plan consistent with the requirements in O.R.C. 4928.143(B)(2)(h).[19] But infrastructure modernization as described under the statute is different from the day to day costs associated with maintaining a distribution system. DP&L has proposed no plan other than its normal and routine day-to-day expenses to maintain its distribution system. These are expenses that should be reviewed and ultimately collected from customers, if justified, via a rate case proceeding.

Expenses associated with maintaining the distribution system may be considered ordinary and necessary expenses that may be requested in an application to increase rates.[20] Such a request would be governed by statutory provisions in Ohio Revised Code 4909. As a matter of regulatory policy, utilities must maintain necessary and adequate distribution facilities and are prohibited from charging unjust or unreasonable rates. Also, as a matter of regulatory policy, the PUCO must consider a number of factors in determining the justness and reasonableness of rates -- including those in Ohio Revised Code 4909.15.

[19] Direct Testimony of Kevin Hall at 3.

[20] Ohio Revised Code 4909.15.

Q10. WHEN DID THE PUCO LAST EXAMINE DP&L'S DISTRIBUTION RATES?

A10. DP&L base rates were last established as bundled rates in 1991, in Case No. 91-414-EL-AIR. Rates established in that case began to be charged to customers in 1992. As part of the restructuring of the electric industry, the PUCO approved the unbundling of electric rates as part of a transition plan in Case No. 99-1687-EL-ETP. However, the distribution rates that customers pay today are based largely on the outcome from the 1991 rate case.

Q11. HOW WILL DP&L DETERMINE WHICH DISTRIBUTION EXPENSES WILL BE COLLECTED FROM CUSTOMERS THROUGH BASE RATES AND WHICH EXPENSES WILL BE COLLECTED THROUGH THE DIR?

A11. DP&L Witness Adams claims that the DIR will collect incremental investment costs for used and useful distribution property that is not already included in base rates.[21] Furthermore, Mr. Adams claims that the DIR will collect specific incremental operations and maintenance expenses that are not already included in base rates.[22]

DP&L filed a distribution rate case (as Case No. 15-1830-EL-AIR) on October 30, 2015. But, the PUCO has not ruled on the application. It has not determined what the just and reasonable rates are for DP&L distribution customers to pay, based on the utility's request. So, there is no basis to determine whether the costs

[21] Direct Testimony of Robert Adams at 2.

[22] Id.

under the DIR are already included within existing base rates and which expenses are incremental to base rates. And DP&L has not presented evidence to show that the O&M to be collected under the DIR is only "incremental" to existing base distribution rates.

Q12. IS DP&L CLAIMING THAT IT CANNOT REPLACE AGING ELECTRICAL EQUIPMENT THROUGH BASE RATES?

A12. No. The DP&L response to OCC INT-245 (attached herein as JDW-4) could not make this point clearer. When asked why cost recovery through base rates was not sufficient to address any aging infrastructure issues, DP&L claimed that DIR allows more expedient cost recovery, which is permitted by statute. In other words it's about collecting the money from customers faster.

DP&L does not say it is unable to replace aging infrastructure without a DIR. Distribution rates that have been in effect since 1992 have been more than sufficient to enable DP&L to perform the functions necessary to operate and maintain the distribution system in a safe and reliable manner. Otherwise, DP&L would have previously requested rate increases to collect such costs. Rates ultimately determined in Case 15-1830-EL-AIR should provide DP&L with the ability on a going-forward basis to continue operating its distribution system in a safe and reliable manner -- without a DIR.

Q13. DOES DP&L CLAIM THAT CUSTOMER SATISFACTION AND RELIABILITY WILL DECLINE IF THE PROPOSED DIR IS NOT APPROVED?

A13. Yes. DP&L Witness Hall claims that both reliability and customer satisfaction "will suffer" if the DIR is not approved.[23]

Q14. IS THERE ANY VALIDITY TO MR. HALL'S CLAIM THAT CUSTOMER SATISFACTION AND RELIABILITY WILL SUFFER?

A14. Absolutely not. DP&L has a responsibility to provide customers with the necessary and adequate services and facilities that are in all respects just and reasonable.[24] This obligation is not contingent on the PUCO granting special rate treatment through a DIR Rider.

DP&L already has a pending base rate case and that is the proper proceeding for the PUCO to consider all of DP&L's distribution rates comprehensively on a going-forward basis. Interesting, in defending the DP&L rate case, Mr. Hall filed Direct Testimony where he concludes that DP&L already makes capital investments in its distribution system that functions to serve new or growing load, maintain or improve the overall condition of its distribution plant, and return to service any failed assets due to failures or storms.[25] There is no indication in his

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[23] Direct Testimony of DP&L Witness Hall at 7.

[24] See, e.g., Ohio Revised Code 4905.22.

[25] Case No. 15-1830-EL-AIR, Direct Testimony of Kevin L Hall at 8.

testimony that the utility is unable to do these things without the extraordinary use of single issue ratemaking such as a DIR.

Q15. DOES THE PUCO HAVE SPECIFIC MINIMUM SERVICE QUALITY, SAFETY, AND RELIABILITY STANDARDS THAT RELATE TO CUSTOMERS' SATISFACTION AND RELIABILITY?

A15. Yes. Ohio policy described in Revised Code 4928.11 requires the PUCO to adopt rules that specify the minimum service quality, safety, and reliability requirements. These requirements are promulgated in the PUCO Electric Service and Safety Standards, Ohio Adm. Code 4901:1-10. Standards related to inspection, maintenance, repair and replacement are included in Ohio Adm. Code 4901:1-10-27. Electric utilities must file with the PUCO copies of their inspection, maintenance, repair and replacement programs. A copy of DP&L's current transmission and distribution inspection, maintenance, repair and replacement program[26] is included herein as JDW-5.

In addition, standards related to distribution reliability are listed in Ohio Adm. Code 4901:1-10-10. Each electric utility must file an annual system improvement plan pursuant to Ohio Adm. Code 4901:1-10-26, which includes reporting about the status of the inspection, maintenance, repair

[26] *In the Matter of the Application of the Dayton Power and Light Company to Amend its Transmission and Distribution Inspection, Maintenance, Repair and Replacement Programs Pursuant to Section 4901:1-27, Ohio Administrative Code, Regarding Electric Companies.*, Case No. 14-1771-EL-ESS October 30, 2014.

and replacement programs.[27] And electric utilities are required to file an annual report about the reliability performance of the distribution system during the previous year.[28]

I have reviewed DP&L's annual system improvement plan and the latest annual reports involving DP&L reliability performance.

Q16. CAN YOU SUMMARIZE THE RESULTS OF YOUR REVIEW?

A16. Yes. The annual system improvement plan includes a section where each electric utility is required to report compliance with the inspection, maintenance, repair and replacement program requirements in Ohio Adm. Code 4901:1-0-27(E) and that was attached as JDW-5.[29] The 2015 annual system improvement plan report where DP&L reported compliance with all inspection, maintenance, repair and replacement requirements is attached herein as JDW-6.[30] My review of the 2014 and 2013 annual system improvement plan reports also confirmed that DP&L complied

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[27] Ohio Adm. Code 4901:1-0-26(B)(3)(f).

[28] Ohio Adm. Code 4901:1-10-10(F).

[29] Ohio Adm. Code 4901:1-10-26(B)(3)(f).

[30] *In the Matter of the Annual Report of Dayton Power and Light Co Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-26,* Case No. 16-1000-EL-ESS, 2015 System Improvement Plan Report at 48-52 (March 31, 2016).

with each of the inspection, maintenance, repair, and replacement program requirements for each of those years.[31] From this I conclude that DP&L has been able to successfully operate its distribution system, without the assistance of an extraordinary mechanism like the DIR.

Q17. DO YOU HAVE ANY REASON TO BELIEVE THAT UNDER THE PROPOSED DIR DP&L COULD BE CHARGING CUSTOMERS TWICE FOR DISTRIBUTION EXPENDITURES?

A17. *Yes.* DP&L appears to be proposing funding for DIR initiatives when it already recovers the expenses in base rates. For example, DP&L claims that DIR would be used to fund the vegetation management of "danger trees."[32] Danger trees are defined by Mr. Hall as trees that are located outside the right of way or easement that have experienced disease or decay and place the trees at risk of falling into nearby power lines.[33] DP&L already performs vegetation management on trees that are outside the right of way where the trees pose imminent danger to its distribution system.[34]

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[31] *In the Matter of the Annual Report of Dayton Power and Light Co Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-26*, Case No. 15-1000-EL-ESS, 2014 System Improvement Plan Summary Report at 47-51 (March 31, 2015). *In the Matter of the Annual Report of Dayton Power and Light Co Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-26*, Case No. 14-1000-EL-ESS, 2013 System Improvement Plan Report at 39-44 (March 28, 2014).

[32] Direct Testimony of Kevin Hall at 8.

[33] Id.

[34] Id.

But in the DP&L response to PUCO DR 12-7 (attached herein as JDW-7), DP&L claimed that while it tracks outages caused by trees inside and outside of the right of way, it does not track outages caused by the "danger trees." In the DP&L response to OCC INT-255 (attached herein as JDW-8), the Utility claims that it does not track costs related to vegetation management of "danger trees." But DP&L then states that expenditures related to vegetation management of danger trees are captured within the overall vegetation management O&M budget.[35] Therefore, it appears as though DIR could provide a way for DP&L to double-recover several million dollars annually over a five-year term in vegetation management costs from customers. This would be unreasonable.

Q18. ARE THERE OTHER EXAMPLES WHERE DP&L IS PROPOSING UNNECESSARY SPENDING THAT COULD RESULT IN CHARGING CUSTOMERS TWICE FOR DISTRIBUTION EXPENDITURES?

A18. Yes, the potential problem with double collections extends beyond vegetation management. For instance, Mr. Hall claims that certain types of transformer bushings are known to have industry-wide failure risks.[36] In the Company response to OCC INT-260 (attached herein as JDW-9), DP&L claims that it does not track outage causes to any specific component in a substation. In the DP&L response to OCC INT-261

[35] Id.

[36] Id.

(attached herein as JDW-10), the Company claims that the costs for transformer bushings are captured within the substation O&M expenses. Therefore, DIR would just provide DP&L with the ability to double-recover a substantial amount in unnecessary substation costs from customers.

Another example relates to DP&L claims that certain underground cable is widely observed across the industry as being exposed to deterioration and ultimately to failure.[37] But in the DP&L response to OCC INT-252 (attached herein as JDW-11), the Utility was unable to support when the industry determined that certain underground cable was subject to deterioration. Then in the DP&L response to OCC INT-251 (attached herein as JDW-12), the Utility provided a table that shows the number of outages associated with underground cable have declined from 421 in 2010 to 345 in 2015. In the DP&L response to OCC INT-254 (attached herein as JDW-13), the Utility provided a table that shows capital investment related to underground cable has declined from $5.3 million in 2011 to $3.5 million in 2015, which makes sense if the outages have been declining. This does not support the need for the PUCO to approve a DIR rider. Nor does it justify charging customers tens of millions annually over a five–year plan twice for expenses related to the maintenance of underground cables.

[37] Id.

Q19. CAN YOU BRIEFLY DESCRIBE THE PUCO POLICIES RELATED TO DISTRIBUTION RELIABILITY?

A19. Yes. Ohio Adm. Code 4901:101-10 requires each of the electric utilities to establish service reliability indices and minimum performance standards. There are two different reliability indices measured in Ohio including a System Average Interruption Frequency Index ("SAIFI") and a Customer Average Interruption Duration Index ("CAIDI"). SAIFI represents the average number of interruptions per customer on an annual basis. CAIDI represents the average time to restore service. Performance standards reflect historical system performance, system design, technological advancements, service area geography, customer perception survey results, and other relevant factors. The reliability standards apply to sustained outages that are defined as lasting for durations exceeding five minutes. Outages that occur during major events or as a result of transmission failure are excluded from the standards. Each electric utility must file an annual report with the actual distribution performance from the previous year.

Q20. CAN YOU SUMMARIZE THE DP&L RELIABILITY PERFORMANCE FOR EACH OF THE LAST FIVE YEARS?

A20. Yes. Table 1 provides a comparison of the DP&L SAIFI reliability performance compared with the PUCO standard for the last five years. Table 2 provides a comparison of the DP&L CAIDI reliability performance compared with the PUCO standard for each of the last five years.

Table 1: DP&L Reliability SAIFI (2011 – 2015)

Year	SAIFI Standard	DP&L Performance
2011[38]	1.07	0.81
2012[39]	1.07	0.80
2013[40]	0.88	0.70
2014[41]	0.88	0.82
2015[42]	0.88	0.85
Five Year Average Performance		0.8

[38] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 12-883-EL-ESS, March 27, 2012.

[39] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 13-402-EL-ESS, March 25, 2013.

[40] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 14-0369-EL-ESS, March 28, 2014.

[41] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 15-0360-EL-ESS, March 31, 2015.

[42] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No. 16-0430-EL-ESS, March 22, 2016.

Table 2: DP&L Reliability CAIDI (2011 – 2015)

Year	CAIDI Standard (minutes)	DP&L Performance (minutes)
2011[43]	125.51	120.61
2012[44]	125.51	120.15
2013[45]	125.04	110.51
2014[46]	125.04	121.86
2015[47]	125.04	118.69
Five Year Average Performance		118.36

As seen in Tables 1 and 2, DP&L has met or exceeded both the SAIFI and the CAIDI reliability performance standards for each of the last five years. The five year average SAIFI performance exceeds the standard by approximately ten percent. The five year average CAIDI performance exceeds the standard by approximately six percent. DP&L customers experience on average less than one sustained outage on an annual basis. The duration of the average outage is less than two hours.

[43] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 12-883-EL-ESS, March 27, 2012.

[44] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 13-402-EL-ESS, March 25, 2013.

[45] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 14-0369-EL-ESS, March 28, 2014.

[46] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No 15-0360-EL-ESS, March 31, 2015.

[47] In the Matter of the Annual Report of the Dayton Power and Light Company Pursuant to Rule 10 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-10, Case No. 16-0430-EL-ESS, March 22, 2016.

Q21. IS DP&L PROPOSING TO IMPROVE ITS RELIABILITY STANDARDS CONCURRENT WITH THE ADDITIONAL DIR FUNDING FROM CUSTOMERS?

A21. No. Quite the opposite. DP&L admits that there are no guarantees for any improvement in reliability.[48]

Q22. ARE DP&L CUSTOMERS REQUESTING BETTER RELIABILITY?

A22. No. Based on the results of customer perception surveys performed by DP&L, the vast majority of respondents reported having one (or fewer) outages during the previous 12 months.[49] Over two thirds of the respondents reported experiencing fewer or as many sustained power outages as they regard as acceptable.[50] 60 percent of the respondents who experienced power outages indicated that the outage durations were less than two hours.[51] 83 percent of the respondents indicated that sustained power outages should last two hours or less.[52] The results from the customer perception survey appear to align closely with the reliability standards and the system performance over the last five years. The results do not suggest that customers are seeking improvements in reliability or perceive a need for such. To authorize additional charges to consumers

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[48] Direct Testimony of DP&L Witness Hall at 6-7.

[49] Metrix Matrix Customer Perception Survey provided by DP&L in response to RPD-26 (attached herein a JDW-14).

[50] Id.

[51] Id.

[52] Id.

for distribution investment that is not guaranteed to improve reliability (that consumers do not want) demonstrates that the Utility's and customers' interests are not aligned. The PUCO should not approve DP&L's DIR proposal in this case.

Q23. ARE RESIDENTIAL CUSTOMERS INDICATING THAT THEY ARE INCURRING LOSSES AS A RESULT OF DP&L POWER OUTAGES?

A23. No. Based on the results of a power interruption survey report performed by the University of Dayton,[53] the vast majority of the respondents (76%) indicate that they have incurred no losses associated with sustained DP&L outages. Therefore, there is no direct economic benefit for consumers to spend additional unnecessary monies on the DIR rider. Yet DIR will ultimately result in hundreds of millions in additional unwarranted costs to consumers.

Q24. DO YOU KNOW OF ANY OTHER STUDIES OR ANALYSES THAT INDICATES THE PROPOSED DIR OR ANY OF THE OTHER RIDERS ARE NEEDED?

A24. No. In fact, other studies and analyses support my conclusion that DIR and the other riders are not needed. For example, J.D. Power annually measures customer satisfaction with several electric utilities across the nation to examine numerous factors including price, billing &payment, corporate citizenship, communications, customer service, and power quality, and reliability. DP&L is evaluated annually

[53] DP&L response to RFD-26 Attachment 1 (attached herein as JDW 15).

in this study along with 14 other midsized electric utilities in the Midwest region of the country. Based on the J.D. Power 2016 Residential Customer Satisfaction Study, DP&L's was rated above average in customer satisfaction for the Midwest segment of electric utilities. A copy of the J.D. Power Customer Satisfaction Study is attached herein as JDW-16.

Also of importance is the J.D. Power customer satisfaction ranking of DP&L compared with other Ohio electric utilities. This comparison is provided in Table 3.

Table 3: Ohio EDU Customer Satisfaction Ranking 2016

EDU	Customer Satisfaction Ranking	Infrastructure Modernization ("DIR") Rider
DP&L	681	No
Ohio Edison	679	Yes
Duke Energy – Midwest	679	Yes
AEP Ohio	654	Yes
TE	648	Yes
CEI	644	Yes

Table 3 shows the customer satisfaction ranking for the Ohio EDU's and identifies if the PUCO has authorized incentive ratemaking for infrastructure modernization through riders like the DIR. DP&L has a higher customer satisfaction ranking and does not burden consumers with additional DIR and other monthly rider charges on their bills. I can only conclude from this and the other factors mentioned in this testimony that DP&L does not need special incentive ratemaking (through a DIR) to continue providing adequate and reliable service to consumers. The PUCO Commission should reject the proposed DIR.

IV. OTHER UNRELATED RIDERS

Q25. CAN YOU BRIEFLY DESCRIBE WHY THE OTHER RIDERS DP&L SEEKS TO CHARGE ITS CUSTOMERS SHOULD NOT BE ADDRESSED WITHIN THE ESP?

A25. Yes. As part of the Utility distribution base rate case, DP&L has proposed to charge its customers three new riders including a Regulatory Compliance Rider,[54] an Uncollectible Rider,[55] and a Storm Cost Recovery Rider.[56] DP&L claims that the Regulatory Compliance Rider includes cost recovery for expenses that DP&L has or will incur that are outside the normal course of business. The Utility is seeking recovery of $25,745,328 initially for what it claims are deferred costs.[57] Many of these deferred costs were not authorized by the PUCO and there has not been performed any analysis through the rate case process that customers should or have not already paid these costs. Approval of the Regulatory Compliance Rider can result in double recovery because customers have or are already paying though charges in base rates costs that DP&L would now unnecessarily collect through a rider.

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[54] Direct Testimony of Tyler A. Teuscher.

[55] Id.

[56] Direct Testimony of Claire E. Hale.

[57] Teushler at Exhibit TAT-2.

DP&L claims that the Uncollectible Rider enables the Utility to recover actual uncollectible expense rather than estimated uncollectible expense.[58] But the amount of uncollectible expense has not been justified or resolved through the rate case process so that a determination can be made if customers should appropriately pay these costs. Furthermore, DP&L is seeking recovery of certain Percentage of Income Payment Plan (PIPP) uncollectible expense from November 1, 2010 through September 30, 2015.[59] In addition to the fact that the PUCO did not approve a deferral for recovery of these expenses, the alleged costs occurred outside the test year for the base rate case. Therefore, approval of an Uncollectible Rider can result in customers potentially paying inappropriate uncollectible expenses in base rates and also paying the same costs again in the Uncollectible Rider. Therefore, the PUCO should protect consumers from paying these unsupported charges.

DP&L is proposing a Storm Cost Recovery Rider where the expenses associated with major storm events are recovered through the rider.[60] Major events are days where the reliability performance of the electric distribution systems is excluded from consideration in determining compliance with annual reliability standards.[61] But DP&L has not justified the need for a Storm Cost Recovery Rider or the amount of expenses associated with major storms. Approval of the Storm Cost

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[58] Id at Exhibit TAT-1.

[59] Id.

[60] Hale at 2.

[61] Ohio Adm. Code 4901:1-10-01(T).

Recovery Rider could result in customers paying twice for the same costs in distribution base rates and then again through the rider.

Until there has been a thorough evaluation of DP&L accounting and the amount of money charged to customers in base rates, there is no fair way to discern how any of the costs associated with the three new proposed riders are incremental to costs customers already pay. Therefore, approval of the Regulatory Compliance Rider, the Uncollectible Rider, or the Storm Cost Recovery Rider in the ESP could result in customers being charged twice for the same services. Last, the unilateral right DP&L would give itself to create even more new riders during the term of the ESP is unjust and unreasonable to consumers and should be rejected. The PUCO should protect consumers by not approving any of these riders in the ESP.

V. CONCLUSION

Q26. DOES THIS CONCLUDE YOUR TESTIMONY?

A26. Yes. However, I reserve the right to incorporate new information that may subsequently become available through outstanding discovery or otherwise.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of James D. Williams on Behalf of the Office of the Ohio Consumers' Counsel* has been served via electronic transmission this 21st day of November 2016.

/s/ *Kevin Moore*
Kevin Moore
Assistant Consumers' Counsel

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Testimony of James D. Williams
Filed at the Public Utilities Commission of Ohio

1. *In the Matter of the Application of the Cincinnati Gas and Electric Company for an Increase in Its Rates for Gas Service to All Jurisdictional Customers*, Case No. 95-0656-GA-AIR (August 12, 1996).

2. *In the Matter of the Application of the Cincinnati Gas and Electric Company for an Increase in Its Rates for Gas Service to All Jurisdictional Customers*, Case No. 01-1228-GA-AIR (February 15, 2002).

3. *In the Matter of the Commission's Investigation into the Policies and Procedures of Ohio Power Company, Columbus Southern Power Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, The Toledo Edison Company and Monongahela Power Company regarding installation of new line extensions*, Case No. 01-2708-EL-COI (May 30, 2002).

4. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for an Increase in Its Rates for Gas Service to All Jurisdictional Customers*, Case No. 07-0829-GA-AIR (June 23, 2008).

5. *In the Matter of the Application of the Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution*, Case No. 08-072-GA-AIR (September 25, 2008).

6. *In the Matter of a Settlement Agreement Between the Staff of the Public Utilities Commission of Ohio, The Office of the Consumers' Counsel and Aqua Ohio, Inc. Relating to Compliance with Customer Service Terms and Conditions Outlined in the Stipulation and Recommendation in Case No. 07-564-WW-AIR and the Standards for Waterworks Companies and Disposal System Companies*, Case No. 08-1125-WW-UNC (February 17, 2009).

7. *In the Matter of the Application of the Ohio American Water Company to Increase its Rates for water and Sewer Services Provided to its Entire Service Area*, Case No. 09-391-WS-AIR (January 4, 2010).

8. *In the Matter of the Application of Aqua Ohio, Inc. for Authority to Increase its Rates and Charges in its Masury Division,* Case No. 09-560-WW-AIR (February 22, 2010).

9 *In the Matter of the Application of Aqua Ohio, Inc. for Authority to Increase its Rates and Charges in Its Lake Erie Division*, Case No. 09-1044-WW-AIR (June 21, 2010).

10. *In the Matter of the Application of The Ohio American Water Company to Increase its Rates for Water Service and Sewer Service,* Case No. 11-4161-WS-AIR (March 1, 2012).

11. *In the Matter of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, Case No. 11-346-EL-SSO, et al (May 4, 2012).

12. *In the Matter of the Application of The Dayton Power and Light Company for Approval of its Market Rate Offer*, Case No. 12-426-EL-SSO (June 13, 2012).

13. *In the Matter of the Application of Ohio Power Company to Establish Initial Storm Damage Recovery Rider Rates*, Case No. 12-3255-EL-RDR (December 27, 2013).

14. *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, Case No. 13-2385-EL-SSO (May 6, 2014).

15. *In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case 14-841-EL-SS0 (May 29, 2014).

16. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan,* Case No. 14-1297-EL-SSO (December 22, 2014).

17. *In the Matter of the Application of Duke Energy Ohio, Inc., to Adjust Rider DR-IM and Rider AU for 2013 Grid Modernization Costs,* Case No. 14-1051-EL-RDR (December 31, 2014) and (February 6, 2015).

18. *In the Matter of the Application Not for an Increase in Rates Pursuant to Section 4901:18, Revised Code, of Ohio Power Company to Establish Meter Opt Out Tariff,* Case No. 14-1158-EL-ATA (April 24, 2015).

19. *In the Matter of the Application of Duke Energy of Ohio, Inc., for Approval of a Grid Modernization Opt-out Tariff and for a Change in Accounting Procedures Including a Cost Recovery Mechanism.*, Case 14-1160-EL-UNC and 14-1161-EL-AAM (September 18, 2015).

20. *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of an Alternative Rate Plan Pursuant to Section 4929.05, Revised Code, for an Accelerated Service Line Replacement Programs,* Case No. 14-1622-GA-ALT (November 6, 2015).

21. *In the Matter of the Complaint of Jeffrey Pitzer, Complainant, v. Duke Energy Ohio, Inc. Respondent.*, Case No. 15-298-GE-CSS (December 30, 2015).

22. *In the Matter of the Application of Ohio Power Company to Initiate Phase 2 of Its gridSMART Project and to Establish the gridSMART Phase 2 Rider.*, Case No. 13-1939-EL-RDR (July 22, 2016).

23. *In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of Demand Side Management Program for its Residential and Commercial Customers.,* Case No. 16-1309-GA-UNC (September 13, 2016).

24. *In the Matter of the Application of the Dayton Power and Light Company for Approval of Its Electric Security Plan*, Case No. 16-0395-EL-SSO (November 21, 2016).

INT-274. If your response to RFA No. 79 is anything other than an unqualified admission, state all facts underlying your response.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 6 (calls for narrative answer), 9 (vague or undefined), 12 (seeks information that DP&L does not know at this time). Subject to all general objections, DP&L states that the Company provided Typical Bill Comparisons as part of its Electric Security Plan that provides estimates of bill impacts for residential customers. DP&L further responds that the DIR proposal requests tariff approval at a rate of zero.

Witness Responsible: Robert Adams

Map the Meal Gap 2016:

Overall Food Insecurity in Ohio by County in 2014 [1]

County	Population	Food Insecurity rate	Estimated number food insecure individuals (rounded)	Likely Income Eligibility for Federal Nutrition Assistance [2]: % below 130% poverty *SNAP, WIC, free school meals, CSFP, TEFAP*	% between 130% and 185% poverty *WIC, reduced price school meals*	% above 185% poverty *Charitable Response*
Adams	28,342	18.1%	5,140	80%	6%	14%
Allen	105,562	16.5%	17,470	59%	13%	29%
Ashland	53,202	14.2%	7,550	59%	11%	30%
Ashtabula	100,346	15.7%	15,750	65%	12%	23%
Athens	64,840	19.8%	12,810	69%	4%	27%
Auglaize	45,867	11.8%	5,410	46%	19%	35%
Belmont	69,793	14.8%	10,300	51%	15%	34%
Brown	44,464	14.3%	6,370	62%	14%	24%
Butler	371,154	14.0%	52,060	50%	10%	41%
Carroll	28,539	13.7%	3,920	60%	14%	26%
Champaign	39,628	13.2%	5,220	52%	12%	36%
Clark	137,303	16.3%	22,410	61%	14%	25%
Clermont	199,450	12.3%	24,590	48%	9%	44%
Clinton	41,871	16.3%	6,840	56%	12%	32%
Columbiana	106,622	15.0%	15,960	59%	13%	28%
Coshocton	36,768	15.5%	5,700	66%	12%	22%
Crawford	43,036	15.1%	6,510	61%	13%	26%
Cuyahoga	1,267,513	19.4%	245,660	53%	14%	33%
Darke	52,537	13.7%	7,190	57%	17%	27%
Defiance	38,795	12.3%	4,750	58%	15%	27%
Delaware	181,821	9.0%	16,440	29%	11%	60%
Erie	76,416	15.0%	11,450	49%	15%	36%
Fairfield	148,067	13.2%	19,510	47%	12%	41%
Fayette	28,875	16.1%	4,660	64%	11%	25%
Franklin	1,197,592	17.9%	214,500	54%	13%	34%
Fulton	42,541	11.6%	4,920	51%	12%	37%
Gallia	30,763	16.1%	4,950	69%	12%	20%
Geauga	93,819	10.3%	9,680	43%	12%	45%
Greene	163,313	14.5%	23,650	48%	8%	44%
Guernsey	39,794	15.4%	6,140	65%	11%	24%
Hamilton	803,272	18.6%	149,740	53%	12%	36%
Hancock	75,290	12.9%	9,730	57%	10%	33%
Hardin	31,826	15.1%	4,800	61%	10%	29%
Harrison	15,698	14.5%	2,280	62%	15%	23%
Henry	28,074	12.1%	3,390	51%	9%	40%
Highland	43,266	16.5%	7,130	73%	12%	15%
Hocking	29,111	14.6%	4,250	62%	10%	28%
Holmes	43,176	12.4%	5,360	64%	24%	11%
Huron	59,186	14.2%	8,410	55%	14%	31%
Jackson	32,952	17.7%	5,840	73%	8%	19%
Jefferson	68,510	16.7%	11,410	57%	13%	29%
Knox	61,063	14.0%	8,520	56%	12%	32%
Lake	229,602	12.4%	28,410	41%	14%	46%
Lawrence	62,100	15.1%	9,350	61%	16%	23%
Licking	167,911	13.3%	22,330	49%	12%	39%
Logan	45,564	13.9%	6,330	65%	6%	30%
Lorain	302,465	14.3%	43,130	51%	10%	39%
Lucas	438,167	18.3%	80,260	60%	12%	28%
Madison	43,326	13.5%	5,850	44%	11%	45%
Mahoning	235,809	16.9%	39,790	56%	15%	29%
Marion	66,171	15.9%	10,520	61%	8%	31%
Medina	174,091	11.1%	19,280	38%	11%	51%
Meigs	23,564	16.9%	3,970	70%	12%	18%
Mercer	40,789	11.1%	4,530	42%	19%	39%
Miami	103,145	13.7%	14,090	52%	12%	35%
Monroe	14,590	17.1%	2,490	58%	14%	28%
Montgomery	534,801	18.4%	98,470	55%	14%	31%

County	Population	Food insecurity rate	Estimated number food insecure individuals (rounded)	Likely Income Eligibility for Federal Nutrition Assistance[2] % below 130% poverty *SNAP, WIC, free school meals, CSFP, TEFAP*	% between 130% and 185% poverty *WIC, reduced price school meals*	% above 185% poverty *Charitable Response*
Morgan	14,977	16.2%	2,420	65%	13%	22%
Morrow	34,991	12.6%	4,410	53%	12%	35%
Muskingum	85,947	16.7%	14,360	63%	15%	22%
Noble	14,561	14.8%	2,160	47%	21%	33%
Ottawa	41,304	12.6%	5,210	43%	16%	41%
Paulding	19,293	12.8%	2,470	56%	16%	28%
Perry	36,000	15.5%	5,590	65%	13%	22%
Pickaway	56,279	13.5%	7,620	47%	12%	41%
Pike	28,504	17.9%	5,100	74%	11%	15%
Portage	161,553	14.8%	23,930	54%	7%	39%
Preble	41,887	13.1%	5,510	56%	16%	29%
Putnam	34,256	9.6%	3,300	40%	14%	46%
Richland	122,813	16.2%	19,920	55%	14%	31%
Ross	77,552	16.1%	12,480	62%	10%	28%
Sandusky	60,498	12.9%	7,820	62%	12%	26%
Scioto	78,520	18.2%	14,280	70%	8%	23%
Seneca	56,100	14.2%	7,950	56%	11%	33%
Shelby	49,165	13.0%	6,380	51%	12%	38%
Stark	375,090	15.2%	57,080	53%	13%	34%
Summit	541,464	16.2%	87,480	50%	12%	38%
Trumbull	207,596	16.3%	33,820	56%	12%	33%
Tuscarawas	92,616	13.7%	12,690	58%	13%	29%
Union	53,090	11.2%	5,920	40%	13%	47%
Van Wert	28,612	12.7%	3,620	55%	19%	26%
Vinton	13,319	16.6%	2,220	72%	17%	11%
Warren	217,623	10.7%	23,290	30%	11%	59%
Washington	61,473	14.5%	8,880	61%	9%	30%
Wayne	114,978	13.0%	14,990	56%	16%	28%
Williams	37,493	13.3%	4,990	63%	18%	19%
Wood	128,139	13.7%	17,610	53%	7%	40%
Wyandot	22,535	12.5%	2,810	48%	17%	35%
State Total[6]	**11,594,163**	**16.8%**	**1,943,340**	**52.3%**	**12.9%**	**34.7%**

For additional data and maps by county, state, and congressional district, please visit **www.feedingamerica.org/mapthegap** .

Gundersen, C., A. Dewey, A. Crumbaugh, M. Kato & E. Engelhard. *Map the Meal Gap 2016: Food Insecurity and Child Food Insecurity Estimates at the County Level.* Feeding America, 2016. This research is generously supported by the Howard G. Buffett Foundation and The Nielsen Company.

[1]Map the Meal Gap's food insecurity rates are determined using data from the 2001-2014 Current Population Survey on individuals in food insecure households; data from the 2014 American Community Survey on median household incomes, poverty rates, homeownership, and race and ethnic demographics; and 2014 data from the Bureau of Labor Statistics on unemployment rates.

[2]Numbers reflect percentage of food insecure individuals living in households with incomes within the income bands indicated. Eligibility for federal nutrition programs is determined in part by these income thresholds which can vary by state.

[6]Population and food insecurity data in the state totals row do not reflect the sum of all counties in that state. The state totals are aggregated from the congressional districts data in that state. All data in the state totals row pertaining to the cost of food or the "Meal Gap" reflect state-level data and are not aggregations of either counties or congressional districts.

Map the Meal Gap 2016:

***Overall** Food Insecurity in Ohio by Congressional District in 2014* [1]

Congressional District	Population	Food insecurity rate	Estimated number food insecure individuals (rounded)	Likely Income Eligibility for Federal Nutrition Assistance[2] % below 130% poverty *SNAP, WIC, free school meals, CSFP, TEFAP*	% between 130% and 185% poverty *WIC, reduced price school meals*	% above 185% poverty *Charitable Response*
1	729,726	19.3%	141,100	46%	12%	42%
2	724,587	15.9%	115,490	54%	10%	36%
3	755,499	23.0%	173,550	58%	18%	24%
4	709,882	15.4%	109,310	54%	11%	36%
5	730,503	13.0%	94,820	49%	13%	38%
6	713,457	15.9%	113,270	59%	10%	31%
7	725,548	14.4%	104,790	54%	11%	35%
8	722,889	15.0%	108,730	50%	12%	38%
9	709,813	19.4%	137,500	62%	14%	24%
10	720,794	19.0%	137,130	53%	11%	36%
11	699,736	29.8%	208,290	59%	17%	24%
12	755,978	12.4%	93,470	43%	9%	49%
13	707,940	18.0%	127,520	56%	14%	30%
14	722,474	12.2%	88,270	41%	12%	46%
15	740,854	14.3%	105,730	45%	12%	43%
16	724,483	11.6%	84,370	37%	13%	50%

For additional data and maps by county, state, and congressional district, please visit www.feedingamerica.org/mapthegap .

Gundersen, C., A. Dewey, A. Crumbaugh, M. Kato & E. Engelhard. *Map the Meal Gap 2016: Food Insecurity and Child Food Insecurity Estimates at the County Level.* Feeding America, 2016. This research is generously supported by the Howard G. Buffett Foundation and The Nielsen Company.

[1]Map the Meal Gap's food insecurity rates are determined using data from the 2001-2014 Current Population Survey on individuals in food insecure households; and data from the 2014 American Community Survey on median household incomes, unemployment rates, poverty rates, homeownership, and race and ethnic demographics.

[2]Numbers reflect percentage of food insecure individuals living in households with incomes within the income bands indicated. Eligibility for federal nutrition programs is determined in part by these income thresholds which can vary by state.

OBJECTIONS AND RESPONSES TO INTERROGATORIES

INT-245. Referring to the Direct Testimony of Mr. Hall at page 3, line 18, please explain why cost recovery through base rates is not sufficient for the Company to address any aging distribution infrastructure issues?

RESPONSE: General Objections Nos. 2 (unduly burdensome), 6 (calls for narrative answer), 9 (vague and undefined), 11 (calls for a legal conclusion), 13 (mischaracterization). Subject to all general objections, DP&L states that cost recovery through the DIR allows DP&L more expedient recovery, as permitted by R.C. 4928.143(b)(2)(h), to ensure that DP&L will be able to provide safe, reliable, and affordable energy delivery to its customers that it might not otherwise be able to provide absent the DIR Rider.

Witness Responsible: Kevin Hall

DP&L

Working For You Today And Tomorrow

PRICING SERVICES

October 26, 2009

ELECTRONIC FILING
Betty McCauley
PUCO – Docketing Division
180 East Broad Street, 13th Floor
Columbus, Ohio 43215

Re: Case No. 09-794-EL-ESS

Dear Ms. McCauley:

Pursuant to the Commission's Entry dated May 6, 2009 in Case No. 06-653-EL-ORD, The Dayton Power and Light Company herewith electronically submits its amended filing of inspection, maintenance, repair and replacement programs in conformance with the requirements of the Electric Service and Safety Standards, Section 4901:1-10-27 (E) (2) OAC. The attached amended filing reflects discussions with Staff and their request for modifications to the above mentioned programs.

Thank you for your assistance and your attention to this matter. If you have any questions please feel free to call me at (937) 259-7238.

Very truly,

John Wagner

John Wagner
Manager, Retail Pricing

The Dayton Power and Light Company
Inspection, Maintenance, Repair and Replacement of Transmission
And Distribution Facilities (Circuits and Equipment) Program

Introduction

The Dayton Power & Light Company has adopted a results-based approach to the development and evaluation of maintenance and inspection programs. All maintenance, inspection and capital planning practices contribute to overall system performance. Reliability performance is regularly reviewed and integrated into our programs. DP&L's system level reliability performance is measured by the following industry standard indicators

- SAIFI (System Average Interruption Frequency Index)
- CAIDI (Customer Average Interruption Duration Index)
- SAIDI (System Average Interruption Duration Index)

This report provides a detailed overview of Dayton Power and Light's maintenance and inspection programs. In addition to the programs listed herein, the following operational practices work to ensure safe and reliable operation of the electric transmission and distribution system:

- Dayton Power and Light maintains a 24-hour emergency response operation and all unplanned outages are promptly addressed.

- Adequate inventory is maintained such that the supply of parts does not impact restoration time.

- All employees performing maintenance and inspection work are properly trained to do their jobs safely. OSHA (Occupational Health and Safety Administration) guidelines are followed for inspection and maintenance programs, just as they are for all other types of work.

- All facilities are designed and operated to meet NESC (National Electric Safety Code) requirements. Any safety violation noted during an inspection is promptly repaired.

Table of Contents

a. Poles and Towers

1. **Program objectives**
   The goal of this program is to inspect, maintain, repair and replace poles to ensure safe and reliable operation of the distribution system.

2. **Overview of procedures**
   Poles with an actual or estimated vintage greater than 25 years, or those poles that have visible defects will be tested to determine suitability, structural soundness and need for maintenance, repair, or replacement (if applicable). Identified poles shall be sound tested, bored and ground line excavated by a third party contractor. Poles which fail visual and physical screening as referenced in the '*Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)*', will either be replaced or reinforced.

3. **Identification of poles inspected and tested**
   Ten percent (10%) of DP&L's circuits will be identified on an annual basis for pole inspections and test[1]. All poles from the substation to the customer drop will be examined. Poles with an actual or estimated vintage greater than 25 years or older will be visually and physically inspected and tested. Poles that fail either the visual inspection or the physical inspection and test will be replaced or reinforced. At any point in the inspection process, a pole is designated as "fail", no additional visual or physical inspection or testing will be performed; the pole will be scheduled for replacement or reinforcement.

4. **Justification for program schedule**
   Industry standards generally indicate a 10 year inspection cycle is warranted. Where possible, this evaluation program is to coincide with DP&L's Overhead Distribution Patrol Program (DLP), referenced in the '*Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)*'.

5. **Process of documenting and recording program activities**
   Circuits identified for inspection will be electronically documented annually. Inspection data on all inspected poles will be gathered in accordance with the procedures outlined in the, '*Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)*'. Inspection data for all poles which receive physical inspection and testing will be tracked using GPS coordinates and/or pole numbers. All pole inspection and test information will be recorded into electronic database files or other appropriate records. Pole inspection information shall be kept in an electronic format that has the capability of generating statistical information. The inspection process also includes the identification and documentation of any two-pole conditions that may be present.

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[1] DP&L will complete the first cycle of the pole inspection within 8 years (i.e. first cycle 2006 through 2013, second cycle 2016 – 2025). All subsequent cycles will be based upon a 10 year cycle.

Pole failure statistics will be tracked (effective 1/1/2006) and monitored by circuit to evaluate program performance and effectiveness.

6. **Process for reviewing program results and making repair/replacements based upon those findings.**
The decision to repair or replace a pole will be based upon field testing results by qualified field personnel in accordance with inspection procedures outlined in the, *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*. Poles and Towers with recorded defects that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection or testing that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of the many inputs into the capital planning and budgeting process.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed.**
Reliability Operations will review the progress of the inspections on a periodic basis to ensure program compliance. On an annual basis, the effectiveness of the program will be evaluated.

b. Circuit and Line Inspections

1. Program objectives

The goal of this program is to maintain reliable operation of the electric distribution system.

2. Overview of procedures

This primarily corrective program is designed to target reliability problem areas. Distribution circuit and branch line reliability performance is monitored, problem areas are identified and corrective action is taken as needed. The detailed procedures, which inspect all segments of the distribution circuit (primary and secondary) from the substation to the customer service drop are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*. The Program components are as follows:

a. ***Task Name***: Monitor circuit reliability performance
Frequency: Annually
Description: Identify circuits that are performing poorly in terms of reliability. Evaluate the outage history and physical condition of all circuits and initiate remedial action, if necessary, on the worst 8% of the circuits (as defined by the previously submitted DPL index).

b. ***Task Name***: Monitor branch line reliability performance
Frequency: Monthly
Description: Identify branch lines that are performing poorly in terms of reliability. Evaluate the outage history and physical condition of the branch lines and initiate remedial action if necessary.

c. ***Task Name***: Electric Distribution Patrol (Overhead Distribution Patrol Program)
Frequency: Every five years (20% of the overhead circuits will be inspected on an annual basis)
Description: The Overhead Distribution Patrol Program is designed to examine the condition of the hardware, conductor, poles, clearances, and tree conditions on the specified overhead distribution circuits. This comprehensive inspection includes the mainline overhead distribution facilities from the substation including all branch lines. The inspection process also includes the identification and documentation of any two-pole conditions that may be present.

3. Identification of equipment examined

Distribution poles, conductor and hardware.

4. Justification for program schedule

The methodology for this program is based on engineering judgment and industry standards.

5. **Process of documenting and recording program activities**
Record keeping practices vary for each of the programs described above. At a minimum, inspections and deficiencies are documented and maintained.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
The decision to repair or replace is based on field experience and engineering judgment.

For the Overhead Distribution Patrol Program, the program will be reviewed periodically by Reliability Operations to ensure that the inspections are being conducted correctly and that sufficient progress is being made in conducting the inspections. Any recorded deficiencies noted during the Distribution Line Patrol Program that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of distribution circuits and branch lines, if field inspectors identify a high percentage of pole replacements and repairs in a particular area, a capital project may be initiated to rebuild that section of the circuit.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed. In the case of distribution circuits and branch lines, reliability performance is reviewed on a monthly basis and problem areas are targeted as needed.

c. **<u>Primary enclosures (e.g., pad-mounted transformers and pad-mounted switch gear) and secondary enclosures (e.g., pedestals and hand holes)</u>**

1. **<u>Program objectives</u>**
The U.R.D. (Underground Residential Distribution) inspection program is a comprehensive program to verify the physical and visual condition of U.R.D. devices and to correct any safety issues. The detailed procedures, which inspect all segments of the distribution circuit (primary and secondary) from the substation to the customer's service are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*.

2. **<u>Overview of procedures</u>**

    a. ***Task Name***: Inspect U.R.D. equipment
    Frequency: The inspections will be performed by "map grid", not by circuit. 20% of all grids will be inspected yearly, with the entire system being inspected once every five years.
    Description: Inspect and make repairs as needed

3. **<u>Identification of equipment examined</u>**
The underground device inspection program includes Pad-Mounted Transformers, Pedestals, LBC's (Load Break Centers), PMH's (Pad Mounted Housing Switches) and risers.

4. **<u>Justification for program schedule</u>**
The program guidelines are based on NESC requirements, industry practice and company experience

5. **<u>Process of documenting and recording program activities</u>**
Underground devices are highlighted on inspection prints and any repair items are documented on the "Departmental Order" form at the time of inspection. Devices requiring follow-up work are documented and tracked in the Maintenance Work Order (MWO) database until completion.

6. **<u>Process for reviewing program results and making repairs/replacements based on those findings</u>**
The decision to repair or replace is based on the judgment of qualified field personnel. Field inspectors carry a repair kit and all minor repairs are completed at the time of the inspection. If more extensive work is required, the problem is documented and scheduled for repair. Deficiencies that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **<u>Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process</u>**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process.

8. **<u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>**
The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

d. Line Reclosers

1. **Program objectives**
   The goal of this program is to maintain reliable operation of key components of the distribution system.

2. **Overview of procedures**
   Distribution system device maintenance programs are primarily preventive in nature. The detailed procedures are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*.

   a. ***Task Name***: Line Recloser Inspections
      Frequency: Annually
      Description: Visually check physical condition, record counter reading, ambient temperature and load.

3. **Identification of equipment examined**
   This program includes line reclosers.

4. **Justification for program schedule**
   Maintenance and inspection schedules for overhead distribution devices are based on a combination of manufacturer recommendations and company experience.

5. **Process of documenting and recording program activities**
   Record keeping practices vary for each of the programs described below. At a minimum, inspections and deficiencies are documented and maintained.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   The determination to repair versus replace varies for each component and is generally based on the judgment of qualified field personnel and engineering. Deficiencies that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection or testing that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of distribution system components, capital projects may be initiated based on the finding of field inspections.

8. <u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>

The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

e. Line Capacitors

1. **Program objectives**
   The goal of this program is to maintain reliable operation of key components of the distribution system.

2. **Overview of procedures**
   Distribution system device maintenance programs are primarily preventive in nature. The detailed procedures are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*.

   a. ***Task Name***: Capacitor Inspections
      Frequency: Annually
      Description: Check cutouts, switches and controls. Repair or adjust as needed.

3. **Identification of equipment examined**
   This program includes capacitors.

4. **Justification for program schedule**
   Maintenance and inspection schedules for overhead distribution devices are based on a combination of manufacturer recommendations and company experience.

5. **Process of documenting and recording program activities**
   Record keeping practices vary for each of the programs described below. At a minimum, inspections and deficiencies are documented and maintained.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   The determination to repair versus replace varies for each component and is generally based on the judgment of qualified field personnel and engineering. Deficiencies that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection or testing that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of distribution system components, capital projects may be initiated based on the finding of field inspections.

8. <u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>

The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

f. Distribution Right of Way (Vegetation Management)

1. Program objectives

The goal of this program is to maintain the reliability of the electric distribution system by preventing outages and equipment damage due to trees or other vegetation contacting the lines. The detailed procedures are outlined in the *'Dayton Power & Light Company Line Clearance Program Alliance (Rev. 2009)'*.

2. Overview of procedures

a. ***Task Name***: Distribution line clearance
Frequency: 5 Years
Description: Trim or remove trees and brush as needed. Clearances will vary depending upon tree species.

3. Identification of equipment examined

Complete a 5 year trim cycle from substation to the customer service drop with no circuit having a last trim date of greater than 60 months. Line clearance is performed on overhead primary and secondary distribution conductors using ANSI standards (including, but not limited to "A300" and "Z133.1-1994") as a basis for clearance.

4. Justification for program schedule

The 5 year cycle interval has been determined to be an optimal timeframe between circuit trims to limit tree outages caused by Trees in ROW and also to meet state regulatory needs.

5. Process of documenting and recording program activities

Line clearance activity is tracked in a database including last trim date, total circuit miles and circuit miles trimmed. Subcontractors update primary prints to document their progress. Records will be maintained for a minimum of 5 years.

6. Process for reviewing program results

Line clearance field inspectors audit subcontractor performance to ensure clearances are adequate. Deficient work is returned to the subcontractor for remediation. However, The Dayton Power & Light Company does note that exceptions to strict clearances may occur as a result of property owner refusal, political & societal factors, community ordinances and easement rights.

7. Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process

Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process.

8. **<u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>**

The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

Audits are conducted to ensure contractor work meets specifications. Tree related outages are also reviewed on a monthly basis.

g. Substations

Substation Transformers

1. **Program objectives**
The goal of this program is ensure reliable operation and to extend the operating life of substation class transformers.

2. **Overview of procedures**
This program is primarily preventive in nature. In addition to the tasks listed below, predictive maintenance is applied to selected units in the form of continuous monitoring of nitrogen pressure, LTC/main tank temperature differential, and main tank oil temperature. Additional tasks such as internal visual inspections, megger test, etc. are performed as needed based on engineering judgment. Substation transformer loading is also continuously monitored to ensure that thermal limits are not exceeded. Routine scheduled tasks include the following:

    a. ***Task Name***: External Visual Inspection
    Frequency: Monthly
    Description: Check for oil leaks, ground faults, failed cooling fans, high temperature, high or low pressure, clogged or damaged grills, damaged gauges.

    b. ***Task Name***: Thermographic Imaging
    Frequency: Yearly
    Description: Check for hot spots due to loose connections.

    c. ***Task Name***: Dielectric Oil Breakdown Test
    Frequency: Every five years
    Description: Test the dielectric strength of the oil. Replace or filter oil if needed.

    d. ***Task Name***: LTC Maintenance
    Frequency: Every five years
    Description: Perform routine maintenance on LTC's

    e. ***Task Name***: Perform Doble Test
    Frequency: Every five years
    Description: Perform this test to check for insulation degradation.

3. **Identification of equipment examined**
All substation transformers are included in this program.

4. **Justification for program schedule**
Maintenance and inspection practices are based on engineering experience and industry practices. The criticality of equipment is determined based on the voltage class, system configuration and loading.

5. **Process of documenting and recording program activities**
All data is tracked in a Computerized Maintenance Management System (CMMS) program. The CMMS system holds a Maintenance Task Table that shows historical and scheduled maintenance for each device. The system also generates and tracks maintenance and repair work orders.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
Repair versus replacement determination is made based on engineering judgment and life cycle cost. The CMMS program is an excellent tool for tracking reliability by equipment manufacturer and model. If CMMS data shows a pattern of problems or failures, the entire class of like equipment may be scheduled for replacement or repair.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of substation equipment, specific classes of equipment may be scheduled for replacement based on failure history or total owning cost.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

Circuit Breakers

1. **Program objectives**
The goal of this program is ensure reliable operation and extend the operating life of circuit breakers.

2. **Overview of procedures**

   a. ***Task Name***: Operational Test
   Frequency: As needed to ensure breakers are operated at least once per year
   Description: Test to ensure proper operation. Repair or adjust as needed.

   b. ***Task Name***: Visual Inspection
   Frequency: Monthly
   Description: Check for oil leaks, cracked or damaged bushings and other items depending on the type of unit. Repair or adjust as needed.

   c. ***Task Name***: Preventive Maintenance
   Frequency: Varies depending on type (i.e. oil, vacuum, SF6, etc.) and vintage
   Description: Varies depending on type (i.e. oil, vacuum, SF6, etc.) and vintage

3. **Identification of equipment examined**
   This program includes all substation circuit breakers.

4. **Justification for program schedule**
   The breaker maintenance program is preventive in nature and methodology is based on company experience. The criticality of equipment is determined based on the voltage class, system configuration and loading.

5. **Process of documenting and recording program activities**
   All data is tracked in a Computerized Maintenance Management System (CMMS) program. The CMMS system holds a Maintenance Task Table that shows historical and scheduled maintenance for each device. The system also generates and tracks maintenance and repair work orders.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   Repair versus replacement determination is made based on engineering judgment and life cycle cost. The CMMS program is an excellent tool for tracking reliability by equipment manufacturer and model. If CMMS data shows a pattern of problems or failures, the entire class of like equipment may be scheduled for replacement or repair.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of substation equipment, specific classes of equipment may be scheduled for replacement based on failure history or total owning cost.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
   The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

Relays

1. **Program objectives**
   The goal of this program is ensure reliable operation of relays.

2. **Overview of procedures**
   This program is preventive in nature. The testing schedule is as follows:

   a. ***Task Name***: Calibration and Trip Test
      Frequency: 345 kV – every six years, 138 kV, 69 kV and 33 kV – every eight years, 12 kV and 4 kV – every ten years
      Description: Calibrate and test to ensure proper operation.

3. **Identification of equipment examined**
   All relays are included in the program.

4. **Justification for program schedule**
   Procedures are based on company experience and manufacturer documentation. Criticality is determined based on voltage class.

5. **Process of documenting and recording program activities**
   Calibration/trip test results are documented on Relay Field Test Cards. The most recent test results are kept on file for every relay on the system. The Computerized Maintenance Management System (CMMS) shows the overall program schedule and status.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   After reviewing test results, the decision to repair or replace is made based on engineering judgment and manufacturer specifications.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
   The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

Substation Switches

1. **Program objectives**
   The goal of this program is to maintain the reliable operation of switches in substations.

2. **Overview of procedures**
   This program is preventive in nature.

3. **Identification of equipment examined**
   All substation switches are included in the program.

4. **Justification for program schedule**
   Equipment criticality is determined based on voltage class and system configuration.

   a. ***Task Name***: Thermographic Inspection
      Frequency: Annually
      Description: Check for hot spots and repair or adjust as needed.

5. **Process of documenting and recording program activities**
   All data is tracked in a Computerized Maintenance Management System (CMMS) program. The CMMS system holds a Maintenance Task Table that shows historical and scheduled maintenance for each device. The system also generates and tracks maintenance and repair work orders.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   Repair versus replacement determination is based on company experience. If field personnel experience problems operating a particular switch, the switch will be maintained and lubricated. The CMMS program is an excellent tool for tracking reliability by equipment manufacturer and model. If CMMS data shows a pattern of problems or failures, the entire class of like equipment may be scheduled for replacement or repair.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of substation equipment, specific classes of equipment may be scheduled for replacement based on failure history or total owning cost.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
   The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

h. Air Break Switches

1. **Program objectives**
   The goal of this program is to maintain reliable operation of key components of the distribution system.

2. **Overview of procedures**
   Distribution system device maintenance programs are primarily preventive in nature. The detailed procedures are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*.

   a. ***Task Name***: Visual Inspection of Air Break Switches
      Frequency: Annually
      Description: Visually check handle and locking mechanism, ground connections, insulators and lightning arresters.

3. **Identification of equipment examined**
   This program includes air break switches.

4. **Justification for program schedule**
   Maintenance and inspection schedules for overhead distribution devices are based on a combination of manufacturer recommendations and company experience.

5. **Process of documenting and recording program activities**
   Record keeping practices vary for each of the programs described below. At a minimum, inspections and deficiencies are documented and maintained.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
   The determination to repair versus replace varies for each component and is generally based on the judgment of qualified field personnel and engineering. Deficiencies that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection or testing that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of distribution system components, capital projects may be initiated based on the finding of field inspections.

i. Voltage Regulators

1. **Program objectives**
The goal of this program is to maintain reliable operation of key components of the distribution system.

2. **Overview of procedures**
Distribution system device maintenance programs are primarily preventive in nature. The detailed procedures are outlined in the *'Distribution Maintenance and Inspection Programs Manual (Rev. October 5, 2009)'*.

    a. ***Task Name***: Voltage Regulator Inspections
    Frequency: Biennially
    Description: Inspection that includes a control check, and visual check of the physical condition and indicator readings (min, max and current).

3. **Identification of equipment examined**
This program includes voltage regulators.

4. **Justification for program schedule**
Maintenance and inspection schedules for overhead distribution devices are based on a combination of manufacturer recommendations and company experience.

5. **Process of documenting and recording program activities**
Record keeping practices vary for each of the programs described below. At a minimum, inspections and deficiencies are documented and maintained.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
The determination to repair versus replace varies for each component and is generally based on the judgment of qualified field personnel and engineering. Deficiencies that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected or isolated. All remaining deficiencies that are likely to cause an outage shall be corrected within one year of the completion of the inspection or testing that originally revealed such deficiencies. All other remaining deficiencies that are not expected to endanger life or property or are not likely to cause an outage will be tracked until complete.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process. In the case of distribution system components, capital projects may be initiated based on the finding of field inspections.

8. <u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>

The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

j. Transmission

Transmission Lines

1. **Program objectives**
   The goal of this program is to maintain the reliability and safety of the electric transmission system including facilities ranging from 33kV to 345 kV.

2. **Overview of procedures**
   This preventive program consists primarily of visual and infrared inspections of structures/poles, insulators, switches and conductors. Guidelines for each voltage class/type are as follows:

   345 kV

   a. ***Task Name***: Helicopter Patrol
   Frequency: Quarterly
   Description: Look for mechanical problems, erosion and vegetation problems. Initiate corrective action as needed.

   b. ***Task Name:*** Thermography
   Frequency: As needed
   Description: Check line switches for heating indicative of poor electrical connections. Identify "hot spots" and classify according to elevation above ambient temperature. Complete necessary repairs.

   138 kV

   a. ***Task Name***: Helicopter Patrol or ground patrols for areas in Metro Dayton "No Fly" Zones.
   Frequency: Quarterly
   Description: Look for mechanical problems, erosion and vegetation problems. Initiate corrective action as needed.

   b. ***Task Name:*** Thermography
   Frequency: As needed
   Description: Check line switches for heating indicative of poor electrical connections. Identify "hot spots" and classify according to elevation above ambient temperature. Complete necessary repairs.

69 kV and 33 kV

a. ***Task Name*:** Helicopter Patrol or ground patrols for areas in Metro Dayton "No Fly" Zones.
***Frequency*:** Semiannually
***Description*:** Look for mechanical problems, erosion and vegetation problems. Initiate corrective action as needed.

b. ***Task Name:*** Thermography
Frequency: As needed
***Description*:** Check line switches for heating indicative of poor electrical connections. Identify "hot spots" and classify according to elevation above ambient temperature. Complete necessary repairs.

Underground

a. ***Task Name*:** Cathodic Protection System Test (if applicable)
***Frequency*:** Yearly
***Description*:** Test the integrity of the corrosion protection on the steel pipe housing for the underground transmission cable. Initiate corrective action as needed.

3. **Identification of equipment examined**
This program includes transmission structures/poles, insulators, switches and conductors from 33kV through 345 kV.

4. **Justification for program schedule**
The National Electric Safety Code is used as a guideline to establish minimum requirements. Criticality of equipment is determined by voltage class (i.e. 345 kV lines are the most critical).

5. **Process of documenting and recording program activities**
All deficiencies are documented and maintained in a database.

6. **Process for reviewing program results and making repairs/replacements based on those findings**
The determination to repair or replace is based on the inspection findings combined with engineering judgment.

7. **Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process**
Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process.

8. **Process for reviewing the progress and effectiveness of the program and implementing change where needed**
The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

Transmission Right of Way (Vegetation Management)

1. **Program objectives**
The goal of this program is to maintain the reliability of the electric transmission system by preventing outages and equipment damage due to trees or other vegetation contacting the lines.

2. **Overview of procedures**

   a. ***Task Name***: Line Clearance
   Frequency: Varies depending on line location, clearance requirements and species of vegetation present
   Description: Trim or remove trees and brush as needed. Clearance will vary based on the species of tree and the voltage class of the line.

   b. ***Task Name***: Herbicide Application
   Frequency: As needed.
   Description: Herbicide is applied as needed.

   c. ***Task Name***: Visual Inspection
   Frequency: "Walking patrols" are used to inspect the Metro Dayton "No Fly" Zones. These inspection patrols are scheduled three to four times per year.

   "Helicopter Patrols" are targeted as follows:

All 345kV circuits	Quarterly
All 138kV circuits	Quarterly
All 69kV circuits	Semi annually
All 33kV circuits	Semi annually

   Description: Visually inspect and identify any problems spots. Off-cycle trimming "hot-spotting" will be performed as needed to correct problem areas.

3. **Identification of equipment examined**
All overhead transmission lines are included in the vegetation management program.

4. **Justification for program schedule**
The vegetation management program is preventive in nature and the guidelines are based on company experience. Criticality of lines is determined based on voltage class and system configuration. DP&L also maintains and keeps current its Transmission Vegetation Management Program as required in NERC Standard FAC-003-1.

5. **<u>Process of documenting and recording program activities</u>**
   Program activities are recorded in a database.

6. **<u>Process for reviewing program results and making repairs/replacements based on those findings</u>**
   Information from field inspections is entered into the transmission line clearance database. This database is used to track the progress of all work from originating inspection to final inspection. This database is targeted for weekly updates. All completed work is inspected for quality control.

7. **<u>Process for incorporating program findings into the company's capital planning and budgeting, and T&D system reliability process</u>**
   Budgets and long range plans are continually updated as new information becomes available. Results from maintenance and inspection programs are one of many inputs into the capital planning and budgeting process.

8. **<u>Process for reviewing the progress and effectiveness of the program and implementing change where needed</u>**
   The adequacies of all maintenance and inspection programs are evaluated based on the results achieved. Program effectiveness is continually assessed and change is implemented as needed.

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DP&L

Regulatory Operations

March 31, 2016

Docketing Division
The Public Utilities Commission of Ohio
180 East Broad Street, 11th Floor
Columbus, Ohio 43215

Re: Case No. 16-1000-EL-ESS

Docketing Division:

Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-26(B), The Dayton Power and Light Company herewith electronically submits its Annual Report.

Thank you for your assistance and your attention to this matter. If you have any questions please feel free to call me at (937) 259-7906.

Sincerely,

Robert Adams
Regulatory Operations

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Annual Report of Dayton Power and Light Co Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio Administrative Code 4901:1-10-26	: : : : :	Case No. 16-1000-EL-ESS

ANNUAL REPORT
OF DAYTON POWER AND LIGHT CO

Pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio, Administrative Code 4901:1-10-26, Dayton Power and Light Co submits the following Annual Report. The Report is attached.

We/I certify that the following Report accurately and completely reflects the Annual Report requirements pursuant to Rule 26 of the Electric Service and Safety Standards, Ohio, Administrative Code 4901:1-10-26

Barry J. Bentley

Barry J. Bentley, Vice President, Customer Operations
Responsible For Transmission & Distribution Reporting

3/31/2016
Date

Report Date & Time: March 31, 2016 10:36 am

DPL Inc
Dayton Power and Light Co
Rule #26
2015
Electric Service And Safety Standards

1. **4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years)**

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
CAP-008	D	Capacitor Program - install new capacitors and controls to optimize reactive supply on circuits	Various	Various	185,000	04/01/2015	12/31/2015	12/31/2015
CAP-009	D	Capacitor Program - install new capacitors and controls to optimize reactive supply on circuits	Various	Various	200,000	01/01/2016	12/31/2016	
CAP-010	D	Capacitor Program - install new capacitors and controls to optimize reactive supply on circuits	Various	Various	200,000	01/01/2017	12/31/2017	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
CAP-011	D	Capacitor Program - install new capacitors and controls to optimize reactive supply on circuits	Various	Various	200,000	01/01/2018	12/31/2018	
CAP-012	D	Capacitor Program - install new capacitors and controls to optimize reactive supply on circuits	Various	Various	200,000	01/01/2019	12/31/2019	
CRP-009	D	Cable Replacement Program - replace or inject deteriorating bare neutral primary cable	Various	Various	3,700,000	01/01/2016	12/31/2016	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
CRP-010	D	Cable Replacement Program - replace or inject deteriorating bare neutral primary cable	Various	Various	3,700,000	01/01/2017	12/31/2017	
CRP-011	D	Cable Replacement Program - replace or inject deteriorating bare neutral primary cable	Various	Various	4,500,000	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
CRP-012	D	Cable Replacement Program - replace or inject deteriorating bare neutral primary cable	Various	Various	5,000,000	01/01/2019	12/31/2019	
DIS-049	D	Replace 10 MVA transformer with a 30 MVA transformer at Urbana Substation	Urbana	Rural	1,250,000	01/01/2018	07/01/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
DIS-050	D	Extend three phase distribution on Waynesville circuit GF1204 to improve reliability and switching flexibility	Waynesville	Rural	400,000	01/01/2016	09/01/2016	
DIS-052	D	Extend three phase distribution on Indian Lake circuit EG1205 to improve reliability and switching flexibility	Indian Lake	Rural	350,000	01/01/2018	12/31/2018	
DIS-053	D	Upgrade section of Hoover circuit AV1227	Dayton	Metro	120,000	01/01/2017	12/31/2017	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	**Transmission or distribution ("T" or "D")**	**Description of project/program and goals of planned investment**	**Portion of service territory effected**	**Characteristics of territory effected**	**Estimated cost for implementation**	**Date of initiation of program or project**	**Planned completion date**	**Actual completion date**
ORP-008	D	Overhead Reliability Program - complete repairs, upgrades or other reliability improvements to least-reliable circuits	Various	Various	1,005,000	01/01/2015	12/31/2015	12/31/2015
ORP-009	D	Overhead Reliability Program - complete repairs, upgrades or other reliability improvements to least-reliable circuits	Various	Various	600,000	01/01/2016	12/31/2016	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
ORP-010	D	Overhead Reliability Program - complete repairs, upgrades or other reliability improvements to least-reliable circuits	Various	Various	600,000	01/01/2017	12/31/2017	
ORP-011	D	Overhead Reliability Program - complete repairs, upgrades or other reliability improvements to least-reliable circuits	Various	Various	1,000,000	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
ORP-012	D	Overhead Reliability Program - complete repairs, upgrades or other reliability improvements to least-reliable circuits	Various	Various	1,000,000	01/01/2019	12/31/2019	
PCR-006	D	Planned replacement of cutouts	Various	Various	2,950,000	01/01/2016	12/31/2016	
PCR-007	D	Planned replacement of cutouts	Various	Various	5,040,000	01/01/2017	12/31/2017	
PRC-008	D	Planned replacement of cutouts	Various	Various	1,250,000	01/01/2018	12/31/2018	

1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
PRC-008	D	Planned replacement of cutouts	Various	Various	1,250,000	01/01/2019	12/31/2019	
PRP-009	D	Distribution Pole Inspection and Replacement Program - inspect distribution poles and repair/replace poles as necessary	Various	Various	3,650,000	01/01/2016	12/31/2016	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
PRP-010	D	Distribution Pole Inspection and Replacement Program - inspect distribution poles and repair/replace poles as necessary	Various	Various	4,050,000	01/01/2017	12/31/2017	
PRP-011	D	Distribution Pole Inspection and Replacement Program - inspect distribution poles and repair/replace poles as necessary	Various	Various	4,850,000	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
PRP-012	D	Distribution Pole Inspection and Replacement Program - inspect distribution poles and repair/replace poles as necessary	Various	Various	4,625,000	01/01/2019	12/31/2019	
RAP-009	D	Reliability Action Plan - complete repairs, upgrades or other reliability improvements to least-reliable branch-lines	Various	Various	250,000	01/01/2016	12/31/2016	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
RAP-010	D	Reliability Action Plan - complete repairs, upgrades or other reliability improvements to least-reliable branch-lines	Various	Various	250,000	01/01/2017	12/31/2017	
RAP-011	D	Reliability Action Plan - complete repairs, upgrades or other reliability improvements to least-reliable branch-lines	Various	Various	500,000	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
RAP-012	D	Reliability Action Plan - complete repairs, upgrades or other reliability improvements to least-reliable branch-lines	Various	Various	500,000	01/01/2019	12/31/2019	
RTO-009	T	PJM Regional Transmission Expansion Plan - Second West Milton 345/138 kV transformer and second 138/69 kV transformer	Bulk Electric System (BES)	Various	11,000,000	01/01/2020	12/31/2021	

1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
RTU-009	D	RTU Installation Program - replace obsolete monitoring equipment with new RTU's that also provide control functions	Various	Various	200,000	01/01/2016	12/31/2016	
RTU-010	D	RTU Installation Program - replace obsolete monitoring equipment with new RTU's that also provide control functions	Various	Various	200,000	01/01/2017	12/31/2017	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
RTU-011	D	RTU Installation Program - replace obsolete monitoring equipment with new RTU's that also provide control functions	Various	Various	200,000	01/01/2018	12/31/2018	
RTU-012	D	RTU Installation Program - replace obsolete monitoring equipment with new RTU's that also provide control functions	Various	Various	384,000	01/01/2019	12/31/2019	

1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
TBR-008	T	Transmission Breaker Replacements - replace breakers as needed	Various	Various	0	01/01/2015	12/31/2015	12/31/2015
TBR-009	T	Transmission Breaker Replacements - replace breakers as needed	Various	Various	0	01/01/2016	12/31/2016	
TBR-010	T	Transmission Breaker Replacements - replace breakers as needed	Various	Various	0	01/01/2017	12/31/2017	
TBR-011	T	Transmission Breaker Replacements - replace breakers as needed	Various	Various	0	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
TBR-012	T	Transmission Breaker Replacements - replace breakers as needed	Various	Various	0	01/01/2019	12/31/2019	
TCW-002	T	Transmission communication wire replacement project at Crown Hoover and Overlook Substations	Various	Various	600,000	01/01/2017	12/31/2017	
TCW-003	T	Transmission communication wire replacement project at Crown Hoover and Overlook Substations	Various	Various	600,000	01/01/2018	12/31/2018	

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1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
TPI-009	T	Transmission Pole Inspection - inspect transmission poles and repair or replace as necessary	Various	Various	750,000	01/01/2016	12/31/2016	
TPI-010	T	Transmission Pole Inspection - inspect transmission poles and repair or replace as necessary	Various	Various	500,000	01/01/2017	12/31/2017	

1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
TPI-011	T	Transmission Pole Inspection - inspect transmission poles and repair or replace as necessary	Various	Various	500,000	01/01/2018	12/31/2018	
TPI-012	T	Transmission Pole Inspection - inspect transmission poles and repair or replace as necessary	Various	Various	1,000,000	01/01/2019	12/31/2019	
TRU-008	T	Transmission Relay Upgrade - replacing/upgrading transmission relays	Various	Various	1,370,000	01/01/2016	12/31/2016	

1. 4901:1-10-26 (B)(1) Future Investment Plan For Facilities And Equipment (covering period of no less than three years) ...
Continued ...

a.	b.	c.	d.	e.	f.	g.	h.	i.
Identification of project/program or plan by facility, equipment, or project name	Transmission or distribution ("T" or "D")	Description of project/program and goals of planned investment	Portion of service territory effected	Characteristics of territory effected	Estimated cost for implementation	Date of initiation of program or project	Planned completion date	Actual completion date
TRU-009	T	Transmission Relay Upgrade - replacing/upgrading transmission relays	Various	Various	1,200,000	01/01/2017	12/31/2017	
TRU-010	T	Transmission Relay Upgrade - replacing/upgrading transmission relays	Various	Various	1,800,000	01/01/2018	12/31/2018	
TRU-011	T	Transmission Relay Upgrade - replacing/upgrading transmission relays	Various	Various	1,800,000	01/01/2019	12/31/2019	

Notes
The projects and programs detailed in this report are designed to ensure high quality, safe, and reliable delivery of energy to customers and/or provide for additional capacity for future load growth. The capital and maintenance resources invested are generally focused in specific localized areas and do not necessarily translate into improvements in global or system-wide reliability performance indices such as CAIDI and SAIFI.

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1.a. 4901:1-10-26 (B)(1)(a) Relevant Characteristics Of The Service Territory

Facility Type	Total Overhead Miles	Total Underground Miles	Other Notable Characteristics
D	10,510	3,656	
T	1,833	4	

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1.b 4901:1-10-26 (B)(1b) Future investment plan for facilities and equipment (covering period 2015 to 2019)

All Cost	2015		2016	2017	2018	2019
	Planned	Actual	Planned	Projected	Projected	Projected
D	$14,050,000	$13,652,000	$12,700,000	$14,160,000	$14,100,000	$12,959,000
T	$3,900,000	$2,031,000	$2,330,000	$2,300,000	$2,900,000	$2,800,000

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2. 4901:1-10-26 (B)(1)(d)&(f) Complaints From Other Entities

a.	b.	c.	d.	e.	f.	g.
Complaint(s) from other electric utility companies, regional transmission entity, or competitive retail electric supplier(s) (list individually)	Date complaint received	Nature of complaint	Action taken to address complaint	Complaint resolved (Yes or No)	Date resolved	If unresolved give explanation why

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3.a. 4901:1-10-26 (B)(1)(e) Electric Reliability Organization Reliability Standards Violation

Standard number violated	Standard name violated	Date of violation	Violation risk factor	Violation severity factor	Total amount of penalty dollars	Description

3.b. 4901:1-10-26 (B)(1)(e) Regional Transmission Organization (RTO) Violations

Name of RTO violation	Description

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3.c. 4901:1-10-26 (B)(1)(e) Transmission Load Relief (TRL)

TLR Event Start	TLR Event End	Highest TLR level during event	Firm load interrupted	Amount of load (MW) interrupted	Description

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3.d. 4901:1-10-26 (B)(1)(e) Top Ten Congestion Facilities By Hours Of Congestion

Rank	Description of facility causing congestion

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3.e. 4901:1-10-26 (B)(1)(e) Annual System Improvement Plan And Regional Transmission Operator (RTO) Expansion Plan

Relationship between annual system improvement plan and RTO transmission expansion plan
Our annual system improvement plan includes the regional transmission operator's transmission project plan. The RTO driven project is the West Milton -Eldean transmission line which is in the permitting process at The Ohio Power Siting Board.

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4. 4901:1-10-26 (B)(2) Report Of Implementation Plan From Previous Reporting Period

a.	b.	c.	d.	e.	f.
Identification of previously planned action	Transmission or Distribution ("T" or "D")	Planned completion date	Actual completion date of action	Identification of deviation(s) from goals of previous plan	Reason(s) for each identified deviation
CRP-008	D	12/31/2015	12/31/2015	reduced dollars	Based on 2015 actual cost
DIS-054	D	12/31/2016		new project	address load growth
DIS-055	D	12/31/2016		new project	address load growth
PCR-005	D	12/31/2015	12/31/2015	increased dollars	Adjusted spend to reflect failure rates
PRP-008	D	12/31/2015	12/31/2015	increased dollars	Based on 2015 actual cost
RAP-008	D	12/31/2015	12/31/2015	reduced dollars	reduced scope of work
RTO-003	T	06/01/2017		reduced dollars	Working with PJM on need and timing
RTO-004	T	06/01/2017		reduced dollars	Working with PJM on need and timing

4. 4901:1-10-26 (B)(2) Report Of Implementation Plan From Previous Reporting Period ... Continued ...

a.	b.	c.	d.	e.	f.
Identification of previously planned action	Transmission or Distribution ("T" or "D")	Planned completion date	Actual completion date of action	Identification of deviation(s) from goals of previous plan	Reason(s) for each identified deviation
RTO-005	T	06/01/2018		reduced dollars	Working with PJM on need and timing
RTU-008	D	12/31/2015	12/31/2015	Reduced dollars	Reduced scope
TCW-001	T	12/31/2016		New project	Address relay protection communication reliability
TPI-008	T	12/31/2015	12/31/2015	increased dollars	Based on 2015 actual cost
TRU-007	T	12/31/2015	12/31/2015	reduced dollars	projects delays due to timing issues with other utilities in taking out key transmission lines

5. 4901:1-10-26 (B)(3)(a) Characterization Of Condition Of Company's System

	a.	b.
Type of System	**Qualitative characterization of condition or system**	**Explanation of criteria used in making assessment for each characterization**
T	System reliability performance is a good indicator of the physical condition of the system and industry standard measures show that system performance is consistently reliable.	DP&Ls transmission has the capacity to meet projected loading, System Operating monitors the condition of the transmission system on a daily basis. Any findings that may impact safety or reliability are immediately addressed.
D	A review of Dayton Power & Light's historical reliability performance clearly shows the distribution system to be in excellent condition.	The performance of the electric system over a period of several years is reflective of its physical condition. Consistently safe and reliable service can only be achieved through a well-maintained distribution system. System level reliability performance is tracked on a and monthly basis and reported annually as required by O.A.C. 4901:1-10-10.

6. 4901:1-10-26 (B)(3)(b) Safety and Reliability Complaints

	a.
Type of system	Total number of safety & reliability complaints received directly from customers
D	47

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6.a. 4901:1-10-26 (B)(3)(b) **Safety and Reliability Complaints Detailed Report**

	1.	2.	3.	4.	5.	6.	7.
Type of system	Availability of service	Damage	Momentary interruption	Out of service	Quality of utility product	Repair service	Public safety
D	0	6	0	24	10	6	1

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7.a. 4901:1-10-26 (B)(3)(c)(i) Transmission Capital Expenditures

Total Transmission Capital Expenditures in 2015	$11,936,000
Total Transmission Investment as of 12/31/2015	$442,243,515
Transmission Capital Expeditures as a percent of Total Transmission Investment	2.7%

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7.b. 4901:1-10-26 (B)(3)(c)(i) Transmission Maintenance Expenditures

Total Transmission Maintenance Expenditures in 2015	$4,915,647
Total Transmission Investment as of 12/31/2015	$442,243,515
Transmission Maintenance Expeditures as a percent of Total Transmission Investment	1.1%

7.c. 4901:1-10-26 (B)(3)(c)(ii) and (iii) Transmission Capital Expenditures - Reliability Specific

Budget Category	2015 Budget	2015 Actual	Budget Variance as percent	2016 Budget	Explanation of variance if over 10%
Transmission-Substation Reliability	$0	$593,000	Over 100%	$0	Transmission Catastrophic Repairs and Distribution Catastrophic Repairs were budgeted together as one number. The budget is only included in Distribution Catastrophic Repairs.
Transmission Blankets-Other	$800,000	$658,000	-17.8%	$800,000	Fewer forced repairs
Transmission Reliability-Projects	$6,901,000	$5,817,000	-15.7%	$3,220,000	RTEP projects delayed
Transmission Reliability-CCD	$1,200,000	$1,069,000	-10.9%	$500,000	Projects delayed - permitting process

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7.d. 4901:1-10-26 (B)(3)(c)(ii) and (iii) Transmission Maintenance Expenditures - Reliability Specific

Budget Category	2015 Budget	2015 Actual	Budget Variance as percent	2016 Budget	Explanation of variance if over 10%
Transmission Reliability	$2,222,090	$2,709,749	21.9%	$2,902,533	Increased cost of CCD lines

8.a. 4901:1-10-26 (B)(3)(d)(i) Distribution Capital Expenditures

Total Distribution Capital Expenditures in 2015	$73,924,000
Total Distribution Investment as of 12/31/2015	$1,627,053,021
Distribution Capital Expeditures as a percent of Total Distribution Investment	4.5%

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8.b. 4901:1-10-26 (B)(3)(d)(i) Distribution Maintenance Expenditures

Total Distribution Maintenance Expenditures in 2015	$49,318,713
Total Distribution Investment as of 12/31/2015	$1,627,053,021
Distribution Maintenance Expeditures as a percent of Total Distribution Investment	3.0%

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8.c. 4901:1-10-26 (B)(3)(d)(ii) and (iii) Distribution Capital Expenditures - Reliability Specific

Budget Category	2015 Budget	2015 Actual	Budget Variance as percent	2016 Budget	Explanation of variance if over 10%
Distribution-Specific Projects	$2,913,000	$3,881,000	33.2%	$5,326,000	Completed additional capital circuit projects.
Distribution-Field Reliability	$7,750,000	$9,811,000	26.6%	$8,350,000	Increased spend to reflect failure rates.
Distribution-Substation Reliability	$4,473,000	$5,269,000	17.8%	$5,883,000	Transmission Catastrophic Repairs and Distribution Catastrophic Repairs were budgeted together as one number. The budget is only included in Distribution Catastrophic Repairs.
Distribution-Underground Reliability	$4,000,000	$3,586,000	-10.4%	$3,700,000	Amount adjusted to be in-line with failure rate and identified projects.
Distribution Blanket-Other	$8,300,000	$7,570,000	-8.8%	$7,900,000	
Distribution-Planning Reliability	$2,907,000	$2,652,000	-8.8%	$2,553,000	
Distribution Blanket-Transformers	$15,000,000	$14,287,000	-4.8%	$14,000,000	

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8.d. 4901:1-10-26 (B)(3)(d)(ii) and (iii) Distribution Maintenance Expenditures - Reliability Specific

Budget Category	2015 Budget	2015 Actual	Budget Variance as percent	2016 Budget	Explanation of variance if over 10%
Distribution Reliability	$36,601,292	$38,236,910	4.5%	$37,740,609	

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9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
D	Installations on Customer Premises	371	20	20.00	0	0.00%	Net Plant/Gross Plant
D	Installations on Customer Premises	371	50	36.00	14	28.00%	Net Plant/Gross Plant
D	Leased Property on Customer Premises	372	40	40.00	0	0.00%	Net Plant/Gross Plant
D	Line Transformers	368	44	17.00	27	61.36%	Net Plant/Gross Plant
D	Meters	370	32	10.00	22	68.75%	Net Plant/Gross Plant
D	Overhead Conductors and Devices	365	40	20.00	20	50.00%	Net Plant/Gross Plant
D	Poles, Towers and Fixtures	364	38	23.00	15	39.47%	Net Plant/Gross Plant
D	Services	369	33	27.00	6	18.18%	Net Plant/Gross Plant
D	Services	369	33	19.00	14	42.42%	Net Plant/Gross Plant
D	Station Equipment	362	50	21.00	29	58.00%	Net Plant/Gross Plant

9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
D	Station Equipment	362	50	50.00	0	0.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	38.00	12	24.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	25.00	25	50.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	22.00	28	56.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	16.00	34	68.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	32.00	18	36.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	40.00	10	20.00%	Net Plant/Gross Plant
D	Station Equipment	362	11	11.00	0	0.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	50.00	0	0.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	13.00	37	74.00%	Net Plant/Gross Plant
D	Station Equipment	362	50	50.00	0	0.00%	Net Plant/Gross Plant

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9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
D	Station Equipment	362	50	15.00	35	70.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	25.00	20	44.44%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	1.00	44	97.78%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	24.00	21	46.67%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	23.00	22	48.89%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	16.00	29	64.44%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	19.00	26	57.78%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	45.00	0	0.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	45.00	0	0.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	0.00	45	100.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	45.00	0	0.00%	Net Plant/Gross Plant

9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
D	Structures and Improvements	361	45	18.00	27	60.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	29.00	16	35.56%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	45.00	0	0.00%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	33.00	12	26.67%	Net Plant/Gross Plant
D	Structures and Improvements	361	45	22.00	23	51.11%	Net Plant/Gross Plant
D	Underground Conductor and Devices	367	38	19.00	19	50.00%	Net Plant/Gross Plant
D	Underground Conduit	366	55	29.00	26	47.27%	Net Plant/Gross Plant
T	Overhead Conductors and Devices	356	48	29.00	19	39.58%	Net Plant/Gross Plant
T	Overhead Conductors and Devices	356	39	37.00	2	5.13%	Net Plant/Gross Plant
T	Overhead Conductors and Devices	356	39	25.00	14	35.90%	Net Plant/Gross Plant

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9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
T	Poles and Fixtures	355	47	27.00	20	42.55%	Net Plant/Gross Plant
T	Poles and Fixtures	355	47	19.00	28	59.57%	Net Plant/Gross Plant
T	Poles and Fixtures	355	47	47.00	0	0.00%	Net Plant/Gross Plant
T	Poles and Fixtures	355	47	21.00	26	55.32%	Net Plant/Gross Plant
T	Roads and Trails	359	45	29.00	16	35.56%	Net Plant/Gross Plant
T	Station Equipment	353	50	25.00	25	50.00%	Net Plant/Gross Plant
T	Station Equipment	353	50	38.00	12	24.00%	Net Plant/Gross Plant
T	Station Equipment	353	32	20.00	12	37.50%	Net Plant/Gross Plant
T	Station Equipment	353	32	24.00	8	25.00%	Net Plant/Gross Plant
T	Station Equipment	353	11	11.00	0	0.00%	Net Plant/Gross Plant
T	Structures and Improvements	352	50	27.00	23	46.00%	Net Plant/Gross Plant

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9. 4901:1-10-26 (B)(3)(e) Average Remaining Depreciation Life Of Distribution And Transmission Facilities ... Continued ...

a.	b.	c.	d.	e.	f.	g.	h.
Transmission or distribution ("T" or "D")	Asset Type	Asset's assigned FERC subaccount (account/sub account)	Total depreciable life of asset	Total depreciated life of asset	Total remaining life of asset	Percent of average remaining depreciation life of asset	Depreciation of how age was determined
T	Structures and Improvements	352	50	46.00	4	8.00%	Net Plant/Gross Plant
T	Structures and Improvements	352	38	10.00	28	73.68%	Net Plant/Gross Plant
T	Structures and Improvements	352	38	38.00	0	0.00%	Net Plant/Gross Plant
T	Towers and Fixtures	354	50	50.00	0	0.00%	Net Plant/Gross Plant
T	Towers and Fixtures	354	39	39.00	0	0.00%	Net Plant/Gross Plant
T	Towers and Fixtures	354	39	38.00	1	2.56%	Net Plant/Gross Plant
T	Underground Conductor and Devices	358	45	10.00	35	77.78%	Net Plant/Gross Plant
T	Underground Conduit	357	60	17.00	43	71.67%	Net Plant/Gross Plant

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10. 4901:1-10-26 (B)(3)(f)(i) & (ii) Inspection, Maintenance, Repair And Replacement Distribution, Transmission And Substation Programs Summary Report

a.	b.	c.	d.	e.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals	Achieve ("Y" or "N")	Summary of findings
DS	12/4 kV Relay Calibration	155- Distribution relays (12/4 kV) scheduled	Y	Inspections completed as planned
D	Capacitor Inspections	Complete the inspection of approximately 1349 capacitors	Y	Inspections completed as planned
D	Distribution Circuit Patrol	Inspect 86 circuits	Y	Inspections completed as planned
D	Distribution Line Clearance	Perform full circuit vegetation maintenance on approximately 20% of distribution system	Y	Trimming completed as planned
D	Distribution Line Clearance Inspection	Evaluate 86 circuits	Y	Program goals were met
D	Monitor Branch Line Reliability Performance	Evaluate least-reliable branch lines and initiate remedial action where needed	Y	All work completed as planned
D	Monitor Circuit Reliability Performance	Evaluate least-reliable circuits and initiate remedial action where needed	Y	Circuits were reviewed and reported as required

10. 4901:1-10-26 (B)(3)(f)(i) & (ii) Inspection, Maintenance, Repair And Replacement Distribution, Transmission And Substation Programs Summary Report ... Continued ...

a.	b.	c.	d.	e.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals	Achieve ("Y" or "N")	Summary of findings
D	Pole Replacement and Testing Program	Inspect and test poles on approximately 10% of DP&L's circuits	Y	Inspections completed as planned
D	Recloser Inspections	Complete the inspection of approximately 582 reclosers	Y	Inspections completed as planned
D	Underground Device Inspections	Inspect URD devices on 344 map grids	Y	Inspections completed as planned
D	Visual Inspection of Airbreak Switches	Inspect approximately 1,575 switches	Y	Inspections completed as planned
D	Voltage Regulator Inspections	558 regulator inspections scheduled for 2015	Y	Inspections completed as planned
T	138 kV Aerial Patrol	Inspect 138 kV circuits, 4 times per year	Y	Inspections completed as planned
TS	138/69/33 kV Relay Calibration	79 Non-BES transmission relays tested.	Y	Inspections completed as planned

10. 4901:1-10-26 (B)(3)(f)(i) & (ii) Inspection, Maintenance, Repair And Replacement Distribution, Transmission And Substation Programs Summary Report ... Continued ...

a.	b.	c.	d.	e.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals	Achieve ("Y" or "N")	Summary of findings
T	345 kV Aerial Patrol	Inspect 345 kV circuits, 4 times per year	Y	Inspections completed as planned
TS	345 kV Relay Calibration	229 BES relays tested.	Y	Inspections completed as planned
T	69 kV Aerial Patrol	Inspect 69 kV circuits, semi-annually	Y	Inspections completed as planned
TS	Circuit Breaker Preventive Maintenance	Complete maintenance on 175 circuit breakers	Y	Maintenance completed as planned
TS	External Visual Inspection of Substation Transformers	Inspect approximately 300 Substation Transformers monthly	Y	Inspections completed as planned
T	Herbicide Application	Apply herbicide as needed	Y	Spray program completed

10. 4901:1-10-26 (B)(3)(f)(i) & (ii) Inspection, Maintenance, Repair And Replacement Distribution, Transmission And Substation Programs Summary Report ... Continued ...

a.	b.	c.	d.	e.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals	Achieve ("Y" or "N")	Summary of findings
TS	Operational Testing of Circuit Breakers	Conduct an operational test for breakers that are not otherwise operated during the calendar year	Y	Completed 99.4% of scheduled testing. One breaker at Moraine Substation and 3 breakers at Webster Substation are out of service and being replaced in 2016.
TS	Substation Transformer Doble Test	Perform power factor tests on 50 substation transformers	Y	Testing completed as planned.
TS	Substation Transformer LTC Maintenance	Complete maintenance on 34 LTCs	Y	Maintenance completed as planned
TS	Substation Transformers Dielectric Oil Breakdown Test	Perform 50 transformer oil dielectric breakdown tests	Y	Testing completed as planned.
TS	Thermographic Imaging of Substation Transformers	Infrared approximately 300 Substation Transformers	Y	Inspections completed as planned

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10. 4901:1-10-26 (B)(3)(f)(i) & (ii) Inspection, Maintenance, Repair And Replacement Distribution, Transmission And Substation Programs Summary Report ... Continued ...

a.	b.	c.	d.	e.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals	Achieve ("Y" or "N")	Summary of findings
TS	Thermographic Inspection of Substation Switches	Infrared approximately 2,362 Substation Switches	Y	Inspections completed as planned
T	Thermographic Inspection of Transmission Lines	Perform thermographic inspections where needed	Y	No thermographic inspection of transmission lines were scheduled in 2015
T	Transmission Line Clearance	Trim trees where needed	Y	All goals met in 2015
TS	Visual Inspection of Circuit Breakers	Inspect approximately 1,300 Circuit Breakers monthly	Y	Inspections completed as planned
T	Visual Inspection of Transmission Lines/Right-Of-Way	Inspect 25 circuits in metro - no fly zone	Y	Inspections completed as planned

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes"

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
12/4 kV Relay Calibration GOAL - 155- Distribution relays (12/4 kV) scheduled	Testing completed as planned	All program goals were met	277 Distribution relays (12/4 kV) test	100% complete
Capacitor Inspections GOAL - Complete the inspection of approximately 1349 capacitors	Inspections were completed as planned	All program goals were met	Inspected 1331 capacitor banks. Difference is related to circuits being re-evaluated and removing capacitor banks.	100% Complete
Distribution Circuit Patrol GOAL - Inspect 86 circuits	Inspections were completed as planned	All program goals were met	Inspected 86 circuits in 2015.	100% Complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Distribution Line Clearance GOAL - Perform full circuit vegetation maintenance on approximately 20% of distribution system	Trimming completed as planned	All program goals were met	Performed full circuit vegetation management on 2215 miles of our distribution system which encompasses 99 circuits. We also addressed 7 branch lines and completed 44 customer tickets.	100% complete
Distribution Line Clearance Inspection GOAL - Evaluate 86 circuits	Inspections were completed as planned	All program goals were met	Inspected 86 circuits in 2015.	100% Complete

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10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Monitor Branch Line Reliability Performance GOAL - Evaluate least-reliable branch lines and initiate remedial action where needed	Evaluated least reliable branch lines, inspected distribution facilities and initiated remedial action where needed	All program goals were met	Multiple branchlines on 7 distribution circuits were inspected and reliability plans initiated where appropriate	100% Complete
Monitor Circuit Reliability Performance GOAL - Evaluate least-reliable circuits and initiate remedial action where needed	Analyzed the 39 Rule 11 circuits through the Overhead Reliability Program	All program goals were met	Inspected and remediated reliability problems on ORP circuits	100% Complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Pole Replacement and Testing Program GOAL - Inspect and test poles on approximately 10% of DP&L's circuits	Inspections were completed as planned	All program goals were met	29,414 poles were inspected and tested through the pole replacement program	100% Complete
Recloser Inspections GOAL - Complete the inspection of approximately 582 reclosers	Inspections were completed as planned	All program goals were met	Inspected 590 reclosers	100% Complete
Underground Device Inspections GOAL - Inspect URD devices on 344 map grids	Inspections were completed as planned	All program goals were met	Inspected 344 map grids containing URD devices	100% Complete

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10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Visual Inspection of Airbreak Switches GOAL - Inspect approximately 1,575 switches	Inspections were completed as planned	All program goals were met	Inspected 1615 switches	100% Complete
Voltage Regulator Inspections GOAL - 558 regulator inspections scheduled for 2015	Inspections were completed as planned	N/A	561 regulator banks were completed in 2015.	100% Complete
138 kV Aerial Patrol GOAL - Inspect 138 kV circuits, 4 times per year	Inspections were completed as planned	All program goals were met	Inspected 33-138 kV transmission lines, 4 times each	100% Complete

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10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
138/69/33 kV Relay Calibration GOAL - 79 Non-BES transmission relays tested.	Testing completed as planned	All program goals were met	79 Non-BES transmission relays tested.	100% complete
345 kV Aerial Patrol GOAL - Inspect 345 kV circuits, 4 times per year	Inspections were completed as planned	All program goals were met	Inspected 14-345 kV transmission lines, 4 times each	100% Complete
345 kV Relay Calibration GOAL - 229 BES relays tested.	Inspections were completed as planned	All program goals were met	222 BES relays tested. Difference is a result of relays retired or replaced.	100% Complete
69 kV Aerial Patrol GOAL - Inspect 69 kV circuits, semi-annually	Inspections were completed as planned	All program goals were met	Inspected 89-69 kV transmission lines, 2 times each	100% Complete

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10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Circuit Breaker Preventive Maintenance GOAL - Complete maintenance on 175 circuit breakers	1 breaker postponed until 2016 in order to get breaker out of service.	All program goals were met	Performed maintenance on 174 circuit breakers in 2015	100% complete
External Visual Inspection of Substation Transformers GOAL - Inspect approximately 300 Substation Transformers monthly	Inspections were completed as planned	All program goals were met	Performed monthly inspections on 300 transformer units	100% Complete
Herbicide Application GOAL - Apply herbicide as needed	Herbicide applications were made in applicable areas for safety and reliability	All program goals were met	41 areas received herbicide application	100% Complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Operational Testing of Circuit Breakers GOAL - Conduct an operational test for breakers that are not otherwise operated during the calendar year	Testing completed	All program goals were met	693 out of 697 breakers operated or were operated in 2015. One breaker at Moraine Substation and 3 breakers at Webster Substation are out of service and being replaced in 2016.	99.4% complete
Substation Transformer Doble Test GOAL - Perform power factor tests on 50 substation transformers	Completed as planned	All program goals were met	Power factor testng was performed on 49 transformers. One transformer at a customer location was unable to be tested in 2015 due to an outage to the customer required for testing.	100% complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Substation Transformer LTC Maintenance GOAL - Complete maintenance on 34 LTCs	Inspections were completed as planned	All program goals were met	Performed maintenance on 35 LTCs	100% complete
Substation Transformers Dielectric Oil Breakdown Test GOAL - Perform 50 transformer oil dielectric breakdown tests	Completed as planned	All program goals were met	Performed oil dielectric breakdown tests on 49 transformers. One transformer at a customer location was unable to be tested in 2015 due to an outage to the customer required for testing.	100% complete
Thermographic Imaging of Substation Transformers GOAL - Infrared approximately 300 Substation Transformers	Inspections were completed as planned	All program goals were met	Performed infrared inspection on 300 transformer units	100% complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	Explanation of how goal were achieved	Description of extent of achievement	Quantitative description of goal in either numerical values or percentages	Quantitative description of actual performance in either numerical values or percentages
Thermographic Inspection of Substation Switches GOAL - Infrared approximately 2,362 Substation Switches	Inspections were completed as planned	All program goals were met	Performed inspections on 2362 substation switches	100% complete
Thermographic Inspection of Transmission Lines GOAL - Perform thermographic inspections where needed	N/A	N/A	No inspections were scheduled in 2015	N/A
Transmission Line Clearance GOAL - Trim trees where needed	Spot trimmed as necessary	All program goals were met	Spot trimming completed in 516 locations	100% Complete

10.a. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "d" Of Report 10 Is "Yes" ... Continued ...

1.	2.	3.	4.	5.
Program name	**Explanation of how goal were achieved**	**Description of extent of achievement**	**Quantitative description of goal in either numerical values or percentages**	**Quantitative description of actual performance in either numerical values or percentages**
Visual Inspection of Circuit Breakers GOAL - Inspect approximately 1,300 Circuit Breakers monthly	Inspections were completed as planned	All program goals were met	1300 circuit breakers were inspected monthly.	100% complete
Visual Inspection of Transmission Lines/Right-Of-Way GOAL - Inspect 25 circuits in metro - no fly zone	Inspections were completed as planned	All program goals were met	Inspected 25 circuits in metro no fly zone	100% Complete

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10b. 4901:1-10-26 (B)(3)(f)(i) If Response In Column "D" Of Report 10 Is "No"

1.	2.	3.	4.	5.
Program name	Cause(s) for not achieving goal(s)	Description of level of completion of goal	Quantitative description of goal in either numerical values or percentages	Quantitative description of level of completion of goal in either numerical values or percentages

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
12/4 kV Relay Calibration GOAL - 155- Distribution relays (12/4 kV) scheduled	DS					
138 kV Aerial Patrol GOAL - Inspect 138 kV circuits, 4 times per year	T					
138/69/33 kV Relay Calibration GOAL - 79 Non-BES transmission relays tested.	TS					

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
345 kV Aerial Patrol GOAL - Inspect 345 kV circuits, 4 times per year	T	The following maintenance items were identified during transmission line inspections: Critical: 6 items, Medium priority: 20 items, Minor: 8 items	Completed 6 repairs to critical items, 17 repairs to medium priority items and 2 repairs to minor items	12/31/2015	3 medium and 6 minor repair items to be completed when line is switched out of service	
345 kV Relay Calibration GOAL - 229 BES relays tested.	TS					
69 kV Aerial Patrol GOAL - Inspect 69 kV circuits, semi-annually	T					

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	**Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"**	**Program finding(s) causing remedial activity**	**Remedial activity performed**	**Actual completion date**	**Remedial activity yet to be performed**	**Estimated completion date**
Capacitor Inspections GOAL - Complete the inspection of approximately 1349 capacitors	D	102 repair items were indentified during the capacitor inspections. Typical repairs include replacing blown fuses, bad capcitors, control and/or grounding issues.	Completed 76 repairs to capacitors in 2015.	02/04/2016	26 maintenance repairs to be completed from the 2015 inspections. Additionally, 15 repair items need to be completed from 2014, 6 repair items need to be completed from 2013 inspections, 7 repair items from 2012 inspections and 9 repair items from 2011 inspections which will be scheudled with regular work on the circuit.	

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Capacitor Inspections GOAL - Complete the inspection of approximately 1349 capacitors	D	38 problems identified during regulator inspections	37 repairs complete	12/31/2015	1 repair item remains	
Circuit Breaker Preventive Maintenance GOAL - Complete maintenance on 175 circuit breakers	TS					

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Distribution Circuit Patrol GOAL - Inspect 86 circuits	D	8,939 repairs were identified during the inspections. Repair items include broken down guys, blown arrestors, broken x-arms, etc.	As of 3/10/2016, 7,995 items have been completed	03/10/2016	944 items are remain from the 2015 inspections. Additionally, 583 repair items still need to be completed from 2014 inspections, 2,659 repair items from 2013 inspections, 744 repair items from 2012 inspections, 403 repair items from 2011 inspections and 128 repair items from 2010 inspections which will be scheduled with routine work on the circuits.	

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Distribution Line Clearance GOAL - Perform full circuit vegetation maintenance on approximately 20% of distribution system	D					
Distribution Line Clearance Inspection GOAL - Evaluate 86 circuits	D					

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
External Visual Inspection of Substation Transformers GOAL - Inspect approximately 300 Substation Transformers monthly	TS	28 maintenance items were identifed as requiring remedial activity. Examples of repair items include: inoperative cooling fans, inoperative winding temperature guage, bushing low oil level, low oil level in main tank or LTC compartments, major LTC filter oil leak and sudden pressure relay operations.	Repairs were completed on 26 transformers	12/31/2015	2 minor repairs of substation transformers are scheduled in conjunction with next maintenance cycle.	
Herbicide Application GOAL - Apply herbicide as needed	T					

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Monitor Branch Line Reliability Performance GOAL - Evaluate least-reliable branch lines and initiate remedial action where needed	D					
Monitor Circuit Reliability Performance GOAL - Evaluate least-reliable circuits and initiate remedial action where needed	D	Repair items were identified during the inspection of ORP circuits. Typical repair items include: Lightning arrestors, cut-out, pole replacements/reinforcements, cable injection or replacement	Refer to Rule 11 for specifics on remedial items for individual ORP circuits		Refer to Rule 11 for specifics on remedial items for individual ORP circuits	12/31/2016

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Operational Testing of Circuit Breakers GOAL - Conduct an operational test for breakers that are not otherwise operated during the calendar year	TS					
Pole Replacement and Testing Program GOAL - Inspect and test poles on approximately 10% of DP&L's circuits	D	1,564 poles failed the inspection or integrity test	190 poles have been reinforced and 378 poles have been replaced		As of 3/2/2015, 996 pole replacements to be completed	12/31/2017

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Recloser Inspections GOAL - Complete the inspection of approximately 582 reclosers	D					
Substation Transformer Doble Test GOAL - Perform power factor tests on 50 substation transformers	TS					

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Substation Transformer LTC Maintenance GOAL - Complete maintenance on 34 LTCs	TS					
Substation Transformers Dielectric Oil Breakdown Test GOAL - Perform 50 transformer oil dielectric breakdown tests	TS	Changes in power factor readings require remedial actions such as bushing or transformer replacement. 7 problems were identified requiring bushing changeout	3 bushing replacement completed	12/31/2015	4 bushing replacements will be prioritized and scheduled in conjunction with next maintenance cycle.	

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	**Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"**	**Program finding(s) causing remedial activity**	**Remedial activity performed**	**Actual completion date**	**Remedial activity yet to be performed**	**Estimated completion date**
Thermographic Imaging of Substation Transformers GOAL - Infrared approximately 300 Substation Transformers	TS					
Thermographic Inspection of Substation Switches GOAL - Infrared approximately 2,362 Substation Switches	TS	Infrared inspections of substation switches identified bad or deteriorated contacts. 6 problems were identified during inspections.	A second thermographic picture was taken to confirm problem. Once the problem(s) was confirmedthe switches were replaced ro removed from service, cleaned, maintenanced and returned to service. 6 repairs were completed in 2015.	12/31/2015		

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Thermographic Inspection of Transmission Lines GOAL - Perform thermographic inspections where needed	T					
Transmission Line Clearance GOAL - Trim trees where needed	T					

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10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Underground Device Inspections GOAL - Inspect URD devices on 344 map grids	D	663 repair items were identified during the underground device inspection program. Typical repair items can be described as defective locking mechanisms, defective pads, exposed cable	As of 1/11/16, 526 repairs are complete		137 repair items still need to be completed. Additionally, 21 repair items still need to be completed from 2014 inspections, 15 repair items from 2013 and 13 repair items from 2010 inspections.	12/31/2016

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Visual Inspection of Airbreak Switches GOAL - Inspect approximately 1,575 switches	D	43 repair items were indentified during the air break inspections. Typical repairs include blown lightning arresters and pole grounds, etc.	Completed 20 air break repairs completed.	01/31/2016	23 maintenance repairs to be completed from the 2015 inspections. Additionally, 5 repair item needs to be completed from 2014 inspections, and 9 repairs items from 2013 and 1 repair item from 2010 inspections which will be scheduled with regular work on the circuit.	
Visual Inspection of Circuit Breakers GOAL - Inspect approximately 1,300 Circuit Breakers monthly	TS	Compressor or motor problems, low oil or SF6 gas levels are examples of findings requiring remedial attention. 85 breaker problems were identified and prioritized	Repaired 81 breaker problems		4 minor breaker problems are scheduled to be repaired in conjunction with next maintenance cycle.	12/31/2014

10.c. 4901:1-10-26 (B)(3)(f)(iii) Remedial Activity ... Continued ...

1.	2.	3.	4.	5.	6.	7.
Program name	Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program finding(s) causing remedial activity	Remedial activity performed	Actual completion date	Remedial activity yet to be performed	Estimated completion date
Visual Inspection of Transmission Lines/Right-Of-Way GOAL - Inspect 25 circuits in metro - no fly zone	T					
Voltage Regulator Inspections GOAL - 558 regulator inspections scheduled for 2015	D	38 problems identified during regulator inspections	37 repairs complete	12/31/2015	1 repair item remains	

Notes
For many programs, remedial activity was completed at various dates throughout the year. For these programs, the completion date is listed as 12/31. Remedial activity for all transmission line aerial and foot patrols is combined and listed under the 345 kV aerial patrol programs. Minor items will be completed as maintenance schedules permit.

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10.d. 4901:1-10-26 (B)(3)(f) Current Year Goals

1.	2.	3.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals
DS	12/4 kV Relay Calibration	335- 12/4 kV relays scheduled
D	Capacitor Inspections	Complete the inspection of approximately 1331 capacitors
D	Distribution Circuit Patrol	Inspect 91 circuits
D	Distribution Line Clearance	Perform full circuit vegetation maintenance on approximately 20% of distribution system
D	Distribution Line Clearance Inspection	Evaluate 91 circuits
D	Monitor Branch Line Reliability Performance	Evaluate least-reliable branch lines and initiate remedial action where needed
D	Monitor Circuit Reliability Performance	Evaluate least-reliable circuits and initiate remedial action where needed
D	Pole Replacement and Testing Program	Inspect and test poles on approximately 10% of DP&L's circuits
D	Recloser Inspections	Complete the inspection of approximately 590 reclosers

10.d. 4901:1-10-26 (B)(3)(f) Current Year Goals ... Continued ...

1.	2.	3.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals
D	Underground Device Inspections	Inspect URD devices on 382 map grids
D	Visual Inspection of Airbreak Switches	Inspect approximately 1,615 switches
D	Voltage Regulator Inspections	0 regulator inspections scheduled for 2016
T	138 kV Aerial Patrol	Inspect 138 kV circuits, 4 times per year
TS	138/69/33 kV Relay Calibration	230 Non-BES transmission relays scheduled
T	345 kV Aerial Patrol	Inspect 345 kV circuits, 4 times per year
TS	345 kV Relay Calibration	149 BES relays scheduled
T	69 kV Aerial Patrol	Inspect 69 kV circuits, semi-annually
TS	Circuit Breaker Preventive Maintenance	Complete maintenance on 188 circuit breakers

10.d. 4901:1-10-26 (B)(3)(f) Current Year Goals ... Continued ...

1.	2.	3.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals
TS	External Visual Inspection of Substation Transformers	Inspect approximately 300 Substation Transformers monthly
T	Herbicide Application	Apply herbicide as needed
TS	Operational Testing of Circuit Breakers	Conduct an operational test for breakers that are not otherwise operated during the calendar year
TS	Substation Transformer Doble Test	Perform power factor tests on 41 substation transformers
TS	Substation Transformer LTC Maintenance	Complete maintenance on 24 LTCs
TS	Substation Transformers Dielectric Oil Breakdown Test	Perform 41 transformer oil dielectric breakdown tests
TS	Thermographic Imaging of Substation Transformers	Infrared approximately 300 Substation Transformers
TS	Thermographic Inspection of Substation Switches	Infrared approximately 2,362 Substation Switches

10.d. 4901:1-10-26 (B)(3)(f) Current Year Goals ... Continued ...

1.	2.	3.
Transmission "T", distribution "D", transmission substation "TS", or distribution substation "DS"	Program name	Program goals
T	Thermographic Inspection of Transmission Lines	Perform thermographic inspections where needed
T	Transmission Line Clearance	Trim trees where needed
TS	Visual Inspection of Circuit Breakers	Inspect approximately 1,300 Circuit Breakers monthly
T	Visual Inspection of Transmission Lines/Right-Of-Way	Inspect 25 circuits in metro - no fly zone

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11. 4901:1-10-26 (B)(3)(f)(iv) Prevention Of Overloading Or Excessive Loading Of Facilities And Equipment Program(s)

a.	b.	c.
Transmission or Distribution ("T" or "D")	**Program or plan name**	**Program Description**
D	Distribution Planning	The distribution planning process includes an ongoing analysis of each component and its response to current and projected peak loads. Short and long-range plans are developed and continually refined based on changing customer needs and the dynamic nature of the distribution system.
T	Transmission Planning	DP&L performs an evaluation of its transmission system on an annual basis and in response to significant proposed changes to the system, such as the installation of a generating plant or a large change in customer load at a given location. DP&L bases its transmission system evaluations on a recent power flow model developed by ReliabilityFirst on behalf of its members. A detailed model of the DP&L transmission system is then inserted in order to include all 69 kV and 138 kV facilities. Changes may be made to the generation dispatch in order to evaluate the most stressful conditions on the system. The evaluations typically consist of comprehensive contingency analyses including outages of single segment transmission lines, multiple-terminal transmission lines, transformers, generating units, and double circuits. The results of these studies are checked for thermal overloading and excessive voltage drop according to NERC/ReliabilityFirst.

PUCO Staff Data Request #12
Case No. 16-0395-EL-SSO
DP&L Electric Security Plan

From:	Jacob Nicodemus
To:	DP&L
Date Sent:	6/8/16

1. How many total miles of distribution line does DP&L maintain?

   Response: DP&L maintains 10,510 overhead distribution line miles, as reported in Rule 26.

   Witness Responsible: Kevin Hall

2. How many miles of distribution line maintained by DP&L is underground?

   Response: DP&L maintains 3,656 underground distribution line miles, as reported in Rule 26.

   Witness Responsible: Kevin Hall

3. How many miles of underground distribution line maintained by DP&L is bare concentric neutral (BCN)?

   Response: DP&L estimates that it has more than 1,300 miles of BCN cable based on the amount of cable installed for the years prior to 1990 as indicated in its plant accounting system. DP&L began installing jacketed cable in 1990.

   Witness Responsible: Kevin Hall

4. Regarding replacement of BCN:
   a. What quantitative indicators does DP&L employ to determine if and when BCN should be replaced?
   b. Does DP&L propose full replacement of all BCN?
   c. What is the approximate timeline for replacement of BCN?
   d. Please provide workpapers and any other related documentation to support the assessment of BCN on DP&L's system

   Response:

   a. DP&L replaces BCN cable on a reactive basis when the first fault occurs on the cable segment and the cable segment is 600 feet in length or less. As part of the proposed replacement program under its DIR, the Company will look to replace cable on a more proactive basis using proven testing technologies along with analysis of a cable's failure history.

b. As indicated in the Company's response to Staff DR #10, PUCO ESP DR 10-01 Attachment 1 - CONFIDENTIAL, DP&L plans to address approximately 900 miles of BCN cable. This would be a combination of replacement as well as injection of BCN cable.

c. Replacement of the remainder of the BCN cable will occur as operational performance and other factors guide the Company's decision making.

d. DP&L does not possess workpapers or documentation supporting its BCN replacement proposal other than what has been filed with the case and subsequently provided in response to Staff DR #10, PUCO ESP DR 10-01 Attachment 1 - CONFIDENTIAL. Further, DP&L relied upon experience gained over the years with the performance of BCN on the Company's system.

Witness Responsible: Kevin Hall

5. For each of the last five years, please provide the following data for those outages determined to have been caused by a BCN failure:
   a. Number of outages
   b. Customers interrupted
   c. Customer minutes interrupted

Response: DP&L tracks primary URD outages and has the number of equipment failures which includes cable failures. However, DP&L does not have the data to be able to differentiate which outages are specifically BCN cable faults. The table below details information for primary URD outages.

Year	Number of URD Outages	Total Customers Impacted	Total CMI
2010	421	37,304	5,244,630.82
2011	399	37,920	4,978,930.63
2012	406	24,365	3,889,020.27
2013	355	14,537	2,410,749.20
2014	365	27,565	4,061,851.80

Witness Responsible: Kevin Hall

6. **Regarding danger trees as DP&L defines them in Hall's testimony:**
   a. Please provide the proposed schedule for removal/trimming of danger trees
   b. Please provide the proposed schedule for miles of easement to be inspected yearly

Response:

a. As indicated in the Company's response to Staff DR 10, Question 2, and included on PUCO ESP DR 10-01 Attachment 1 – CONFIDENTIAL, DP&L is estimating the removal of 1,900 danger trees per year. This will generally be accomplished in conjunction with the Company's planned trim cycle. Trees identified outside of the normal trim cycle inspections will be removed based upon resource availability.
b. The Company's inspection and trim cycle for the next five years is as follows: 2017 - 2,114.25 miles, 2018- 2,009 miles, 2019 – 1,977.25 miles, 2020 – 2,215 miles, 2021 – 2,145.8 miles.

Witness Responsible: Kevin Hall

7. For each of the last five years, please provide the following data for those outages determined to have been caused by danger trees:
    a. Number of outages
    b. Customers interrupted
    c. Customer minutes interrupted

Response: See attached spreadsheet PUCO ESP DR 12-07 Attachment 1. DP&L tracks outages caused by trees both within as well as outside of its rights-of-way. Attachment 1 provides the data for those outages due to trees outside of the right-of-way.

Witness Responsible: Kevin Hall

8. How many total cutouts are on DP&L's system?

Response: DP&L has 173,365 cutouts on its distribution system.

Witness Responsible: Kevin Hall

9. Regarding replacement of porcelain cutouts:
    a. What percentage of cutouts on DP&L's system are porcelain?
    b. With the exception of failure, what criteria does DP&L use to determine if and when a porcelain cutout should be replaced?
    c. Please provide workpapers and any other related documentation to support the assessment of porcelain cutouts on DP&L's system

Response:

a. The Company does not have the requested information. DP&L has been identifying Chance brand cutouts since 2010 through the Distribution Line Patrol (DLP) and Pole Replacement Program (PRP) circuit inspections. DP&L has been experiencing a higher failure rate of Chance cutouts as a result of a suspected manufacturing flaw. Beginning in 2016, DP&L started to identify all porcelain cutouts through the DLP and PRP.
b. See attached document PUCO ESP DR 12-09 Attachment 1 - CONFIDENTIAL.
c. See attached document PUCO ESP DR 12-09 Attachment 1 - CONFIDENTIAL.

Witness Responsible: Kevin Hall

10. How many total network protectors are on DP&L's system?

Response: DP&L has 133 network protectors on its system.

Witness Responsible: Kevin Hall

11. Regarding replacement of network protectors:
    a. What type(s) of network protectors does DP&L propose replacing, and why?
    b. Please provide workpapers and any other related documentation to support the assessment of network protectors on DP&L's system

Response:
a. DP&L is planning on replacing 35 network protectors located in spot network vaults, which serve critical loads in the downtown Dayton area. These protectors have a "live-front" design, meaning there are exposed energized parts. The plan is to replace them with a new "dead-front" protector which provides a much safer working environment for the Company's employees and contractors. The age of these protectors is 60+ years. Thus, they have reached or exceeded their designed life. By proactively replacing these protectors, we are potentially avoiding a catastrophic failure which could cause damage to surrounding equipment. In addition, 28 of the protectors are Westinghouse CM-22 designs, which have had a product alert regarding an issue of possible deterioration of insulators within the protector.
b. DP&L does not possess workpapers or documentation supporting its proposal to replace network protectors other than what has been filed with the case and subsequently provided in response to Staff DR #10, PUCO ESP DR 10-01 Attachment 1 - CONFIDENTIAL. Further, DP&L relied upon experience gained over the years with the performance of network protectors on the Company's system.

Witness Responsible: Kevin Hall

12. How many total transformer bushings are on DP&L's system?

Response: DP&L has approximately 2,450 transformer bushings in service.

Witness Responsible: Kevin Hall

13. Regarding replacement of transformer bushings:
    a. What type(s) of transformer bushings does DP&L propose replacing, and why?
    b. Please provide workpapers and any other related documentation to support the assessment of transformer bushings on DP&L's system

Response:

a. DP&L is proposing to replace primarily General Electric (GE) Type "U" bushings, which have a history of above-average deterioration resulting in an overall shorter life. The GE Type "U" bushing is a known, industry-wide concern. Numerous papers have been written and presented describing the issue with these GE bushings, the root cause of the deterioration and potential consequences of a bushing failure.
b. See PUCO ESP DR 12-13 Attachment 1.

Witness Responsible: Kevin Hall

14. How many total substation transformers are on DP&L's system?

Response: DP&L has 290 substation class transformers on its system.

Witness Responsible: Kevin Hall

15. Regarding replacement of substation transformers:
    a. What type(s) of substation transformers does DP&L propose replacing, and why?
    b. Please provide workpapers and any other related documentation to support the assessment of substation transformers on DP&L's system.

Response:

a. DP&L does not expect to replace substation transformers under the DIR as part of this proceeding.

b. Please refer to response in question 15 a. above.

Witness Responsible: Kevin Hall

INT-255. Referring to the Direct Testimony of Mr. Hall at page 8, lines 7-16, annually for 2011 through 2015, what were the Company's total expenditures for vegetation management of danger trees?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). Subject to all general objections, DP&L states that the Company does not track costs to that level of specificity in the ordinary course of business and would be unduly burdensome to provide. Expenditures for vegetation management related to danger trees are captured within DP&L's overall vegetation management O&M expenses.

Witness Responsible: Kevin Hall

INT-260. Referring to the Direct Testimony of Mr. Hall at page 8, line 18, annually for 2011 through 2015, provide the total number of: (a) outage events, (b) customers interrupted, and (c) customer minutes interrupted that are attributed to "certain types of transformer bushings."

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 9 (vague and undefined), 12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). Subject to all general objections, DP&L states that the Company does not track the causes of outage events down to the specific components of substations in the ordinary course of business and it would be unduly burdensome to provide.

Witness Responsible: Kevin Hall

INT-261. Referring to the Direct Testimony of Mr. Hall at page 8, line 18, annually for 2011 through 2015, what are the Company's expenditures incurred for replacing "certain types of transformer bushings"?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 9 (vague and undefined),12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). Subject to all general objections, DP&L states that the Company does not track costs to that level of specificity in the ordinary course of business and it would be unduly burdensome to provide. The costs of transformer bushings are captured within the Company's substation O&M expenses.

Witness Responsible: Kevin Hall

INT-252. Referring to the Direct Testimony of Mr. Hall at page 8, lines 4-5, when did the industry determine that underground cable with a bare concentric neutral was subject to deterioration?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), 5 (inspection of business records), 6 (calls for a narrative response), 7 (not in DP&L's possession or available on PUCO website), 9 (vague or undefined), 12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). DP&L further objects that the term "industry" is vague and undefined. DP&L further objects that the request the Company to answer on behalf of other entities deemed "the industry." Subject to all general objections, DP&L states that it is not aware of a specific timeframe when it was determined that bare concentric neutral was subject to deterioration.

Witness Responsible: Kevin Hall

INT-251. Referring to the Direct Testimony of Mr. Hall at page 8, lines 3-5, annually for 2011 through 2015, provide the total number of: (a) outage events, (b) customers interrupted, and (c) customer minutes interrupted that are attributed to underground cable with a bare concentric neutral failure.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). Subject to all general objections, DP&L states please see the following table:

Year	Number of URD Outages	Total Customers Impacted	Total CMI
2010	421	37,304	5,244,630.82
2011	399	37,920	4,978,930.63
2012	406	24,365	3,889,020.27
2013	355	14,537	2,410,749.20
2014	365	27,565	4,061,851.80
2015	345	33,649	4,263,280

Witness Responsible: Kevin Hall

INT-254. Referring to the Direct Testimony of Mr. Hall at page 8, lines 4-5, annually for 2011 through 2015, what were the Company's total expenditures for (a) repairing or (b) replacing underground cable with a bare concentric neutral?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 5 (inspection of business records), 12 (seeks information that DP&L does not know at this time), 13 (mischaracterization). Subject to all general objections, DP&L states that the Company does not track bare concentric neutral cable separate from other types of cable in the ordinary course of business. Additionally, the Company does not separately track any O&M expenses related to maintenance or repairs of underground cable in the ordinary course of business. Further responding, DP&L's annual capital expenditures for underground cable injection and replacement for 2011 through 2015 are included in the table below:

Year	Underground Cable Capital Expenditures ($000)
2011	5,328
2012	4,543
2013	3,909
2014	4,426
2015	3,586

Witness Responsible: Kevin Hall

METRIX MATRIX INC.

Dayton Power & Light
Customer Perception Survey / RESIDENTIAL
Executive Summary Report

May 2015

1. Table of Contents

2. Methodology

The following are the results of a customer power interruption survey designed to gather customer feedback regarding residential power interruptions experienced within the 12 months prior to participating in the survey. The questions and methodology were specified by Dayton Power and Light. The survey was conducted on a quarterly schedule outlined in the following table.

Time Period	Sample
2nd Quarter 2014	100
3rd Quarter 2014	100
4th Quarter 2014	103
1st Quarter 2015	103

This report presents the summary results of 406 telephone surveys performed with a random sample of residential Dayton Power and Light customers. The surveys were completed between May 16, 2014 and March 18, 2015.

The maximum margin of error, calculated at a 95% confidence level, for the top-level percentages in this report are as follows:

Segment	Sample Size	Margin of Error
Customer Population > 10,000	406	± 4.9%

3. Executive Summary

Momentary Power Interruption, Experienced and Acceptable: Over a third of respondents (35%) reported experiencing no momentary interruptions in the last 12 months, while just under a fifth of respondents (16%) thought the maximum acceptable number of momentary interruptions was zero. Just 24% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Sustained Power Interruptions, Experienced and Acceptable: Almost half (45%) of the sample indicated they experienced no sustained power interruptions in the past twelve months. This outperforms the 25% of respondents who indicated zero sustained outages was acceptable. A third (36%) had experienced one or two outages in the 12 month time period while 42% found one or two outages to be acceptable. A third (34%) (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more sustained interruptions than they had found acceptable.

Length of Average Power Outages for Sustained Power Interruptions: The average sustained interruption lasted 5 hours. Fifty percent (50%) of respondents who had sustained power outages averaged less than 2 hours per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less while ones that were storm related should last 4 hours or less.

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths: If all sustained power interruptions were non-storm related in the last 12 months, then 48% of those who experienced such interruptions indicated they experienced a length of power interruption, on average, longer than was acceptable. If all sustained power interruptions were storm related in the last 12 months, then only 20% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable.

Importance Ratings for Three Aspects of Power Outages: Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.4 on a 1 to 10 importance scale) followed by the Frequency of Sustained Interruptions (7.2). The Mean Importance rating for reducing by half the number of momentary interruptions was significantly less (6.2).

4. Detailed Results

Momentary Power Interruption, Experienced and Acceptable

There is a category of electric power interruptions that occur for five minutes or less but result in a disruption of power to electronic appliances. As an example, these momentary power interruptions might only be noticeable because of a digital clock blinking. In the past 12 months, how many momentary interruptions have you experienced?

How many momentary interruptions would you consider to be acceptable during a 12 month period?

Over a third of respondents (35%) reported experiencing no momentary interruptions in the last 12 months while less than one fifth of respondents (16%) thought the maximum acceptable number of momentary interruptions was zero. Ten percent (10%) of the sample respondents reported experiencing more than 4 momentary interruptions.

	Momentary Interruptions			
	Experienced		Acceptable	
Number of momentary interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	143	35%	65	16%
1	58	14%	42	10%
2	68	17%	82	20%
3	38	9%	66	16%
4	20	5%	31	8%
5	16	4%	31	8%
6	9	2%	15	4%
7	1	0%	2	0%
8 or more	15	4%	15	4%
Don't Know	38	9%	57	14%
Total	406	100%	406	100%

Table 1: Experienced and Acceptable Momentary Power Interruptions

Comparing the number of momentary interruptions experienced to the number that respondents found acceptable, (see Table 2 below):

Approximately a quarter (24%) (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Difference between experienced and acceptable momentary interruptions	Respondents	Percent
8	3	1%
7	2	1%
6	3	1%
5	6	2%
4	7	2%
3	21	7%
2	15	5%
1	19	6%
Total experiencing more momentary interruptions than they regard as acceptable.	76	24%
0	83	26%
-1	28	9%
-2	50	15%
-3	44	14%
-4	18	6%
-5	14	4%
-6	6	2%
-7	1	0%
-8	3	1%
Total experiencing fewer or as many momentary interruptions as they regard as acceptable	247	76%
Total	323	100%

Table 2: Momentary Interruptions, Experienced Number Minus Acceptable Number

Sustained Power Interruption, Experienced and Acceptable

Sustained power interruptions are power outages that last for more than five minutes. In the past 12 months, how many sustained interruptions have you experienced?

How many sustained interruptions would you consider to be acceptable during a 12 month period?

Almost half (45%) of respondents indicated they did not experience a sustained power interruption in the past 12 months, while only a quarter of respondents indicated zero outages in that time frame as being acceptable.

While 42% of respondents indicated one or two sustained interruptions would be acceptable, only 36% actually experienced one or two sustained outages the in the past 12 months.

	Sustained Power Interruptions			
	Experienced		Acceptable	
Number of sustained interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	183	45%	103	25%
1	83	20%	81	20%
2	65	16%	90	22%
3	27	7%	43	11%
4	11	3%	16	4%
5	7	2%	15	4%
6	6	1%	6	1%
7	1	0%	0	0%
8 or more	5	1%	5	1%
Don't Know	18	5%	47	12%
Total	406	100%	406	100%

Table 3: Experienced and Acceptable Sustained Power Interruptions

A third (34%) of respondents who experienced sustained power interruptions experienced more than they found acceptable (Table 4). It should be noted that a quarter of this group (25% of the total sample) only experienced 1 or 2 more sustained power interruptions than they found acceptable.

A quarter of respondents (24%) indicated they had experienced the same amount of interruptions as they had indicated were acceptable.

Difference between experienced and acceptable sustained power interruptions	Respondents	Percent
8	1	0%
7	1	0%
6	2	1%
5	3	1%
4	7	2%
3	17	4%
2	29	7%
1	71	18%
Total experiencing more sustained power interruptions than they regard as acceptable.	131	34%
0	95	24%
-1	60	15%
-2	62	16%
-3	22	6%
-4	5	1%
-5	9	2%
-6	2	1%
-7	2	1%
-8	0	0%
Total experiencing fewer or as many sustained power interruptions as they regard as acceptable	257	66%
	388	100%

Table 4: Sustained Power Interruptions, Experienced Number Minus Acceptable Number

Length of Average Power Outages for Sustained Power Interruptions

Respondents who indicated that they had at least 1 sustained power interruption in the last 12 months were asked:

On average, for how long was your power out during the sustained interruptions?

As a follow-up, all respondents were asked:

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that was NOT storm related?

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that was Storm related?

Table 5 provides information on the mean and median time in hours that people experienced during sustained power interruptions, as well as the mean and median times that people found acceptable for both storm related and non-storm related outages.

Sixty percent (60%) of respondents who had sustained power outages indicated the outages were less than 2 hours per episode. At the same time, 83% percent of the same respondents indicated that sustained power interruptions that are not storm related should last 2 hours or less while only 40% indicated storm-related interruptions should be 2 hours or less.

	Average time power out for sustained interruptions experienced in the last 12 months[1]	Acceptable time for power to be out for sustained interruption – **NOT storm related**	Acceptable time for power to be out for sustained interruption – **storm related**
Mean Hours	5.0	2.7	11.8
Median Hours	2.0	1.0	4.0
Standard Deviation (in Hours)	12.8	5.3	20.6
Range (in Hours)	120.0	48	192.0
Minimum (in Hours)	0.0	0.0	0.0
Maximum Value (in Hours)	120.0	48	192.0
Sample Size	200	384	371

Table 5: Average and Median Length of Times Experienced and Acceptable for Sustained

[1] Asked only of respondents who reported a sustained power interruption.

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths

For the subset of customers who had experienced a sustained power interruption and provided an estimate of the accepted length of time for a **non-storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if non-storm related), (Table 6).

If all sustained power interruptions were non-storm related in the last 12 months, then half (48%) of those who experienced such interruptions indicated they experienced a length of power interruption, on average, longer than was acceptable.

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Non-Storm Related	100	53%
More than 48 hours	3	2%
24 to 48 hours	1	1%
12 to 24 hours	5	3%
6 to 12 hours	7	4%
3 to 6 hours	24	13%
1 to 3 hours	45	24%
1 hour or less	15	8%
Average Experience Matched Acceptable	37	19%
Average Experience Time Less than Acceptable	54	28%
Total	191	100%

Table 6: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Non-Storm Related Interruption

For the subset of customers who had experienced a sustained power interruption and provide an estimate of the acceptable length of time **for a storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if storm related), (Table 7).

If all sustained power interruptions were storm related in the last 12 months then only 20% (in contrast to 53% if non-storm related) of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable.

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Storm Related	38	20%
More than 48 hours	0	0%
24 to 48 hours	1	1%
12 to 24 hours	4	2%
6 to 12 hours	3	2%
3 to 6 hours	5	3%
1 to 3 hours	22	12%
1 hour or less	3	2%
Average Experience Matched Acceptable	23	12%
Average Experience Time Less than Acceptable	127	68%
Total	188	100%

Table 7: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Storm Related Interruption

Importance Ratings for Three Aspects of Power Outages

Next we are going to ask you to rate the importance of reducing each of these three aspects of power outages on a 1 to 10 scale, where 1 is not at all important and 10 is very important, so ... On a 1 to 10 scale where 1 is not at all important and 10 is very important, could you indicate how important it is to you:

to reduce by half the frequency of sustained outages?

to reduce by half the duration of sustained outages?

to reduce by half the number of momentary power outages?

Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.4) followed by the Frequency of Sustained Interruptions (7.2). The Mean Importance rating for reducing by half the number of momentary interruptions was substantially less (6.2).

	Frequency of Sustained Interruptions	Duration of Sustained Interruptions	Number of Momentary Interruptions
1 Not at all Important	4%	3%	8%
2	4%	4%	10%
3	6%	4%	6%
4	1%	4%	3%
5	18%	14%	20%
6	4%	5%	7%
7	8%	9%	8%
8	14%	15%	9%
9	9%	9%	5%
10 Very Important	32%	33%	25%
Total	100%	100%	100%
Mean Importance Rating	7.2	7.4	6.2
Sample Size	393	391	393

Table 8: Respondent Ratings of the Importance of Reducing Frequency and Duration of Sustained Interruptions and Number of Momentary Interruptions

METRIX MATRIX INC.

Dayton Power & Light
Customer Perception Survey / BUSINESS
Executive Summary Report

May 2015

1. Table of Contents

2. Methodology

The following are the results of a customer power interruption study designed to gather customer feedback regarding business power interruptions experienced within the 12 months prior to participating in the survey. The questions and methodology were specified by Dayton Power and Light. The survey was conducted on a quarterly schedule outlined in the following table.

Time Period	Sample
2nd Quarter 2014	100
3rd Quarter 2014	100
4th Quarter 2014	103
1st Quarter 2015	103

This report presents the summary results of approximately 406 telephone surveys performed with a random sample of Dayton Power and Light business customers. The surveys were completed between May 16, 2014 and March 18, 2015.

The maximum margin of error, calculated at a 95% confidence level, for the top-level percentages in this report are as follows:

Segment	Sample Size	Margin of Error
Customer Population > 10,000	406	± 4.9%

3. Executive Summary

Momentary Power Interruption, Experienced and Acceptable: Forty percent (40%) of respondents reported experiencing no momentary interruptions in the last 12 months, while just over a fifth of respondents (22%) thought the maximum acceptable number of momentary interruptions was zero. Just 24% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had indicated was acceptable.

Sustained Power Interruptions, Experienced and Acceptable: Almost half (45%) of the sample indicated they experienced no sustained power interruption in the past twelve months. This outperforms the 29% of respondents who indicated zero sustained outages was acceptable. A third (36%) had experienced one or two outages in the 12 month time period while 45% found one or two outages to be acceptable. A quarter (24%) (of those who provided both a count of experienced and acceptable sustained power interruptions) had experienced more sustained interruptions than they had indicated was acceptable.

Length of Average Power Outages for Sustained Power Interruptions: The average sustained interruption lasted 2.7 hours. Fifty percent (50%) of respondents who had sustained power outages averaged less than 1 hour per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less while sustained power interruptions that were storm related should last 3 hours or less.

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths: If all sustained power interruptions were non-storm related in the last 12 months then 53% of those who experienced such interruptions indicated they experience a length of power interruption, on average, longer than was acceptable. If all sustained power interruptions were storm related in the last 12 months then only 20% of those who experienced such interruptions indicated they experienced a length of power interruption on average longer than was acceptable.

Importance Ratings for Three Aspects of Power Outages: Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.8 on a 1 to 10 importance scale) followed by the Frequency of Sustained Interruptions (7.7). The Mean Importance rating for reducing by half the number of momentary interruptions was significantly less (7.0).

4. Detailed Results

Momentary Power Interruption, Experienced and Acceptable

There is a category of electric power interruptions that occur for five minutes or less but result in a disruption of power to electronic appliances. As an example, these momentary power interruptions might only be noticeable because of a digital clock blinking. In the past 12 months, how many momentary interruptions have you experienced?

How many momentary interruptions would you consider to be acceptable during a 12 month period?

Forty percent (40%) of respondents reported experiencing no momentary interruptions in the last 12 months while slightly more than a fifth of respondents (22%) thought the maximum acceptable number of momentary interruptions was zero. Eleven percent (11%) of the sample respondents reported experiencing more than 4 momentary interruptions.

	Momentary Interruptions			
	Experienced		Acceptable	
Number of momentary interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	161	40%	90	22%
1	48	12%	48	12%
2	59	15%	77	19%
3	38	9%	54	13%
4	25	6%	34	8%
5	12	3%	33	8%
6	18	4%	15	4%
7	1	0%	2	0%
8 or more	18	4%	31	8%
Don't Know	26	6%	22	5%
Total	406	100%	406	100%

Table 1: Experienced and Acceptable Momentary Power Interruptions

Comparing the number of momentary interruptions experienced to the number that respondents found acceptable, (see Table 2 below):

A quarter (24%) (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Difference between experienced and acceptable momentary interruptions	Respondents	Percent
8	5	1%
7	0	0%
6	7	2%
5	4	1%
4	7	2%
3	18	5%
2	21	6%
1	26	7%
Total experiencing more momentary interruptions than they regard as acceptable.	88	24%
0	99	27%
-1	39	11%
-2	52	14%
-3	27	7%
-4	19	5%
-5	14	4%
-6	7	2%
-7	5	1%
-8	13	4%
Total experiencing fewer or as many momentary interruptions as they regard as acceptable	275	76%
	363	100%

Table 2: Momentary Interruptions, Experienced Number Minus Acceptable Number

Sustained Power Interruption, Experienced and Acceptable

Sustained power interruptions are power outages that last for more than five minutes. In the past 12 months, how many sustained interruptions have you experienced?

How many sustained interruptions would you consider to be acceptable during a 12 month period?

Almost half (45%) of respondents indicated they did not experience a sustained power interruption in the past 12 months, while 29% of respondents indicated zero outages in that time frame as being acceptable.

While 45% of respondents indicated one or two sustained interruptions would be acceptable, only 36% actually experienced one or two sustained outages in the past 12 months.

	Sustained Power Interruptions			
	Experienced		Acceptable	
Number of sustained interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	181	45%	119	29%
1	91	22%	86	21%
2	58	14%	98	24%
3	32	8%	35	9%
4	12	3%	13	3%
5	8	2%	19	5%
6	7	2%	7	2%
7	2	0%	2	0%
8 or more	1	0%	7	2%
Don't Know	14	3%	20	5%
Total	406	100%	406	100%

Table 3: Experienced and Acceptable Sustained Power Interruptions

A quarter (24%) of respondents who experienced sustained power interruptions experienced more than they found acceptable (Table 4).

A third of respondents (32%) indicated they had experienced the same amount of interruptions as they had indicated were acceptable.

Difference between experienced and acceptable sustained power interruptions	Respondents	Percent
8	0	0%
7	1	0%
6	3	1%
5	3	1%
4	2	1%
3	13	3%
2	34	9%
1	35	9%
Total experiencing more sustained interruptions than they regard as acceptable.	91	24%
0	118	32%
-1	58	16%
-2	58	16%
-3	19	5%
-4	10	3%
-5	8	2%
-6	5	1%
-7	2	1%
-8	3	1%
Total experiencing fewer or as many sustained power interruptions as they regard as acceptable	281	76%
	372	100%

Table 4: Sustained Power Interruptions, Experienced Number Minus Acceptable Number

Length of Average Power Outages for Sustained Power Interruptions

Respondents who indicated that they had at least 1 sustained power interruption in the last 12 months were asked:

On average, for how long was your power out during the sustained interruptions?

As a follow-up, all respondents were asked:

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that was NOT storm related?

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that was Storm related?

Table 5 provides information on the mean and median time in hours that people experienced sustained power interruptions for, as well as the mean and median times that people found acceptable for both storm related and non-storm related outages.

The average sustained outage experienced by business respondents was 2.7 hours, slightly more than they consider acceptable for non-storm related outages (2.4) but considerably less than what is acceptable for storm related outages (8.6). Fifty percent (50%) of respondents who had sustained power outages indicated the outages were less than 1 hour per episode. At the same time, 50% percent of the same respondents also indicated that sustained power interruptions that are not storm related should last 1 hour or less while 50% indicated storm-related interruptions should be 3 hours or less.

	Average time power out for sustained interruptions experienced in the last 12 months	Acceptable time for power to be out for sustained interruption – **NOT storm related**	Acceptable time for power to be out for sustained interruption – **storm related**
Mean Hours	2.7	2.4	8.6
Median Hours	1.0	1.0	3.0
Standard Deviation (in Hours)	6.3	6.9	17.2
Range	72.0	72	168.0
Minimum	0.0	0	0.0
Maximum Value	72.0	72	168.0
Sample Size	206	384	369

Table 5: Average and Median Length of Times Experienced and Acceptable for Sustained

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths

For the subset of customers who had experienced a sustained power interruption and provided an estimate of the accepted length of time for a **non-storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if non-storm related), (Table 6).

If all sustained power interruptions were non-storm related in the last 12 months, then half (53%) of those who experienced such interruptions indicated they experienced a length of power interruption, on average, longer than was acceptable.

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Non-Storm Related	94	48%
More than 48 hours	1	1%
24 to 48 hours	0	0%
12 to 24 hours	5	3%
6 to 12 hours	8	4%
3 to 6 hours	14	7%
1 to 3 hours	35	18%
1 hour or less	31	16%
Average Experience Matched Acceptable	38	19%
Average Experience Time Less than Acceptable	64	33%
Total	196	100%

Table 6: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Non-Storm Related Interruption

For the subset of customers who had experienced a sustained power interruption and provide an estimate of the acceptable length of time **for a storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if storm related), (Table 7).

If all sustained power interruptions were storm related in the last 12 months then only 20% (in contrast to 48% if non-storm related) of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable.

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Storm Related	37	20%
More than 48 hours	0	0%
24 to 48 hours	0	0%
12 to 24 hours	3	2%
6 to 12 hours	3	2%
3 to 6 hours	10	5%
1 to 3 hours	15	8%
1 hour or less	6	3%
Average Experience Matched Acceptable	17	9%
Average Experience Time Less than Acceptable	132	71%
Total	186	100%

Table 7: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Storm Related Interruption

Importance Ratings for Three Aspects of Power Outages

Next we are going to ask you to rate the importance of reducing each of these three aspects of power outages on a 1 to 10 scale, where 1 is not at all important and 10 is very important, so ...
On a 1 to 10 scale where 1 is not at all important and 10 is very important, could you indicate how important it is to you:

to reduce by half the frequency of sustained outages?

to reduce by half the duration of sustained outages?

to reduce by half the number of momentary power outages?

Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.8) followed by the Frequency of Sustained Interruptions (Mean Rating 7.7). The Mean Importance rating for reducing by half the number of momentary interruptions was substantially less (7.0).

	Frequency of Sustained Interruptions	Duration of Sustained Interruptions	Number of Momentary Interruptions
1 Not at all Important	4%	3%	7%
2	5%	5%	4%
3	2%	2%	3%
4	1%	1%	4%
5	12%	11%	19%
6	3%	2%	4%
7	8%	9%	7%
8	11%	14%	11%
9	8%	8%	6%
10 Very Important	45%	43%	35%
Total	100%	100%	100%
Mean Importance Rating	7.7	7.8	7.0
Sample Size	406	406	405

Table 8: Respondent Ratings of the Importance of Reducing Frequency and Duration of Sustained Interruptions and Number of Momentary Interruptions

DP&L Power Interruption Residential Survey Report

I. Introduction and Executive Summary

The Business Research Group at the University of Dayton assisted Dayton Power & Light in its study of electric consumers' experience with power interruptions and their rating of the importance of reducing the frequency and duration of power interruptions.

During March, 2012, 800 telephone surveys were conducted in the Dayton Power & Light service area; 400 of the surveys were with a random sample of residential customers and 400 with a random sample of business customers.

The sample margin of error in both the residential and business surveys at a 95% confidence level of opinion is equally divided is +/-4.9%.

In what follows a summary of the results are provided for the residential surveys. A separate report is available on the results of the business survey.

Momentary Power Interruption, Experienced and Acceptable: Approximately a third of respondents (32%) reported experiencing no momentary interruptions in the last 12 months while just over a fifth of respondents (22%) thought the maximum acceptable number of momentary interruptions was zero. Just 27% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Sustained Power Interruptions, Experienced and Acceptable: 77% of the sample indicated they had experienced 2 or fewer sustained power interruptions and 76% of the sample indicated the acceptable number of sustained power interruptions was 2 or fewer. Despite the rough proportionality of the experienced and acceptable sustained power interruption distribution, a substantial minority of respondents (31%) did experience more sustained power interruptions than they found acceptable.

Length of Average Power Outages for Sustained Power Interruptions: Fifty percent of people had sustained power outages that averaged less than 2 hours per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less while ones that were storm related should last 4 hours or less.

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths: If all sustained power interruptions were non-storm related in the last 12 months than 64% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. Not surprising, if all sustained power interruptions were storm related in the last 12 months than only 27% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable.

Importance Ratings for Three Aspects of Power Outages: Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.5 on a 1 to 10 importance scale) followed by the Frequency of Sustained Interruptions (Mean Rating 7.2). The Mean Importance rating for reducing by half the number of momentary interruptions was substantially less (5.9).

Loss Estimates as a Result of Power Outages in Last 12 Months: Just under a quarter (24%) of those who had experienced a power interruption in the last 12 months indicated they had suffered losses as a result. Mean dollar losses were $378 for those who reported dollar losses. This value is driven up substantial by a single response that placed the dollar value at $6,000. The median dollar value of losses was $200.

II. Detailed Results

A. Momentary Power Interruption, Experienced and Acceptable

There is a category of electric power interruptions that occur for five minutes or less but result in a disruption of power to electronic appliances. As an example, these momentary power interruptions might only be noticeable because of a digital clock blinking. In the past 12 months, how many momentary interruptions have you experienced?

0 1 2 3 4 5 6 7 8 or more

How many momentary interruptions would you consider to be acceptable during a 12 month period?

0 1 2 3 4 5 6 7 8 or more

Approximately a third of respondents (32%) reported experiencing no momentary interruptions in the last 12 months while just over a fifth of respondents thought the maximum acceptable number of momentary interruptions was zero. Sixteen percent of the sample respondents reported experiencing more than 4 momentary interruptions.

Table 1: Experienced and Acceptable Momentary Power Interruptions

	Momentary Interruptions			
	Experienced:		Acceptable:	
Number of Interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	126	32%	88	22%
1	38	10%	35	9%
2	69	17%	106	27%
3	41	10%	51	13%
4	20	5%	20	5%
5	19	5%	26	7%
6	12	3%	23	6%
7	3	1%	4	1%
8 or more	28	7%	21	5%
Don't Know	44	11%	26	7%
Total	400	100%	400	100%

Comparing the number of momentary interruptions experienced to the number that respondents found acceptable, (see Table 2 below):

27% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Table Two: Momentary Interruptions, Experienced Number Minus Acceptable Number

Difference between experienced and acceptable momentary interruptions	Respondents	Percent
8	5	1%
7	2	1%
6	12	4%
5	7	2%
4	8	2%
3	16	5%
2	19	6%
1	20	6%
Total experiencing more momentary interruptions than they regard as acceptable	89	27%
0	111	33%
-1	38	11%
-2	44	13%
-3	23	7%
-4	4	1%
-5	10	3%
-6	8	2%
-7	3	1%
-8	5	1%
Total experiencing fewer or as many momentary interruptions as they regard as acceptable	246	73%
Total	335	100.0

B. Sustained Power Interruptions, Experienced and Acceptable

Sustained power interruptions are power outages that last for more than five minutes. In the past 12 months, how many sustained interruptions have you experienced?

0 1 2 3 4 5 6 7 8 or more

How many sustained interruptions would you consider to be acceptable during a 12 month period?

0 1 2 3 4 5 6 7 8 or more

At the level of distribution of responses, there is rough equality between the reported number of sustained power interruptions experienced in 12 months and the number of acceptable sustained power interruptions (Table 3). While 36% of the sample experienced no sustained power interruptions, 29% indicated that that was the only acceptable number of sustained power interruptions; 77% of the sample indicated they had experienced 2 or fewer sustained power interruptions and 76% of the sample indicated the acceptable number of sustained power interruptions was 2 or fewer.

Table 3: Experienced and Acceptable Sustained Power Interruptions

	Sustained Power Interruptions			
	Experienced:		Acceptable:	
Number of Sustained Interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	142	36%	116	29%
1	84	21%	92	23%
2	78	20%	94	24%
3	41	10%	34	9%
4	12	3%	17	4%
5	7	2%	12	3%
6	5	1%	5	1%
7	1	0%	0	0%
8	8	2%	8	2%
Don't Know	22	6%	22	6%
Total	400	100%	400	100%

Despite the rough proportionality of the experienced and acceptable sustained power interruption distribution, a substantial minority of respondents (31%) did experience more sustained power interruptions than they found acceptable (Table 4). It should be noted that the greatest percentage of this group (22% of the total sample) only experienced 1 or 2 more sustained power interruptions than they found acceptable.

Table Four: Sustained Power Interruptions, Experienced Number Minus Acceptable Number

Difference between experienced and acceptable sustained power interruptions	Respondents	Percent
8	1	0%
7	1	0%
6	3	1%
5	5	1%
4	5	1%
3	18	5%
2	27	8%
1	52	14%
Total experiencing more sustained power interruptions than they regard as acceptable	112	31%
0	110	31%
-1	57	16%
-2	45	13%
-3	16	4%
-4	8	2%
-5	5	1%
-6	2	1%
-7	1	0%
-8	3	1%
Total experiencing fewer or as many sustained power interruptions as they regard as acceptable	247	69%
Total	359	100%

C. Length of Average Power Outages for Sustained Power Interruptions

Respondents who indicated that they had at least 1 sustained power interruption in the last 12 months were asked: *On average, for how long was your power out during the sustained interruptions?*

As a follow-up, all respondents were asked:

*On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that **was Not storm related**?*

*On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that **was Storm related**?*

Table 5 provides information on the mean and median time in hours that people experienced sustained power interruptions for and the mean and median times that people found acceptable for losses of power during power interruptions that are not storm related and ones that are storm related.

It should be noted that all of the median values for experienced and acceptable lengths of time are well below the mean values. This is because the distributions cluster closer to zero hours with a relatively long tail. Fifty percent of people had sustained power outages that averaged less than 2 hours per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less while ones that were storm related should last 4 hours or less.

Table 5: Average and Median Length of Times Experienced and Acceptable for Sustained Power Interruptions

	Average Time Power Out for Sustained Interruptions Experienced in Last 12 Months *	Acceptable Time for Power to Be Out for Sustained Interruption Not Storm Related	Acceptable Time for Power to Be Out for Sustained Interruption that was Storm Related
Mean Hours	8.6	2.7	12.1
Median Hours	2.0	1.0	4.0
Standard Deviation (in Hours)	18.5	5.6	17.0
Range	99.0	60.5	99.2
Minimum Value (in Hours)	0	0	0
Maximum Value (in Hours)	99.0	60.5	99.2
Sample Size	240	377	363

* Asked only of respondents who reported a sustained power interruption

D. Differential between Average Lengths of Experienced Sustained Power Outages And Acceptable Lengths

For the subset of customers who had experienced a sustained power interruption and provide an estimate of the accepted length of time **for a non-storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if non-storm related), (Table 6).

If all sustained power interruptions were non-storm related in the last 12 months than 64% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. However, it should be noted that for two thirds of that group (41% overall), the differential was 3 hours or less.

Table 6: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Non-Storm Related Interruption

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Non-Storm Related	146	64%
> 48 hours	11	5%
24 to 48 hours	8	4%
12 to 23 hours	12	5%
from 6 hours to 12 hours	8	4%
from 3 hours to 6 hours	13	6%
from 1 hour to 3 hours	46	20%
1 hour or less	48	21%
Average Experienced Matched Acceptable	34	15%
Average Experienced Time Less than Acceptable	48	21%
Total	228	100%

* Calculated for respondents who had experienced a sustained power interruption and provided an estimate of the acceptable length of time for a non-storm related power interruption

For the subset of customers who had experienced a sustained power interruption and provide an estimate of the accepted length of time **for a storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if storm related), (Table 7, next page).

Not surprising, if all sustained power interruptions were storm related in the last 12 months than only 27% (in contrast to 64% if non-storm related) of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. In this case, for about half (13%) of that group, the differential was 3 hours or less.

Table 7: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Storm Related Interruption		
	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Storm Related	58	27%
> 48 hours	2	1%
24 to 48 hours	11	5%
12 to 23 hours	9	4%
from 6 hours to 12 hours	4	2%
from 3 hours to 6 hours	5	2%
from 1 hour to 3 hours	19	9%
1 hour or less	8	4%
Average Experienced Matched Acceptable	26	12%
Average Experienced Time Less than Acceptable	134	61%
Total	218	100%

* Calculated for respondents who had experienced a sustained power interruption and provided an estimate of the acceptable length of time for a storm related power interruption

E. Importance Ratings for Three Aspects of Power Outages

Next we are going to ask you to rate the importance of reducing each of these 3 aspects of power outages on a 1 to 10 scale where 1 is not at all important and 10 is very important, so... On a 1 to 10 scale where 1 is not at all important and 10 is very important; could you indicate how important it is to you:

to reduce by half the frequency of sustained outages?
to reduce by half the duration of sustained outages?
to reduce by half the number of momentary power outages?

Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 7.5) followed by the Frequency of Sustained Interruptions (Mean Rating 7.2). The Mean Importance rating for reducing by half the number of momentary interruptions was substantially less (5.9).

Table 8: Respondent Ratings of the Importance of Reducing Frequency and Duration of Sustained Interruptions and Number of Momenmtary Interruptions On a 1 to 10 scale where 1 is Not at all important and 10 is Very Important

	Importance of Reducing:		
	Frequency of Sustained Interruptions	Duration of Sustained Interruptions	Number of Momentary Interruptions
1 Not at all Important	4%	2%	10%
2	3%	2%	7%
3	4%	4%	7%
4	2%	4%	4%
5	18%	15%	21%
6	5%	5%	8%
7	9%	8%	7%
8	13%	20%	11%
9	8%	7%	5%
10 Very Important	33%	34%	20%
Total	100%	100%	100%
Mean Importance Rating	7.2	7.5	5.9
Median Importance Rating	8	8	6
Sample Size	387	383	384

F. Loss Estimates as a Result of Power Outages in Last 12 Months

Respondents who indicated they had suffered a sustained power outage in the last 12 months were asked:

Would you say that you have suffered losses as a result of power outages you have experienced in the last 12 months? Examples of losses might be the cost of spoiled food and damaged electrical appliances.

Just under a quarter (24%) of those who had experienced a power interruption in the last 12 months indicated they had suffered losses as a result, (Table 9).

Table 9: Suffered Losses from Sustained Power Outages This Last 12 Months?

Have Losses from Power Outage?	Respondents	As Percent of Those Having a Sustained Power Outage	As Percent of Total Sample
Yes	63	24%	16%
No	195	76%	49%
Number with Power Outage	258	100%	65%
Number without Power Outage	142		36%
Total Sample	400		100%

Those who indicated they suffered losses were asked: *Please estimate the dollar value of losses you have suffered as a result of power outages in the last 12 months.*

Table 10: Dollar Value of Losses from Power Outages in Last 12 months

	Respondents	Percent
Under $100	15	27%
$100 to $300	27	48%
$350 to $750	9	16%
$1,000	3	5%
$1,500	1	2%
$6,000	1	2%
Total	56	100%
Mean Dollar Losses	$378	
Median Dollar Losses	$200	

Asked of those who indicated they had dollar losses

Mean dollar losses were $378 for those who reported dollar losses. This value is driven up substantial by a single response that placed the dollar value at $6,000. The median dollar value of losses was $200.

Note that of the 63 who indicated dollar losses only 56 could put a dollar value on them.

DP&L Power Interruption Business Survey Report

I. Introduction and Executive Summary

The Business Research Group at the University of Dayton assisted Dayton Power & Light in its study of electric consumers' experience with power interruptions and their rating of the importance of reducing the frequency and duration of power interruptions.

During March, 2012, 800 telephone surveys were conducted in the Dayton Power & Light service area; 400 of the surveys were with a random sample of residential customers and 400 with a random sample of business customers.

The sample margin of error in both the residential and business surveys at a 95% confidence level of opinion is equally divided is +/-4.9%.

In what follows a summary of the results are provided for the business surveys. A separate report is available on the results of the residential survey.

Experienced and Acceptable Number of Momentary Power Interruptions: Slightly more than a third of respondents (36%) reported experiencing no momentary interruptions in the last 12 months while just over a quarter of respondents (26%) thought the maximum acceptable number of momentary interruptions was zero. However, 26% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Experienced and Acceptable Number of Sustained Power Interruptions: While 42% of the sample experienced no sustained power interruptions, 32% indicated that that was the only number of acceptable sustained power interruptions. Slightly more than a quarter of respondents (26%) did experience more sustained power interruptions than they found acceptable.

Length of Average Power Outages for Sustained Power Interruptions: Fifty percent of people who had sustained power outages indicated they averaged 2 hours or less per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less. This same percentage indicated that sustained interruptions that were storm related should last 4 hours or less.

Differential between Average Lengths of Experienced Sustained Power Outages and Acceptable Lengths: If all sustained power interruptions were non-storm related in the last 12 months than 57% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. BY contrast, if all sustained power interruptions were storm related in the last 12 months than only 24% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable.

II. Detailed Results

A. Experienced and Acceptable Number of Momentary Power Interruptions

There is a category of electric power interruptions that occur for five minutes or less but result in a disruption of power to electronic appliances. As an example, these momentary power interruptions might only be noticeable because of a digital clock blinking. In the past 12 months, how many momentary interruptions have you experienced?

0 1 2 3 4 5 6 7 8 or more

How many momentary interruptions would you consider to be acceptable during a 12 month period?

0 1 2 3 4 5 6 7 8 or more

Slightly more than a third of respondents (36%) reported experiencing no momentary interruptions in the last 12 months while just over a quarter of respondents (26%) thought the maximum acceptable number of momentary interruptions was zero. Twelve percent of the sample respondents reported experiencing more than 4 momentary interruptions.

Table 1: Experienced and Acceptable Momentary Power Interruptions

	Momentary Interruptions			
	Experienced:		Acceptable:	
Number of Interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	145	36%	103	26%
1	43	11%	35	9%
2	60	15%	100	25%
3	38	10%	54	14%
4	19	5%	27	7%
5	14	4%	30	8%
6	22	6%	20	5%
7	2	1%	0	0%
8 or more	16	4%	8	2%
Don't Know	41	10%	23	6%
Total	400	100%	400	100%

Comparing the number of momentary interruptions experienced to the number that respondents found acceptable, (see Table 2 below):

26% (of those who provided both a count of experienced and acceptable momentary interruptions) had experienced more momentary interruptions than they had found acceptable.

Table Two: Momentary Interruptions, Experienced Number Minus Acceptable Number

Difference between experienced and acceptable momentary interruptions	Respondents	Percent
8	6	1.7%
7	1	0.3%
6	10	2.9%
5	10	2.9%
4	6	1.7%
3	18	5.2%
2	23	6.7%
1	15	4.4%
Total experiencing more momentary interruptions than they regard as acceptable	89	26%
0	108	31.5%
-1	32	9.3%
-2	56	16.3%
-3	28	8.2%
-4	8	2.3%
-5	10	2.9%
-6	10	2.9%
-8	2	0.6%
Total experiencing fewer or as many momentary interruptions as they regard as acceptable	254	74%
Total	343	100%

B. Experienced and Acceptable Number of Sustained Power Interruptions

Sustained power interruptions are power outages that last for more than five minutes. In the past 12 months, how many sustained interruptions have you experienced?

0 1 2 3 4 5 6 7 8 or more

How many sustained interruptions would you consider to be acceptable during a 12 month period?

0 1 2 3 4 5 6 7 8 or more

At the level of distribution of responses, the distribution of experienced sustained power interruptions is slightly to the left (shifted toward zero) of the distribution of the acceptable sustained power interruptions (Table 3). While 42% of the sample experienced no sustained power interruptions, 32% indicated that that was the only acceptable number of sustained power interruptions. However, 83% of the sample indicated they had experienced 2 or fewer sustained power interruptions and 81% of the sample indicated the acceptable number of sustained power interruptions was 2 or fewer.

Table 3: Experienced and Acceptable Sustained Power Interruptions

	Sustained Power Interruptions			
	Experienced:		Acceptable:	
Number of Sustained Interruptions in 12 months	Respondents	Percent	Respondents	Percent
0	167	41.8%	127	31.8%
1	95	23.8%	106	26.5%
2	69	17.3%	91	22.8%
3	23	5.8%	33	8.3%
4	14	3.5%	11	2.8%
5	7	1.8%	16	4.0%
6	2	0.5%	1	0.3%
7	1	0.3%	0	0.0%
8	1	0.3%	2	0.5%
Don't Know	21	5.3%	13	3.3%
Total	400	100.0%	400	100.0%

Despite the rough proportionality of the experienced and acceptable sustained power interruption distribution, a quarter of respondents (26%) did experience more sustained power interruptions than they found acceptable (Table 4). It should be noted that the greatest percentage of this group (20% of the total sample) only experienced 1 or 2 more sustained power interruptions than they found acceptable.

Table Four: Sustained Power Interruptions, Experienced Number Minus Acceptable Number

Difference between experienced and acceptable sustained power interruptions	Respondents	Percent
7	1	0%
6	0	0%
5	5	1%
4	8	2%
3	8	2%
2	29	8%
1	44	12%
Total experiencing more sustained power interruptions than they regard as acceptable	95	26%
0	122	33%
-1	71	19%
-2	43	12%
-3	20	5%
-4	7	2%
-5	8	2%
Total experiencing fewer or as many sustained power interruptions as they regard as acceptable	271	74%
Total	366	100%

C. Length of Average Power Outages for Sustained Power Interruptions

Respondents who indicated that they had at least 1 sustained power interruption in the last 12 months were asked: *On average, for how long was your power out during the sustained interruptions?*

As a follow-up, all respondents were asked:

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that ***was Not storm related****?*

On average, what would you consider an acceptable amount of time for it to take to restore power to your home during a sustained interruption that ***was Storm related****?*

Table 5 provides information on the mean and median time in hours that business respondents experienced sustained power interruptions for and the mean and median times that respondents found acceptable for losses of power during power interruptions that are not storm related and ones that are storm related.

It should be noted that all of the median values for experienced and acceptable lengths of time are well below the mean values. This is because the distributions cluster closer to zero hours with a relatively long tail. Fifty percent of people had sustained power outages that averaged 2 hours or less per episode. At the same time, fifty percent of people indicated that sustained power interruptions that were not storm related should last 1 hour or less while ones that were storm related should last 4 hours or less.

Table 5: Average and Median Length of Times Experienced and Acceptable for Sustained Power Interruptions

	Average Time Power Out for Sustained Interruptions Experienced in Last 12 Months *	Acceptable Time for Power to Be Out for Sustained Interruption Not Storm Related	Acceptable Time for Power to Be Out for Sustained Interruption that was Storm Related
Mean Hours	5.2	2.4	11.6
Median Hours	2.0	1.0	4.0
Standard Deviation (in Hours)	12.3	5.7	16.7
Range (in Hours)	72.0	72.0	96.0
Minimum Value (in Hours)	.0	.0	.0
Maximum Value (in Hours)	72.0	72.0	96.0
Sample Size	207	379	362

* Asked only of respondents who reported a sustained power interruption

D. Differential between Average Lengths of Experienced Sustained Power Outages And Acceptable Lengths

For the subset of business customers who had experienced a sustained power interruption **and** provide an estimate of the accepted length of time **for a non-storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if non-storm related), (Table 6).

If all sustained power interruptions were non-storm related in the last 12 months than 57% of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. However, it should be noted that for more than half of that group (38% overall), the differential was less than 3 hours.

Table 6: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Non-Storm Related Interruption

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Non-Storm Related	112	57%
> 48 hours	4	2%
24 to 48 hours	4	2%
12 to 23 hours	4	2%
from 6 hours to 12 hours	9	5%
from 3 hours to 6 hours	21	11%
from 1 hour to 3 hours	27	14%
1 hour or less	47	24%
Average Experienced Matched Acceptable	22	11%
Average Experienced Time Less than Acceptable	59	30%
Total	197	100%

For the subset of customers who had experienced a sustained power interruption and provide an estimate of the accepted length of time **for a storm related power interruption**, a calculation can be made of the percent who experienced on average longer sustained power interruptions than were acceptable to them (if storm related), (Table 7, next page).

Not surprising, if all sustained power interruptions were storm related in the last 12 months than only 24% (in contrast to 57% if non-storm related) of those who experienced such interruptions indicated they experience a length of power interruption on average longer than was acceptable. In this case, for a little over half (14%) of that group, the differential was 3 hours or less.

Table 7: Comparison of Average Experienced Time of Sustained Power Interruption to Acceptable Time for Storm Related Interruption

	Respondents	Percent
Average Experienced Sustained Power Interruption Longer than Acceptable for Storm Related	45	24%
> 48 hours	2	1%
24 to 48 hours	3	2%
12 to 23 hours	4	2%
from 6 hours to 12 hours	2	1%
from 3 hours to 6 hours	8	4%
from 1 hour to 3 hours	11	6%
1 hour or less	15	8%
Average Experienced Matched Acceptable	21	11%
Average Experienced Time Less than Acceptable	118	64%
Total	184	100%

E. Importance Ratings for Three Aspects of Power Outages

Next we are going to ask you to rate the importance of reducing each of these 3 aspects of power outages on a 1 to 10 scale where 1 is not at all important and 10 is very important, so... On a 1 to 10 scale where 1 is not at all important and 10 is very important; could you indicate how important it is to you:

to reduce by half the frequency of sustained outages?
to reduce by half the duration of sustained outages?
to reduce by half the number of momentary power outages?

Business Respondents rated Duration of Sustained Interruptions as most important to reduce by half, (Mean Rating 8.3) followed by the Frequency of Sustained Interruptions (Mean Rating 8.1). The Mean Importance rating for reducing by half the number of momentary interruptions was slightly less (7.4).

Table 8: Respondent Ratings of the Importance of Reducing Frequency and Duration of Sustained Interruptions and Number of Momenmtary Interruptions
On a 1 to 10 scale where 1 is Not at all important and 10 is Very Important

	Importance of Reducing:		
	Frequency of Sustained Interruptions	Duration of Sustained Interruptions	Number of Momentary Interruptions
1 Not at all Important	2%	1%	6%
2	2%	1%	2%
3	1%	2%	3%
4	2%	1%	2%
5	13%	12%	15%
6	4%	3%	5%
7	9%	7%	8%
8	14%	15%	14%
9	6%	9%	5%
10 Very Important	47%	48%	40%
Total	100%	100%	100%
Mean Importance Rating	8.1	8.3	7.4
Median Importance Rating	9	9	8
Sample Size	389	394	393

F. Loss Estimates as a Result of Power Outages in Last 12 Months

Respondents who indicated they had suffered a sustained power outage in the last 12 months were asked:

Would you say that you have suffered losses as a result of power outages you have experienced in the last 12 months? Examples of losses might be the cost of spoiled food and damaged electrical appliances.

A substantial minority (39%) of those who had experienced a power interruption in the last 12 months indicated they had suffered losses as a result, (Table 9). This represented 23% of the total business sample.

Table 9: Suffered Losses from Sustained Power Outages This Last 12 Months?

	Respondents	As Percent of Those Having a Sustained Power Outage	As Percent of Total Sample
Have Losses from Power Outage?			
Yes	92	39%	23%
No	141	61%	35%
Number with Power Outage	233	100%	58%
Number without Power Outage	167		42%
Total Sample	400		100%

Table 10: Dollar Value of Losses from Power Outages in Last 12 months

	Respondents	Percent
Under $500	23	29%
$500 to $700	9	11%
$800 to $1,000	14	18%
$1,200 to $2500	14	18%
$2,600 To $5,000	9	11%
$8,000 to $13,400	6	8%
$20,000	1	1%
$40,000	1	1%
$62,000	1	1%
$100,000	1	1%
Total	79	100%
Mean Dollar Losses	$4,649	
Median Dollar Losses	$1,000	

Asked of those who indicated they had dollar losses

Those who indicated they suffered losses were asked: *Please estimate the dollar value of losses you have suffered as a result of power outages in the last 12 months.*

Of the 79 who could provide an estimate of dollar loss, (out of the 92 who indicated they had a dollar loss), 60% had dollar losses of a $1,000 or less. A few participants indicated much more substantial losses with one participant estimating a $62,000 loss and another $100,000.

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J.D. POWER

Press Releases

Overall Satisfaction Is Up and Monthly Bills Down, Yet Electric Providers Still Lag Behind Other Industries in Customer Satisfaction, J.D. Power Study Finds

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Power Reliability Shows Improvement; Communications about Outages Is Key

COSTA MESA, Calif.: 13 July 2016 — Although customer-reported monthly electric bills have fallen to their lowest levels in 10 years and overall satisfaction is on the rise, electric utility providers continue to struggle to match other industries in customer satisfaction, according to the J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study,SM released today.

The study, now in its 18th year, measures customer satisfaction with electric utility companies by examining six factors: power quality & reliability; price; billing & payment; corporate citizenship; communications; and customer service. Satisfaction is calculated on a 1,000-point scale.

Overall satisfaction has improved for the fourth consecutive year, averaging 680, up by 12 points from 2015. However, the industry continues to trail far behind many of the other industries J.D. Power tracks, including auto insurance (averaging 811 in 2016), retail banking (793), and airline (726).[1] In fact, only 11 of the 137 utility brands included the study outperform the airline industry average.

"The lesson that utilities can learn from other high-performing service providers is that to excel you need a culture that puts customers and employees first," said **John Hazen, senior director of the utility practice at J.D. Power**. "And because customer expectations continue to increase, you need to have a mindset of continuous improvement to keep up."

Following are some of the key findings of the study:

- Average monthly bill: Customer-reported monthly electric bills are the lowest in 10 years, averaging $129 in 2016, down from $132 in 2015. Satisfaction in the price factor improves the most this year, increasing by 16 points from 2015.
- Satisfaction by state: Satisfaction is highest among customers in Georgia, Alabama and Oregon, and lowest in West Virginia, Connecticut and New Hampshire.
- Power reliability: The average frequency of brief power interruptions (outages of 5 minutes or less) reported by customers has continued to decline since 2010. Further, 41% of customers experience "perfect power," or no brief or long interruptions, up from 37% in 2010. While lengthy interruptions have remained fairly constant, the length of the longest outage has fallen to an average of 6.4 hours in 2016 from 7.0 hours in 2015.

The study finds that utilities are improving in terms of informing customers about scheduled utility work, with 73% of customers indicating they were notified ahead of time, up from 71% in 2015.

However, only 40% of customers say they were informed about an outage this year, down from 42% in 2015.

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"It's hard to overstate how important consistent and proactive communications are to alleviate the frustration customers feel when they experience any kind of power interruption," said Hazen. "People rely so heavily on electric power, which is why providers are under such intense scrutiny when something goes wrong. Improving the accuracy and the amount of outage information provided to customers requires an investment by providers, but it's one with measurable benefits."

Study Rankings

The Electric Utility Residential Customer Satisfaction Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 100,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers. For the first time, the study also includes a new segment that includes brands serving cooperative residential customers, which were previously included in regional segments.

East Region

PPL Electric Utilities ranks highest among large utilities in the East region for a fifth consecutive year, with a score of 705. PSE&G (690) ranks second, followed by BGE (680), PECO (675) and Con Edison (672).

Among midsize utilities in the East region, Green Mountain Power ranks highest with a score of 681. Following in the rankings are Met-Ed (672), Delmarva Power and Rochester Gas & Electric in a tie (670 each), and Penn Power (664).

Midwest Region

MidAmerican Energy ranks highest in the large utility segment in the Midwest region for a ninth consecutive year, with a score of 713. DTE Energy (703) ranks second, followed by Xcel-Energy Midwest (692) and Alliant Energy and We Energies in a tie (687 each).

Kentucky Utilities ranks highest in the midsize segment in the Midwest region with a score of 712. Following Kentucky Utilities are Otter Tail Power Company (703), Omaha Public Power District (700), Louisville Gas & Electric (696) and Lincoln Electric System (694).

South Region

Florida Power & Light (FPL) ranks highest in the large utility segment in the South region with a score of 724. Following in the rankings are Alabama Power (721), Georgia Power (712), OG&E (711) and CPS Energy and Entergy Arkansas in a tie (707 each).

EPB ranks highest in the midsize utility segment in the South region with a score of 737. Following EPB are Entergy Texas (715), Entergy Mississippi (714) and Gulf Power (711).

West Region

Salt River Project (SRP) ranks highest in the large utility segment in the West region for a 15th consecutive year, with a score of 730. SMUD (719) ranks second, followed by Portland General Electric (710), Pacific Power (698) and APS (691).

Clark Public Utilities ranks highest in the midsize utility segment in the West region for a ninth consecutive year, with a score of 743. Colorado Springs Utilities ranks second (712), followed by Idaho Power (704) and Imperial Irrigation District and Seattle City Light in a tie (699 each).

Cooperatives Segment

SECO Energy ranks highest in the newly designated cooperatives segment with a score of 769. Following SECO Energy are Jackson EMC (763), NOVEC (748), Sawnee EMC (741) and Walton EMC (740).

The 2016 Electric Utility Residential Customer Satisfaction Study is based on responses from 101,138 online interviews conducted July 2015 through May 2016 among residential customers of 137 electric utility brands across the United States, which collectively represent more than 97.7 million households.

For more information about the 2016 Electric Utility Residential Customer Satisfaction Study, visit http://www.jdpower.com/resource/us-electric-utility-residential-customer-satisfaction-study/.

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About J.D. Power and Advertising/Promotional Rules www.jdpower.com/about-us/press-release-info

[1] Sources: J.D. Power 2016 U.S. Auto Insurance Study^{SM}; J.D. Power 2016 U.S. Retail Banking Satisfaction Study^{SM}; and J.D. Power 2016 North America Airline Satisfaction Study^{SM}

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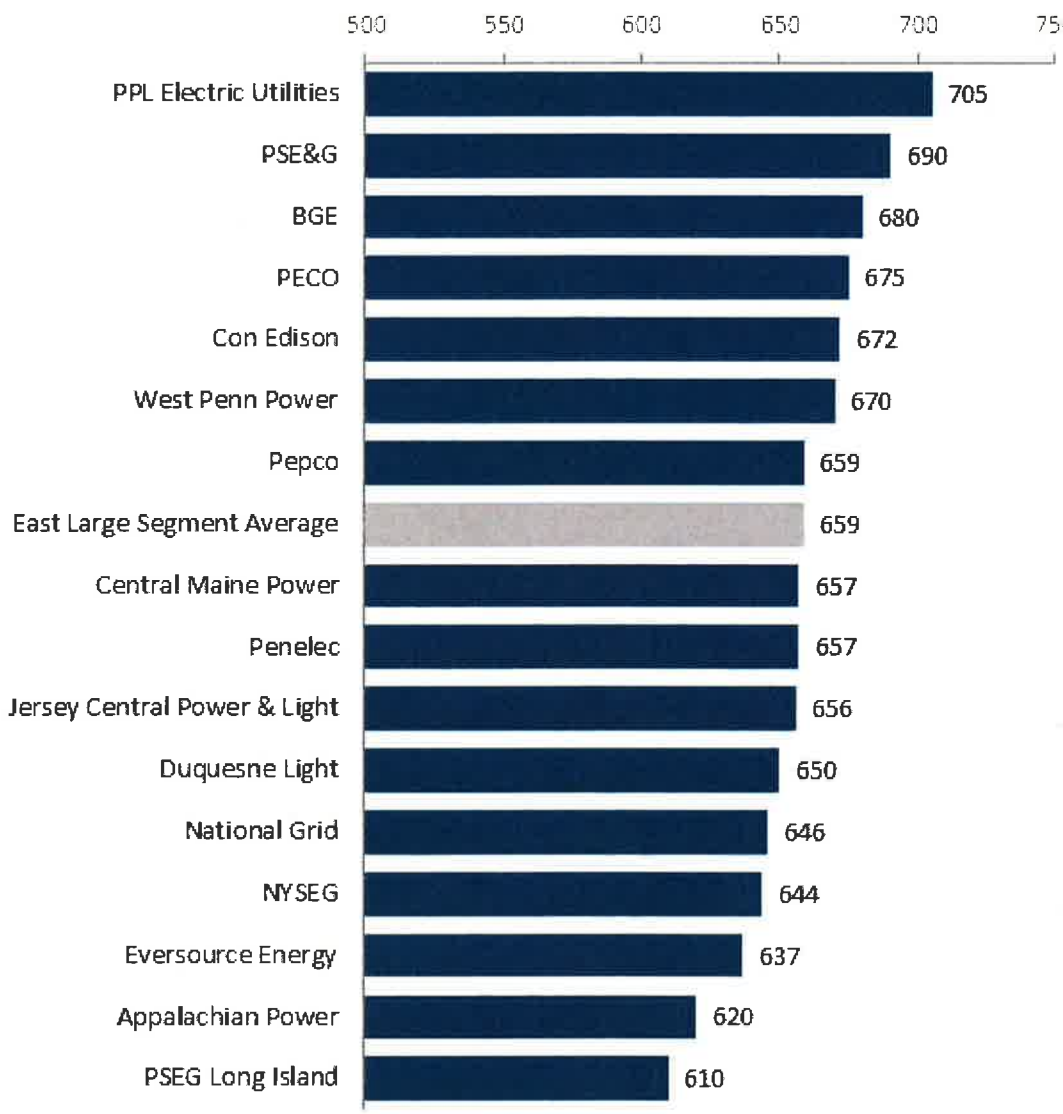
2016 Electric Utility Residential Customer Satisfaction Stuay

East Region: Large Segment
Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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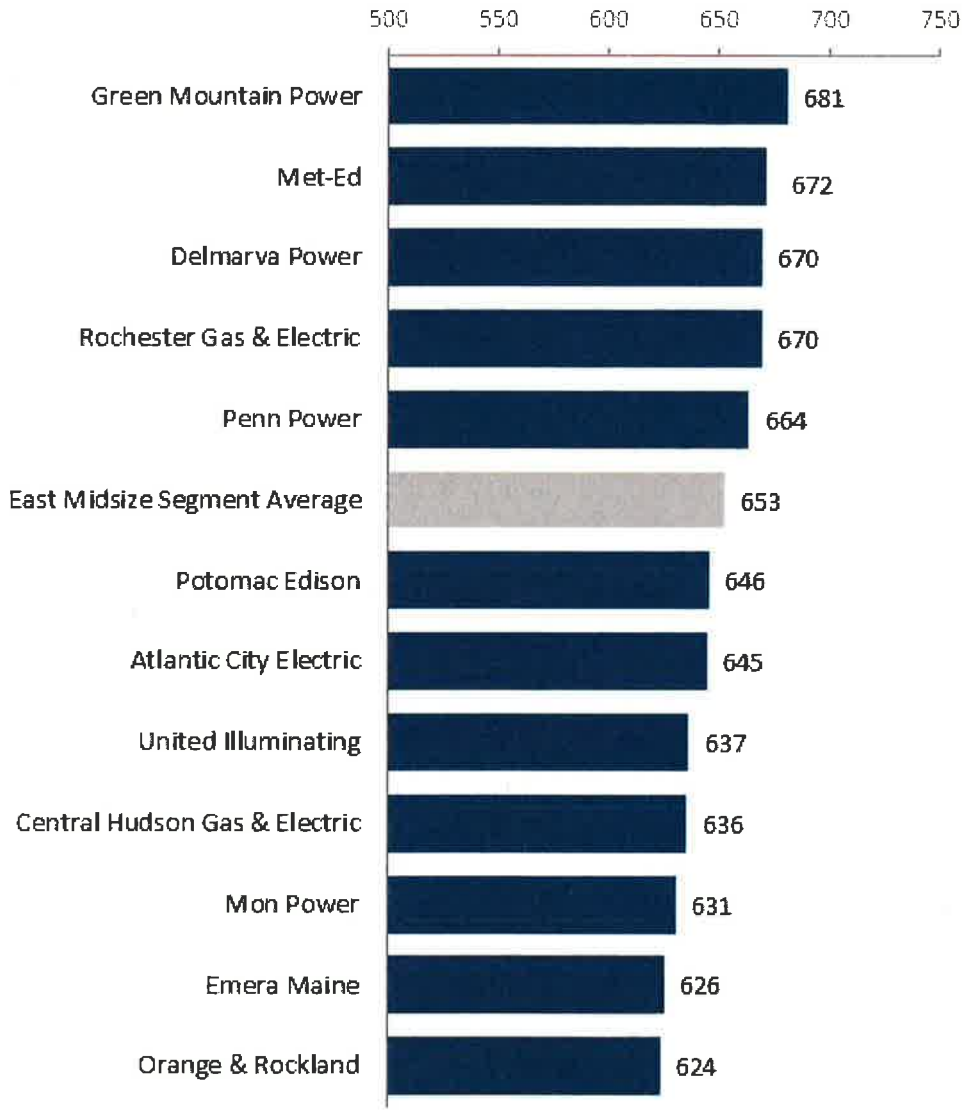
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study

East Region: Midsize Segment Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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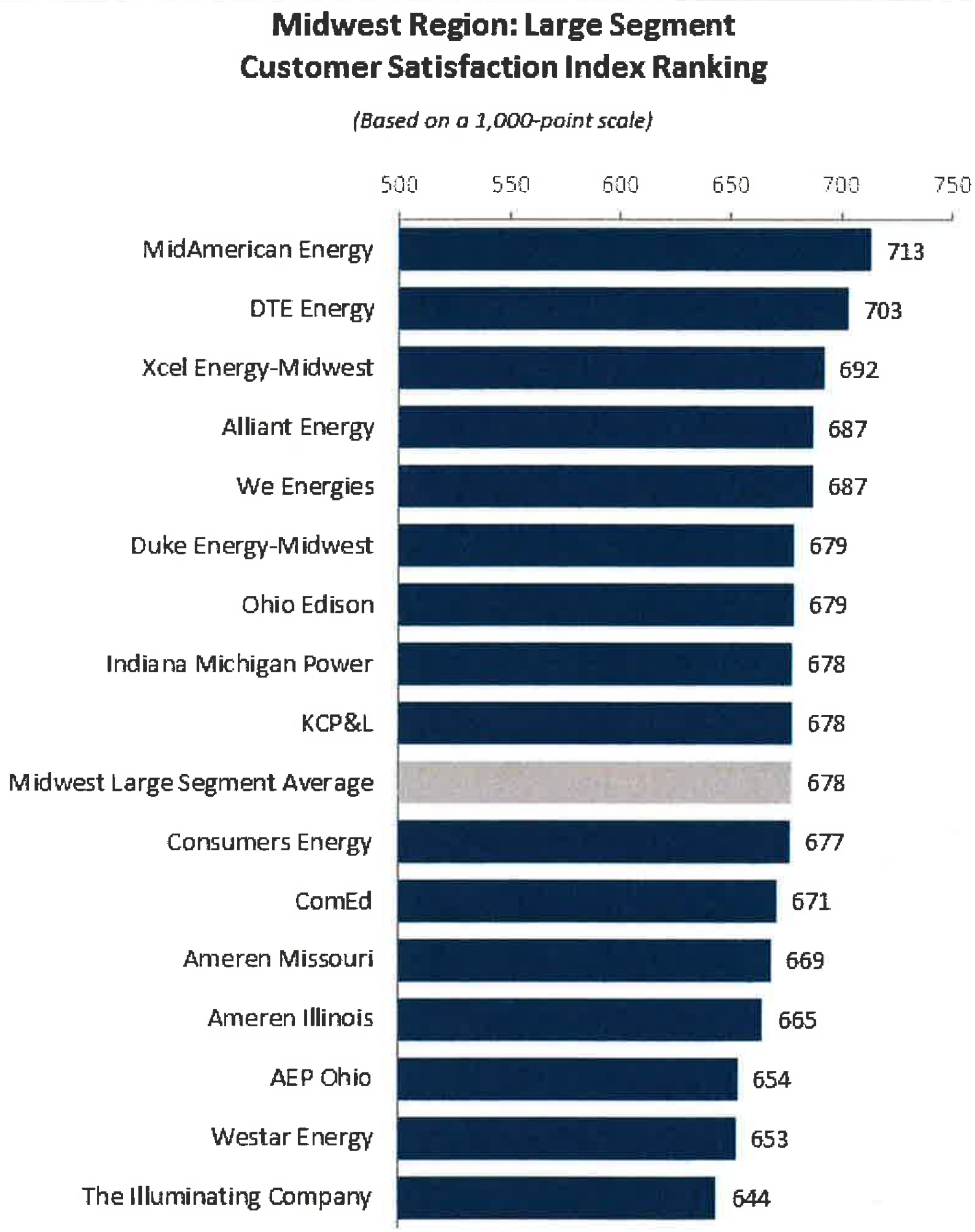
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study℠

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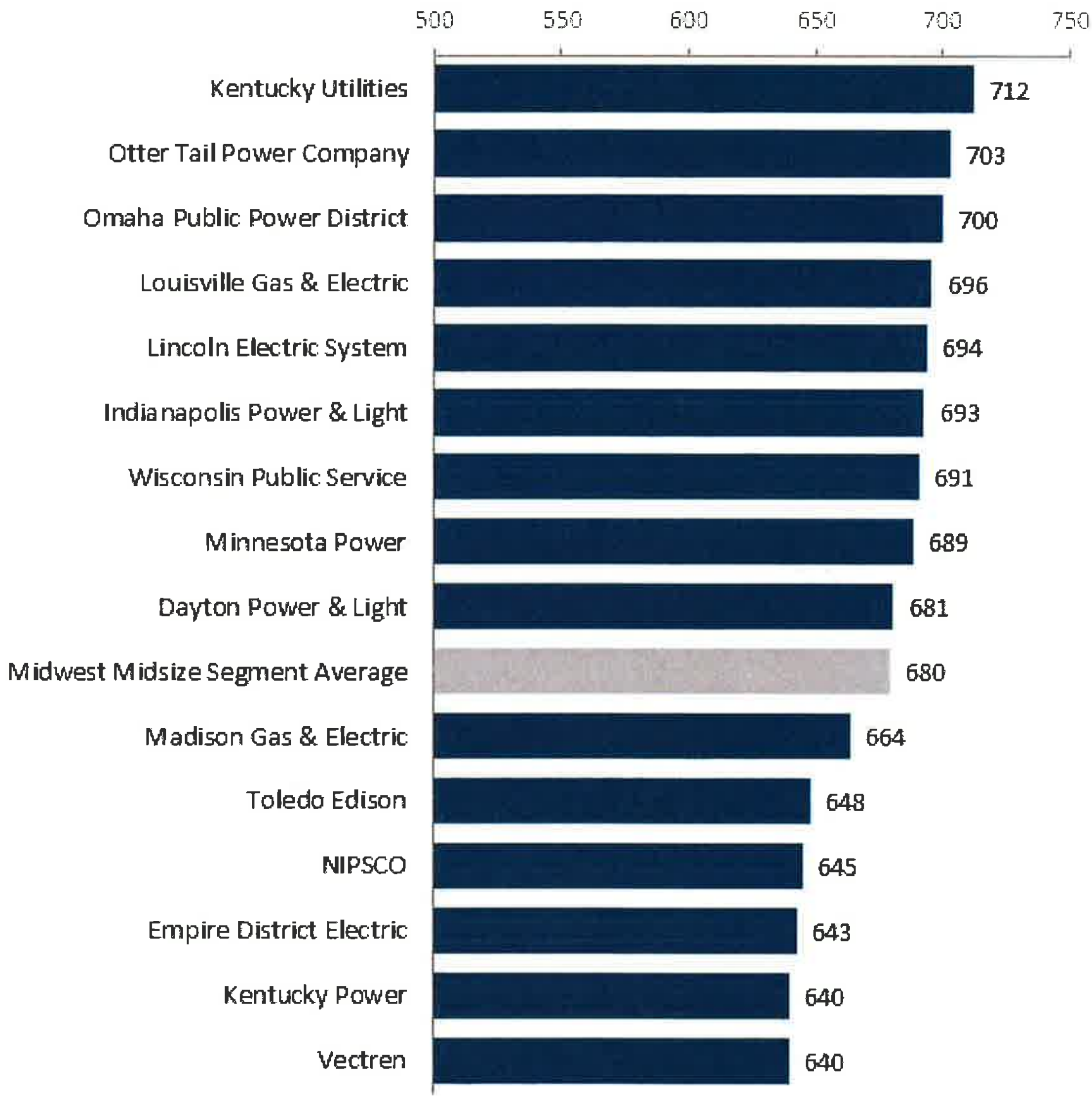
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study

Midwest Region: Midsize Segment Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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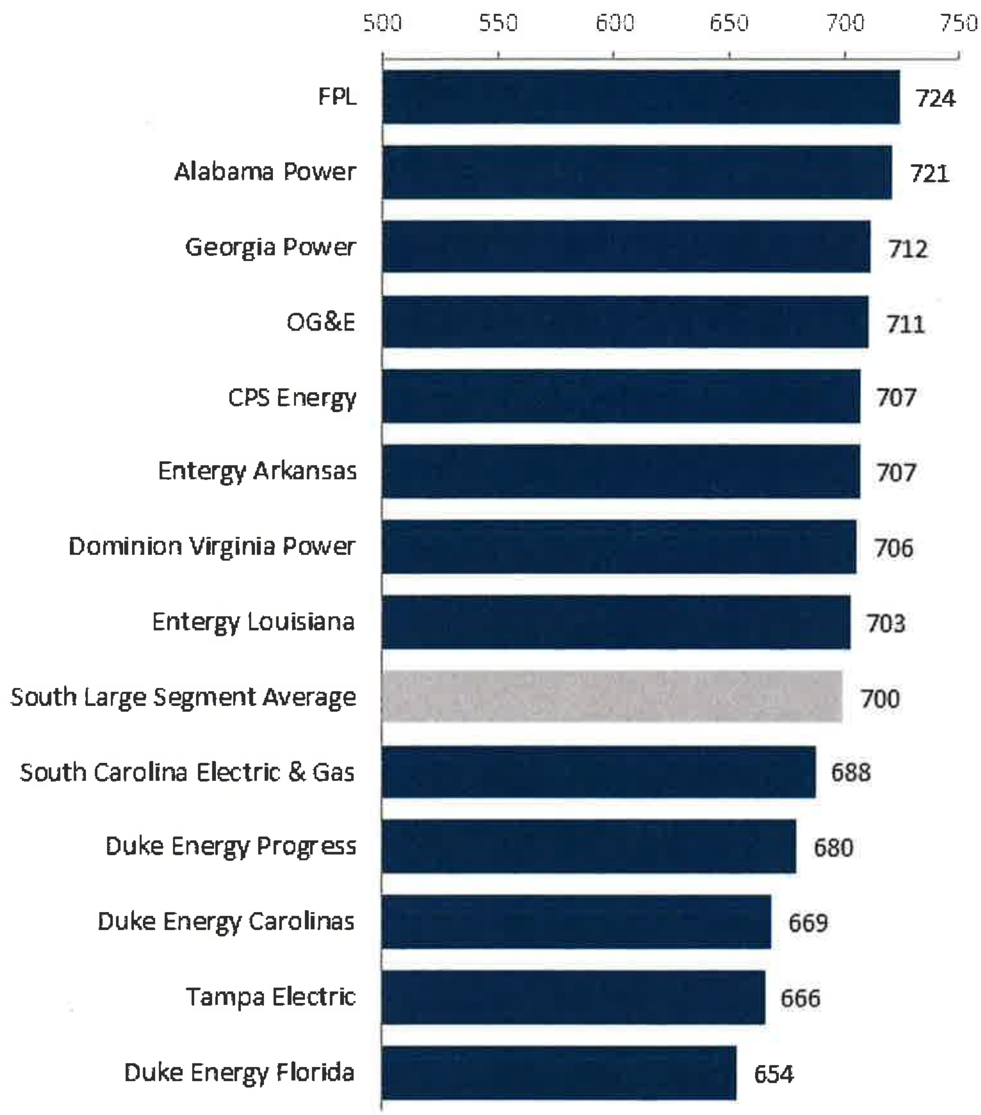
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Stuay

South Region: Large Segment Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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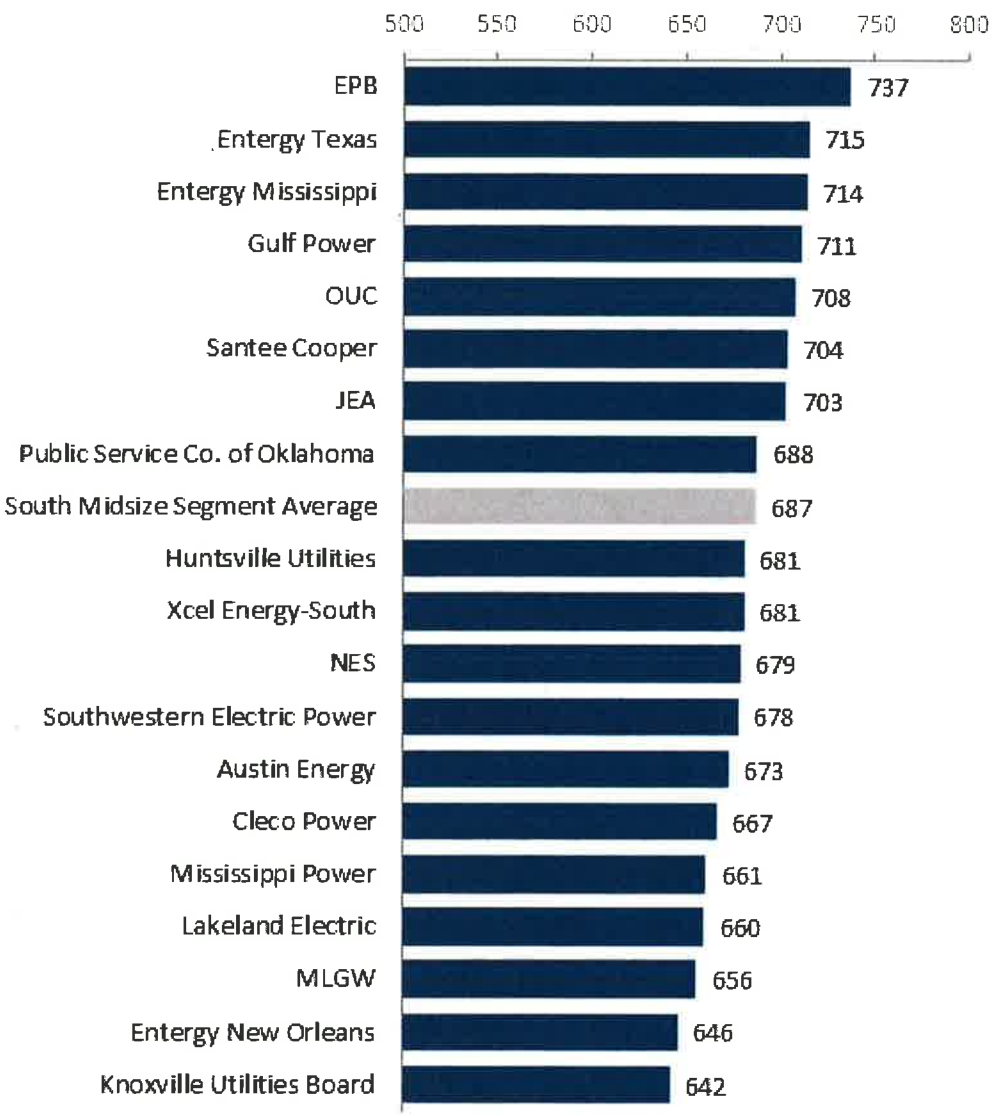
2016 Electric Utility Residential Customer Satisfaction Study

South Region: Midsize Segment
Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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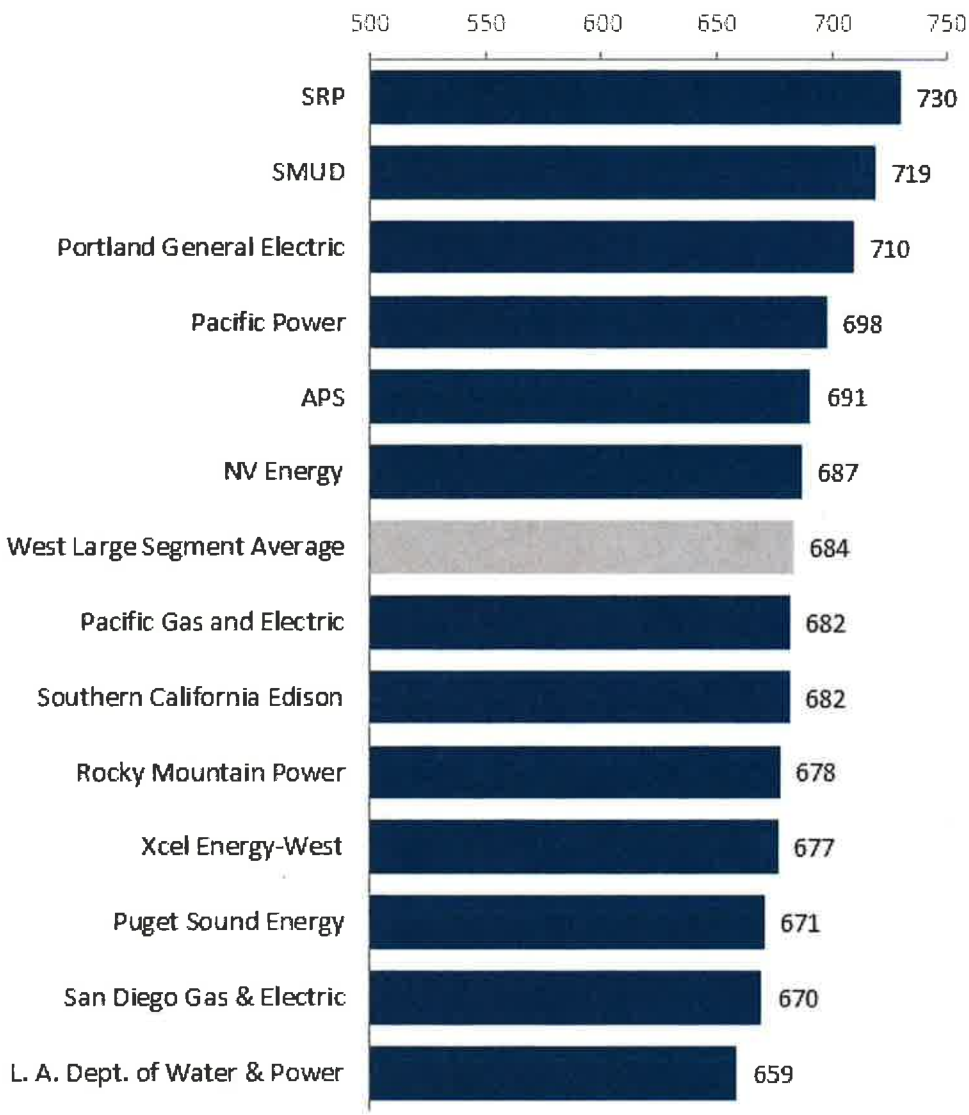
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Stuay

West Region: Large Segment Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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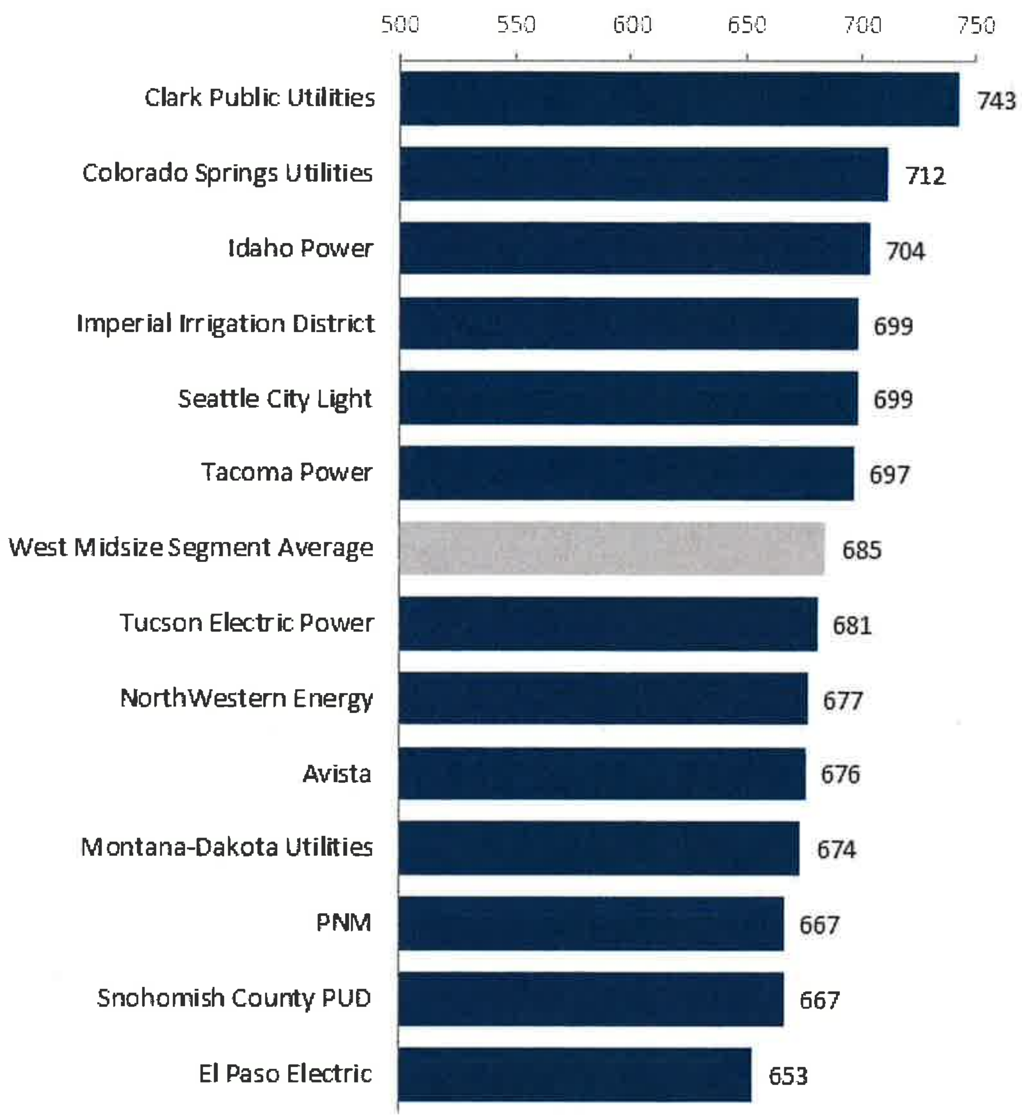
J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study

West Region: Midsize Segment Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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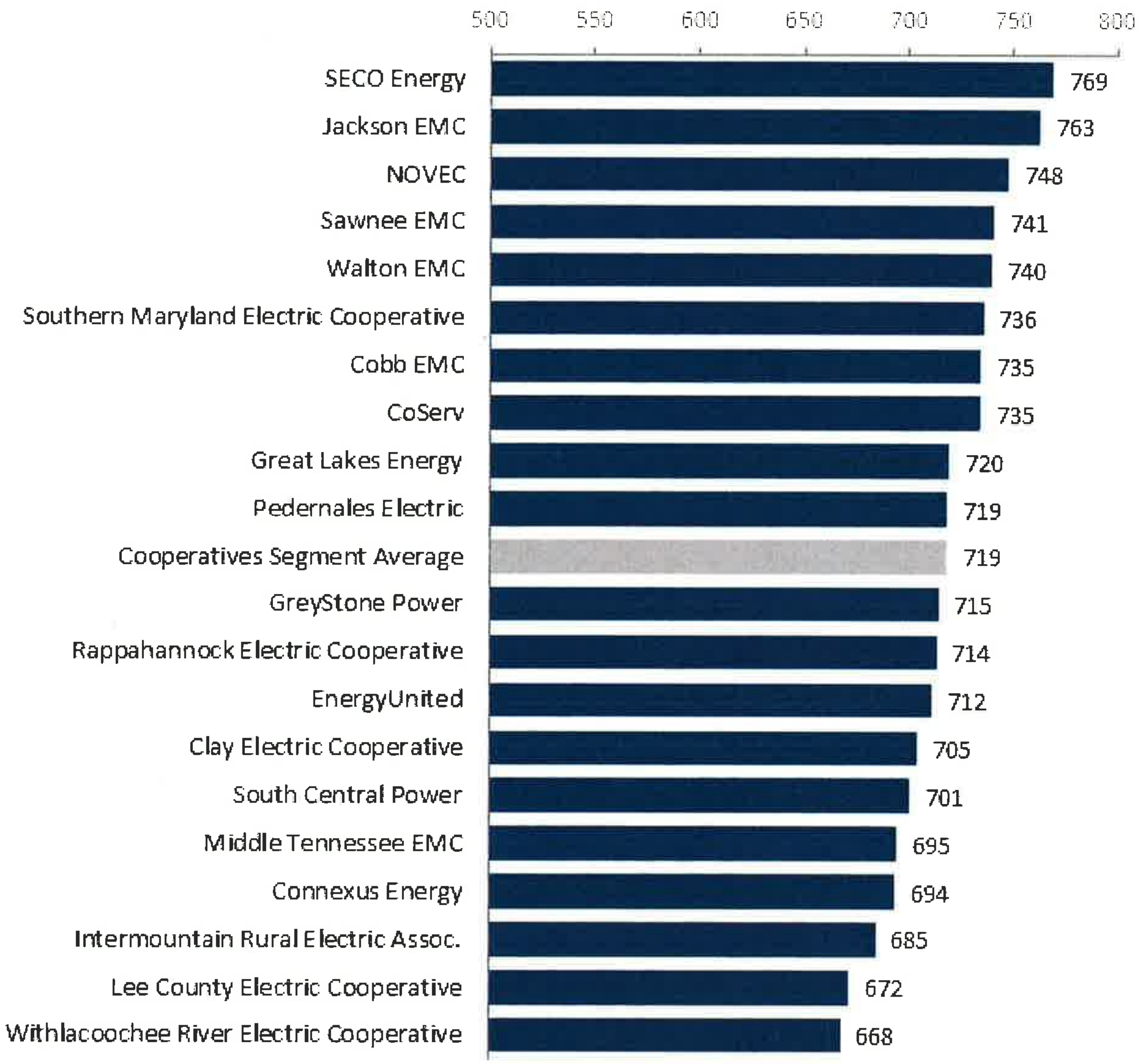
2016 Electric Utility Residential Customer Satisfaction Study

Cooperatives Segment
Customer Satisfaction Index Ranking

(Based on a 1,000-point scale)



Source: J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study[SM]

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