I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
A. My name is Steven M. Fetter. My business address is 1240 West Sims Way, Port Townsend, Washington 98368.

Q. ON WHOSE BEHALF ARE YOU PROVIDING DIRECT TESTIMONY?
A. I am testifying on behalf of AEP Texas Inc. (AEP Texas or Company).

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?
A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. (Fitch), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission (Michigan PSC).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.
A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. PLEASE DESCRIBE YOUR SERVICE ON THE MICHIGAN PUBLIC SERVICE COMMISSION.
A. I was appointed as a Commissioner to the three-member Michigan PSC in October 1987 by Democratic Governor James Blanchard. In January 1991, I was promoted to Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993. During my tenure as Chairman, timeliness of commission processes was a major focus and my colleagues and I achieved the goal of eliminating the agency's
case backlog for the first time in 23 years. While on the Michigan PSC, I also served as Chairman of the Board of the National Regulatory Research Institute (NRRI), the research arm of the National Association of Regulatory Utility Commissioners, which was then located at The Ohio State University. After leaving regulatory service, I was appointed to the NRRI Board as a public member.

Q. WHAT WAS YOUR ROLE IN YOUR EMPLOYMENT WITH FITCH?
A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

Q. HOW LONG WERE YOU EMPLOYED BY FITCH?
A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

Q. PLEASE DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UNFETTERED.
A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients have included investor-owned and municipal electric, natural gas and water utilities, state public utility...
commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. HOW DOES YOUR EXPERIENCE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience as Chairman and Commissioner on the Michigan PSC and my subsequent professional experience with financial analysis and ratings of the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role vis-à-vis regulated utilities, both in setting their rates as well as the appropriate terms and conditions for the service they provide.

In addition, for almost 20 years I have served as a member of the Wall Street Utility Group, an organization comprised of debt and equity analysts assigned to cover and make recommendations on companies within the utility sector.

Q. HAVE YOU PREVIOUSLY GIVEN TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, federal district and bankruptcy courts, and various state and provincial legislative, judicial, and regulatory bodies in more than 100 proceedings or hearings on the subjects of credit risk and cost of capital within the utility sector, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, regulated utility mergers and acquisitions, construction work in progress and other interim rate recovery structures,
utility securitization bonds, and nuclear energy. I have previously filed testimony
before the Public Utility Commission of Texas (PUC or Commission) on behalf of:

- Entergy Gulf States, Inc. (in Docket Nos. 30123, 32907 and 33687);
- TXU Corp./Oncor Electric Delivery Co./Texas Energy Future Holdings
  Limited (in Docket No. 34077);
- Entergy Texas Inc. (in Docket No. 34800);
- Southwestern Electric Power Co. (in Docket No. 37364); and
- Gexa Energy (in Docket No. 45188 involving Oncor Electric Delivery,
  Ovation Acquisition, and Shary Holdings).

My full educational and professional background is presented in
EXHIBIT SMF-1.

II. PURPOSE OF TESTIMONY

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

A. AEP Texas has asked me to review its filing related to AEP Texas’ capital structure
and, utilizing my past experience as a state utility commission chairman, head of a
major utility credit rating practice, and utility consultant to regulated utilities, utility
commissions, and consumer advocates, offer an opinion as to whether Commission
approval of the Company’s proposed capital structure comprised of 55% debt and
45% equity, as part of its overall decision in this rate case, aligns with the public
interest in Texas.
Q. WHAT DID YOU CONCLUDE?

A. In reviewing the Company’s proposal, I focused on the following factors:

- Commission approval of AEP Texas’ proposed 45% equity component would be consistent with recently-set distribution utility authorized equity levels across the U.S., though I note that the Company’s level would still be near the bottom end;

- Commission support for the Company’s overall rate case filing, including the proposed capital structure, should allow AEP Texas to maintain its current credit ratings, with the potential that over time both ratings could be in “A” category; and

- In the absence of abuse or other imprudent behavior, during my time as a regulator, I sought to be supportive of utility managerial decision-making that fell within a reasonable range of alternatives.

Accordingly, I conclude that AEP Texas’ proposed capital structure of 55% debt and 45% equity is consistent with the public interest and should be approved.

III. CREDIT RATINGS AND THEIR IMPORTANCE TO REGULATED UTILITIES

Q. YOU HIGHLIGHT CREDIT RATINGS ABOVE. COULD YOU EXPLAIN WHAT A CREDIT RATING IS AND WHY IT IS IMPORTANT?

A. A credit rating reflects an independent judgment of the general creditworthiness of an obligor or of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company.

Credit rating determinations are made by credit rating agencies through a committee process involving individuals with knowledge of a company, its industry,
and its regulatory environment. Corporate rating designations of Standard and Poor's (S&P) and Fitch have 'AAA', 'AA', 'A' and 'BBB' category ratings within the investment-grade ratings sphere, with 'BBB-' as the lowest investment-grade rating and 'BB+' as the highest non-investment-grade rating. Comparable rating designations of Moody's Investors Service (Moody's) at the investment-grade dividing line are 'Baa3' and 'Ba1', respectively. The following chart illustrates the comparability of ratings between the three agencies.

**CHART 1**

**Ratings Categories – Comparability Between Agencies**

<table>
<thead>
<tr>
<th>Investment Grade</th>
<th>S&amp;P and Fitch</th>
<th>Moody's</th>
</tr>
</thead>
<tbody>
<tr>
<td>AAA</td>
<td>Aaa</td>
<td></td>
</tr>
<tr>
<td>AA+</td>
<td>Aa1</td>
<td></td>
</tr>
<tr>
<td>AA</td>
<td>Aa2</td>
<td></td>
</tr>
<tr>
<td>AA-</td>
<td>Aa3</td>
<td></td>
</tr>
<tr>
<td>A+</td>
<td>A1</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>A2</td>
<td></td>
</tr>
<tr>
<td>A- (1)</td>
<td>A3</td>
<td></td>
</tr>
<tr>
<td>BBB+</td>
<td>Baa1 (2)</td>
<td></td>
</tr>
<tr>
<td>BBB</td>
<td>Baa2</td>
<td></td>
</tr>
<tr>
<td>BBB-</td>
<td>Baa3</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Below Investment Grade</th>
<th>S&amp;P and Fitch</th>
<th>Moody's</th>
</tr>
</thead>
<tbody>
<tr>
<td>BB+</td>
<td>Ba1</td>
<td></td>
</tr>
<tr>
<td>BB</td>
<td>Ba2</td>
<td></td>
</tr>
<tr>
<td>BB-</td>
<td>Ba3</td>
<td></td>
</tr>
<tr>
<td>B+</td>
<td>B1</td>
<td></td>
</tr>
<tr>
<td>B</td>
<td>B2</td>
<td></td>
</tr>
<tr>
<td>B-</td>
<td>B3</td>
<td></td>
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<td>CCC</td>
<td>Caa</td>
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<tr>
<td>CC</td>
<td>Ca</td>
<td></td>
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<tr>
<td>C</td>
<td>C</td>
<td></td>
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<tr>
<td>D</td>
<td>[C]</td>
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</tr>
</tbody>
</table>

Corporate credit rating analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income debt issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be

1 AEP Texas corporate rating from S&P with a Stable outlook.
2 AEP Texas corporate rating from Moody's with a Stable outlook.
used by contractual counterparties to gauge both the short-term and longer-term
financial health and viability of a company, including decisions related to required
collateral levels, with higher-rated entities facing lower requirements.

Q. WHY ARE CREDIT RATINGS IMPORTANT FOR REGULATED UTILITIES
AND THEIR CUSTOMERS?

A. A utility’s credit ratings have a significant impact on its ability to raise capital on a
timely basis and upon reasonable terms. As economist Charles F. Phillips states in
his treatise on utility regulation, which is a widely-respected and reliable authority on
utility regulatory frameworks and policies, especially those related to financial issues:

Bond ratings are important for at least four reasons: (1) they are used
by investors in determining the quality of debt investment; (2) they are
used in determining the breadth of the market, since some large
institutional investors are prohibited from investing in the lower
grades; (3) they determine, in part, the cost of new debt, since both the
interest charges on new debt and the degree of difficulty in marketing
new issues tend to rise as the rating decreases; and (4) they have an
indirect bearing on the status of a utility’s stock and on its acceptance
in the market.\(^3\)

I particularly agree with Dr. Phillips on his observation that a credit rating
helps drive a utility’s debt costs. Thus, a utility with strong credit ratings is not only
able to access the capital markets on a timely basis at reasonable rates, it is also able
to share the benefit from those attractive interest rate levels with customers since cost

\(^3\) Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia: Public Utilities Reports,
Reports, Inc., 2004 at pp. 6-7 (“Generally, the higher the rating of the bond, the better the access to capital
markets and the lower the interest to be paid.”).
of capital is factored into customer rates. Conversely, but of equal importance, the lower a utility’s credit rating, the more the utility must pay to raise funds from debt and equity investors to carry out its capital-intensive operations, which results in higher costs included in customer rates.

Q. WHAT CREDIT RATINGS DOES AEP TEXAS NOW HOLD?

A. As noted on the chart above, the Company currently holds corporate credit ratings of “A-” with a Stable outlook from S&P, and “Baa1” with a Stable outlook from Moody’s.

Q. HOW DO YOU VIEW THOSE RATINGS?

A. I view the Company’s ratings as relatively strong. I have long advocated that regulated utilities should endeavor to have ratings no lower than “BBB+” / “Baa1” with a longer term goal of achieving “A” category status for all of their ratings.

Q. WHY IS THAT?

A. I believe that while ratings at the “BBB+” level provide substantial protection related to financing in the case of a major downturn in the economy or unrest in the capital markets, one step higher into the “A” category creates a situation where I cannot imagine that funding would ever be restricted in the face of severe financial or operational duress. The example that brought me to that opinion relates to Consolidated Edison of New York (Con Ed) and its response to September 11. At the time, Con Ed held two “A” category ratings. After that tragedy, Con Ed was able to immediately begin one of the largest remedial infrastructure recoveries in utility history, with no financial limitations on its ability to do so.
Q. WOULD AUTHORIZATION OF THE 45% EQUITY LEVEL HELP IMPROVE AEP TEXAS' CREDIT RATINGS?

A. Interestingly, not immediately, because the Company has been managing its equity capitalization at approximately the 45% level in order to maintain its current ratings. If it were to lower its equity to match the current authorization, its financial profile would weaken and the potential for a negative outlook or rating action would outweigh potential upside results. As noted by Moody's in its recent report on the Company, "When compared to other electric utilities nationwide however, AEP Texas has a lower allowed equity cushion within its capital structure (60/40 debt to equity)." 

Q. COULD YOU PROVIDE BACKGROUND INFORMATION ABOUT MOODY'S STATEMENT THAT THE COMPANY'S AUTHORIZED EQUITY IS LOWER THAN OTHER ELECTRIC UTILITIES ACROSS THE U.S.?

A. Yes. Following upon that reference, I researched recent electric rate case decisions across the U.S. to compare them to both AEP Texas' current authorized level of 40%, as well as the proposed 45% level which tracks the amount of equity the Company has been maintaining. Chart 2 shows the authorized equity levels decided for electric distribution utilities during 2018, as compared to AEP Texas' situation.

---

## CHART 2

Electric Distribution Rate Case Decisions – 2018

<table>
<thead>
<tr>
<th>Regulated Utility</th>
<th>Equity/Capitalization (%)</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>UGI Utilities (PA)</td>
<td>54.02</td>
<td>10/04/18</td>
</tr>
<tr>
<td>Public Service Electric Gas (NJ)</td>
<td>54.00</td>
<td>10/29/18</td>
</tr>
<tr>
<td>Connecticut Light &amp; Power</td>
<td>53.00</td>
<td>04/18/18</td>
</tr>
<tr>
<td>Narragansett Electric (RI)</td>
<td>50.95</td>
<td>08/24/18</td>
</tr>
<tr>
<td>Duke Energy Ohio</td>
<td>50.75</td>
<td>12/19/18</td>
</tr>
<tr>
<td>Delmarva Power &amp; Light (DE)</td>
<td>50.52</td>
<td>08/08/18</td>
</tr>
<tr>
<td>Potomac Electric Power (MD)</td>
<td>50.44</td>
<td>05/31/18</td>
</tr>
<tr>
<td>Potomac Electric Power (DC)</td>
<td>50.44</td>
<td>08/08/18</td>
</tr>
<tr>
<td>Ameren Illinois</td>
<td>50.00</td>
<td>11/01/18</td>
</tr>
<tr>
<td>Green Mountain Power (VT)</td>
<td>49.85</td>
<td>12/21/18</td>
</tr>
<tr>
<td>Emera Maine</td>
<td>49.00</td>
<td>06/28/18</td>
</tr>
<tr>
<td>Niagara Mohawk Power (NY)</td>
<td>48.00</td>
<td>03/15/18</td>
</tr>
<tr>
<td>Central Hudson Gas &amp; Electric (NY)</td>
<td>48.00</td>
<td>06/14/18</td>
</tr>
<tr>
<td>Dayton Power &amp; Light (OH)</td>
<td>47.52</td>
<td>09/26/18</td>
</tr>
<tr>
<td>Commonwealth Edison (IL)</td>
<td>47.11</td>
<td>12/04/18</td>
</tr>
<tr>
<td><strong>AEP TEXAS PROPOSED EQUITY</strong></td>
<td><strong>45.00</strong></td>
<td></td>
</tr>
<tr>
<td>Texas-New Mexico Power (TX)</td>
<td>45.00</td>
<td>12/20/18</td>
</tr>
<tr>
<td><strong>AEP TEXAS AUTHORIZED EQUITY</strong></td>
<td><strong>40.00</strong></td>
<td></td>
</tr>
</tbody>
</table>

2018 Equity/Capitalization:

Average = 49.91% / Median = 50.00% – 50.44%

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5 Source: Regulatory Research Associates
As can be seen, the Company's current 40% equity authorization would fall well below the lowest decided result of 45%, and also that what is proposed in this case would match that lowest result. Notwithstanding that each state operates under its own legal framework and that risk and opportunity varies from jurisdiction to jurisdiction, the average figure of 49.91% and median of approximately 50.22% indicates that it would be difficult to argue that the 45% equity component of the capitalization proposed in this case would fall into the category of being an unreasonable request.

Q. WITH THOSE RESULTS, DID YOU DO ANY FURTHER ANALYSIS OF THE EXPERIENCE IN OTHER STATES?

A. Yes I did. With such a starkly positive result vis-à-vis the capitalization proposed in this case, I wanted to make sure that 2018 did not just represent an outlier year. Accordingly, I carried out the same analysis for 2017. As can be seen in Chart 3, the results were similarly positive, with the average and median just a small amount lower than in 2018.
<table>
<thead>
<tr>
<th>Regulated Utility</th>
<th>Equity/Capitalization (%)</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Western Massachusetts</td>
<td>54.51</td>
<td>11/30/17</td>
</tr>
<tr>
<td>NSTAR Electric (MA)</td>
<td>53.34</td>
<td>11/30/17</td>
</tr>
<tr>
<td>Unitil Energy Systems (NH)</td>
<td>50.97</td>
<td>04/20/17</td>
</tr>
<tr>
<td>Atlantic City Electric (NJ)</td>
<td>50.47</td>
<td>09/22/17</td>
</tr>
<tr>
<td>Potomac Electric Power (MD)</td>
<td>50.15</td>
<td>10/20/17</td>
</tr>
<tr>
<td>Liberty Utilities Granite State (NH)</td>
<td>50.00</td>
<td>04/12/17</td>
</tr>
<tr>
<td>Ameren Illinois</td>
<td>50.00</td>
<td>12/06/17</td>
</tr>
<tr>
<td>Rockland Electric (NJ)</td>
<td>49.70</td>
<td>02/22/17</td>
</tr>
<tr>
<td>Potomac Electric Power (DC)</td>
<td>49.14</td>
<td>07/24/17</td>
</tr>
<tr>
<td>Delmarva Power &amp; Light (MD)</td>
<td>49.10</td>
<td>02/15/17</td>
</tr>
<tr>
<td>Consolidated Edison of New York</td>
<td>48.00</td>
<td>01/24/17</td>
</tr>
<tr>
<td>Commonwealth Edison (IL)</td>
<td>45.89</td>
<td>12/06/17</td>
</tr>
</tbody>
</table>

**AEP TEXAS PROPOSED EQUITY** 45.00

**AEP TEXAS AUTHORIZED EQUITY** 40.00

**2017 Equity/Capitalization:**

Average = 49.52% / Median = 50.00%

---

6 Source: Regulatory Research Associates
Q. WITH YOUR PAST HISTORY OF SERVING AS A STATE UTILITY CHAIRMAN, HOW DO YOU VIEW THESE RESULTS FROM LITIGATED AND SETTLED COMMISSION RATE CASE PROCEEDINGS?

A. While serving first as a commissioner and later as chairman, I gave deference to utility managerial decision-making if the actions proved to be both prudent and within a reasonable range of behavior. Acknowledging that conditions differ between jurisdictions, the data I see above is so strongly probative as to lead me to conclude that Commission authorization of a capital structure including 45% equity would be reasonable, especially since it is clear that the Company’s maintenance of that level on a voluntary basis has been a positive financial factor for both customers and investors.

IV. CONCLUSION

Q. DO YOU HAVE CONCLUDING THOUGHTS?

A. Yes I do. Regulatory decision-making calls for a careful weighing of facts and law, the assessment of risks, and the setting of a fair risk-adjusted return on investment. In this case, AEP Texas’ proposed 45% equity component has already been “field-tested” in that the Company has maintained that level, notwithstanding that its rates are currently set consistent with equity authorized at the 40% level. The result has been a relatively strong credit profile with ratings of “Baa1” and “A-” – to the benefit of both customers and investors. Acceptance of the proposed 45% figure should ensure continuation of the Company’s current actual capitalization, and would
indicate to investors the type of sustained regulatory support that attracts them to provide funding to Texas’ regulated utilities when needed. Further, as a former regulator, I would view with favor a Commission finding that the Company’s managerial decision-making and actions regarding capitalization have been reasonable and thus should be reflected in rates. For all of these reasons, I strongly recommend that the Commission authorize equity at the 45% level within its overall decision in this rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.
STEVEN M. FETTER
1240 West Sims Way
Port Townsend, WA 98368
732-693-2349
RegUnF@gmail.com
www.RegUnF.com

Education  University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. Media (Communications) 1974

April 2002 – Present
President - Regulation UnFettered- Port Townsend, Washington
Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; skills training in ethics, negotiation, and management efficiency.

Service on Boards of Directors of: Central Hudson (Fortis Inc. subsidiary) (Chairman, Governance and Human Resources Committee); and Previously CH Energy Group (Lead Independent Director; Chairman, Audit Committee, Compensation Committee, and Governance and Nominating Committee); National Regulatory Research Institute (Chairman); Keystone Energy Board; and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York / Chicago
Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

Led an effort to restructure the global power group that in three years’ time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial
deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.


March 1994 – April 2002

Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993

Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan’s public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of
management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University’s Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987

**Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC**

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (*U.S. Labor Law and the Future of Labor-Management Cooperation*, w/S. Schlossberg, 1986).

January 1983 - August 1985

**Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing**

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.
March 1982 - January 1983

**Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing**

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982

**Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC**

**Other Significant Speeches and Publications**

Filing for Bankruptcy Isn’t the Right Solution for Puerto Rico (Forbes Online, November 2015)

The “A” Rating (Edison Electric Institute Perspectives, May/June 2009)

Perspective: Don’t Fence Me Out (Public Utilities Fortnightly, October 2004)


Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)

The Feds Can Lead…By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)

Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF
AEP TEXAS INC.
FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF
THOMAS M. COAD
FOR
AEP TEXAS INC.

MAY 2019
# TESTIMONY INDEX

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas M. Coad. My business address is 539 N. Carancahua, Corpus Christi, Texas 78401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President of Distribution Operations for AEP Texas Inc. (AEP Texas or the Company). AEP Texas is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP Texas is headquartered in Corpus Christi, Texas.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF DISTRIBUTION OPERATIONS FOR AEP TEXAS?

A. I am responsible for overseeing the planning, construction, operation, and maintenance of the AEP Texas distribution system. My duties include the oversight and management of service extensions to new customers, distribution capacity additions, the safe and reliable delivery of service to customers, and restoring service when outages occur. My responsibilities also include overseeing AEP Texas' distribution asset management and major reliability programs, system planning programs, employee and contractor safety performance as well as the distribution system vegetation management program. In my testimony, when the term customer is used, I am referring to the end-use customer.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I graduated from The Ohio State University with a Bachelor of Science degree in Electrical Engineering in 1986. I also have a Bachelor of Arts degree in Anthropology.
from The Ohio University. My electric utility career spans thirty years. I began my
career with the Ohio Edison Company, currently known as FirstEnergy, in 1986 as a
distribution engineer. In 1988, I accepted a position as a planning engineer from
Columbus Southern Power, a unit of AEP. During the period from 1988 to 2003, I held
a variety of engineering and supervisory positions. In 2003, I relocated to Texas to
serve as the Manager of Distribution Systems in Laredo, Texas for the Laredo District
of AEP Texas. In 2010, I transferred to the Rio Grande Valley to serve as the Manager
of Distribution Systems for the Rio Grande Valley District. I assumed my current
position, Vice President of Regional Distribution Operations of AEP Texas, on August
15, 2015.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY?

A. Yes. I have previously provided testimony before the Public Utility Commission of
Texas (PUC or Commission) in prior AEP Texas Distribution Cost Recovery Factor
(DCRF) proceedings, Docket Nos. 45787, 45788, 47015, and 48222. I also provided
testimony in Docket No. 46050, Application of AEP Texas Central Company, AEP
Texas North Company and AEP Utilities, Inc. for Approval of Merger; Docket No.
48577, Application of AEP Texas Inc. for Determination of System Restoration Costs;
and Docket No. 49402, Joint Report and Application of AEP Texas Inc. and Oncor
Electric Delivery Company LLC for Approval of Transfer of Facilities, Transfer of
Rights Under and Amendment of Certificates of Convenience and Necessity, and for
Other Approvals.
II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

• provide an overview of AEP Texas’ service territory, its distribution system, and the distribution organization;
• explain the importance of the distribution system in providing reliable electric services to the Company’s customers;
• discuss the programs required to maintain and enhance the reliability of the distribution system and support AEP Texas’ reliability and quality of service performance during the test year;
• present AEP Texas’ proposal for additional distribution spend above the test year distribution operation and maintenance (O&M) expense to enable the Company to increase vegetation management activities;
• address the reasonableness of test year O&M expenses, including affiliate expenses; and
• support the prudence and reasonableness of distribution capital additions placed in service since the last rate case.

III. OVERVIEW OF THE AEP TEXAS SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Q. PLEASE DESCRIBE THE AEP TEXAS SERVICE TERRITORY.

A. AEP Texas spans 97,000 square miles or roughly 36 percent of Texas. From the north near the Texas Panhandle and the Oklahoma border, AEP Texas’ service territory extends more than 700 miles to reach its southern tip, South Padre Island, Texas. In addition, the service territory covers more than 600 miles from Corpus Christi on the Gulf Coast to Presidio in far west Texas. Notably, AEP Texas has the largest amount of coastal exposure, 240 miles, of any utility in the state. Customer density as well as customer growth varies significantly across the AEP Texas service territory.

Please refer to EXHIBIT TMC-1 for a map of the AEP Texas service territory.
Q. PLEASE DESCRIBE THE AEP TEXAS DISTRIBUTION SYSTEM.

A. AEP Texas' Distribution Operations organization oversees the safe and reliable delivery of electric service to homes, businesses, and industry across its service territory in south and west Texas. Specifically, AEP Texas provides wires services to slightly over 1 million homes, businesses, and industries located in nearly 375 communities in all or parts of 92 counties in the south and west Texas regions. AEP Texas' distribution system includes approximately 43,000 miles of overhead and underground primary and secondary line types.

IV. AEP TEXAS DISTRIBUTION OPERATIONS ORGANIZATION

Q. PLEASE DESCRIBE THE AEP TEXAS DISTRIBUTION OPERATIONS ORGANIZATION.

A. The AEP Texas Distribution Operations organization is divided into five geographic operating districts: Corpus Christi, Laredo, Rio Grande Valley, San Angelo, and Abilene. These districts are responsible for the day-to-day operation of the distribution system, including the construction of new facilities, maintenance of existing facilities, and restoration of service.

Three functional support departments are charged with carrying out the Distribution Operations organization's activities:

1. Risk and Project Management – responsible for project management;
2. Operations Support – responsible for resource planning, contracting activities, and vegetation management; and
3. Engineering – responsible for distribution system engineering design activities and operation of the distribution electrical system for the entire AEP Texas service territory.

Figure 1 shows the AEP Texas Distribution Operations organizational structure during the test year.

**Figure 1** — AEP Texas Distribution Operations Organization

---

Q. PLEASE DESCRIBE THE DISTRIBUTION OPERATIONS ORGANIZATION’S FUNCTIONS.

A. Generally, the Distributions Operations organization designs, constructs, operates, and maintains the electric delivery system within the AEP Texas service area. The specific distribution functions include engineering, distribution line construction, operations
and maintenance, meter testing and installation, vegetation management, design and
execution of Distribution Asset Management programs, and underground network
construction and maintenance.

Q. PLEASE DESCRIBE AEP TEXAS' PROGRAMS USED TO MAINTAIN AND
ENHANCE THE RELIABILITY OF ITS DISTRIBUTION SYSTEM.

A. Programs to maintain and improve reliability by minimizing service interruptions on
the Company's distribution system can be divided into five categories: 1) Distribution
Asset Management; 2) Distribution Reliability; 3) Distribution Vegetation
Management; 4) Distribution Contamination Mitigation; and 5) Distribution Grid
Modernization.

A. Distribution Asset Management

Q. PLEASE DESCRIBE THE DISTRIBUTION ASSET MANAGEMENT PROGRAM.

A. AEP Texas has implemented proactive asset management programs whereby it
inspects distribution facilities to identify and correct potential problems before they
cause service interruptions. To that end, AEP Texas inspects and repairs assets such
as poles, transformers, reclosers, conductors, pedestals, and switchgear to avoid
outages. The Distribution Asset Management programs, which serve to prolong the
useful life of the distribution assets and enhance the distribution system's reliability,
include the following:

- Overhead Circuit Facilities Inspection and Maintenance;
- Animal Mitigation;
- Underground Facilities Inspection and Maintenance;
- Pole Maintenance / Replacement;
- Recloser Maintenance / Replacement;
• Overhead Conductor;
• Underground Cable;
• Lightning Mitigation; and
• Sectionalizing.

B. Distribution Reliability

Q. PLEASE DESCRIBE THE DISTRIBUTION RELIABILITY PROGRAM.
A. Each year, AEP Texas undertakes various major distribution reliability improvements in addition to those included in the Distribution Asset Management program activities described above. These reliability improvements range from the simple construction of new distribution feeder ties to the complex addition of new substations with new distribution feeders to better serve customers.

A major aspect of the Distribution Reliability program is to proactively address areas of the distribution system on which the projected demand for electricity is approaching the system’s current capacity limit. These programs either re-conductor the existing feeders or allow portions of the existing distribution system to be reconfigured. The expansion of the distribution system to serve new customers can also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to AEP Texas’ existing customers.

An example of a proactive reliability planning project is the recent addition of a second substation transformer bank and a new distribution feeder at the Pueblo substation in Eagle Pass, Texas. The existing 30 MVA transformer at the Pueblo substation was projected to be overloaded with continued growth in the area. The project resulted in the installation of a second 30 MVA transformer at the Pueblo substation, addition of a new distribution feeder, replacement of an existing 12 kV
switchgear, and reconductoring and reconfiguration of 5.5 miles of two existing
distribution feeders. This project not only provides capacity for future growth, but also
the replacement of existing aged infrastructure enhances reliability.

Q. WHAT OTHER PROGRAMS CONTRIBUTE TO DISTRIBUTION RELIABILITY?
A. The Distribution Infrastructure Improvement Program plays a significant role in
maintaining or improving distribution reliability. Specifically, the program is designed
to address the replacement of aging distribution line equipment along with the re-
engineering of facilities to be less susceptible to the impacts of weather. The program
targets aging grid components such as feeder circuit breakers and relays, poles, and
overhead and underground conductors. This equipment must be replaced or upgraded
to take advantage of technological improvements to materials and equipment, and to
improve reliability and power quality for customers. AEP Texas utilizes asset records,
field inspections, and system performance data to prioritize the replacement of aging
distribution system components that have exceeded operational life and are prone to
failure.

It is important to realize that it is much more efficient and cost effective to
replace equipment before failure than after failure. Planned replacement before failure
yields the lowest replacement cost because the work is scheduled during normal
business hours and the pre-planning optimizes efficiency. When equipment fails
during adverse conditions, the restoration work may require higher labor costs for
overtime, additional crew hours, and multiple trips to the work site to assess the damage
and determine the needed materials and equipment to complete the work. In addition,
the planned replacement of equipment before failure prevents or minimizes outages to customers.

C. Distribution Vegetation Management

Q. PLEASE DESCRIBE AEP TEXAS’ DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

A. AEP Texas’ existing Distribution Vegetation Management program includes pruning and clearing vegetation along distribution circuits to protect its lines. AEP Texas uses vegetation management practices such as mechanized clearing, manual trimming, manual clearing, and herbicide applications. AEP Texas currently uses a performance-based approach for vegetation management, which means that AEP Texas addresses circuits with the greatest need for vegetation management. Each fall, the following year’s annual vegetation plan is developed based on current circuit performance. The annual vegetation management work plans are flexible and dynamic. Inputs into the work plan include historical reliability data, line inspections, customer density, circuit performance, weather, and customer complaints.

Additional information with respect to vegetation activities is provided in AEP Texas’ annual vegetation management summary submitted to the Commission, as required by 16 Tex. Admin. Code (TAC) § 25.96.¹

D. Distribution Contamination Mitigation

Q. PLEASE DESCRIBE AEP TEXAS’ DISTRIBUTION CONTAMINATION MITIGATION PROGRAM.

A. AEP Texas experiences salt water contamination typical of coastal utilities, as well as contamination from other sources such as agriculture and industrial chemicals, dust from windy and arid conditions, and smoke or soot from the burning of sugar cane after harvest. All of these sources can produce significant contamination of distribution equipment. The build-up of contaminates reduces the dielectric effectiveness of insulators and bushings. During times of very high humidity or light mist, the particulates will absorb moisture and electrical flashovers can occur, potentially leading to pole fires and service interruptions. To reduce flashovers, the Company periodically applies a silicone grease to the insulators in the areas with the highest risk. Annually, AEP Texas prepares for contamination through visual inspection of high-risk equipment and the use of power washing of the aforementioned equipment.

E. Distribution Grid Modernization

Q. HOW DOES AEP TEXAS DEFINE GRID MODERNIZATION?

A. AEP Texas defines grid modernization as the transformation from the traditional electric grid and its associated inherent limitations to a “future grid” that deploys existing and emerging technologies to produce benefits for customers.

Q. PLEASE DESCRIBE AEP TEXAS’ GRID MODERNIZATION PLAN.

A. AEP Texas’ Grid Modernization Plan includes a portfolio of programs designed to meet current and evolving customer expectations. These programs focus on upgrading aging infrastructure with compatible grid modernization assets, which employ a wide
range of technology and analytics to enhance grid performance and security, re-
engineer the existing one-way power flow grid to an interconnected system capable of
supporting distributed generation devices, and enable customer service options. The
AEP Texas distribution grid is a complex system of substations, overhead and
underground primary voltage circuits and associated facilities, overhead and
underground secondary voltage facilities, metering devices, and control systems used
to deliver safe and economical electric power to residential, commercial, and industrial
customers. The Grid Modernization Plan considers the value and benefits of new and
emerging technologies and the implementation of current design and material standards
along with industry best practices.

Q. WHAT FACTORS REQUIRE AEP TEXAS TO MODERNIZE ITS GRID?

A. There are two primary factors that require AEP Texas to take deliberate actions to
modernize the electric grid. The first and immediate concern is the aging distribution
line and substation infrastructure. The largest contributors to AEP Texas' total annual
System Average Interruption Duration Index (SAIDI) and Customer Minutes of
Interruption (CMI) are age-related distribution line and distribution substation
equipment failures during weather events. The distribution line equipment failures are
related to poles, cross arms, overhead and underground lines, and overhead and
underground transformers (referred to collectively as distribution facilities). The
distribution substation equipment failures are related to power transformers, voltage
regulators or load tap changers, breakers, relays, and power cables.

The second factor related to grid modernization is the need to support new
technologies and equipment that will enhance the performance of the distribution grid
by improving network communications, system monitoring, automating line
sectionalizing, overall power quality, and grid security. The available technologies will
allow AEP Texas to more quickly assess system conditions, improve customer
response time, and improve system reliability through the use of new automation
equipment.

Q. WHAT ARE THE SPECIFIC ELEMENTS OF AEP TEXAS’ GRID
MODERNIZATION PLAN?

A. AEP Texas’ multi-year grid modernization plan includes the following programs:
   system automation, comprehensive system monitoring and analytics, grid security, and
   infrastructure improvement, which I discussed earlier in my testimony. AEP Texas’
   implementation of these grid modernization programs will be flexible and adaptable to
   changing customer needs, technological advancements and lessons learned during
   deployment.

Q. PLEASE DESCRIBE THE SYSTEM AUTOMATION COMPONENT OF AEP
TEXAS’ GRID MODERNIZATION PLAN.

A. The Company’s proposed system automation program calls for the automation of grid
   components and the ability to gather system data on a real-time basis. This program
   will improve system resiliency by reducing the length of outages and limiting sustained
   outages to smaller numbers of customers, as I further discuss below. Additionally, as
   the number of customer-owned Distributed Energy Resources (DER) devices
   connected to the grid grows, the digitalization of the distribution grid will improve
   control of grid components, which must react quickly and without human intervention
   to maintain the stability of the electric system. Enhanced automation of distribution
components and the ability to connect or disconnect DER devices will allow AEP Texas to more effectively and efficiently monitor and control the distribution system, which should minimize sustained customer outages.

Q. PLEASE EXPLAIN HOW THE COMPANY WILL IMPLEMENT SYSTEM AUTOMATION.

A. System automation involves the installation of distribution automation/circuit reconfiguration schemes (DA/CR) on looped distribution circuits. The DA/CR scheme functions by monitoring electric current levels at multiple points along the circuit and will automatically communicate between switching points via radio communications and distributed control equipment to “self-heal” the grid when a fault is detected within the switching points. Once a fault is detected, the automated switches on either side of the faulted section or “zone” of the circuit are automatically opened and the normally open switch positioned between the affected circuit and the backup or adjacent circuit closes. Customers on both sides of the fault location experience a brief interruption (less than 30 seconds typically) but avoid a sustained outage. The automated switches isolate the faulted section and pinpoint the damaged area for repair crews, which can reduce the time it takes to address the outage and restore service. Additionally, the DA/CR distribution control scheme monitors pre-fault loading on each automated switching zone. Prior to shifting load for unaffected circuit zones to an adjacent circuit, the DA/CR control logic compares the pre-fault load conditions with the calculated, pre-determined load limits of the backup source. The capacity of the backup sources is determined by the thermal limits of the circuit conductor, substation exit cables, and substation transformer capacity. The component with the lowest thermal rating
becomes the limiting factor and determines the available spare capacity or "contingent capacity" available for load transfer that is loaded into the DA/CR control logic to establish pre-determined capacity limits. If the pre-fault zone loads are lower than the pre-determined capacity limits of the backup source, the normally open circuit loop switch will close and restore service to customers impacted by the circuit fault. If the pre-fault zone loads exceed the pre-determined capacity limits of the backup source, the switch remains open. Under AEP Texas' overall grid modernization plan, the Company will evaluate and install DA/CR schemes on multiple distribution circuits during the program execution period.

Q. PLEASE DESCRIBE THE COMPREHENSIVE SYSTEM MONITORING AND ANALYTICS ASPECT OF AEP TEXAS' GRID MODERNIZATION PLAN.

A. To maintain and operate a safe and reliable electric grid, AEP Texas must have increased real-time visibility of the distribution system. Our system operators, engineers, and planners have a continual need to collect additional and more frequent data from targeted locations along the distribution system to determine real-time asset status, monitor performance, and respond quickly to grid performance problems. To enhance system operational visibility, AEP Texas will install distribution real-time monitoring units in substations to allow for communications to smart switches and controls.

Q. PLEASE DESCRIBE THE GRID SECURITY ELEMENT OF AEP TEXAS' GRID MODERNIZATION PLAN.

A. Grid security is a top priority for AEP Texas, and there are hosts of security threats the Company must identify and address every day. The threats come in many forms such
as viruses, malware, phishing attacks, scams, thefts, unlawful entry, and violent confrontations. Consequently, grid security has many facets and includes the protection of Company and customer information, phones, computers, email, servers, routers, communication networks (both public and private), radio communications, data storage, software applications, equipment firmware, and the physical security of office buildings, service centers, personnel, vehicles and substations.

AEP Texas addresses security issues on a constant basis, and as grid reliability attacks evolve, the Company's response to these attacks must also evolve. AEP Texas works with multiple entities including AEP, government, and industry partners to develop and implement best practices, training, monitoring, firewalls, anti-virus protection, access controls, security cameras, and evaluation of threat intelligence. The equipment associated with grid modernization has microprocessors, firmware, software, and communication interfaces, all of which can be susceptible to security risks. As the distribution grid is modernized, AEP Texas must take the necessary steps to keep the grid secure and mitigate the security threats.

Grid security projects have become a necessity in the current operating environment. As the Company rolls out new technologies, new security projects will be implemented to protect the grid and maintain grid reliability.
V. RELIABILITY AND QUALITY OF SERVICE PERFORMANCE

Q. HOW DOES THE COMMISSION MEASURE DISTRIBUTION RELIABILITY?

A. In accordance with 16 TAC § 25.52, electric distribution reliability is measured by: (1) overall system performance, and (2) feeder performance.

A. System Performance

Q. PLEASE DESCRIBE HOW SYSTEM PERFORMANCE IS MEASURED.

A. The overall system performance is measured by the annual frequency of interruptions, referred to as System Average Interruption Frequency Index (SAIFI). SAIFI is calculated by dividing the total number of customers who experienced interruptions for outage events in the year by the total number of customers served. System performance is also measured by the annual total duration of interruptions as measured in minutes, referred to as System SAIDI. SAIDI is calculated by dividing the total number of customer minutes interrupted during outage events by the total number of customers served.

Although outages obviously drive the values for SAIFI and SAIDI, the number of outages does not figure into the calculations. Instead, the number of customers interrupted is used to help distinguish the severity of the outage. In this manner, an outage affecting 1,000 customers has a ten times greater impact than a similar outage to 100 customers. Figures 2 and 3 show AEP Texas’ 2018 calculations for SAIFI and SAIDI.
Figure 2 — 2018 AEP Texas SAIFI Calculation

<table>
<thead>
<tr>
<th>SAIFI = Customers Interrupted / Customers Served</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customers Interrupted = 1,370,670</td>
</tr>
<tr>
<td>Customers Served = 1,036,443</td>
</tr>
<tr>
<td>SAIFI = 1,370,670/ 1,036,443= 1.322</td>
</tr>
</tbody>
</table>

Figure 3 — 2018 AEP Texas SAIDI Calculation

<table>
<thead>
<tr>
<th>SAIDI = Total Customer Minutes Interrupted / Customers Served</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Customer Minutes Interrupted = 141,843,426</td>
</tr>
<tr>
<td>Customers Served = 1,036,443</td>
</tr>
<tr>
<td>SAIDI = 141,843,426/ 1,036,443= 136.86 Minutes</td>
</tr>
</tbody>
</table>

As shown in Figures 2 and 3, the average AEP Texas customer experienced 1.322 outages and 136.86 minutes of interruption in 2018.

Major outages, as defined in 16 TAC § 25.52(c)(2)(D), include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours. Such events are excluded from SAIFI and SAIDI calculations.

Q. PLEASE DISCUSS YOUR GENERAL ASSESSMENT OF AEP TEXAS’ RELIABILITY PERFORMANCE DURING THE TEST YEAR.

A. Statistically, distribution service reliability at AEP Texas is good. Generally speaking, customers have an expectation the lights will come on when they flip the switch. When looking at the numbers in that context and thinking about what it really means to the electric service customer, those on the AEP Texas distribution system experience an average of just over one outage annually, and their service is available 99.97 percent of the time.
Q. PLEASE DESCRIBE THE RELIABILITY PERFORMANCE FOR AEP TEXAS’ SERVICE AREA IN RECENT YEARS.

A. AEP Texas’ annual SAIFI and SAIDI indices for the years 2015-2018 are shown in Figure 4.

Figure 4 — AEP Texas Reliability Indices Trend

<table>
<thead>
<tr>
<th>Year</th>
<th>SAIFI</th>
<th>SAIDI</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>1.29</td>
<td>149.34</td>
</tr>
<tr>
<td>2016</td>
<td>1.32</td>
<td>138.09</td>
</tr>
<tr>
<td>2017</td>
<td>1.27</td>
<td>133.19</td>
</tr>
<tr>
<td>2018</td>
<td>1.322</td>
<td>136.86</td>
</tr>
</tbody>
</table>

Q. PLEASE FURTHER DESCRIBE AEP TEXAS’ EFFORTS TO IMPROVE THE RELIABILITY OF ITS DISTRIBUTION SYSTEM.

A. AEP Texas has a Distribution Reliability Group that develops long range and annual distribution reliability plans. Other reliability-related efforts include developing feeder protection plans, scoping automated sectionalizing schemes, and identifying system-hardening opportunities.

B. Feeder Performance

Q. DESCRIBE THE COMMISSION’S METHOD UTILIZED TO DETERMINE INDIVIDUAL FEEDER PERFORMANCE.

A. Feeder performance, the second of the two reliability standards mentioned above, is the measure of how individual feeders perform. Under 16 TAC § 25.52(g)(2), a utility’s distribution system must operate in a manner such that no distribution feeder serving ten or more customers sustains a SAIFI or SAIDI value for a reporting year that is more than 300 percent greater than the system average of all feeders during any two consecutive reporting years. There are two lists: one for SAIFI and one for SAIDI.
Details of individual feeder performance and the number of customers on each feeder are provided in AEP Texas' 2018 Service Quality Report, filed in accordance with 16 TAC § 25.81.²

Q. HOW HAS AEP TEXAS PERFORMED WITH RESPECT TO THE COMMISSION'S FEEDER PERFORMANCE STANDARDS?

A. For the reporting year 2018, AEP Texas had 1,200 feeders serving ten or more customers. Of those feeders, AEP Texas lists 21 feeders that had a SAIFI value more than 300 percent greater than the system average while 55 had a SAIDI value more than 300 percent greater than the system average. The total number of feeders and portion of those feeders appearing on the SAIDI and SAIFI lists for the past three years are shown below in Figure 5:

**Figure 5 — AEP Texas SAIDI/SAIFI Feeder List**

<table>
<thead>
<tr>
<th>AEP Texas</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Feeders</td>
<td>1,180</td>
<td>1,190</td>
<td>1200</td>
</tr>
<tr>
<td>No. of Feeders on SAIFI List</td>
<td>25</td>
<td>15</td>
<td>21</td>
</tr>
<tr>
<td>Percent of Total Feeders</td>
<td>2.1%</td>
<td>1.3%</td>
<td>1.8%</td>
</tr>
<tr>
<td>No. of Feeders on SAIDI List</td>
<td>55</td>
<td>53</td>
<td>55</td>
</tr>
<tr>
<td>Percent of Total Feeders</td>
<td>4.7%</td>
<td>4.5%</td>
<td>4.6%</td>
</tr>
</tbody>
</table>

Q. ARE THERE CONSEQUENCES FOR A FEEDER HAVING SAIDI/SAIFI VALUES MORE THAN 300 PERCENT GREATER THAN SYSTEM AVERAGES?

A. Yes, the Commission may take appropriate enforcement action, including action against a utility, if the system and feeder performance is not operated and maintained in accordance with Commission rules.

² See 2018 Electric Service Quality Reports Pursuant to 16 TAC § 25.52 and 25.81, Project No. 49068, AEP Texas' Service Quality Report in Accordance with Substantive Rule § 25.81 (Feb. 14, 2019).
Q. DOES AEP TEXAS LIST ANY FEEDERS THAT REPEAT FOR TWO CONSECUTIVE YEARS?

A. Yes, as shown in Figure 6 below, AEP Texas has had a small number of feeders that repeat on either the SAIFI or SAIDI feeder list for two consecutive years. The number of repeat feeders appearing on the lists for the past three years is shown below in Figure 6:

Figure 6 – AEP Texas Repeat Feeders on SAIDI/SAIFI List

<table>
<thead>
<tr>
<th>AEP Texas</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Feeders</td>
<td>1,180</td>
<td>1,190</td>
<td>1,200</td>
</tr>
<tr>
<td>No. of Feeders on SAIFI List</td>
<td>3</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Percent of Total Feeders</td>
<td>0.3%</td>
<td>0.1%</td>
<td>0.2%</td>
</tr>
<tr>
<td>No. of Feeders on SAIDI List</td>
<td>16</td>
<td>9</td>
<td>8</td>
</tr>
<tr>
<td>Percent of Total Feeders</td>
<td>1.4%</td>
<td>0.8%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>

Q. WHAT IS AEP TEXAS DOING TO IMPROVE ITS FEEDER PERFORMANCES?

A. AEP Texas has initiated a plan to systematically improve its worst performing feeders. Specifically, in addition to the Distribution Asset Management programs described above, the Company has begun installing automatic sectionalizing devices. These devices allow for the automated isolation of faulted circuits from the remainder of the distribution system, which reduces the duration of outages as well as the number of affected customers.

Q. IS SAIDI MORE OF AN ISSUE THAN SAIFI WITH RESPECT TO FEEDER PERFORMANCE?

A. Yes. The feeders that repeat on the SAIDI list are typically lengthy, extremely rural circuits with low customer counts. For those that repeated in 2018, the customer counts ranged from 28 to 632 with feeder lengths ranging from approximately 33 to 220 miles.
The total number of customers served by the eight feeders that repeated on the SAIDI list in 2018 is 2,047 or about 0.2% of the total number of customers at AEP Texas.

AEP Texas will continue to make improvements to affect feeder performance while exercising efforts to balance the Company’s objectives of controlling costs and providing reliable distribution service. The balancing of costs and reliability are particularly important in investing in these types of reliability improvements because feeders in this category typically extend for miles in rural areas of the service territory, which significantly exposes the feeder to disruptive events. Further, these feeders typically cross property owned by multiple landowners who secure their land with fences and numerous locked gates making access and egress time consuming in an outage event. With few customers served by these long rural feeders, significant investment in performance improvement will result in a relatively small difference in reliability at both the system and customer levels.

VI. CUSTOMER SATISFACTION

Q. WHAT OTHER MEASURES DOES AEP TEXAS TRACK TO GAUGE ITS DISTRIBUTION SYSTEM PERFORMANCE?

A. AEP Texas continually measures and monitors customer satisfaction and perceptions for both residential and commercial customers. These surveys are fielded by The MSR Group. Using an independent survey research firm helps ensure the integrity and quality of the data. Topic areas of the survey include overall satisfaction, reliability, relationship attributes and future needs.
Q. HOW ARE THE CUSTOMER SATISFACTION SURVEYS ADMINISTERED?

A. The residential and commercial customer satisfaction surveys are administered on a continuous basis by telephone, employing a random selection of customers. Each year, approximately 600 residential and 600 commercial customers serviced by AEP Texas complete these surveys.

Q. WHAT WERE THE RESULTS OF THESE SURVEYS FOR CALENDAR YEARS 2016 to 2018 REGARDING SERVICE INTERRUPTION?

A. During 2016 to 2018, AEP Texas’ customer satisfaction score regarding service reliability has shown a consistent positive trend as referenced in Figure 7.

**Figure 7: Customer Satisfaction Survey**

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Commercial</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>86%</td>
<td>89%</td>
</tr>
<tr>
<td>2017</td>
<td>86%</td>
<td>85%</td>
</tr>
<tr>
<td>2018</td>
<td>88%</td>
<td>88%</td>
</tr>
</tbody>
</table>

The results reflect the customer satisfaction score of AEP Texas’ performance in providing electricity without interruption. The Company is committed to listening to our customers and use their feedback constructively.

VII. REQUEST FOR INCREASED VEGETATION MANAGEMENT O&M EXPENSE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the need for increased levels of distribution vegetation management. A robust vegetation management program is critical to maintaining the reliability of the Company’s distribution system and serving our customers.
Q. WHAT IS AEP TEXAS PROPOSING IN REGARDS TO DISTRIBUTION VEGETATION MANAGEMENT IN THIS PROCEEDING?

A. AEP Texas is proposing a total annual distribution vegetation management spend of $16.2 million. This is an increase of $5 million over the $11.2 million in vegetation management expenses in the test year.

Q. WHY IS AEP TEXAS PROPOSING AN INCREASE IN VEGETATION MANAGEMENT SPENDING TO BE INCLUDED IN BASE RATES?

A. The AEP Texas distribution vegetation management work plan in effect during the test year is primarily driven by reliability improvement objectives. The performance-based approach centers on past SAIDI and SAIFI circuit performance driven by vegetation forced interruptions. The current level of annual vegetation management spend only allows for addressing about 3 percent of the AEP Texas distribution system. As shown in Figure 8, the vegetation related SAIDI is not getting worse but it is also not getting better.

Figure 8 – AEP Texas SAIDI due to Vegetation

<table>
<thead>
<tr>
<th>Vegetation Management Outage Information</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI due to Vegetation</td>
<td>21.29</td>
<td>17.24</td>
<td>15.16</td>
<td>17.72</td>
</tr>
<tr>
<td>AEP Texas Total SAIDI Percent</td>
<td>14.4%</td>
<td>12.5%</td>
<td>11.4%</td>
<td>13.0%</td>
</tr>
</tbody>
</table>

Additionally, an increase in distribution vegetation management spend is necessary as the Company increases the rate of aging infrastructure replacement as part of its grid modernization plan. Tree trimming is often required to provide the working clearances necessary for the equipment replacement. For example, of the feeders with
a SAIDI value greater than 100 minutes identified in AEP Texas’ 2018 Summary
Regarding Vegetation Management Required by 16 TAC § 25.96, approximately 29%
would be candidates for grid modernization.³

Q. IS THE CURRENT DISTRIBUTION VEGETATION MANAGEMENT PROGRAM
O&M LEVEL SUFFICIENT TO PROVIDE AEP TEXAS CUSTOMERS WITH THE
LEVEL OF RELIABILITY THE COMPANY DESIRES TO PROVIDE?

A. No, it is not. AEP Texas is proposing focused vegetation management activity in areas
that would not currently be addressed under the existing plan for the benefit of electric
delivery customers that cannot be provided at test year O&M levels.

Q. IF GRANTED WILL THIS INCREASE ALLOW AEP TEXAS TO ESTABLISH A
VEGETATION MANAGEMENT CYCLE?

A. No, it will not. It would take an estimated incremental increase of $35 million for AEP
Texas to establish a four-year trim cycle. Although neither scenario can be considered
a cycle based program, the vegetation management spend in the test year equates to
about a 35-year cycle. The additional funding would result in approximately an 18-
year cycle.

Q. PLEASE SUMMARIZE WHY AEP TEXAS’ ADDITIONAL LEVEL OF
DISTRIBUTION VEGETATION MANAGEMENT SPEND SHOULD BE
APPROVED BY THIS COMMISSION.

A. A vegetation management program is critical to maintaining the reliability of the AEP
Texas distribution system and serving our customers. In addition to providing

³ See Project No. 41381, AEP Texas’ Summary Regarding Vegetation Management Required by 16 TAC §
25.96 (providing data for the 2017 reporting year).
improved reliability on targeted circuits, the increased level of vegetation management spend will provide for a level of tree trimming necessary to replace aging infrastructure as a part of the AEP Texas grid modernization plan. The ability to leverage synergies between these two programs provides for lower equipment replacement costs and improved reliability. As previously noted, the proactive replacement of distribution equipment is more cost effective than doing so during outage conditions.

AEP Texas is open to periodic reporting to this Commission and interested parties to show information such as the circuits trimmed, trimming progress completed, and the funds spent.

Q. HAVE YOU ADJUSTED THE DISTRIBUTION TEST YEAR O&M COSTS YOU DISCUSS BELOW TO ACCOUNT FOR AEP TEXAS’ REQUEST FOR INCREASED VEGETATION MANAGEMENT O&M EXPENSES?

A. Yes, the requested increase for vegetation management O&M expenses is included below as an adjustment to the test year Distribution O&M costs.

VIII. DISTRIBUTION O&M COSTS

Q. WHAT LEVEL OF O&M EXPENSES DID AEP TEXAS DISTRIBUTION INCUR IN THE TEST YEAR?

A. AEP Texas’ total company adjusted test year Distribution O&M expenses including AEP Texas’ own costs plus AEPSC charges for distribution activities necessary to provide safe, reliable distribution services were $113,058,001. The test year level of distribution O&M is summarized by FERC account in Figure 9.
### Figure 9 - AEP Texas’ Adjusted Distribution O&M Expenses

<table>
<thead>
<tr>
<th>FERC Account Description</th>
<th>2018 (TY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(580) Dis Oper Supervision &amp; Engineering $</td>
<td>$7,795,706</td>
</tr>
<tr>
<td>(581) Dis Oper Load Dispatching $</td>
<td>$3,556,649</td>
</tr>
<tr>
<td>(582) Dis Oper Station Expenses $</td>
<td>$1,548,391</td>
</tr>
<tr>
<td>(583) Dis Oper Overhead Line Expenses $</td>
<td>$5,876,627</td>
</tr>
<tr>
<td>(584) Dis Oper Underground Line Expenses $</td>
<td>$1,268,563</td>
</tr>
<tr>
<td>(585) Dis Oper Street Lighting &amp; Signal System $</td>
<td>$103,205</td>
</tr>
<tr>
<td>(586) Dis Oper Meter Expenses $</td>
<td>$7,427,114</td>
</tr>
<tr>
<td>(587) Dis Oper Customer Installation Expenses $</td>
<td>$1,240,622</td>
</tr>
<tr>
<td>(588) Dis Oper Misc Expenses $</td>
<td>$27,904,703</td>
</tr>
<tr>
<td>(589) Dis Oper Rents $</td>
<td>$2,009,215</td>
</tr>
<tr>
<td>(590) Dis Maint Supervision &amp; Engineering $</td>
<td>$153,114</td>
</tr>
<tr>
<td>(591) Dis Maint Structures $</td>
<td>$18,936</td>
</tr>
<tr>
<td>(592) Dis Maint Station Equipment $</td>
<td>$2,625,066</td>
</tr>
<tr>
<td>(593) Dis Maint Overhead Lines $</td>
<td>$46,799,475</td>
</tr>
<tr>
<td>(594) Dis Maint Underground Lines $</td>
<td>$1,989,939</td>
</tr>
<tr>
<td>(595) Dis Maint Line Transformers $</td>
<td>$1,162,583</td>
</tr>
<tr>
<td>(596) Dis Maint Street Lighting &amp; Signal Systems $</td>
<td>$894,874</td>
</tr>
<tr>
<td>(597) Dis Maint Meters $</td>
<td>$462,854</td>
</tr>
<tr>
<td>(598) Dis Maint Misc Distribution Plant $</td>
<td>$220,363</td>
</tr>
</tbody>
</table>

**Total Distribution Expenses $**

$113,058,001

2. **Q. HOW DO AEP TEXAS’ TEST YEAR DISTRIBUTION O&M EXPENSES COMPARE HISTORICALLY?**

4. **A.** Figure 10 shows AEP Texas’ distribution O&M expenditures since 2015 through the test year in this case. The costs range from a low of $90.8 million in 2016 to a high of $113.1 million in 2018.

### Figure 10 — AEP Texas Distribution O&M Costs by Year

<table>
<thead>
<tr>
<th>AEP Texas</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018 (TY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grand Total</td>
<td>$106,468,326</td>
<td>$90,817,003</td>
<td>$97,420,746</td>
<td>$113,058,001</td>
</tr>
</tbody>
</table>

---

The test year O&M expenses presented in Figure 9 have been adjusted to include: (1) $3,801,774 in test year capitalized forestry expenses, as explained by Company witness Hamlett; and (2) the additional $5 million in annual distribution vegetation management the Company is proposing, as I discuss in Section VII above.
Q. PLEASE EXPLAIN THE PRIMARY REASON FOR O&M COST CHANGES OVER THIS PERIOD.

A. The annual variability in distribution O&M for AEP Texas can be attributed to environmental and economic factors across all of the O&M accounts. Employees and contractors from across the AEP Texas service territory responded to the effects of Hurricane Harvey in 2017. The cost of those restoration activities were specifically charged to the recovery effort and not to their routine daily activities. We are recovering the costs associated with the restoration in a separate filing.

In 2015, a drop in the price of oil led to an associated drop in requests for capital construction to connect new customers including several substation projects. This resulted in a reprioritization of the workload that moved some planned 2016 activities into 2015. This effect is illustrated by the associated drop in outside services and contractor spend in 2016 as shown in figure 11 below.

Figure 11 – AEP Texas Outside Services O&M Spend

<table>
<thead>
<tr>
<th>AEP Texas</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grand Total</td>
<td>$29,992,504</td>
<td>$19,113,750</td>
<td>$26,914,932</td>
<td>$29,148,265</td>
</tr>
</tbody>
</table>

A stabilization in oil prices and a reasonably routine weather year provided the opportunity for AEP Texas to increase spending as a part of its multiyear grid modernization plan in 2018. The effect of this increased spend is illustrated by the increase in outside service spend shown in figure 11. The bulk of the increased costs are in three areas; distribution operations expense FERC account 5830, distribution operations miscellaneous expense FERC account 5880 and distribution maintenance overhead lines FERC account 5930.
Q. DO YOU BELIEVE THE TEST YEAR O&M COSTS ARE REASONABLE AND REPRESENTATIVE OF ONGOING COSTS?

A. Yes, I do. This belief is based on the discussion above explaining the variable nature of distribution O&M and showing that test year O&M compares favorably to the historic O&M cost trend, as well as the O&M benchmarking discussed later in my testimony.

A. Budget Controls and Cost Control Initiatives

Q. PLEASE DESCRIBE THE BUDGETING, PLANNING, AND COST REVIEW PROCESSES USED TO MANAGE BOTH AFFILIATE AND NON-AFFILIATE DISTRIBUTION COSTS.

A. AEP Texas and AEPSC employ ongoing rigorous internal forecasting and cost control processes to ensure costs are kept to the minimum reasonable level. During the annual forecasting process, projects are evaluated and expenses are scrutinized to ensure they are in line with the forecast target.

The budget process requires each department to estimate all transactions they anticipate making for the budget year. During the course of the year, each department manager receives a monthly budget variance report. It is the responsibility of that department manager to analyze charges against the approved budget for the department and to explain material variances either over or under the budget. The manager is then responsible for re-projecting the amount of expenditures the department is expected to incur for the remainder of the year, if that estimate differs from the budget.

Q. PLEASE EXPLAIN THE PROCESSES AEP TEXAS HAS IN PLACE TO KEEP THE COST OF DISTRIBUTION PROJECTS REASONABLE.
AEP Texas keeps the cost of distribution projects reasonable through proper control of project scope, and efficient engineering, procurement, and construction practices. In 2011 and 2015 competitive bids from distribution line contractors were obtained to work in each geographic district of AEP Texas. Distribution line contracts were again competitively bid in September 2017.

Furthermore, distribution projects are designed based on standardized engineering design criteria. This allows AEP Texas to use materials that are standard across AEP corporate-wide. The AEP Supply Chain organization (Supply Chain) is responsible for the purchasing of the materials for AEP Texas and leverages its buying power to get the lowest reasonable cost. The efforts of the Supply Chain organization to acquire materials are described by Company witness John Burns. An annual plan is developed for the completion of major distribution projects. AEP Texas crews or contractors complete the projects according to the plan.

As opportunities are identified to improve system performance and reliability, operating personnel are consulted to define the proper scope of the project. This action results in cost-saving efficiencies, such as routing distribution feeders in conjunction with area residential and commercial development, rebuilding of older lines as part of the project, or combining with a system improvement project. Likewise, distribution substation improvement projects are scoped to include needed equipment replacement to lower overall O&M costs.
B. Outsourcing

Q. DOES AEP TEXAS MAKE USE OF OUTSOURCING IN CONNECTION WITH THE CONSTRUCTION, OPERATION AND MAINTENANCE OF THE AEP TEXAS DISTRIBUTION SYSTEM TO CONTROL COSTS?

A. Yes. AEP Texas’ philosophy is to staff certain functions of its business with internal employees and to supplement that work force by outsourcing. Distribution functions that AEP Texas does not outsource include, for example, distribution dispatch and management of distribution O&M. These functions involve the exercise of judgment and discretion based on experience and expertise that is unique to distribution utility operations.

AEP Texas augments internal staffing with third-party contract resources, although the management of such activities remains the responsibility of Company employees. For example, AEP Texas has contracts for physical tree-trimming crews, construction crews for overhead and underground facilities, pole inspection, and joint-use engineering for cable pole attachments. Further, AEP Texas balances contracting and self-provisioning within certain functions, such as overhead and underground line construction, in order to keep adequate resources and to ensure the best value is provided at a reasonable cost. The objective is to achieve the best overall long-term cost profile. AEP Texas’ outsourcing is based upon these criteria:

- High volume, non-electrical work requiring focused effort and/or specialized skills (e.g., vegetation management and joint-use inventory);
- Unique low-volume work (e.g., landscaping and concrete repair); and
- Unique/extraordinary resource requirements (e.g., fill in during the peaks).
Q. HOW DOES AEP TEXAS OBTAIN CONTRACTOR RESOURCES WHEN NEEDED?

A. AEP Texas obtains contractor resources by competitively bidding base work or specific projects using qualified contractors. This is accomplished with the help of two AEPSC groups, Supply Chain and Distribution Contract Management.

Supply Chain sends out a bid package to bidders along with the contractual information, supplemental terms, and conditions within a Request for Quotes. They provide oversight of the bidding process. Distribution Contract Management qualifies contractors by reviewing their safety records, financial records, management philosophies, references, etc. Distribution Contract Management maintains a list of contractors that are capable of meeting AEP Texas’ needs.

When AEP Texas needs contractor resources for base work or specific projects, Supply Chain sends out notices of a pre-bid meeting to discuss the project. Distribution Contract Management facilitates the pre-bid meetings. The projects are presented and questions that the contractors may have are answered. Bids are typically due back two weeks following the pre-bid meeting. Bids are received by Supply Chain, reviewed by Distribution Contract Management, and evaluated by AEP Texas. Distribution Contract Management notifies the successful and unsuccessful bidders, and Supply Chain executes a contract with the successful bidder. AEP Texas then coordinates the construction oversight of the project and payment to the contractor.

C. Benchmarking

Q. HAVE YOU PERFORMED ANY STUDIES THAT FURTHER SUPPORT THE REASONABLENESS OF AEP TEXAS’ DISTRIBUTION EXPENSES?
A. Yes. AEP Texas' distribution costs are comparable to its peers in benchmarking studies using FERC Form 1 data from 2015-2017. The studies compare AEP Texas' total company distribution O&M and average capital costs to three peer groups. The three peer groups were a Texas peer group, a south central regional peer group, and a national peer group. These studies provide the minimum, maximum, and median values for each metric and the relative position of the corresponding AEP Texas metric for comparison.

Q. WHAT ARE THE RESULTS OF THE BENCHMARKING STUDIES?

A. As shown in EXHIBIT TMC-3, AEP Texas' average distribution capital expenditures for the year ending 2017 were $5,303 per line mile, which is less than the Texas group median of $6,505 and is much less than the maximum of $8,871 for the same period. This also compares similarly to the south central regional peer group median and maximum of $6,032 and $8,871, respectively, for 2017. The national peer group median and maximum was $6,116 and $12,771, respectively, for 2017.

As shown in EXHIBIT TMC-3, AEP Texas' distribution O&M cost per line mile for 2017 was $2,129 compared to the Texas group median and maximum of $2,804 and $4,540, respectively. This $2,129 cost is below the 2017 south central regional peer group median of $2,673 per line-mile and much less than the maximum value of $5,284. Compared to the national peer group, this amount is also below the 2017 median value of $3,123 per line-mile and well below the maximum value of $7,015. These results are reasonable given the particular challenges posed by AEP Texas' service area, and given AEP Texas' efforts to balance the objectives of cost control and reliable distribution service.
Comparisons alone cannot prove that a utility’s costs are reasonable, given that each company faces different circumstances and specific challenges posed by service territories. Nonetheless, the benchmarking studies provide support for the conclusion that AEP Texas’ distribution costs are reasonable.

IX. AEP TEXAS AFFILIATE COSTS

A. O&M Costs

Q. WHAT IS THE TOTAL AMOUNT OF THE AEPSC DISTRIBUTION O&M AFFILIATE CHARGES THAT YOU SUPPORT IN THIS PROCEEDING?

A. I support adjusted affiliate distribution service costs charged to AEP Texas Distribution from AEPSC during the test year ending December 31, 2018, totaling $4,662,626. This amount was included in the test year overall distribution O&M expenses mentioned earlier. Affiliate distribution costs constitute approximately 4.1% of the total distribution O&M costs for the test year. These affiliate charges are further addressed in the direct testimony of Company witness Brian Frantz.

Q. WHAT HAS BEEN THE COST TREND FOR AEP TEXAS DISTRIBUTION AFFILIATE COSTS SINCE 2015?

A. AEP Texas’ overall distribution O&M affiliate costs have increased since 2015. Figure 12 shows the distribution affiliate O&M costs for AEP Texas for calendar years 2015 through 2017 and the Test Year. These costs are reflective of the services received by the Company and include an emphasis on projects to improve customer support.
Figure 12 – AEP Texas Affiliate O&M Costs

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$3,173,255</td>
</tr>
<tr>
<td>2016</td>
<td>$3,676,429</td>
</tr>
<tr>
<td>2017</td>
<td>$4,230,883</td>
</tr>
<tr>
<td>Test Year (2018)</td>
<td>$4,662,626</td>
</tr>
</tbody>
</table>

Q. PLEASE PROVIDE A BREAKDOWN OF THE AEPSC O&M CHARGES TO AEP TEXAS BY MAJOR COST CATEGORY.

A. The affiliate distribution service charges fall into the following major categories in the test year as shown in Figure 13:

Figure 13 – AEP Texas Test Year Affiliate Expense Categories

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Amount</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor/Benefits</td>
<td>$3,617,450</td>
<td>77.6</td>
</tr>
<tr>
<td>Outside Services</td>
<td>$793,475</td>
<td>17.0</td>
</tr>
<tr>
<td>Other</td>
<td>$251,701</td>
<td>5.4</td>
</tr>
<tr>
<td>Total</td>
<td>$4,662,626</td>
<td>100</td>
</tr>
</tbody>
</table>

In addition to my testimony, the reasonableness of the labor and benefits costs are supported by Company witnesses Andrew R. Carlin (reasonableness of employee compensation) and Curt Cooper (reasonableness of employee benefit costs).

B. AEPSC Distribution Services

Q. WHAT WILL YOU COVER IN THIS SECTION OF YOUR TESTIMONY?

A. I will be providing a description of the AEPSC Customer & Distribution Services (C&DS), Enterprise Innovation and Resiliency, Technology Business Development, and Utilities organizations and their services.

Q. PLEASE SUMMARIZE THE SERVICES PROVIDED BY THE AEPSC C&DS ORGANIZATION AND WHY THESE SERVICES ARE NECESSARY.
The AEPSC C&DS organization provides customer service and distribution support to AEP Texas and the other AEP operating companies. Specifically, the organization provides specialized energy delivery support services and expertise across the AEP System. I discuss the C&DS organization’s distribution services, which are provided through the following two departments:

1. Distribution and Performance Management & Data Analytics; and
2. Distribution Services Support.

AEP Texas witness Joel S. Murphy addresses the C&DS organization’s customer service functions in his direct testimony.

The C&DS organization is also responsible for the operational support of all core information technology (IT) systems that support day-to-day operations of the distribution and customer functions. For example, these systems include outage management, office and fieldwork management, customer information systems, choice customer systems and engineering analysis and evaluation software systems. These IT systems are integral to the efficient operation of the AEP operating companies.

Q. PLEASE DESCRIBE THE FUNCTIONS PERFORMED BY THE DISTRIBUTION AND PERFORMANCE MANAGEMENT & DATA ANALYTICS DEPARTMENT.

A. The Distribution and Performance Management & Data Analytics department includes the Performance Management group, which conducts data analysis and benchmarking, supports system-wide process improvement initiatives, and manages system budgeting and expenditure tracking. The Data Analytics and Customer & Grid Analytics groups
examine information obtained from the utility distribution operations across the AEP footprint to identify and manage operational efficiencies, as well as the needs and expectations of our customers.

Q. PLEASE DESCRIBE THE FUNCTIONS PERFORMED BY THE DISTRIBUTION SERVICES SUPPORT DEPARTMENT.

A. The Distribution Services Support department focuses on functions tied to system reliability and performance in AEP’s eleven-state service territory. This organization provides overall coordination for distribution standards, system capacity planning, network engineering, reliability planning, forestry, and emergency restoration planning activities. While each operating company has command and control of the day-to-day functions of distribution forestry, Distribution Services Support focuses on process improvements, best practices, hardware and system development, and contract negotiations in order to improve overall operating efficiencies.

There are eight sections in Distribution Services Support:

- Distribution Reliability Planning supports evaluation and implementation of AEP’s reliability programs and focuses on developing and maintaining engineering standards;

- System Planning conducts and implements system improvement planning across AEP and provides distribution capacity planning efficiencies;

- Forestry supports AEP’s forestry contract negotiations, administration and the sharing of best practices across AEP;

- Geographic Information System (GIS) mapping group, which leverages GIS expertise and system support from across the AEP system to support AEP Texas’ operations;

- Distribution Human Performance which supports two major functions: Distribution Line Training, which provides AEP with safe and effective employees through education and the promotion of consistent practices and procedures, and Human Performance Improvement, which uses well-founded principles in error reduction to improve employee safety and health;
• Distribution Engineering and Operations Systems group manages the development, enhancement, support, and maintenance of distribution information technology systems for the AEP Utility Organization. The Utility Organization is made up of the operating companies, along with the C&DS central support organization. The systems supported by the Distribution Engineering and Operations Systems organization include the Outage Management System, Distribution Work Management System, and the GIS Mapping System. These information technology systems are integral to the efficient operation of the AEP operating companies.

• Research and Development is primarily supported through the evaluation of new technologies at AEP’s Dolan Lab.

• Emergency Restoration Planning supports the acquisition of emergency resources in support of major service restoration events and for the planning, training and oversight of the Incident Command System used to respond to such major events like a hurricane.

Q. WHAT OTHER SERVICES DOES THE DISTRIBUTION SERVICES ORGANIZATION PROVIDE?

A. The remaining distribution-related organizations, Enterprise Innovation and Resiliency, Technology Business Development, and Utilities, provide the following services:

• Technology Innovation, Development and Integration – Identify and develop innovative, transformational technologies and develop strategies for appropriately integrating such technologies in AEP operating company distribution services.

• Technology and Customer Expectations – Identify where customer expectations and advanced or evolving technology converge, and develop strategies to deploy appropriate technology solutions to meet customer expectations.

• Strategic Partnership – Define, support, develop and execute strategic partnerships, priorities and long-term goals for the organization.

• Open Innovation & Employee Engagement – Gather insights of customer expectations that can be satisfied with technology integration or industry-first solutions.

• Business Continuity— Manage and oversee AEP’s business continuity program that prepares the enterprise with an adequate state of readiness to effectively
respond to and recover from disruptions with minimal impact to critical business functions.

- Crisis Response—Conduct AEP's emergency management planning and preparedness activities that provide a coordinated and standardized method to activating and responding to all types of emergencies throughout the enterprise.

- Operational Risk Management—Implement AEP's enterprise wide framework to identify, assess, monitor and raise awareness to appropriately manage operational risks across the corporation.

Q. HOW DO AEP TEXAS AND THE AEPSC DISTRIBUTION SERVICES ORGANIZATION COORDINATE THEIR EFFORTS?

A. AEP Texas and AEPSC Distribution Services work collaboratively to provide safe, reliable distribution service. The AEPSC asset planning employees regularly attend AEP Texas staff meetings and conference calls and function as integral parts of the team. During regularly-scheduled meetings and conference calls among the operating company vice presidents and the service company distribution services organization leadership, service issues are discussed and resolved. Additionally, the central organization's leadership team travels to each operating company periodically to discuss operating company-specific issues or problems and to obtain feedback on the quality of service being provided to the operating company.

Q. DO THESE SERVICES DUPLICATE SERVICES PROVIDED BY PERSONNEL WITHIN AEP TEXAS OR BY ANY OTHER ENTITY?

A. No, none of the services I describe above are provided by AEP Texas. These services require specialized expertise that is best provided within a structure that allows for sharing of experience and knowledge across all operating companies.
HAS THE NUMBER OF FULL-TIME EMPLOYEES WITHIN THE AEPSC DISTRIBUTION SERVICES ORGANIZATION CHANGED SINCE THE END OF 2015?

A. Yes. There has been an increase in the total number of support employees, which has resulted in increased affiliate charges to AEP Texas as indicated in Figure 12. The AEPSC Distribution Services organization had approximately 159, 173, 201, and 220 employees at the end of 2015, 2016, 2017, and 2018 respectively, which provided support to AEP Texas. Of the 2018 total, there are 13 AEPSC Distribution Services employees located in AEP Texas’ service territory. This headcount and billing trend to AEP Texas from AEPSC for distribution support is indicative of Company growth, customer support, and the efficient delivery of services to AEP Texas by AEPSC.

C. AEPSC Distribution Services Budget Controls and Cost Control Initiatives

WHAT PLANNING, BUDGETING, COST REPORTING, AND OTHER COST CONTROL MEASURES DOES THE AEPSC C&DS ORGANIZATION HAVE IN PLACE TO CONTROL COSTS?

A. AEPSC C&DS employees follow rigorous internal forecasting and cost control processes similar to those employed by AEP Texas employees. Each year, forecasts are developed for each business unit based on current and planned activity levels. O&M forecast increases are generally limited to cost of living increases and capital forecasts are project specific. Throughout the year, costs are tracked on a monthly basis, and any variances to the planned forecasts must be explained. Distribution Services also employs strict employee and management approval levels to ensure the reasonableness of all expenditures.
Q. HOW DOES THE AEPSC C&DS ORGANIZATION PROCURE MATERIALS AND SERVICES AT REASONABLE PRICES?

A. AEPSC C&DS works with Supply Chain when it needs to enter into contracts and obtain services. The C&DS organization follows competitive bidding procedures to obtain contracts and services at a reasonable price for equipment purchases, engineering services, and forestry activities, to name a few. It is able to leverage the buying power of multiple companies in order to achieve volume discounts that reduce the overall unit prices, as explained in the testimony of Company Witness Burns. Even when specific products or services are required for AEP Texas, AEPSC C&DS is able to provide technical support at a lower cost than AEP Texas would incur independently, due to the economies of scale provided by a centralized organization.

Q. PLEASE DESCRIBE ANY PROCESS IMPROVEMENTS RECENTLY INSTITUTED BY THE AEPSC C&DS ORGANIZATION.

A. C&DS constantly looks for ways to provide more efficient and effective services to AEP Texas and the other AEP operating companies. The C&DS organization led the development, training and implementation of the Incident Command System (ICS) in AEP Texas and across the AEP System. This critical process improvement aligns with both state and local Emergency Management Agencies and provides an AEP system-wide consistent process enabling AEP Texas to draw upon competent and fully trained resources for the support of a major service restoration event, such as major hurricane direct hit on the Texas coastline. ICS is recognized as a national best practice by FEMA and was used in the restoration efforts after Hurricane Harvey.
D. Benchmarking

Q. IS THE BENCHMARKING YOU DESCRIBED EARLIER CONCERNING THE OVERALL DISTRIBUTION COSTS RELEVANT TO THE REASONABLENESS OF AFFILIATE DISTRIBUTION CHARGES?

A. Yes. The benchmarking studies I discussed above comparing AEP Texas' overall distribution O&M costs to those of other electric utilities also support the reasonableness of AEP Texas' affiliate O&M distribution charges. FERC Form 1 data does not separately record affiliate charges. Accordingly, it is not possible to directly benchmark affiliated distribution services costs using FERC Form 1 data. However, affiliate charges represent a portion of the overall O&M costs provided in FERC Form 1 filings. Moreover, the distribution services I have described are provided to the overall distribution operation using a combination of service company employees, AEP Texas employees and contractors. Consequently, benchmarking at the overall cost level is consistent with the manner in which the services are provided and managed, and supports the conclusion that the affiliate portion of those costs is also the product of effective management and contributes to an overall reasonable level of costs.

Q. PLEASE SUMMARIZE THE EVIDENCE YOU HAVE OFFERED REGARDING THE REASONABLENESS OF AFFILIATE COSTS.

A. In my testimony regarding both total costs and affiliate costs, I have demonstrated that total distribution costs for the AEPSC C&DS and AEP Texas distribution organization are reasonable; have a rigorous budgeting and cost control process; that outsourcing is used to effectively manage costs; that there is no duplication of services by AEP Texas
Distribution and the AEPSC C&DS organization; and that when benchmarked against other utilities, AEP Texas’ distribution costs are comparable.

X. CAPITAL COSTS

Q. WHAT IS THE VALUE OF AEP TEXAS’ DISTRIBUTION CAPITAL ADDITIONS SINCE THE LAST TEST YEAR?

A. A total of approximately $3,021,880,357 in distribution capital additions were added to plant in service between July 1, 2006 and December 31, 2018. See the following Figure 14 for the Capital Additions added each year since the last rate base case:

Figure 14 — AEP Texas Capital Additions by Year

<table>
<thead>
<tr>
<th>Year</th>
<th>Distribution</th>
<th>Intangible</th>
<th>General</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>$62,463,364</td>
<td>$2,386,696</td>
<td>$1,342,635</td>
<td>$66,192,694</td>
</tr>
<tr>
<td>2007</td>
<td>$134,913,743</td>
<td>$5,320,165</td>
<td>$6,897,906</td>
<td>$147,131,814</td>
</tr>
<tr>
<td>2008</td>
<td>$166,892,030</td>
<td>$6,237,144</td>
<td>$9,891,519</td>
<td>$183,020,693</td>
</tr>
<tr>
<td>2009</td>
<td>$112,029,251</td>
<td>$1,208,534</td>
<td>$9,659,740</td>
<td>$122,897,525</td>
</tr>
<tr>
<td>2010</td>
<td>$146,285,629</td>
<td>$24,378,111</td>
<td>$7,022,397</td>
<td>$177,686,137</td>
</tr>
<tr>
<td>2011</td>
<td>$167,534,726</td>
<td>$10,635,384</td>
<td>$15,921,269</td>
<td>$194,091,379</td>
</tr>
<tr>
<td>2012</td>
<td>$191,487,187</td>
<td>$11,808,350</td>
<td>$13,575,156</td>
<td>$216,870,693</td>
</tr>
<tr>
<td>2013</td>
<td>$239,960,588</td>
<td>$11,539,552</td>
<td>$23,862,961</td>
<td>$275,363,100</td>
</tr>
<tr>
<td>2014</td>
<td>$231,133,353</td>
<td>$15,663,500</td>
<td>$7,016,212</td>
<td>$253,813,065</td>
</tr>
<tr>
<td>2015</td>
<td>$232,112,610</td>
<td>$16,206,511</td>
<td>$15,901,125</td>
<td>$264,220,246</td>
</tr>
<tr>
<td>2016</td>
<td>$235,394,492</td>
<td>$21,787,159</td>
<td>$16,120,618</td>
<td>$273,302,269</td>
</tr>
<tr>
<td>2017</td>
<td>$249,462,674</td>
<td>$26,324,241</td>
<td>$5,689,697</td>
<td>$281,476,612</td>
</tr>
<tr>
<td>2018</td>
<td>$402,933,934</td>
<td>$25,546,612</td>
<td>$137,333,584</td>
<td>$565,814,130</td>
</tr>
<tr>
<td>Total</td>
<td>$2,572,603,580</td>
<td>$179,041,959</td>
<td>$270,234,818</td>
<td>$3,021,880,357</td>
</tr>
</tbody>
</table>

* Note: 2006 is only a 6-month period.

As Figure 14 clearly demonstrates, after a dip in the wake of the “Great Recession” (triggered in 2008), the Company’s distribution capital investment has trended up significantly. This trend is attributable largely to growth in the AEP Texas service area,
driven particularly by the boom in the oil and gas industry associated with shale-related
exploration and production. It is also noteworthy that this need for distribution
infrastructure has risen in non-traditional growth areas, resulting in more capital
investment (new substations, substation upgrades, distribution lines) needed to provide
adequate infrastructure improvement.

Q. WHAT IS INCLUDED IN THE INTANGIBLE AND GENERAL PLANT
COLUMNS?
A. The Intangible Plant includes FERC Account 301 – 303 and the General Plant includes
FERC Accounts 389 – 399. The capital additions shown in these columns are the
capital costs assigned to Distribution and includes items such as property, buildings,
office furniture, tools and communication equipment. The increase in the 2018 General
Plant was largely due to the upgrade or addition of new distribution service buildings,
which I describe in more detail below.

Q. PLEASE DESCRIBE THE NATURE OF AEP TEXAS’ MAJOR DISTRIBUTION
CAPITAL ADDITIONS.
A. Capital Additions represent the annual investment in infrastructure needed to provide
reliable electric service to new and existing customers. The following descriptions are
for the major capital project types:

- **Asset Improvement** – This is largely the replacement of aging infrastructure
  that is approaching the end of its useful life. Replacing infrastructure before it
  fails reduces outages and improves reliability.

- **Customer Service** – This capital work is related to the installation of service for
  new residential and commercial customers. This work is required to connect
  new customers to the distribution system as well as the costs of the necessary
  transformers and meters.
- **Reliability** - Reliability programs are specific capital programs that target known reliability issues affecting groups of customers or whole circuits experiencing reliability issues.

- **Planning Capacity** – This work is related to the installed assets required for AEP Texas’ long-range planning for meeting electrical load on AEP Texas’ distribution system. The need for capacity expansion can be due to either new customers or new load by existing customers in an area.

- **Forestry** – This activity is for the widening of ROW where additional easements have been purchased and for the removal of trees with trunks 18 inches or larger in diameter outside the ROW.

- **Restoration** – This is capital work related to the restoration of the distribution electrical system.

- **Other** – This work is related to capital expenditures that are not included in the other six capital addition categories.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ON THE NATURE OF THE DISTRIBUTION PLANT?

A. Yes. A breakdown of the costs by year and category is provided in Figure 15:

**Figure 15 – Capital Additions by Category**

<table>
<thead>
<tr>
<th>Category</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asset Improvement</td>
<td>$50,371,595</td>
<td>$63,525,983</td>
<td>$85,794,306</td>
</tr>
<tr>
<td>Customer Service</td>
<td>$103,797,724</td>
<td>$103,457,676</td>
<td>$113,222,251</td>
</tr>
<tr>
<td>Forestry</td>
<td>$2,092,351</td>
<td>$1,884,924</td>
<td>$3,801,774</td>
</tr>
<tr>
<td>Other</td>
<td>$0</td>
<td>$0</td>
<td>$1,266,357</td>
</tr>
<tr>
<td>Planning Capacity</td>
<td>$111,198,616</td>
<td>$18,067,903</td>
<td>$32,439,415</td>
</tr>
<tr>
<td>Reliability</td>
<td>$54,865,110</td>
<td>$51,430,623</td>
<td>$63,369,600</td>
</tr>
<tr>
<td>System Restoration</td>
<td>$13,069,095</td>
<td>$11,095,565</td>
<td>$103,040,231</td>
</tr>
<tr>
<td>Distribution Total</td>
<td>$235,394,492</td>
<td>$249,462,674</td>
<td>$402,933,934</td>
</tr>
<tr>
<td>Intangible Total</td>
<td>$21,787,159</td>
<td>$26,324,241</td>
<td>$25,546,612</td>
</tr>
<tr>
<td>General Total</td>
<td>$16,120,618</td>
<td>$5,689,697</td>
<td>$137,333,584</td>
</tr>
<tr>
<td>Grand Total</td>
<td>$273,302,269</td>
<td>$281,476,612</td>
<td>$565,814,130</td>
</tr>
</tbody>
</table>

Q. DO ANY OF THE YEARS INCLUDE THE CAPITAL COSTS ASSOCIATED WITH HURRICANE HARVEY?
A. Yes. The Hurricane Harvey capital costs were tracked in Project ID DMS17TC31. The 2017 Distribution Plant includes $132,388 in plant additions for Hurricane Harvey and the 2018 Distribution Plant includes $84,570,784 in plant additions. The 2018 General Plant includes $2,052,275 in plant additions for Hurricane Harvey. The quantification of the Hurricane Harvey capital costs was reviewed in Docket No. 48577. The recovery of these costs is being addressed through the AEP Texas storm securitization case, Docket No. 49308. The adjustment to move the capital out of the Revenue Requirement calculation is further discussed by Company witness Hamlett.

Q. PLEASE DESCRIBE THE NEW DISTRIBUTION BUILDING INFRASTRUCTURE PLACED IN SERVICE SINCE AEP TEXAS’ PREVIOUS BASE RATE CASES?

A. Since the last AEP Texas Central Company and Texas North Company base rate cases, the Company has placed in service new and upgraded service building infrastructure that are utilized for distribution functions in Texas for the benefit of AEP Texas. AEP Texas witness Randolph J. Ware addresses in his direct testimony the actions taken to support the prudency of the construction costs associated with the new and upgraded building facilities. In my testimony, I address the use of the new Distribution facilities, including descriptions of the distribution-related services provided and the benefits from the buildings.

Q. ARE THE NEW SERVICE BUILDINGS EXCLUSIVELY FOR DISTRIBUTION ACTIVITIES?

A. No, some building facilities solely house distribution personnel and equipment, while some buildings house both transmission and distribution personnel to provide their
respective support services. AEP Texas witness Daniel R. Boezio discusses in his Direct Testimony the transmission functions carried out in the facilities housing transmission personnel.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MOST NOTEWORTHY FACILITIES PROVIDING DISTRIBUTION-RELATED BENEFITS.

A. Since the Company’s last base rate case, several facilities providing distribution-related benefits have been placed in service, including the following: 1) San Benito Service Center; 2) Corpus Christi Service Center; 3) Los Fresnos Service Center; 4) Hebbronville Service Center; and 5) Alice Service Center. These facilities were added to accommodate the increase in personnel needed to adequately support the operation and maintenance of AEP Texas’ new and aging distribution assets. In many cases, it was more economical to build new facilities, taking into consideration the existing facilities’ condition and space constraints. Where economical, renovations of existing facilities were completed.

Q. WHAT BENEFITS DO THESE FACILITIES PROVIDE TO THE DISTRIBUTION SYSTEM OF AEP TEXAS?

A. In general, providing facilities that have adequate space and technology enables the Company’s employees to safely and efficiently complete their job responsibilities, directly influencing the effectiveness of the operations and maintenance of the distribution system assets. The new service centers give the distribution crews easier access to the equipment they need to maintain and repair the electric grid in the region.

In addition to the employee-related benefits, the San Benito Service Center, Corpus Christi Service Center, and the Los Fresno Service Center, are noteworthy due
to additional design considerations for those facilities. Because of their near proximity to the Gulf Coast, these facilities were built to withstand wind forces equivalent to those expected if a Category 5 hurricane on the Saffir-Simpson hurricane scale impacts the nearby coastline. The service centers were sized with sufficient space to serve as AEP Texas staging areas during storm restoration efforts.

Q. COULD YOU PLEASE DESCRIBE THE TYPES OF FUNCTIONS CARRIED OUT IN THE NEW AND UPGRADED DISTRIBUTION BUILDING FACILITIES BY PERSONNEL IN THE DISTRIBUTION ORGANIZATION?

A. These new facilities house the employees, equipment and materials necessary for the day-to-day operation of the distribution system, including the construction of new facilities, maintenance of existing facilities, and restoration of service. They enhance the ability of the Company to provide the safe and reliable delivery of electric service to homes, businesses, and industry across its service territory in south and west Texas.

Q. DO THE CAPITAL ADDITIONS ABOVE INCLUDE ANY AFFILIATE CHARGES?

A. Yes, the capital additions are the fully allocated costs and include the affiliate charges. These affiliate charges are explained in more detail in the direct testimony of Company witness Brian Frantz and Schedule V-K-5.

Q. WHAT TYPES OF COSTS ARE REFLECTED IN THE AFFILIATE PORTION OF THE CAPITAL PROJECTS?

A. Most of the costs reflected in the affiliate portion of the capital projects are distribution capitalized software and costs associated with AEPSC distribution planning, design, and construction management attributable to the various AEP Texas distribution projects.
Additionally, the distribution substation design work is completed by AEPSC as an affiliate cost. For example, when a new distribution substation is needed, Station Projects Engineering will prepare the design and Construction Management will manage the physical construction, both of which are affiliate costs. The AEPSC budgeting processes and staffing trends I previously described, as well as the compensation and employee benefit standards and practices explained by Company witnesses Carlin and Cooper, apply to AEPSC labor and activities in support of AEP Texas distribution capital projects, and further support the reasonableness of the related affiliate charges.

Q. WHAT PROCESSES DOES AEP TEXAS EMPLOY TO ENSURE THAT CAPITAL PROJECTS ARE PRUDENTLY CONSTRUCTED AT A REASONABLE COST?

A. The Company uses internal processes to ensure project costs are competitive and look for opportunities to implement process improvements to further reduce costs. Large projects and blanket work are competitively bid following AEP’s Corporate Guidelines administered by the Contract Administration Group. Project Management oversees and monitors expenditures during construction to ensure that the costs are reasonable and that the project scope is achieved.

As previously discussed, AEP Texas has conducted benchmarking studies using FERC Form 1 data to compare AEP Texas’ costs with other utilities. The benchmarking analyses provided earlier in my testimony support the reasonableness of the overall level of distribution capital costs including affiliate charges. In addition, my discussion of AEP Texas’ budgeting, outsourcing, contracting, and materials acquisition processes and procedures presented previously in my testimony applies
equally to capital costs, and further illustrates the measures in place whereby AEP Texas ensures that its capital expenditures are reasonable. Finally, my earlier discussion of the efficiencies resulting from the provision by AEPSC of centralized distribution support services also supports the reasonableness of the affiliate capital costs.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.
AEP Energy Delivery

Distribution Asset Programs

Program Definitions

2014

7-11-14

8-7-18 (pole program only)
Overview

The seven AEP Operating Units (made up of one or more Operating Companies) operate an extensive distribution system in portions of eleven states in the United States covering approximately 83,000 square miles of service territory and serving approximately 5.3 million customers. AEP’s distribution system includes approximately 222,000 miles of distribution lines with voltage ratings ranging from 4 kV through 34.5 kV. Overhead distribution line assets are classified into pole, conductor and equipment categories. Underground distribution line assets are classified into conductor and equipment categories.

The initial construction of overhead and underground facilities follows AEP’s material and construction standards (except as modified to comply with other codes and standards established by regulatory authority). AEP’s material and construction standards incorporate National Electrical Safety Code requirements and other industry standards and were adopted to safely and reliably operate AEP’s extensive distribution system. Once built and energized, the facilities are subject to mechanical and electrical stresses from various causes, including conductor and equipment electrical loadings, severe weather, accidents, and vandalism and to normal deterioration from aging. These conditions will eventually lead to the need for maintenance, repair or replacement of the assets.

Industry research and AEP’s experience and expertise in the construction, operation and maintenance of distribution systems in varied geographic and demographic areas are applied to manage and maintain AEP’s assets. AEP develops objectives and plans to achieve optimal performance in a safe and reliable manner over the expected life of the asset, while at the same time balancing costs and benefits. An example of this type of planning can be demonstrated in AEP’s annual operation and maintenance plans. A major part of these annual plans is the Distribution Asset Programs.

The Distribution Asset Programs are designed to optimize expenditures and system performance. These programs consist of two basic components: periodic inspection and maintenance programs and targeted mitigation programs. Periodic inspection and maintenance programs are designed to assess the condition of assets to assure compliance with National Electrical Safety Code, state utility regulatory requirements and AEP requirements and to maintain and improve system performance. Targeted mitigation programs are designed to improve equipment reliability and safety performance and maintain and improve system reliability and performance.

AEP utilizes industry research and internal system and equipment performance analyses to develop and implement targeted mitigation programs. Program examples include animal mitigation and lightning mitigation. Recent program enhancements include the addition of animal guards, grounding improvements and the application of surge arresters. Continuing research, development and testing of new materials and equipment are providing new opportunities for increasing the performance and life of distribution assets.
Distribution Asset Programs

Introduction to Distribution Asset Programs -

The Distribution Asset Programs are an important part of Distribution’s strategic annual operation and maintenance plans. The definitions below are intended to define 1) the objective of each program, 2) the activities included in each program and 3) how each program fits into the overall operation and maintenance plans and budgets.

One common area of confusion is the definition of “maintenance”. The definition of “maintenance” used by accounting considers maintenance as an expense that is written off. When the term “maintenance” is used in the context of Distribution’s annual operation and maintenance plans and the Distribution Asset Programs, it has a broader meaning than the accounting definition. Webster defines maintenance as “the upkeep of property or equipment”. Some of the activities we classify as “capital” by the accounting rules are “maintenance” using the broader non-accounting definition of “maintenance”.

For example, when we replace a deteriorated pole because it does not have sufficient strength to meet the National Electrical Safety Code (NESC) requirements, the accounting rules classify the cost to install the replacement pole as a capital cost, not a maintenance expense. However, the new pole is a maintenance replacement according to the NESC and in terms of our Asset Program. The new pole is considered a maintenance replacement because it is upkeep of our pole plant property. Maintenance replacements need not be modified to meet the current NESC edition requirements. Please refer to NESC, Article 013 (see Appendix A on page 14) for rules pertaining to maintenance replacements versus other types of work such as voltage conversion, rebuild, multiphasing and reconductor work, etc.

OVERHEAD CIRCUIT FACILITIES INSPECTION AND MAINTENANCE

Objective: The objective of this program is to visually inspect all overhead facilities on a 5-year cycle to identify and correct deficiencies necessary for the safety of employees and the public under the conditions specified in the NESC and for system reliability.

Activities Included In Program: The program consists of a visual inspection of poles (including foreign owned poles with company owned attachments), conductors, and pole-mounted equipment (transformers, regulators, reclosers, capacitors, etc.) and related materials (insulators, brackets, terminations, cutouts, surge arresters, etc.) owned by the company. It includes inspection of foreign attachments (CATV, telephone, etc.) to the company’s poles for any safety related electrical or mechanical defects. Electrical and mechanical defects observed will be identified and the information will be collected so appropriate corrective action can be taken. Driving or foot patrol inspections are conducted as appropriate looking for obvious defects such as loose down guys, broken grounds, cracked insulators, lightning arresters with blown isolators, deteriorated crossarms having inadequate strength, etc.
OVERHEAD CIRCUIT FACILITIES INSPECTION AND MAINTENANCE (continued from page 3)

The performance of minor maintenance activities such as replacement of property ownership tags or pole location tags, occasional replacement of blown lightning arresters, tightening loose down guys, replacement of a few occasional deteriorated crossarms, etc. are included in the program. The program does not include major replacement of pole equipment and replacement of secondaries, service drops, etc. Any major corrective replacement work is to be supplemented with other Operating Unit budget funds. The program does not include inspecting the above ground portions of underground facilities except for the riser poles with their associated overhead equipment and materials.

How The Program Fits Into Operations and Maintenance Plans:

This program is designed to proactively identify defects involving company owned overhead facilities so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system operation. The corrective actions taken are to include necessary maintenance and replacement as a part of this program. If defects should be discovered that pose a safety risk, then timely corrective action by qualified personnel is required. In rare instances the inspector may be required to guard the site of a safety hazard until qualified personnel arrive to correct the hazard. Defects involving foreign owned facilities are to be reported to the owner for correction. However, in some situations action may be required on the company’s part to correct a safety hazard involving foreign owned facilities with appropriate billing of AEP’s cost to the foreign party.

UNDERGROUND FACILITIES INSPECTION AND MAINTENANCE

Objective: The objective of this program is to visually inspect the external, above ground portions of underground facilities on a 5-year cycle to identify and correct deficiencies necessary for the safety of employees and the public under the conditions specified in the NESC and for system reliability.

Activities Included In Program: The program consists of an external, visual inspection of the above ground portion of underground systems including pad-mounted equipment (transformers, switches, primary metering enclosures, junction cabinets, etc.), pedestals and the underground associated components of primary riser poles. The program also includes the visual inspection of company owned outdoor lights and light poles fed from underground systems in URD developments and similar installations. Note that all wood poles will continue to be inspected/treated on a 10-year cycle as part of the separate pole inspection program.

An external inspection will be conducted to determine if the equipment is locked and secure, that there are no open appurtenances that might allow access to the interior of the equipment via soil erosion, cabinet or conduit deterioration or by other means such as
UNDERGROUND FACILITIES INSPECTION AND MAINTENANCE (continued from page 4)

vandalism. Oil filled equipment is also checked for any external leaks. Any defects observed that need attention will be identified and the information will be collected so appropriate corrective action can be taken.

Minor maintenance such as paint touch up, replacement of a missing lock and/or penta head bolt(s) and replacement of an occasional deteriorated pad-mount transformer are also included. Only minimal funding for corrective action is provided for this program. Where significant correction/equipment replacement is required, System Improvement Blanket funds from local budgets are to be utilized. This program does not include underground secondary network systems.

How The Program Fits Into Operations and Maintenance Plans:

This program is designed to proactively identify defects so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system performance. If defects should be discovered that pose a safety risk, then timely corrective action by qualified personnel is required. In rare instances, the inspector may be required to guard the site of a safety hazard until qualified personnel arrive to correct the hazard.

POLE INSPECTION AND MAINTENANCE

Objective: The primary objective of this program is to maintain the mechanical integrity of our wood pole infrastructure necessary for the safety of employees and the public under the conditions specified in the NESC and for system reliability. This objective is accomplished by maintenance treatment to extend the service life of poles, by identifying and mechanically reinforcing weak poles to strengthen them and by identifying and replacing poles that have reached the end of their service life. This program will be performed such that every pole meeting the in service criteria described below will be inspected and maintained as required on a ten year cycle based on the initial pole treatment types (i.e., CCA, Penta, and Creosote):

- Poles in service 15 years and longer (10 years for coastal areas of Texas) treated with Penta, Creosote and Copper Napthenate.

- Poles in service 30 years and longer treated with CCA. These vintage CCA poles shall not be dug or treated but shall be given a visual inspection only.

Activities Included In Program: The program consists of a detailed inspection of company owned wood poles once every 10 years for all poles meeting criteria as shown above. The above ground portion of the pole and its attachments are inspected visually and problems such as decayed pole tops and crossarms are noted.
POLE INSPECTION AND MAINTENANCE (continued from page 5)

Minor work such as repairing broken ground wires and replacing deteriorated guy guards is also included. Replacement of pole location (grid) tags and property ownership tags is performed as needed. When the condition of the above ground portion of the pole is checked to be adequate, then the strength of the wood at the ground line is determined by partial excavation of the pole and by core samples taken from the pole around the ground line.

If the pole strength is determined to be adequate, with no internal or external decay present, the pole is reported as satisfactory with no treatment applied. If the pole strength is determined to be adequate, with internal or external decay present, the pole would be fully excavated to a depth of 18 inches and the exposed area below ground would receive an application of EPA-registered treatment materials, consisting of a pesticide and preservatives, in a bandage arrangement around the base of the wood pole. Additionally, if the pole meets certain conditions, it is to be internally or fumigant treated as appropriate with EPA registered materials.

If the ground line area of the pole does not have sufficient strength, then the pole is evaluated for either pole reinforcement or replacement. Information is compiled regarding the poles inspected, poles treated, the poles needing reinforcement and the poles needing to be replaced. The poles needing reinforcement or replacement are marked with a special tag. The program includes company owned wood light poles fed from underground systems in URD developments and similar installations. Chromated Copper Arsenate (CCA) preservative treated poles are to be inspected visually, but are not to have the detailed ground-line examination or preservative treatment that other non-CCA treated poles are to have.

This program does not include steel or other non-wood poles or foreign owned wood poles having company attachments. Highway relocation project poles (PPR), damage claim poles (car hit pole), make-ready poles (CATV & Telephone) as well as customer service related pole changes (for height or pole class increases) are not a part of this program. The emphasis of this program is to only replace or reinforce poles that need replacing or reinforcing and not to rebuild the system. As a general rule, pole hardware and associated material are to be transferred instead of replacing them with new material. Replacement of existing pole hardware and equipment simply to avoid another trip in the next 5 to 10 years is not included in the program. Pole hardware or equipment should be reused unless it is unsafe or it is clearly more economical to replace rather than reuse it. The program does not include major replacement of pole equipment and replacement of secondaries, service drops, etc. Any major corrective replacement work is to be supplemented with other Operating Unit budget funds. The Operating Units, depending upon the availability of funds from other Operating Unit programs, will have the option to address pole hardware or equipment replacements not covered by this program.

How The Program Fits Into Operations and Maintenance Plans:
This program is designed to proactively identify company owned wood poles whose
service life can be extended through ground line supplemental preservative treatment or reinforcement and those wood poles that have reached the end of their service life so that the pole can be replaced on a timely basis. The importance of maintaining the mechanical integrity in our wood pole infrastructure is fundamental to successful operations based upon the negative experiences of several utilities. If defects should be discovered that pose a safety risk, then timely corrective action by qualified personnel is required. In rare instances the inspector may be required to guard the site of a safety hazard until qualified personnel arrive to correct the hazard.

RECLOSER MAINTENANCE / REPLACEMENT

Objective: The objective of this program is to replace those recloser units that meet specific program criteria in order to maintain system safety and reliability.

Activities Included In Program: The program consists of the replacement of in-service units with like kind units. The maintenance cycle for each recloser in service is based upon the type of recloser (hydraulic or vacuum interruption), number of operations and duty cycle and as such this cycle can vary from Operating Unit to Operating Unit and from circuit to circuit. The Company is transitioning away from oil interrupting hydraulic units to oil-insulated vacuum and solid dielectric units so a number of older hydraulic units are targeted for replacement with new vacuum units.

The **maximum** recommended maintenance frequency for distribution reclosers will be as follows:

- Oil-interrupting reclosers (such as 4H, L, DV, WE)  **100 Operations or 6 Years**  
  (since last maintenance or original installation)

- Oil-insulated vacuum interrupting reclosers  **200 Operations or 12 Years**  
  (since last maintenance or original installation)

- Solid dielectric-insulated vacuum interrupting reclosers (such as Nova and Viper)  
  Nova  **300 Operations or 24 Years** **
  Viper  **200 Operations or 24 Years** **
  (since last maintenance or original installation)

** Where operations data is available (via download from unit control) then 90% of the Duty cycle (as determined per manufacturer recommendation) will replace the set number (300) of operations

Units in known high fault duty locations and/or corrosive environments may require more frequent maintenance.
RECLOSER MAINTENANCE / REPLACEMENT (continued from page 7)

Like-kind units for purposes of this program will generally be defined as the same manufacturer type of recloser. Higher coil ratings for the same type of recloser are allowable – no cost differential. An example would include replacing a 70 amp L with a 100 amp L unit versus replacing a 70 amp L with a 100 amp D unit which is outside the scope of the program.

Three-phase unit replacement with single-phase units is strongly encouraged where possible for reliability improvement purposes. The number of units and the costs for such change outs should be included in this Asset Program during the budget development process.

The intent of this program is not to complete a circuit recoordination upgrade. If circuit recoordination is required then this work should be covered under the System Improvement Blankets as appropriate. In any event it would be important to coordinate any planned circuit recoordination upgrades with the Recloser Maintenance / Replacement Program to prevent unnecessary replacement of reclosers.

The program does not include the cost of shop maintenance and testing. (The removed units are maintained in company repair facilities. Once the unit has been maintained and it meets unit specifications it becomes available as a replacement for another unit needing to be maintained). The program does not include the annual inspection and collection of counter readings for all reclosers in service. This activity is included as part of an Operating Unit’s base program budget.

How The Program Fits Into Operations and Maintenance Plans:

This program is designed to proactively maintain company owned reclosers so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system operation. Properly maintained reclosers positively impact both system safety and system reliability.

OVERHEAD CONDUCTOR AND UNDERGROUND CABLE MAINTENANCE (REPLACEMENT PROGRAM)

A. OVERHEAD CONDUCTOR

Objective: The objective of this portion of the program is to correct primary and secondary conductor deficiencies by replacing deteriorated sections of primary overhead conductor and deteriorated secondary conductors in order to maintain system safety and reliability.
OVERHEAD CONDUCTOR AND UNDERGROUND CABLE MAINTENANCE
(REPLACEMENT PROGRAM) (continued from page 8)

Activities Included In Program: This program targets the replacement of deteriorated sections of overhead primary conductor based on age, condition and reliability history with an equal or larger conductor size as determined to be necessary by appropriate Operating Unit personnel. The smaller size primary conductors are more prone to deterioration due to weather and environmental contamination as well as being older.

However, larger conductor sizes can be subjected to similar external deterioration factors and are included for this reason.

Under this program, for example, a deteriorated section of #8 CU would be replaced with #2 BAA or AAAC (the smallest size conductors currently being stocked). Likewise, a deteriorated section of #2 ACSR could be replaced with #2 BAA or AAAC or a somewhat larger conductor size based on local Operating Unit engineering economic analysis and evaluation. There is no upper limit to the conductor size that can be replaced due to deterioration. Replacement of deteriorated sections of secondary conductor is also included in this program.

This program is not for conductors that are electrically at or over their rated capacity or conductors associated with low voltage conditions. Specific overload conditions and conductors associated with low voltage situations are to be addressed and justified under the Distribution Planning Criteria.

How The Program Fits Into Operations and Maintenance Plans: This program is designed to proactively identify deteriorated sections of overhead primary conductors and deteriorated secondary conductors so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system operation. An analysis based upon age, condition and reliability history is used to pinpoint sections of deteriorated conductor. The deteriorated sections are prioritized as to condition and the sections needing attention first are targeted for this replacement program.

B. UNDERGROUND CABLE

Objective: The objective of this portion of the program is to correct primary cable deficiencies by restoring the integrity of deteriorated sections of underground cable through cable replacement in order to maintain system safety and reliability. Cable injection is also a maintenance option based on specific circumstances and conditions.

Activities Included In Program: This program consists of restoring the integrity of deteriorated underground cable sections by either cable replacement or cable injection with specific circumstances and conditions. Under this program cable sections that are not good candidates for cable injection are replaced using cable of similar or larger size based on local Operating Unit engineering economic analysis and evaluation. There is no upper
OVERHEAD CONDUCTOR AND UNDERGROUND CABLE MAINTENANCE
(REPLACEMENT PROGRAM) (continued from page 9)

limit to the cable size that can be replaced due to deterioration and this program does specifically include underground circuit feeder exit cables.

This program includes all sizes of underground bare concentric neutral and jacketed primary cable sections with deteriorated concentric neutrals and/or insulation.

This program is not for cables that are electrically at or over their rated capacity or cables associated with low voltage conditions. Specific overload conditions and cables associated with low voltage situations are to be addressed and justified under the Distribution Planning Criteria. This program is not for cables associated with secondary network systems.

How The Program Fits Into Operations and Maintenance Plans: This program is designed to proactively identify deteriorated sections of primary underground cables so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system safety and performance. An analysis based upon age, condition and reliability history is used to pinpoint sections of deteriorated primary cable. The deteriorated sections are prioritized as to condition and the sections needing attention first are targeted for the program

ANIMAL MITIGATION

Objective: The objective of this program is to reduce the number of animal caused outages by installation of animal guards on line transformers and other line equipment at locations known to have had or have a high risk of animal caused outages.

Activities Included In Program: This program consists of installing animal guards on the primary bushings of overhead line transformers and other line equipment, which do not have the guards, at locations prone to animal outages based upon historic outage data. Typical transformer locations targeted for guard installation are generally in areas having a high animal population on circuits with the worst animal caused outage history. There are several different approved animal guards that can be used. The Guthrie guard has proven to be versatile and relatively easy to install. This program does not include installation of an animal guard at the time of an animal caused outage event. Such an installation should be made using funds from the Operating Unit’s base budget (service restoration) and does not fall under this program.

How The Program Fits Into Operations and Maintenance Plans: This program is designed to proactively reduce the number of animal caused outages. From historic outage data and concentrating on the worst performing distribution feeders, locations having animal caused outages are identified. Those locations prone to future animal caused outages are to be targeted under this program.
LIGHTNING MITIGATION

Objective: The objective of this program is to reduce the number of lightning caused outages by installation of new arresters at locations within areas known to be prone to lightning caused outages.

Activities Included In Program: This program consists of installing new lightning arresters on overhead lines at locations known to be prone to lightning outages based upon historic outage and lightning strike data. Four arrester installations per mile is the criteria to use for additional installations. Three phase line sections are a priority over single-phase line sections. Existing arresters on equipment are to be considered when deciding the location for the new arresters. This program does not include replacement of existing lightning arresters, which is covered under a different program. Funds for this program are typically allocated based upon the ratio of 34.5 KV vs. lower voltage circuits in each Operating Unit.

How The Program Fits Into Operations and Maintenance Plans: This program is designed to proactively reduce the number of lightning caused outages. Locations having lightning caused outages are identified from historic outage and lightning strike data. Those locations prone to future lightning caused outages are to be targeted under this program.

NETWORK SYSTEM

Objective: The objective of this program is to ensure reliable service to our downtown network system customers, extend the life of these assets and provide a safe environment for both our employees and the public.

Activities included in program: The program includes inspection, testing, and minor maintenance of the network facilities. Some of the specific activities include:

- Annual vault inspections
- Vault water pumping on an as needed basis.
- Annual inspection and 4 year maintenance of network protectors.
- Annual inspection of network transformers including oil sampling and testing
- Four year inspection of manholes
- Annual circuit trip checks.

These activities include visual inspection, load monitoring, electrical testing, oil analysis, and operational checks. The data will be collected in a Network Equipment and Maintenance Tracking database.

Detailed information about these activities can be found in the Network Maintenance Program dated 1/19/2010.
NETWORK SYSTEM (continued from page 11)

How The Program Fits Into Operation and Maintenance Plans: The program is focused on both preventative and predictive maintenance. Network protector annual open door inspections and door gasket checks will help keep moisture out of the enclosure. Moisture is a leading cause of premature protector failures. Vault and transformer inspections will identify problems that can then be corrected and provide detailed data collection that can be trended. This data can then be used for predictive analysis of the systems and determination of necessary corrective activities. Oil sampling and analysis are the predictive tools that will help determine which oil filled equipment to maintain or replace before failure. Cable testing is not included in the program at this time. The focus is to assure that all associated equipment (protectors, switches) works properly so that any cable failure can be isolated quickly without other equipment damage.

SECTIONALIZING

Objective: The objective of this program is to improve the reliability of poor performing distribution circuits by adding new or modifying existing sectionalizing device locations.

This program is not intended to degrade in any way the overcurrent protection on the targeted circuits. Any upgrade in overcurrent protection is to be a secondary benefit. The emphasis is on reducing the number of customers outaged by faults and shortening the outage time for customers who are affected by an outage.

Activities included in program: The program includes the installation of additional sectionalizing equipment and the relocation of existing sectionalizing equipment to include reclosers, sectionalizers, fused cutouts and switches. Fault indicators may be included as an option with the installation of new equipment. See the Sectionalizing Guidelines posted within the Lotus Notes ED Repository.

Some specific guidelines for the program are as follows:
Program cost and reliability improvement effectiveness will be optimized by focusing on circuit-wide improvements based on circuit reliability history (worst performing by SAIFI and/or CAIDI) and by using Navigant tools (Mitigation Analyzer and Optimization). Asset Planning will assist each Operating Unit with identification of program circuits.

Some equipment application guidelines for the program:
Reclosers – Single-phase unit installations are recommended wherever practical for their enhanced reliability benefits\(^1\). Replacement of three-phase units with three

\(^1\) Over 80 percent of faults on the distribution system are single line to ground faults and over 80% of the customers have only single-phase service. When three single-phase reclosers can be used instead of one three phase recloser, about two thirds fewer customers will suffer interruption for single line to ground faults.
SECTIONALIZING (continued from page 12)

single-phase units is included. Specify vacuum type units for these new (additional) installations with the exception of types D and DV units that have no vacuum unit equivalent.

Fused Cutouts – Priority consideration for unfused taps within the feeder breaker zones. Single-phase line length, terrain, outage history, underground and overhead exposure, etc. to be additional considerations. Sub-fusing (additional fusing) of long, existing single-phase lines protected by reclosers or fuses is to be considered also.

Fault Indicators (Optional) – Three-phase installations preferred. Installation in conjunction with other capital equipment offers capitalization of these devices whereas installation would be considered maintenance otherwise. Largest benefits appear to be realized in conjunction with new mainline switch installations.

How The Program Fits Into Operation and Maintenance Plans: This capital intensive funding program is designed to improve circuit operational characteristics associated with fault isolation and restoration for better overall Safety and Reliability. The ability to achieve predictable reliability results for the system will be enhanced with the consistent application of the program guidelines.

Accounting/Reporting Issues:

Normally, improvements to a specific circuit will be written up on an individual work order (avoid multiple circuits on a single work order) in order to facilitate accounting, regulatory reporting, and tracking requirements. The compatible unit work order system can supply the quantity of major units completed (per work order), which will facilitate the ability to have circuit improvements summaries as needed.

In general, sectionalizing improvements to non-program circuits should be charged to the Operating Unit System Improvement Blankets instead of the Sectionalizing Program in order to optimize the effectiveness of the program funds and to allow for improved tracking of the results.

Program monitoring can include tracking of the improvements by circuit and jurisdiction to allow for a before and after improvement value assessment for best practice analysis and for regulatory reporting.

CAPACITOR INSPECTION & MAINTENANCE PROGRAM

Objective: The objective of this program is to visually inspect all switched capacitor banks for proper operation twice annually and all fixed capacitor banks once annually to identify and correct deficiencies necessary for system reliability to include emphasis on capacitor
CAPACITOR INSPECTION & MAINTENANCE PROGRAM (continued from page 13)

bank availability during the summer and winter peak loading seasons.

Activities Included In Program: This program consists of a visual inspection of capacitor bank components that could impact or have impacted proper bank operation, the identification and documentation of observed deficiencies and the necessary maintenance/replacement actions to restore the capacitor bank to normal operation.

Various measurement tests may be required depending on the type of installation and observed conditions and could include current measurements, individual can capacitance checks, etc.

The visual inspection includes such items as checking for blown primary fuses, blown lightning arresters, bulging or leaking capacitor unit cans or oil/vacuum switches and the control operations counter.

The identification of deficiencies found (whether corrected on-site or not) is very important to the overall success of the program. These deficiencies can range from blown fuses to an inoperable capacitor control or oil/vacuum switch to the line post current sensor being installed incorrectly on the pole. Documentation for the inspection results is captured electronically and included as a part of the PMIS (Preventative Maintenance Inspection System) program steps.

Necessary maintenance/replacement actions include whatever is required to return the capacitor bank to normal and proper operation. This would include items such as refusing a blown primary line cutout to replacing a blown control fuse up to replacing bad/failed components such as individual capacitor unit cans or oil/vacuum switches or the bank control.

How The Program Fits Into Operations and Maintenance Plans:

This program is designed to proactively identify defects involving company owned capacitors so that appropriate action can be taken to reduce the possibility of an accident or correct a condition that would adversely affect system operation. Properly maintained capacitors positively impact both system safety and system reliability.

Appendix A

National Electrical Safety Code
C2-2012
Section 1. Introduction to the National Electrical Safety Code®

013. Application
A. New Installations and Extensions
   1. These rules shall apply to all new installations and extensions, except that
APPENDIX A (continued from page 14)

they may be waived or modified by the administrative authority. When so waived or modified, safety shall be provided in other ways.

EXAMPLE: Alternative working methods, such as the use of barricades, guards, or other electrical protective equipment, may be implemented along with appropriate alternative working clearances as a means of providing safety when working near energized conductors.

2. Types of construction and methods of installation other than those specified in the rules may be used experimentally to obtain information if:
   a. Qualified supervision is provided,
   b. Equivalent safety is provided, and
   c. On joint use facilities, all affected joint users are notified in a timely manner.

B. Existing Installations
   1. Where an existing installation meets, or is altered to meet, these rules, such installation is considered to be in compliance with this edition and is not required to comply with any previous edition.
   2. Existing installations, including maintenance replacements, that currently comply with prior editions of the Code, need not be modified to comply with these rules.
      Exception 1: For safety reasons, the administrative authority may require compliance with these rules.
      Exception 2: When a structure is replaced, the current requirements of Rule 238C shall be met, if applicable.
   3. Where conductors or equipment are added, altered, or replaced on an existing structure, the structure or the facilities on the structure need not be modified or replaced if the resulting installation will be in compliance with either (a) the rules that were in effect at the time of the original installation, or (b) the rules in effect in a subsequent edition to which the installation has been previously brought into compliance, or (c) the rules of this edition in accordance with Rule 13B1.

C. Inspection and work rules
   Inspection rules and work rules in the current edition of the NESC shall apply to inspection of or work on all new and existing installations.

202. Application of Rules
   The general requirements for application of these rules are contained in Rule 13. However, when a supporting structure is replaced, the arrangement of equipment shall conform to the current edition of Rule 238C.

238C. Clearances for span wires or brackets
   Span wires or brackets carrying luminaries, traffic signals, or trolley conductors shall have at least the vertical clearances in millimeters or inches from communications equipment set forth in Table 238-2.
Exhibit TMC – 3: AEP Texas Benchmarking Studies

National Peer Group
Distribution O&M per Line Mile

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National Peer Group
AEP Ohio
AEP Texas
APCo
CenterPoint Energy Houston Electric LLC
CLECO Power LLC
Consumers Energy Co
Dayton Power & Light Co (The)
DTE Electric Co
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
El Paso Electric Co
Entergy Arkansas Inc
Entergy Louisiana LLC
Entergy Texas Inc
Indiana Michigan Power Co
Indiana Power & Light
Kentucky Power Co
Kentucky Utilities Co
Louisville Gas & Electric Co
Monongahela Power Co
Northern Indiana Public Service Co
Ohio Edison Co
Oklahoma Gas & Electric Co
Oncor Electric Delivery
Public Service Co of Oklahoma
Southern Indiana Gas & Electric Co
Southwestern Electric Power Co
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Virginia Electric & Power Co
Exhibit TMC – 3: AEP Texas Benchmarking Studies

South Central Peer Group
Distribution O&M per Line Mile

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South Central Peer Group
AEP Texas
CenterPoint Energy Houston Electric LLC
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Exhibit TMC – 3: AEP Texas Benchmarking Studies

National Peer Group
Distribution Capital (CapX 2yr avg) per Line Mile

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National Peer Group

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Southwestern Electric Power Co
Southwestern Public Service Co
Virginia Electric & Power Co
Exhibit TMC – 3: AEP Texas Benchmarking Studies

South Central Peer Group
Distribution Capital (CapX 2yr avg) per Line Mile

Year | 2015 | 2016 | 2017
--- | --- | --- | ---
Lowest | $1,714 | $1,982 | $1,570
Median | $5,662 | $5,431 | $6,032
Highest | $8,884 | $8,848 | $8,871
AEP Texas | $5,228 | $5,413 | $5,303

South Central Peer Group
AEP Texas
CenterPoint Energy Houston Electric LLC
CLECO Power LLC
El Paso Electric Co
Entergy Arkansas Inc
Entergy Louisiana LLC
Entergy Texas Inc
Oklahoma Gas & Electric Co
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Texas Peer Group

AEP Texas
CenterPoint Energy Houston Electric LLC
El Paso Electric Co
Entergy Texas Inc
Oncor Electric Delivery
Southwestern Electric Power Co
Southwestern Public Service Co
PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF
AEP TEXAS INC.
FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF
DANIEL R. BOEZIO
FOR
AEP TEXAS INC.

MAY 2019
# TESTIMONY INDEX

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<td>III. AEP AND AEP TEXAS TRANSMISSION SYSTEMS</td>
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## EXHIBITS

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Daniel R. Boezio. My business address is 539 North Carancahua, Corpus Christi, Texas 78401. I am Vice President, Transmission Field Services for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP).

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT, TRANSMISSION FIELD SERVICES (TFS) FOR THE WESTERN AEP FOOTPRINT.

A. I am responsible for the safe and reliable operation, storm recovery, and maintenance activities of the AEP western transmission system, including that of AEP Texas Inc. (AEP Texas or the Company); Southwestern Electric Power Company (SWEPCO), which operates in portions of Texas, Louisiana, and Arkansas; Public Service Company of Oklahoma (PSO); and Electric Transmission Texas, LLC. (ETT). My responsibilities also include coordinating with AEP Texas and other departments of AEP Transmission related to the transmission operations, construction, maintenance, and budgeting for the AEP western transmission system.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL QUALIFICATIONS AND PROFESSIONAL BUSINESS EXPERIENCE.

A. I earned a Bachelor of Electrical Engineering degree from the University of Dayton in 1985.

My electric utility and transmission career spans 33 years. In December 1985, I began my career as a station engineer with Columbus and Southern Ohio Electric, a
unit of AEP. From 1985 to 1996, I held a variety of engineering and supervisory positions with Columbus and Southern Ohio Electric. In 1996, I joined AEPSC, as the Manager of Operations Engineering. In 2004, I was promoted to Director, Transmission Reliability in the Transmission Operations organization, with responsibility for the operations of the AEP System Control Center, Transmission Operations Engineering, and the Transmission Operations Training & Development functions. I led the Transmission Asset Engineering organization from 2007-2009, and from 2009-2013, the Columbus Region of Transmission Region Operations, which was later named Transmission Field Services. In 2013, I became Director, Technical Support for Transmission Field Services, followed by a promotion to my current role as Vice President, Transmission Field Services for the AEP western transmission system in September of 2018.

Q. WHAT EXHIBITS DO YOU SPONSOR IN THIS PROCEEDING?

A. I sponsor the exhibits listed in the table of contents to my testimony.

II. PURPOSE AND BACKGROUND

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the reasonableness of the Company’s test year operations and maintenance (O&M) expense required to provide safe and reliable transmission service to customers in the AEP Texas transmission service area. I also briefly address new and upgraded transmission building infrastructure that was placed into service since AEP Texas’ predecessors’ AEP Texas Central Company (TCC) and AEP Texas North Company’s (TNC) last base rate cases in Docket Nos. 33309 and
33310, respectively. AEP Texas witness Judith E. Talavera addresses in her direct testimony the merger of TCC and TNC. Specifically, my testimony will cover the following topics:

- The AEP and AEP Texas transmission systems;
- The AEP Transmission organization and how the functions provided by its AEPSC transmission employees complement the functions provided by AEP Texas employees, so that there is no duplication of functions between AEPSC and AEP Texas employees;
- The AEP Texas O&M programs, including those in areas of reliability, asset management, vegetation management, and safety;
- The Company’s new transmission building additions since the last TCC and TNC rate cases; and
- The Company’s transmission-related test year O&M expenses, including the cost of services provided by AEPSC, and the following topics that support the reasonableness and necessity of those expenses:
  - Cost Trends,
  - Benchmarking Studies,
  - Staff Level Trends, and
  - Outsourcing.

III. AEP AND AEP TEXAS TRANSMISSION SYSTEMS

Q. PLEASE PROVIDE AN OVERVIEW OF THE AEP TRANSMISSION SYSTEM.

A. The AEP transmission system is an expansive system spanning AEP’s 11-state service territory located in the footprints of the Electric Reliability Council of Texas (ERCOT) independent system operator, the Southwest Power Pool (SPP) regional transmission organization (RTO), and the PJM RTO. AEP’s transmission system encompasses facilities operating at voltages from 23 kilovolt (kV) to 765 kV, and consists of
approximately 38,000 miles of circuitry. Of this total, approximately 8,000 miles operate at Extra High Voltage -- 345 kV, 500 kV or 765 kV -- as shown in EXHIBIT DRB-1. The AEP transmission system is highly interconnected with its neighboring utility transmission systems.

Q. PLEASE DESCRIBE THE GEOGRAPHIC AREA IN WHICH AEP TEXAS’ TRANSMISSION SYSTEM IS LOCATED.

A. Serving over 1 million electric delivery customers, the AEP Texas territory spans 97,000 square miles or roughly 36 percent of the geographic area of Texas, as illustrated in EXHIBIT DRB-2. From the north, near the Texas Panhandle and the Oklahoma border, it is more than 700 miles to reach the heart of the Rio Grande Valley and the Mexico border to the south. From the east, in Corpus Christi on the Gulf Cost, to Presidio in far west Texas, it is more than 600 miles. Notably, AEP Texas has the largest amount of coastal exposure, 240 miles, of any utility in the state. AEP Texas’ service territory is comprised of a North Division situated in north and west Texas, and a Central Division situated in south Texas. As further discussed below, the AEP Texas transmission system that serves the two divisions is operated and managed as a single transmission system.

Q. PLEASE DESCRIBE THE AEP TEXAS TRANSMISSION SYSTEM.

A. The AEP Texas transmission system delivers power and energy from generators throughout ERCOT and from asynchronous interconnections with other North American Electric Reliability Council (NERC) regions and the Comisión Federal de Electricidad (CFE), the national utility of Mexico, to the loads served by the Company’s distribution system. Additionally, the AEP Texas transmission system also
delivers power at wholesale to loads served by other utilities, co-operatives, and municipalities that provide distribution electric service in ERCOT within the AEP Texas transmission service area. The voltage levels of the AEP Texas transmission facilities range from 69 kV to 345 kV as shown in EXHIBIT DRB-3. There are approximately 8,400 circuit miles of transmission lines in the AEP Texas system, stretching from Matagorda County in southeast Texas to Presidio County in west Texas, and north from the Texas border with Oklahoma at the Red River south to the Texas border with Mexico at the Rio Grande River. AEP Texas owns and the AEP Transmission organization operates and maintains 200 transmission stations.

The Company’s transmission facilities are located within ERCOT, and interconnected to the SPP transmission systems of SWEPCO and PSO, two other AEP Operating Companies, through two high-voltage direct current (HVDC) ties co-owned by the Company. The interconnection between the Company and SWEPCO is through the East HVDC Tie, located in northeast Texas. The interconnection between the Company and PSO is through the North HVDC tie, located near Vernon, Texas. The Company’s transmission system is also interconnected to the CFE transmission system in two locations. The Eagle Pass tie, through a back-to-back voltage source converter, is located at Eagle Pass, Texas. The second interconnection with CFE is at Laredo, Texas through a connection to ERCOT with ETT at its variable frequency transformer. Except for significant load centers at Corpus Christi, Laredo, the Rio Grande Valley, Abilene, and San Angelo, the Company’s transmission service area is mostly sparsely populated with many miles of transmission line between stations.