B. Transmission Planning Process

Q. PLEASE DESCRIBE THE TRANSMISSION PLANNING PROCESS.

A. The transmission planning process determines the need for new or upgraded transmission and substation facilities due to changes in system conditions over time. As such, the transmission planning process is a key determinant of the need for capital investment in facilities.

Q. IS THE COMPANY'S TRANSMISSION PLANNING PROCESS SUBJECT TO THIRD-PARTY OVERSIGHT?

A. Yes. The Company's transmission planning process is overseen by the Electric Reliability Council of Texas, Inc. ("ERCOT").

Q. WHAT IS THE GOAL OF TRANSMISSION PLANNING AND HOW IS THIS GOAL ACCOMPLISHED?

A. The goal of transmission planning is to ensure that facilities are installed to accommodate planned system operation in a cost-effective and reliable manner. In order to determine whether facility additions or modifications are needed, planners must have both a clearly defined standard of adequacy and a good understanding of how the system will be operated in the future. For CenterPoint Houston, the standard of adequacy includes the FERC-approved NERC Transmission Planning Reliability Standard TPL-001-4, the ERCOT Transmission Planning Criteria, and the Company's Transmission System Design Criteria. These three documents are provided in Exhibits DB-2, DB-3 and DB-4.

Each of these documents contains specific performance standards which must be met during or after specific operating conditions. The performance standards typically relate to the protection of equipment, safety, or service reliability. The operating conditions addressed include normal conditions, as well as contingency (equipment outage) conditions.

To identify transmission system needs and plan improvements, computerized models of projected future transmission system conditions are developed and updated on a periodic basis. As a member of the ERCOT Region, CenterPoint Houston personnel participate in ERCOT working groups to develop and update the appropriate transmission system models. These models are then used by ERCOT and Transmission Service Provider ("TSP") planning engineers to identify future transmission system needs as the basis for planning cost-effective transmission system upgrades to address the identified future needs. Within the Asset Planning and Optimization organization, the engineering projects group determines the estimated cost and feasibility of different transmission or substation project alternatives to resolve the future needs identified in the transmission planning process.

Q. WHAT IS THE ROLE OF ERCOT IN THE TRANSMISSION PLANNING PROCESS?

A. ERCOT exercises oversight of the transmission planning processes for the ERCOT Region. ERCOT planning staff coordinates the model building processes I described above, relying upon the planning staffs of each TSP to provide the data for each TSP's portion of the ERCOT transmission system. ERCOT and each TSP must demonstrate compliance with the NERC Transmission Planning Reliability Standard TPL-001-4 and ERCOT Transmission Planning Criteria.

Individual transmission projects are usually initiated by the transmission planning staffs of TSPs, such as CenterPoint Houston, but ERCOT may also initiate transmission projects (typically with TSP input concerning feasibility and cost). TSPs report the status of projects identified through the transmission planning process to ERCOT through ERCOT's Transmission Project Information Tracking ("TPIT") system, in addition to Monthly Construction Report submittals to the Commission for transmission line projects. Transmission planning projects with estimated cost in excess of $25 million or any significant 345kV projects are submitted for ERCOT review and approval through ERCOT's regional planning process. Proposed transmission planning projects in excess of $100 million are additionally submitted by the ERCOT planning staff to the ERCOT Board of Directors for review and approval.

Q. YOU MENTIONED THAT TSPs MUST DEMONSTRATE COMPLIANCE WITH NERC TRANSMISSION PLANNING RELIABILITY STANDARD TPL-001-4. HAS CENTERPOINT HOUSTON DEMONSTRATED COMPLIANCE WITH NERC TRANSMISSION PLANNING RELIABILITY STANDARD TPL-001-4?

A. Yes. In 2016, the Texas RE audited CenterPoint Houston for compliance with applicable NERC Reliability Standards, including TPL-001-4, and determined that CenterPoint Houston complies with this standard.

Q. IS COMMISSION REVIEW AND APPROVAL ALSO NECESSARY FOR CERTAIN PROPOSED TRANSMISSION LINE PROJECTS?

A. Yes. In addition to ERCOT review and approval of all major 345kV projects and projects in excess of $25 million, TSPs must also demonstrate the need for certain proposed transmission line projects in Certificate of Convenience and Necessity ("CCN") applications before the Commission. The criteria for determining which transmission line projects require Commission review and approval of a CCN application is outlined in 16 Texas Administrative Code ("TAC") § 25.101.

Q. PLEASE IDENTIFY THE TRANSMISSION LINE PROJECTS THAT HAVE RECEIVED COMMISSION REVIEW AND APPROVAL SINCE THE COMPANY'S LAST BASE RATE CASE.

A. The transmission line projects that have received Commission review and approval since the Company's last base rate case in Docket No. 38339 include:

Zenith 138kV Project, Docket No. 38307;

138kV Springwoods Project, Docket No. 40049;

138kV Oyster Creek Project, Docket No. 41749;

138kV Zenith-Franz Project, Docket No. 44242; and

Brazos Valley Connection, Docket No. 44547.

Q. DOES ERCOT HAVE A ROLE IN DETERMINING TRANSMISSION SYSTEM INTERCONNECTIONS FOR NEW GENERATING UNITS?

A. Yes. ERCOT also supervises and coordinates generator interconnection studies. Generator interconnection studies are initiated upon generator request to ERCOT. ERCOT performs an initial screening study for each generator interconnection request. If a generation developer wishes to proceed beyond this initial stage, ERCOT designates a lead TSP to perform a Full Interconnection Study ("FIS"), with the opportunity for review and input from ERCOT and other TSPs. The FIS is a more detailed study in which interconnection alternatives are evaluated so that the most reasonable and cost-effective interconnection can be determined.

Q. IS COORDINATION WITH OTHER TSP'S SOMETIMES NECESSARY OR DESIRABLE IN THE TRANSMISSION PLANNING PROCESS?

A. Yes. CenterPoint Houston transmission and substation facilities are part of the ERCOT transmission network. Some CenterPoint Houston substations are connected to substations of other ERCOT TSPs through transmission lines. Accordingly, it is sometimes necessary and desirable for CenterPoint Houston transmission planners to coordinate with transmission planners from other TSP organizations. CenterPoint Houston does so through participation in the ERCOT Regional Planning Group ("RPG"), ERCOT's Regional Transmission Plan process, submission of projects into the TPIT database along with all other TSPs in ERCOT, and the formal Generator Interconnection Process. Also, as I noted earlier, transmission system models used for the transmission planning process are developed and maintained through a coordinated effort of TSP working groups under the direction of the ERCOT planning staff.

Q. WHAT NEW TRANSMISSION SUBSTATIONS DID CENTERPOINT HOUSTON BUILD FROM 2010 – 2018?

A. New transmission substations included Meadow (2010), Rothwood (2010), Zenith 345kV (2011), Zenith 138kV (2012), Jordan (2014), Jones Creek (2017), Bailey (2016), and Oyster Creek (2016).

Q. COULD YOU PROVIDE INFORMATION ON THE REVIEW PROCESS FOR THESE NEW TRANSMISSION SUBSTATIONS?

A. Yes. Meadow substation was built in 2010 to facilitate an interconnection with Texas New Mexico Power Company ("TNMP") for reliability concerns in the TNMP system. The review process entailed a coordinated study between TNMP and CenterPoint Houston. The project was also submitted by TNMP to ERCOT RPG for review. The cost of the new substation was $6.0 million.

Rothwood substation was built in 2010 as a project identified as part of the ERCOT 2007 Five-Year Plan. CenterPoint Houston subsequently submitted the project to ERCOT RPG for approval. The cost of the new substation was $20.8 million.

Zenith 345kV substation was built in 2011 to reduced congestion on the ERCOT system. The project was identified during the ERCOT Independent Review of CenterPoint Houston's Singleton project submittal. The cost of the new substation, inside the substation fence was $14.1 million.

Zenith 138kV substation was built in 2012 to support reliability in northwest Houston. The project was reviewed by ERCOT RPG. The cost of the new substation $7.1 million.

Jordan substation was built in 2014 to support load growth and resolve reliability concerns on the transmission system. The project was reviewed by ERCOT RPG. The cost of the new substation was $25.5 million.

Jones Creek substation was built in 2017 to support load growth and resolve reliability concerns on the transmission system. The project was reviewed by ERCOT RPG. The cost of the new substation was $66.2 million.

Bailey substation was built in 2016 to connect a new generation interconnection project. The project was reviewed as part of the ERCOT Generator Interconnection process. The cost of the new substation was $10.8 million.

Oyster Creek substation was built in 2016 to connect a new generation interconnection project. The project involved a long form CCN reviewed by the Commission and was reviewed as part of the ERCOT Generator Interconnection process. The cost of the new substation was $7.6 million.

Q. HOW DOES THE COMPANY ENSURE THAT, ONCE A TRANSMISSION PROJECT IS FOUND TO BE NECESSARY, THE CAPITAL EXPENDITURES ARE MONITORED AND CONTROLLED?

A. Since transmission capital projects can range in size from a few thousand dollars to several hundred million dollars, there is a range in the level of project controls used to monitor the capital spend. Please refer to the section in Mr. Narendorf's testimony on planning and cost control.

IV. RELIABILITY PROGRAMS

Q. PLEASE ADDRESS THE COMPANY'S COMMITMENT TO RELIABILITY ON BEHALF OF CUSTOMERS.

A. Customers expect reliable electric service for their residences and businesses. The benefit of a reliable system is fewer interruptions of service and faster response times and reduced outage time for customers in the event of an outage.

Q. DOES THE COMMISSION HAVE RELIABILITY STANDARDS THAT APPLY TO CENTERPOINT HOUSTON?

A. Yes. The Commission's distribution standards are contained in 16 TAC § 25.52. The system-wide reliability standard requires that each utility maintain and operate its electric distribution system so that the System Average Interruption Duration Index ("SAIDI"), which represents the average number of outage minutes per customer per year, and the System Average Interruption Frequency Index ("SAIFI"), which represents average number of times that a customer's service is interrupted, values for each year do not exceed the average of the three years, 1998, 1999 and 2000, by more than 5%. In addition, the rule provides that no distribution feeder with more than ten customers sustains a 12-month SAIDI or SAIFI value that is more than 300% greater than the system average of all feeders for any two consecutive years.

Q. HOW DOES CENTERPOINT HOUSTON TRACK RELIABILITY?

A. The Company has a comprehensive reporting system that provides a variety of reports covering all aspects of the transmission and distribution system. These reports include reliability reports and are available to Company employees to drive improvement. Some of the key monthly reliability reports include: 10% highest

SAIFI and SAIDI circuits; SAIFI, SAIDI and Customer Average Interruption Duration Index ("CAIDI") for the service centers; recurring fuse outages for the service centers; ranking measures for all circuits; a report that provides SAIDI, SAIFI, CAIDI and circuit performance measure ("CPM)" results on a one, three, and six month and year-to-date basis for all circuits; and monthly charts of system results for SAIDI, SAIFI, CAIDI, Momentary Average Interruption Frequency Index ("MAIFI"), lockouts and CPM. All of the reports are utilized to determine reliability actions that need to be taken by the Company.

Q. **HAS CENTERPOINT HOUSTON DEVELOPED ANY NEW METHODS TO TRACK RELIABILITY AND SUPPORT RELIABILITY IMPROVEMENT PROGRAMS?**

A. Yes. The Company has also developed dashboards for key distribution metrics that drive Engineering and Operational practices to reduce the frequency and duration of outages. These dashboards visualize key reliability drivers allowing decision makers to process large amounts of information quickly. As a result, the Company has reduced the amount of time between the outage and tracking its impact. This allows the Company to have an enhanced visibility of reliability and take actions much sooner.

Additionally, the Company has developed dashboards to track the asset health score of substation equipment, such as transformers, circuit breakers, and relays. The substation equipment is prioritized for replacement based on analytics information using factors, such as vintage, probability of failure, impact of failure, cost to maintain, design, and most importantly condition or health of the asset. The Company continually and routinely replaces substation equipment to maintain safety and reliability. Asset Life Cycle programs developed in-house help provide actionable intelligence in the form of analytics to asset management, operations, and engineering to prioritize assets for replacement based on asset health scores and support reliability improvement programs.

Q. WHERE DOES CENTERPOINT HOUSTON FOCUS ITS RELIABILITY IMPROVEMENT EFFORTS?

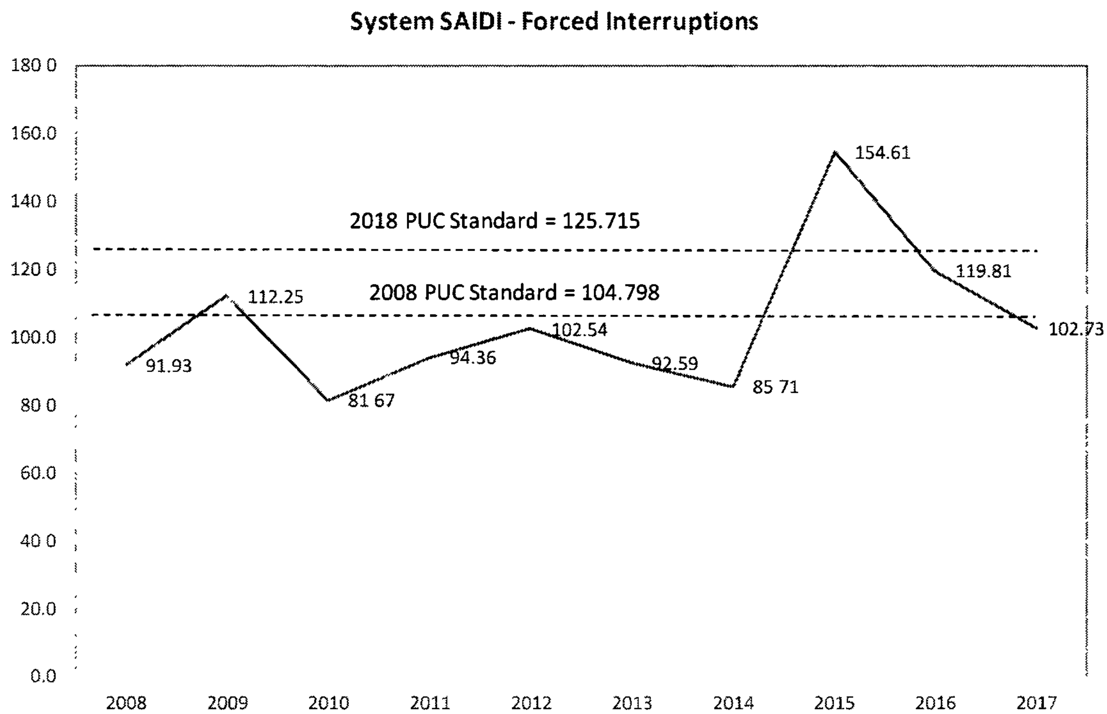
A. CenterPoint Houston's reliability efforts are focused on the circuits and laterals with the highest SAIDI and SAIFI values, so that money is spent where it will be most effective.

Q. HAVE CENTERPOINT HOUSTON'S ACTIONS BEEN SUCCESSFUL?

A. Yes. As shown in Figure 4, the system-wide SAIDI was well below the Commission standard for many years, 2008 – 2014. Because SAIDI represents the average number of outage minutes per customer per year, a reduction in SAIDI means that the average customer experiences fewer minutes of outages in a year. With this level of SAIDI, the average customer experienced less than two hours of outage minutes during the entire year.

One of the components of SAIDI is the frequency of outages, as measured by SAIFI. Programs that reduce the number or frequency of outages, such as the hot fuse program and the infra-red program, which are discussed by Ms. Sugarek, and tree trimming program and the pole maintenance program, which are discussed by Mr. Pryor, will improve reliability by avoiding outages before they can occur. The other component of SAIDI is the duration of outages, as measured by CAIDI. Programs that minimize the duration of outages, such as distribution automation and the service restoration process, which is discussed by Mr. Pryor, improve reliability by reducing restoration times.

Figure 4. System SAIDI



Q. WHAT ABOUT THE INCREASE IN SAIDI IN 2015?

A. In 2015, there were two major developments that impacted the numbers that were reported for system reliability metrics, a new Advanced Distribution Management System and new safety rules.

Q. DID CENTERPOINT HOUSTON SUBMIT A REQUEST TO THE COMMISSION TO REVISE THEIR SYSTEM-WIDE RELIABILITY STANDARD FOR SAIDI?

A. Yes. The Company filed an application to adjust its SAIDI standard. As a result, the Commission has adjusted the SAIDI standard to be the average of the recorded values for 2015, 2016 and 2017. The new SAIDI standard will be 125.715. As you can see, CenterPoint Houston's reliability is trending well below the new standard. System SAIDI for 2018 was 116.46.

Q. WAS THE STANDARD FOR SAIFI CHANGED AS WELL?

A. Yes. The new SAIFI standard will be 1.239.

Q. ARE THERE OTHER PROGRAMS THAT SUPPORT SYSTEM RELIABILITY?

A. Yes. The Power Factor Program.

Q. WHAT IS THE POWER FACTOR PROGRAM?

A. It is a program designed to maintain good power factor on the electric grid. Power factor ("PF") is the ratio of real power (kW or kilowatts) to total power (KVA or kilovolt-amperes) or PF = KW / KVA. While distribution facilities, including conductors and transformers, must transmit KVA, it is only the kW component that does the real work. Therefore, power factor is a relative measure of the amount of real power delivered.

Q. WHY IS POWER FACTOR IMPORTANT?

A. A good power factor reduces the amount of current flowing on a distribution circuit and will, as a result, reduce line losses, reduce voltage drop, and enable the circuit to carry more power. This results in a more efficient operation with less cost.

Q. HOW DOES CENTERPOINT HOUSTON MAINTAIN A GOOD POWER FACTOR?

A. CenterPoint Houston installs capacitors and appropriate controls on distribution lines at optimum locations, which are determined by modeling on DDPs. As stated earlier, the installation of capacitors for power factor control is in accordance with the planning design criteria for power factor.

Q. WHAT OTHER STEPS HAS CENTERPOINT HOUSTON TAKEN TO MAINTAIN GOOD POWER FACTOR?

A. CenterPoint Houston has installed a Remote Control Capacitor System ("RCCS") that provides centralized control of distribution capacitors based on the measured power factor of each distribution circuit. This control system turns capacitors on and off, on a given circuit, based on the precise knowledge of the total circuit KVARs. This enables very close control of distribution power factor.

Q. ARE THERE ANY OTHER BENEFITS TO THE RCCS SYSTEM?

A. Yes. RCCS provides feedback on capacitors that failed to switch properly, which will enable maintenance crews to go directly to faulty capacitors to make repairs, rather than having to perform periodic checks.

Q. HOW MANY CAPACITORS ON THE DISTRIBUTION SYSTEM CURRENTLY HAVE CENTRALIZED CONTROL?

A. Through the end of 2018, CenterPoint Houston has installed remote controls on approximately 5,548 capacitor banks, out of a total of 5,574 banks. Banks without a remote control are usually "fixed" banks.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. For the test year, the Engineering and Asset Optimization division O&M expenditures were $19.325 million. The O&M expenditures incurred by the Engineering & Asset Optimization division during the test year are reasonable and necessary expenses that should be recovered in the Company's rates. My testimony demonstrates that the Engineering & Asset Optimization division is properly structured in order to accomplish the goal of providing a safe and reliable distribution and transmission delivery system at a reasonable cost. Costs associated with this organization are effectively managed and maintained at reasonable levels through the entire process of business planning, budget plan review and ongoing budget plan monitoring. Moreover, the activities performed by the Engineering & Asset Optimization division are a reasonable and necessary part of providing reliable electric utility service.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF HARRIS §

AFFIDAVIT OF DALE BODDEN

BEFORE ME, the undersigned authority, on this day personally appeared Dale Bodden who having been placed under oath by me did depose as follows:

1. My name is Dale Bodden. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Dale Bodden
Dale Bodden

SUBSCRIBED AND SWORN TO BEFORE ME on this 7th day of March, 2019.

GINA QUIJANO
NOTARY ID #11953503
My Commission Expires
April 27, 2020

Gina Quijano
Notary Public in and for the State of Texas

My commission expires: 4/27/2020

Exhibit DB-1

Distribution Planning Design Criteria

The distribution design criteria for circuit loading state the following: (1) under normal conditions, voltage must be a minimum of 120 V and no conductor shall be loaded to greater than its normal rating; (2) under single contingency conditions, voltage must be a minimum of 117.6 V and no conductor shall be loaded to greater than its emergency rating; and (3) service restoration switching of non-faulted circuit sections shall be possible using no more than four pairs of pole-top-switches.

The distribution design criteria for power factor state that (1) the power factor on an overhead distribution circuit shall not be leading and (2) the combined power factor of all overhead circuits connected to the same distribution transformer bus shall not be lagging below 99%.

To support switching flexibility, the distribution design criteria state that (1) customers with loads in excess of 4,000 KVA (185 A) at 12 kV or 6,000 KVA (100 A) at 35 kV, shall be requested to split their loads between two feeders, (2) a new pole-top switch shall be considered when four or more pairs of pole-top switches must be opened to isolate a section under single contingency conditions, and 3) when a circuit section between switches has greater than 1,000 customers that represent 30% or more of the circuit total count then if feasible install additional switching devices on that section to divide customer count as evenly as possible.

Exhibit DB-2

Standard TPL-001-4 Transmission System Planning Performance Requirements

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**
2. **Number:** **TPL-001-4**
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1

- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

8.2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance

	Lower VSL	Moderate VSL	High VSL	Severe VSL
	3.4 or extreme events as described in Requirement R3, Part 3.5.	the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				used within its analysis as described in Requirement R6.
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				reliability related need who requested the Planning Assessment in writing.

Attachment 1
I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected
    b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required</u>

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7 OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1 OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4 Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

E. Regional Variances

None.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	

Version	Date	Action	Change Tracking
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 **and** 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	

Exhibit DB-3

ERCOT Planning Guide

Section 4: Transmission Planning Criteria

July 1, 2018

TRANSMISSION PLANNING CRITERIA

4.1 Introduction

(1) ERCOT employs both reliability criteria and economic criteria in evaluating the need for transmission system improvements. The economic criteria are included in Protocol Section 3.11.2, Planning Criteria. This Planning Guide provides the reliability criteria.

(2) The ERCOT System consists of those generation and Transmission Facilities (60 kV and higher voltages) that are controlled by individual Market Participants and that function as part of an integrated and coordinated system.

(3) To maintain reliable operation of the ERCOT System, it is necessary that all stakeholders observe and subscribe to certain minimum planning criteria. The criteria set forth in this Section 4.1 constitute the aforementioned minimum planning criteria. Tests outlined herein shall be performed to determine conformance to these minimum criteria; however, ERCOT recognizes that events more severe than those outlined in these criteria could cause grid separation and other tests may also be performed.

(4) The complexity and uncertainty inherent in the planning and operation of the ERCOT System make exhaustive studies impracticable; therefore, to gain maximum benefit from the limited number of tests performed, the selection of the specific tests and the frequency of their performance will be made solely upon the basis of the expected value of the reliability information obtainable from the test.

(5) ERCOT shall perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of the ERCOT System and identify appropriate solutions.

(6) Each Transmission Service Provider (TSP) will perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of its portion of the ERCOT System and implement appropriate solutions to meet the reliability performance criteria in this Section 4.1.

(7) The base cases created by the Steady-State Working Group (SSWG) and System Protection Working Group (SPWG) are available for use by Market Participants.

(8) If a TSP has its own planning criteria in addition to those defined in this Planning Guide, the TSP shall provide documentation of those criteria to ERCOT. ERCOT shall post the documentation on the Market Information System (MIS) Secure Area. The TSP shall

notify ERCOT of any changes to their planning criteria and provide revised documentation within 30 days of such change.

Reliability Criteria

4.1.1.1 Planning Assumptions

(1) A contingency loss of an element includes the loss of an element with or without a single line-to-ground or three-phase fault.

(2) A common tower outage is the contingency loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater.

(3) Unavailability of a single generating unit includes an entire Combined Cycle Train, if no part of the train can operate with one of the units Off-Line as provided in the Resource Registration data.

(4) The contingency loss of a single generating unit shall include the loss of an entire Combined Cycle Train, if that is the expected consequence.

(5) The following assumptions may be applied to the SSWG base cases for use in planning studies:

(a) Reasonable variations of Load forecast;

(b) Reasonable variations of generation commitment and dispatch applicable to transmission planning analyses on a case-by-case basis may include, but are not limited to, the following methods:

(i) Production cost model simulation, security constrained optimal power flow, or similar modeling tools that analyze the ERCOT System using hourly generation dispatch assumptions;

(ii) Modeling of high levels of intermittent generation conditions; or

(iii) Modeling of low levels of or no intermittent generation conditions.

4.1.1.2 Reliability Performance Criteria

(1) The following reliability performance criteria (summarized in Table 1, ERCOT-specific Reliability Performance Criteria, below) shall be applicable to planning analyses in the ERCOT Region:

(a) With all Facilities in their normal state, following a common tower outage with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(b) With all Facilities in their normal state, following an outage of a Direct Current Tie (DC Tie) Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(c) With any single generating unit unavailable, followed by Manual System Adjustments, followed by a common tower outage or outage of a DC Tie Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(d) With any single transformer, with the high voltage winding operated at 300 kV or above and low voltage winding operated at 100 kV or above unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, FACTS device, or DC Tie Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition; and

(e) With any single DC Tie Resource or DC Tie Load unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, FACTS device, or DC Tie Resource or DC Tie Load, with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition.

	Initial Condition	**Event**	**Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages**	**Non-consequential Load Loss Allowed**
1	Normal System	Common tower outage, DC Tie Resource outage, or DC Tie Load outage	Yes	No
2	Unavailability of a generating unit, followed by Manual System Adjustments	Common tower outage, DC Tie Resource outage, or DC Tie Load outage	Yes	No

	Initial Condition	Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-consequential Load Loss Allowed
3	Unavailability of a transformer with the high voltage winding operated at 300 kV or above and low voltage winding operated at 100 kV or above, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; 5. FACTS device; or 6. DC Tie Resource or DC Tie Load	Yes	No
4	Unavailability of a DC Tie Resource or DC Tie Load, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; 5. FACTS device; or 6. DC Tie Resource or DC Tie Load	Yes	No

Table 1: ERCOT-specific Reliability Performance Criteria

(2) ERCOT and the TSPs shall endeavor to resolve any performance deficiencies as appropriate. If a Transmission Facility improvement is required to meet the criteria in this Section 4.1.1.2, but the improvement cannot be implemented in time to resolve the performance deficiency, an interim solution may be used to resolve the deficiency until the improvement has been implemented.

4.1.1.3 Voltage Stability Margin

(1) In conducting its planning analyses, ERCOT and each TSP shall ensure that the voltage stability margin is sufficient to maintain post-transient voltage stability under the following study conditions for each ERCOT or TSP-defined area:

(a) A 5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P0 and P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements; and

(b) A 2.5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.

4.1.1.4 Steady State Voltage Response Criteria

(1) In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following steady state voltage response and post-contingency voltage deviation criteria:

(a) 0.95 per unit to 1.05 per unit in the pre-contingency state following the occurrence of any operating condition in category P0 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements;

(b) 0.90 per unit to 1.05 per unit in the post-contingency state following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements; and

(c) Following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard further analysis to assess voltage stability is required in the event of a post-contingency steady-state voltage deviation that exceeds 8% at any load-serving bus above 100 kV, exclusive of buses on a radial system that serve only Resource Entities and/or Load . After further analysis, ERCOT and the TSPs shall endeavor to resolve any voltage instability.

(2) If a TSP has communicated to ERCOT that a Facility has unique characteristics and may operate outside of the above ranges and deviation (e.g. Facilities located near a series capacitor) or that the Facility needs to be operated in a more restrictive range (e.g. a nuclear plant, UVLS relay settings) or its system is designed to operate with different voltage limits or voltage deviation then the TSP's specified limits will be considered acceptable.

4.1.1.5 Transient Voltage Response Criteria

(1) In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following transient voltage response criteria:

(a) For any operating condition in category P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within five seconds after clearing the fault; and

(b) For any operating condition in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within ten seconds after clearing the fault.

4.1.1.6 Damping Criteria

(1) In conducting its planning analyses, ERCOT and each TSP shall ensure that, for any operating condition in categories P1 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, ERCOT and each TSP shall ensure that power oscillation within the range of 0.2 Hz to 2 Hz decays with a minimum 3% damping ratio.

Exhibit DB-4

CenterPoint Energy
Transmission System Design Criteria
December, 2018

I. Overview

CenterPoint Energy Houston Electric, LLC (CenterPoint Energy) has a long history of providing highly reliable and safe transmission service at a reasonable cost to its customers. The purpose of the CenterPoint Energy Transmission System Design Criteria is to maintain excellence in reliability and cost performance while maintaining compliance with applicable regional and national standards.

This document outlines the criteria used by CenterPoint Energy, along with the Electric Reliability Council of Texas, Inc. (ERCOT) Transmission Planning Criteria and North American Electric Reliability Corporation (NERC) Standards, to design its transmission system, connect new customers and generators, and establish transmission interconnections with adjacent electric utilities. It also applies to the modification of existing load or generation customers, or adjacent electric utilities' facilities.

As an ERCOT stakeholder, CenterPoint Energy participates in various working groups, such as the Steady State Working Group (SSWG), Dynamics Working Group (DWG), and System Protection Working Group (SPWG), and their coordinated planning processes. CenterPoint Energy coordinates its transmission planning efforts with the other electric utility transmission planners and with ERCOT staff transmission planners in accordance with the ERCOT Protocols, ERCOT Nodal Operating Guide, ERCOT Planning Guide, and NERC Reliability Standards. CenterPoint Energy follows, at a minimum, the ERCOT Transmission Planning Criteria, contained in Section 4 of the ERCOT Planning Guide in the design of its transmission system. Such planning criteria are included by reference herein. ERCOT and its member utilities, including CenterPoint Energy, design the Bulk Electric System (BES) in compliance with NERC Reliability Standards and such standards are also included by reference herein.

The CenterPoint Energy Transmission System Design Criteria is reviewed and updated periodically as the needs of CenterPoint Energy and its end users change, as well as when ERCOT Transmission Planning Criteria and NERC Reliability Standards change or new NERC Reliability Standards become enforceable.

II. Scope

This document outlines the criteria for making transmission system planning decisions to remedy and eliminate potential steady state, short circuit, voltage stability, or transient stability system performance concerns affecting the CenterPoint Energy transmission system to ensure its reliability. These criteria do not apply to refurbishment, replacement, or repair of electrical facilities or to situations where transmission facilities may be necessary due to distribution system reliability and economic considerations.

III. Planning Process

Like many other electric utilities, CenterPoint Energy uses commercially available computer software to model its transmission system. A set of various cases, known as base cases, is prepared periodically, incorporating the latest projections of relevant information such as load forecasts, anticipated changes in generation, and transmission network data, including known outages of transmission facility(ies) that are expected to produce more severe system impacts. Base case preparation is coordinated with other ERCOT transmission planners through participation in ERCOT Working Groups and committees. CenterPoint Energy models its transmission system six years into the future, consistent with ERCOT practices.

Using these base cases as a starting point, CenterPoint Energy performs steady state, short circuit, and stability studies. Steady state studies include contingency analysis of its transmission system. Short circuit studies include determining the fault current for three-phase and single-phase-to-ground faults at a transmission bus. Stability studies include running dynamic simulations of various planning contingency events and determining their impact on the CenterPoint Energy transmission system. A detailed description of planning events tested can be found in the CenterPoint Energy document Rationale for Contingencies Analyzed by CenterPoint Energy Transmission Planning. The base cases intrinsically include a variety of assumptions and only represent a single operating condition for the period of study. Because a wide variety of operating conditions occur in actual operation, CenterPoint Energy also analyzes reasonable variations of the base cases, known as sensitivity cases, where key assumptions are modified. Modified assumptions may include one or more of the following: generation additions, retirements, or other dispatch scenarios; load level, load forecast, or dynamic load model assumptions; expected transfers; expected in-service dates of new or modified transmission facilities; and reactive resource capability.

IV. Identification of Potential Areas of Concern

CenterPoint Energy tests the adequacy of its transmission system using the ERCOT-specific Reliability Performance Criteria summarized in Table 1 of Section 4 of the ERCOT Planning Guide and the current version of NERC Reliability Standard TPL-001 addressing Transmission System Planning Performance Requirements. CenterPoint Energy facility ratings respect the most limiting applicable equipment rating of the individual equipment that comprises that facility. Transmission system adequacy is tested using NERC Reliability Standard TPL-001 Table 1 Categories P0 through P7 contingencies and Extreme Event conditions as follows:

1. Under Category P0 and Category P1 contingency conditions, a transmission network element should not exceed its Rate A, also called Normal or Continuous Rating, in base cases, with the following exception: a radial tap section can be loaded up to Rate B, also called Emergency Rating, under Category P1 conditions. Rate A is the maximum continuous current rating of a transmission network element and is based upon the most limiting substation terminal

equipment, the transmission line conductor, or autotransformer rating, whichever is applicable. In determining Rate A of a transmission network element, the substation terminal equipment rating is based on the rating of the most limiting substation in-line equipment or substation bay/bus equipment up to the adjacent substation node upon the outage of one substation circuit breaker or switch. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

2. Under Categories P2 and P7 contingency conditions, a transmission network element should not exceed its Rate B in base cases. Rate B is the two-hour rating of a transmission network element based upon the most limiting substation terminal equipment, the transmission line conductor, or autotransformer rating, whichever is applicable. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

   Under Categories P3 and ERCOT-specific Reliability Performance Criteria P6 contingency conditions, a transmission network element should not exceed Rate B in base cases. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

   Under Categories P4 contingencies, P5 contingencies, P6 contingencies that are not ERCOT-specific Reliability Performance Criteria, and Extreme Event conditions, Rate B of a transmission network element is used to evaluate the impact of these conditions that may result in wide area disturbances and cascading.

   In determining Rate B of a transmission network element, the substation terminal equipment rating is based only on the rating of the most limiting substation in-line equipment.

3. Under Categories P1 through P7 contingencies and Extreme Event conditions, transmission elements should be tripped where relay loadability limits are exceeded.

4. The voltage at a transmission bus should remain within a range of 95% to 105% of nominal voltage for Category P0 and Category P1 contingency conditions. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

5. The voltage at a transmission bus should remain within the range of 92% to 105% of nominal voltage for Category P2, P3, P7, and ERCOT-specific Reliability Performance Criteria P6 contingency conditions. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

   Under Categories P4 contingencies, P5 contingencies, P6 contingencies that are not ERCOT-specific Reliability Performance Criteria, and Extreme Event conditions, a voltage range of 92% to 105% of nominal voltage is used to evaluate the impact of these conditions that may result in wide area disturbances and cascading.

6. Available three-phase or single-phase-to-ground fault current should not exceed 99% of any transmission facility short circuit rating with all generation connected to the CenterPoint Energy transmission system modeled in service. Fault current calculations for determining the circuit breaker interrupting capability for faults that they are expected to interrupt is calculated by following the latest IEEE Standard C37.04 and IEEE Standard C37.010. When analysis indicates an inability of the system to meet the performance requirements indicated above, a Corrective Action Plan is developed to resolve the performance deficiency.

Special Considerations for South Texas Project Electric Generating Station:

CenterPoint Energy, as well as the other owners of the South Texas Project (STP) Switchyard, and ERCOT utilizes criteria for the South Texas Project Electric Generating Station as specified in the current South Texas Project Nuclear Plant Interface Coordination Agreement and this agreement is also included by reference herein.

V. Transmission System Design Considerations

When a potential transmission system concern is identified using the guidelines set forth in Section IV above, CenterPoint Energy evaluates various alternatives and identifies an appropriate solution consistent with its goal of providing highly reliable and safe transmission service at a reasonable cost. In determining an appropriate solution, CenterPoint Energy considers the likelihood and severity of the potential system performance concerns, while recognizing the various uncertainties and assumptions inherent in simulating future transmission system conditions. CenterPoint Energy strives to develop timely, cost-effective, and feasible solutions which, to the extent reasonably practical, minimize both landowner impact and the need for extended outages to implement the solutions. This process involves necessary tradeoffs between conflicting objectives and the exercise of engineering judgment.

CenterPoint Energy utilizes standard electric transmission system simulations (power flow, short circuit, stability, etc.) and, when applicable, develops project cost estimates to compare system improvement options. The following technical parameters are also considered in the design of the CenterPoint Energy transmission system:

1. To the extent that it is reasonably and economically practical, CenterPoint Energy seeks to limit the number of two-line, loop breakered substations on a transmission line segment between major (three or more line terminals) substations to three or less. This is to limit the exposure of multiple two-line, loop breakered substations to separation from the CenterPoint Energy transmission system.

2. To the extent that it is reasonably and economically practical, CenterPoint Energy strives to limit the amount of generation that would be tripped to, at most, 1250 MW with the loss of a double circuit transmission line in the design of generator interconnections.

3. CenterPoint Energy considers protective relay system dependability, security, and simplicity when determining transmission circuit configurations (e.g., a long radial tap connected to a transmission line section).

4. CenterPoint Energy designs its transmission system such that switching of its transmission capacitor banks or inductive reactors (static reactive devices) limits the momentary voltage change at a transmission bus to less than 2% with the strongest source out of service for major buses (with three or more network transmission elements). For other buses (with only two network transmission elements), CenterPoint Energy designs its transmission system such that switching of its static reactive devices limits the momentary change at a transmission bus to less than 2% with both network transmission elements in-service.

5. CenterPoint Energy also requires that the starting of customer equipment (motors, arc furnaces, etc.) does not result in a momentary voltage change greater than 2% at the customer's high-side bus with the strongest transmission line segment out-of-service.

6. CenterPoint Energy seeks to limit the number of in-series sectionalizing devices (motor operated disconnect switches, circuit switchers, etc.) on a transmission line segment between breakered substations to three or fewer. This is necessary to limit the number of automatic circuit breaker reclose attempts required to isolate the faulted line section and the increased complexity of fault sectionalizing schemes.

Revision History		
DATE	**DESCRIPTION**	**APPROVED BY**
January, 2000	New Document capturing existing procedure	Transmission Planning Manager
October, 2001	Revision 1	Transmission Planning Manager
May, 2004	Revision 2	Transmission Planning Manager
March, 2008	Revision 3	Transmission Planning Manager
December, 2015	Revision 4	Transmission Planning Manager
December 2018	Revision 5	Transmission Planning Manager

Exhibit DB-5

Engineering Project Justification and Construction Summaries for Springwoods, Fry Road, Tanner, Sandy Point and Village Creek Substations

CenterPoint Energy

ELECTRIC DISTRIBUTION – PLANNING
Engineering Project Justification & Construction Summary
2014 Distribution Development Plan
For 35 kV Springwoods Substation Revision 1

SAP PROJECT #:HLP/00/0875	DATE:	MAY 6, 2013
1) Substation Project Cost (SAP = SH):	Cost:	$ 10,600,000
2) Transmission Project Cost (SAP TR):	Cost:	$ 7,000,000
3) Underground Project Cost (SAP = DM):	Cost.	$ 2,867,737
4) Overhead Project Cost (SAP DT) 2014 Construction		
Greenspoint Service Center	Cost:	$ 68,180
Humble Service Center	Cost:	$ 796,320
Complete by: 06/01/2014	Total.	$ 21,33?,237

2012 Peak Load	0.0 MW
New Demand Load	0.0 MW
Non-Coincident Demand Load	0.0 MW
TkVA Growth Factor 0.5% for 4 years	0.0 MW
Load Switched from Rayford Substation	40.3 MW
Load Switched from Kuykendahl Substation	7.8 MW
Load Switched from Treaschwig Substation	11.7 MW
Load Switched from Louetta Substation	43.9 MW
Load Switched from Westfield Substation	8.8 MW
Facilities Losses	1.4 MW
2016 Plan Load	113.9 MW

Substation Planning 2-Hour Firm: 142.5 MVA

The following construction is called for in this plan:

Build new Springwoods Substation:

- Install two (2) 100MVA 138/35kV substation transformers.
- Build seven (7) low profile T-structures.
- Install twelve (12) breakers for eight (8) distribution circuits.

- Build 13,380 feet of 600 AAC overhead conductor.
- Re-conductor 3590 feet small wire to 600 AAC overhead conductor.
- Install 10,350 feet 35 kV 3-phase 1250 MCM AL cable.
- Build 4685 feet duct bank.
- Install three (3) pole top switches
- Install five (5) Intelligent Grid Switching Devices (IGSD).
- Switch circuits per the plan.

To correct power factor design criteria:

- Install one (1) 1800kVAR capacitor bank.

Budget Category: Growth | Last Plan: New Substation | Costs do not include COH

Prepared: John Maxwell | Checked: [signature] | Approved: [signature] | Date 8-6-13

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CenterPoint Energy

ELECTRIC DISTRIBUTION ENGINEERING – PLANNING
Engineering Project Justification & Construction Summary
2014 Distribution Development Plan
35 KV Fry Road Substation

SAP PROJECT #: HLP/00/0612	DATE: MARCH 9, 2013
1) Substation Project Cost (SAP = SH).	Cost: $7,950,000
2) Transmission Project Cost (SAP = TR):	Cost: $0
3) Underground Project Cost (SAP = DM):	Cost: $777,300
4) Overhead Project Cost (SAP = DT)	Cost: $1,797,262
2014 Construction	
Cypress Service Center	
Completed by: 06/01/2014	Total: $10,524,562

	35 kV
No Peak (New Fry Road Substation)	0.00 MW
kVA Growth Factor (1%) per year from 2014 to 2017	3.17 MW
New Demand Load	0.00 MW
Non-Coincident Demand Load	0.00 MW
Load switched from Gertie	62.93 MW
Load switched from Cy Fair	60.89 MW
Load switched from Franz	2.31 MW
Facilities Losses	2.99 MW
2017 Plan Load	132.29 MW

35 kV Substation 2-Hour Firm: 134.14 MVA

The following summarizes the construction called for in this plan.

To address load growth in the area:

- Install (2) 100 MVA transformers.
- Install (6) 35 kV circuits out of the new Fry Road Substation.
- Build 700' of 9 6" and 250' of 2-6" duct-bank.
- Pull approximately 2,690' of 1250 MCM cable.
- Build approximately 47,377' of 3ph 600 AAC 35 kV feeder.
- Re-conductor approximately 1,065' of small wire to 3ph 600 AAC feeder.
- Convert approximately 6,150 of 12 kV conductor to 3ph 600 AAC feeder.

To increase circuit reliability:

- Install (13) 35 kV pole top switches.
- Install (2) 35 kV IGSD devices.

To maintain unity power factor design criteria

- Install (2) 900 kVAR and (4) 1800 kVAR 35 kV remote controlled capacitor bank.

Budget Category: Growth Last Plan: New Sub Costs do not include: COH

MJG
Prepared M. J. Gentry Checked T. R. Sullivan Approved Date 8-8-13

CenterPoint Energy

ELECTRIC DISTRIBUTION – PLANNING
Engineering Project Justification & Construction Summary
2016 Distribution Development Plan
For 35 kV Tanner Substation – Revision 1

SAP PROJECT #: 1036	DATE:	JUNE 16, 2015
1) Substation Project Cost (SAP – SB):	Cost:	$10,000,000
2) Transmission Project Cost (SAP = TR):	Cost:	$0
3) Underground Project Cost (SAP = DM):	Cost:	$3,150,000
4) Overhead Project Cost (SAP = DT) 2015 Construction Spring Branch Service Center	Cost:	$302,950
Complete by: 06/01/2016	Total:	$13,452,950

2013 Peak Load	0 MW
TkVA Growth Factor (0% per year)	0 MW
New Demand Load	0.9 MW
Non-Coincident Demand Load	0 MW
Load Switched From Addicks Substation	80.6 MW
Load Switched From Satsuma Substation	20.6 MW
Facility Losses	0.7 MW
2016 Plan Load	102.8 MW

Planning: 35 kV Sub 2-Hour Firm: 142.5 MVA

The following construction is called for in this plan:

*** New Substation:**
- Install 2-100 MVA 138 kV / 35 kV distribution transformers, T-structures and (6) 35 kV feeders.
- Install eleven 35kV breakers for the six new circuits.

*** Major Underground Work:**
- Build 3300 feet of 9-6" duct bank from manhole (MH)# 01 to MH# 07. Install 2- 3way manholes and 5- 4way manholes.
- Pull 8,200 feet of 1250 MCM cable from substation breaker to the new circuits TPs and the customer.
- Pull 4000 feet of 1250 MCM cable from substation breaker through MH # 11208.

*** To correct loading and voltage design criteria violations under normal operating conditions:**
- Remove approx. 160 Ft. of 600 MCM AAC.
- Build approx. 3500 feet of 600 AAC conductor.
- Install 7 new 35kV PTS.
- Build 4 - 35kV TP - Terminal Poles and replace 1 - PTS with a 35 kV Terminal Pole.
- Switch circuits according to the plan.

*** Previously Authorized Construction:**
- Build approx. 1100 Ft. of 600 MCM AAC for the Star Park ARS customer. Easement required.
- Install 2 new IGSDs, ARS-IGSD-04 & ARS-IGSD-02 to serve the Star Park ARS customer.

*** To correct power factor design criteria violations under normal operating conditions:**
- Install 3 - new 35kV 1800 kVAR RCCS capacitor banks.
- Remove 2 – 35kV 1800 kVAR capacitor banks.

Budget Category: Growth   Costs do not include: COH

Prepared S. Khan   Checked R. J. Aymond RJA 2/8/16   Approved E. E. Brigg EEB/DXG   Date 02/08/16

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CenterPoint Energy

ELECTRIC DISTRIBUTION PLANNING

Engineering Project Justification & Construction Summary

2017 Distribution Development Plan
For 12 kV Sandy Point Substation

SAP PROJECT #: CNP/00/0954	DATE:	MARCH 1, 2015
1) Substation Project Cost (SAP – SB):	Cost:	$5,600,000
2) Transmission Project Cost (SAP – TR):	Cost:	$2,300,000
3) Underground Project Cost (SAP – DM):	Cost:	$465,000
4) Overhead Project Cost (SAP – DT) Service Center 2016 Baytown Construction	Cost:	$101,500
Complete by: 06/01/2017	Total:	$8,466,500

	12kV
2015 Adjusted Load	00.00 MW
TkVA 2019 Growth Factor 0%	0.00 MW
Non-Coincident Demand Load	0.00 MW
New Demand Load	20.00 MW
Load Switched from LP	3.73 MW
Facilities Losses	0. 06 MW
2019 Plan Load	23.79 MW

Planning's Substation 2-Hour Firm: 71.25MVA

The following construction is called for in this plan:

- To alleviate loading under normal conditions in the Laporte and Alexander Island substation areas, and to provide future service to the Port of Houston, install new 12kV Sandy Point substation.

  Transmission: Install a 138kV double tap supply to the new 138/12kV substation at the Sandy Point site.

  Substation: Install two (2) new 50 MVA transformers, and four (4) circuits with underground getaways.

  Underground: Install 4200' of three phase 1000 MCM AL cable, 400' of 9-6" ducts, 50' of 2-6" ducts, and four (4) manholes. Underground for customer service: Install 500' of three phase parallel 1000MCM AL cable (high capacity circuits for Port of Houston service).

  Distribution. Install two (2) 12kV terminal poles (TP), Build 2700'of 600AAC primary. Install one (1) pole top switch.

- To correct power factor: Install one (1) 12kV 600kVAR RCCS capacitor bank.

Budget Category: Growth　　Last Plan: New　　Costs do not include Overhead

Prepared by: J. D. McLemore　Checked by: R. J. Gaido　Approved by: EEB / RJG　Date: 4/14/16

RJG 4-14-16

Page 1 of 1

CenterPoint Energy

ELECTRIC DISTRIBUTION – PLANNING

Engineering Project Justification & Construction Summary

2017 Distribution Development Plan
For 35 kV Village Creek Substation

SAP PROJECT #:HLP1084	DATE: FEB. 29, 2016
1) Substation Project Cost (SAP = SB):	Cost: $ 10,800,000
2) Transmission Project Cost (SAP – TR):	Cost: $ 0
3) Underground Project Cost (SAP = DM):	Cost: $ 1,489,000
4) Overhead Project Cost (SAP – DT)	
2017 Construction	
Katy Service Center	Cost: $ 1,568,471
Spring Branch Service Center	Cost: $ 61,000
Complete by: 06/01/2017	Total: $ 13,918,471

Total Cost include Deferred Construction

2014 Peak Load	0.00 MW
New Demand Load	4.50 MW
Non-Coincident Demand Load	0.00 MW
TkVA Growth Factor 1.0% for 3 years	1.31 MW
Load Switched from Freeman 12kV Substation	1.06 MW
Load Switched from Katy Substation	12.55 MW
Load Switched from Fry Road Substation	1.86 MW
Load Switched from Franz Substation	66.32 MW
Load Switched to Gertie Substation	-9.69 MW
Facilities Losses	1.45 MW
2020 Plan Load	79.36 MW

Substation Planning 2-Hour Firm: 142.5 MVA

The following construction is called for in this plan:

Build new Village Creek Substation:

- Install two (2) 100MVA 138/35kV substation transformers.
- Build five (5) low profile T-structures and install twelve (6) breakers for four (4) feeders.
- Build 19,182 feet of 35kV 600 AAC overhead conductor.
- Re-conductor and convert 8,605 feet small wire to 35kV 600 AAC overhead conductor.
- Install 4,670 feet 35 kV 3-phase 1250 MCM AL cable.
- Convert 13,650 feet 12kV small wire to 35kV small wire.
- Remove 1,030 feet of existing overhead wire.
- Build 240 feet of 2-6", 50 feet of 4-6", 1200 feet 9-6" and 190 feet of 12-6" PVC duct bank.
- Install two (2) 2-way, two (2) 3-way, & one (1) 4-way manholes.
- Install 4,670 feet 35kV 3phase 1250 AL cable.
- Install eight (8) 35kV terminal poles.
- Install eight (8) 35kV pole top switches & replace one (1) pole top switch with a 3-phase IGSD.
- Convert sixty seven (67) 12kV transformers to 35kV.
- Install three (3) 35/12kV Step-Down transformer bank(s).
- Switch circuits per the plan.

To correct power factor design criteria:

- Install six (6) 35kV 1800kVAR capacitor bank(s).

Previously Authorized Construction on New Load Request:

- Install fifteen (15) 35kV pole top switches.
- Re-conductor /Convert 25,400 feet small wire to 35kV 600 AAC overhead conductor.
- Build 58,510 feet of 35kV 600 AAC overhead conductor.
- Install four (4) 35/12kV Step-Down transformer bank(s).

Budget Category: Growth   Last Plan: New Substation   Costs do not include COH

Prepared: John Maxwell   Checked: DA 6/29/16   Approved: [signature]   Date 6-29-16

DALE BODDEN WORKPAPERS:

Bodden Workpaper - PUC Subst. Rule 25.52.pdf

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter C. INFRASTRUCTURE RELIABILITY.

§25.52. Reliability and Continuity of Service.

(a) **Application**. This section applies to all electric utilities as defined by the Public Utility Regulatory Act (PURA) §31.002(6) and all transmission and distribution utilities as defined by PURA §31.002(19). The term "utility" as used in this section shall mean an electric utility and a transmission and distribution utility.

(b) **General**.

(1) Every utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time.

(2) Each utility shall make reasonable provisions to manage emergencies resulting from failure of service, and each utility shall issue instructions to its employees covering procedures to be followed in the event of emergency in order to prevent or mitigate interruption or impairment of service.

(3) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service entities on a temporary basis until normal service to these agencies can be restored.

(4) Each utility shall maintain adequately trained and experienced personnel throughout its service area so that the utility is able to fully and adequately comply with the service quality and reliability standards.

(5) With regard to system reliability, no utility shall neglect any local neighborhood or geographic area, including rural areas, communities of less than 1,000 persons, and low-income areas.

(c) **Definitions**. The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise.

(1) **Critical loads** — Loads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment.

(2) Interruption classifications:

(A) **Forced** — Interruptions, exclusive of major events, that result from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or manually, or an interruption caused by improper operation of equipment or human error.

(B) **Scheduled** — Interruptions, exclusive of major events, that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair. If it is possible to defer an interruption, the interruption is considered a scheduled interruption.

(C) **Outside causes** — Interruptions, exclusive of major events, that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages.

(D) **Major events** — Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events shall 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.

(3) **Interruption, momentary** — Single operation of an interrupting device which results in a voltage zero and the immediate restoration of voltage.

(4) **Interruption, sustained** — All interruptions not classified as momentary.

(5) **Interruption, significant** — An interruption of any classification lasting one hour or more and affecting the entire system, a major division of the system, a community, a critical load, or service to interruptible customers; and a scheduled interruption lasting more than four hours that affects customers that are not notified in advance. A significant interruption includes a loss of service to 20% or more of the system's customers, or 20,000 customers for utilities serving more than 200,000 customers. A significant interruption also includes interruptions adversely affecting a community such as interruptions of governmental agencies, military bases, universities and schools, major retail centers, and major employers.

(6) **Reliability indices**:

(A) **System Average Interruption Frequency Index (SAIFI)** -- The average number of times that a customer's service is interrupted. SAIFI is calculated by summing the number of customers interrupted for each event and dividing by the total number of customers on the system being indexed. A lower SAIFI value represents a higher level of service reliability.

(B) **System Average Interruption Duration Index (SAIDI)** -- The average amount of time a customer's service is interrupted during the reporting period. SAIDI is calculated by summing the restoration time for each interruption event times the number of customers interrupted for each event, and dividing by the total number of customers. SAIDI is expressed in minutes or hours. A lower SAIDI value represents a higher level of service reliability.

(d) **Record of interruption.** Each utility shall keep complete records of sustained interruptions of all classifications. Where possible, each utility shall keep a complete record of all momentary interruptions. These records shall show the type of interruption, the cause for the interruption, the date and time of the interruption, the duration of the interruption, the number of customers interrupted, the substation identifier, and the transmission line or distribution feeder identifier. In cases of emergency interruptions, the remedy and steps taken to prevent recurrence shall also be recorded. Each utility shall retain records of interruptions for five years.

(e) **Notice of significant interruptions.**

(1) **Initial notice**. A utility shall notify the commission, in a method prescribed by the commission, as soon as reasonably possible after it has determined that a significant interruption has occurred. The initial notice shall include the general location of the significant interruption, the approximate number of customers affected, the cause if known, the time of the event, and the estimated time of full restoration. The initial notice shall also include the name and telephone number of the utility contact person, and shall indicate whether local authorities and media are aware of the event. If the duration of the significant interruption is greater than 24 hours, the utility shall update this information daily and file a summary report.

(2) **Summary report**. Within five working days after the end of a significant interruption lasting more than 24 hours, the utility shall submit a summary report to the commission. The summary report shall include the date and time of the significant interruption; the date and time of full restoration; the cause of the interruption, the location, substation and feeder identifiers of all affected facilities; the total number of customers affected; the dates, times, and numbers of customers affected by partial or step restoration; and the total number of customer-minutes of the significant interruption (sum of the interruption durations times the number of customers affected).

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter C. INFRASTRUCTURE RELIABILITY.

(f) **Priorities for Power Restoration to Certain Medical Facilities.**

(1) A utility shall give the same priority that it gives to a hospital in the utility's emergency operations plan for restoring power after an extended power outage, as defined by Texas Water Code, §13.1395, to the following:

(A) An assisted living facility, as defined by Texas Health and Safety Code, §247.002;

(B) A facility that provides hospice services, as defined by Texas Health and Safety Code, §142.001; and

(C) A nursing facility, as defined by Texas Health and Safety Code, §242.301;

(2) The utility may use its discretion to prioritize power restoration for a facility after an extended power outage in accordance with the facility's needs and with the characteristics of the geographic area in which power must be restored.

(g) **System reliability.** Reliability Standards shall apply to each utility, and shall be limited to the Texas jurisdiction. A "reporting year" is the 12-month period beginning January 1 and ending December 31 of each year.

(1) **System-wide standards.** The standards shall be unique to each utility based on the utility's performance, and may be adjusted by the commission if appropriate for weather or improvements in data acquisition systems. The standards will be the average of the utility's performance from the later of reporting years 1998, 1999, and 2000 or the first three reporting years the utility is in operation.

(A) **SAIFI.** Each utility shall maintain and operate its electric distribution system so that its SAIFI value shall not exceed its system-wide SAIFI standard by more than 5.0%.

(B) **SAIDI.** Each utility shall maintain and operate its electric distribution system so that its SAIDI value shall not exceed its system-wide SAIDI standard by more than 5.0%.

(2) **Distribution feeder performance.** The commission will evaluate the performance of distribution feeders with ten or more customers after each reporting year. Each utility shall maintain and operate its distribution system so that no distribution feeder with ten or more customers sustains a SAIDI or SAIFI value for a reporting year that is more than 300% greater than the system average of all feeders during any two consecutive reporting years.

(3) **Enforcement.** 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 this subsection. In determining the appropriate enforcement action, the commission shall consider:

(A) the feeder's operation and maintenance history;

(B) the cause of each interruption in the feeder's service;

(C) any action taken by a utility to address the feeder's performance;

(D) the estimated cost and benefit of remediating a feeder's performance; and

(E) any other relevant factor as determined by the commission.

APPLICATION OF CENTERPOINT	**§**	**PUBLIC UTILITY COMMISSION**
ENERGY HOUSTON ELECTRIC, LLC	**§**	
FOR AUTHORITY TO CHANGE RATES	**§**	**OF TEXAS**

DIRECT TESTIMONY

OF

JULIENNE P. SUGAREK

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

April 2019

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

1.	ADMS	Advanced Distribution Management System
2.	ANSI	American National Standards Institute
3.	ASTM	American Society for Testing and Materials
4.	CAIDI	Customer Average Interruption Duration Index: the average length of an outage.
5.	CPM	Circuit Performance Measure: The index combines four factors affecting circuit performance, MAIFI, CAIDI, SAIFI and circuit lockouts, to produce one index that provides a relative indication of the reliability of an individual circuit over time.
6.	DCRF	Distribution Cost Recovery Factor
7.	DOE	Department of Energy
8.	DSTAR	Distribution System Testing, Application, and Research
9.	EEI	Edison Electric Institute
10.	EPRI	Electric Power Research Institute
11.	ERCOT	Electric Reliability Council of Texas
12.	FSR	Field Service Representative
13.	IEEE	Institute of Electrical and Electronics Engineers
14.	kV	Kilo-volts
15.	KVA	Kilovolt-amperes: total power.
16.	KVAR	Kilovolt-amperes reactive: reactive power.
17.	kwh	Kilowatt-hour
18.	MUG	Major Underground Construction

19.	MAIFI	Momentary Average Interruption Frequency Index: the average number of times that a customer was momentarily out of service over a period of time, usually a year. Momentary operations are less than one minute and are usually due to instantaneous circuit breaker operations.
20.	MPT	MP Technologies
21.	NEC	National Electrical Code
22.	NEMA	National Electrical Manufacturers Association
23.	NESC	National Electrical Safety Code
24.	NHPL	North Houston Pole Line
25.	OSHA	Occupational Safety and Health Administration
26.	PCB	Polychlorinated Biphenyl
27.	PF	Power factor: ratio of real power (kW or kilowatts) to total power (KVA or kilovolt-amperes) or PF = KW / KVA
28.	PURA	Public Utility Regulatory Act
29.	RCCS	Remote Control Capacitor System
30.	REPs	Retail Electric Providers
31.	SAIDI	System Average Interruption Duration Index: average number of outage minutes per customer per year.
32.	SAIFI	System Average Interruption Frequency Index: average number of times that a customer's service is interrupted.
33.	SEE	Southeastern Electric Exchange
34.	TxSET	Texas Standard Electronic Transaction
35.	TLM	Transformer Load Management Program
36.	URD	Underground Residential Distribution

EXECUTIVE SUMMARY OF JULIENNE P. SUGAREK

CenterPoint Energy Houston Electric, LLC's ("CenterPoint Houston" or the "Company") Power Delivery Solutions division is responsible for facilitating the interconnection process for customers and generators on both the transmission and distribution system, advising distribution customers on power quality solutions, providing design for installations on the distribution system, interfacing with customers to address changing electrical service needs, and responding to service concerns.

My testimony:

- describes the structure and functions of the Power Delivery Solutions division;
- supports the reasonableness and necessity of Operations and Maintenance ("O&M") costs incurred by the Power Delivery Solutions division during the 2018 test year in the amount of $8.8 million;
- describes Power Delivery Solution's major programs and initiatives; and
- supports the Company's requests related to proposed battery assets and to modify CenterPoint Houston's tariffs to facilitate the interconnection of Distributed Energy Resources and development of electric vehicle charging stations.

Together with the cost of service data and testimony of the Company's other witnesses, my testimony and supporting materials demonstrate that the test year O&M expenses for Power Delivery Solutions are reasonable, necessary, and representative of the costs to provide service to customers of CenterPoint Houston and, thus, should be included in the Company's cost of service.

DIRECT TESTIMONY OF JULIENNE SUGAREK

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Julienne P. Sugarek, and I am employed by CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company") as Vice President of Power Delivery Solutions.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Texas with a Bachelor's of Science in 2000 and a Master's in Business Administration in 2005. I joined CenterPoint Houston in 2007. I became a licensed Certified Public Accountant in 2008. My positions with the Company have included Process Project Consultant, Portfolio Manager, Distribution Services Director, Service Area Director, Regional Operations Director and my present position as Vice President of Power Delivery Solutions. I was named to my present position in 2018, at which time I assumed all responsibility for the customer interface, project support and power quality solutions that directly impact CenterPoint Houston customers.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. As Vice President of Power Delivery Solutions, my responsibilities include overseeing the customer interfacing departments which guide customers through the interconnection process, advise distribution customers on power quality solutions, provide design for small and large distribution installations, and interface with customers to address changing electrical needs.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of CenterPoint Houston.

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

A. My testimony identifies the functions of the Power Delivery Solutions division and describes how the division is structured to accomplish the goal of providing a reliable power delivery system at a reasonable cost. I also support the reasonableness and necessity of $8.8 million in Operations and Maintenance ("O&M") expense associated with activities performed by the Power Delivery Solutions division.

Q. PLEASE DESCRIBE THE INTERACTION OF YOUR TESTIMONY WITH OTHER WITNESSES IN THIS CASE.

A. My testimony identifies the functions of the Power Delivery Solutions division and describes how the division is structured to accomplish the goal of providing a reliable power delivery system at a reasonable cost. Company witness Randal M. Pryor sponsors capital investment that has been made in the Company's distribution system since January 1, 2010, test year distribution O&M expense, and his testimony describes the operation, system maintenance, trouble response and meter maintenance of the distribution delivery system. Company witness Dale Bodden's testimony sponsors capital investment associated with the Engineering Planning and Optimization organization, describes the engineering, planning, design and capital budgeting and management process for CenterPoint Houston. Company witness Martin W. Narendorf Jr.'s testimony sponsors the capital investment in the Company's transmission, substation, and major underground assets since January 1, 2010 and demonstrates that the capital and test year O&M costs associated with the Company's transmission and substation facilities are reasonable and necessary. Each of these testimonies explains major reliability and maintenance programs for which the witness is responsible.

Company witness Michelle M. Townsend discusses allocated costs associated with the regulated support organizations and CenterPoint Energy Service Company, LLC. Company witness Kristie L. Colvin provides testimony on the Company's overall planning and budgeting process and cost of service adjustments. Company witness Dane A. Watson sponsors the Company's requested depreciation rate for voltage regulation battery assets. Company witness Matthew A. Troxle sponsors the Company's tariff changes including changes to the Company's Facilities Extension Policy relating to Electric Vehicle ("EV") charging.

II. DESCRIPTION OF POWER DELIVERY SOLUTIONS

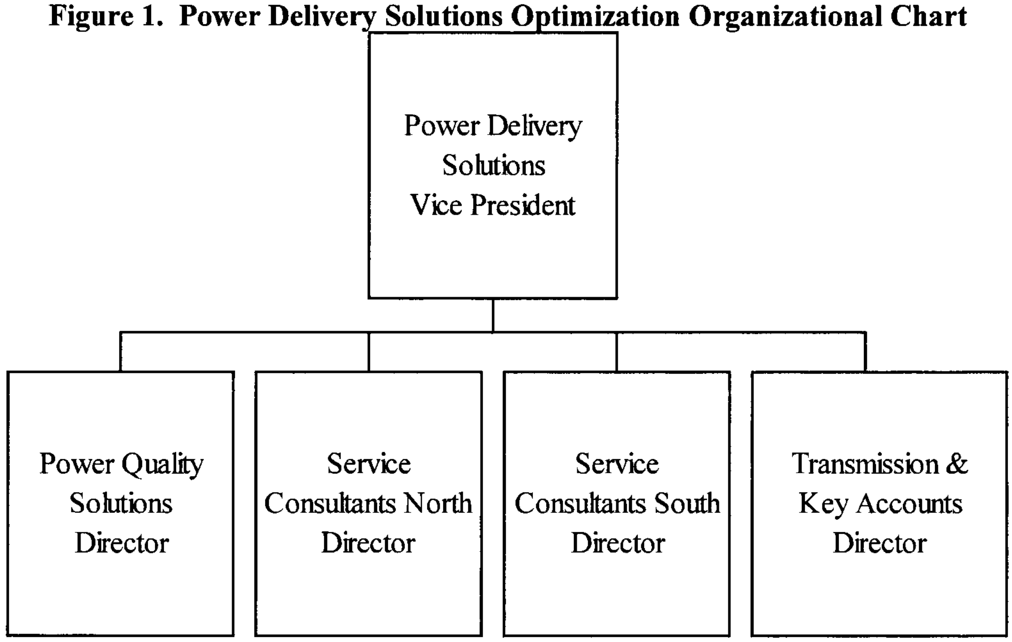
Q. PLEASE DESCRIBE THE POWER DELIVERY SOLUTIONS DEPARTMENT'S PRIMARY FUNCTION AND OBJECTIVES.

A. Power Delivery Solutions division is responsible for facilitating the interconnection process for customers and generators on both the transmission and distribution system, advising distribution customers on power quality solutions, providing design and project support for installations on the distribution system, and interfacing with customers to address changing electrical service needs and responding to service concerns.

Q. WHAT IS THE BASIC STRUCTURE OF THE POWER DELIVERY SOLUTIONS ORGANIZATION?

A. Power Delivery Solutions includes the Power Quality Solutions Department, the Service Consultants North Department, the Service Consultants South Department, and the Transmission and Key Accounts Department. Figure 1 below provides an organizational chart for Power Delivery Solutions.

Figure 1. Power Delivery Solutions Optimization Organizational Chart



Q. PLEASE DESCRIBE THE MAIN FUNCTIONS OF THE POWER QUALITY SOLUTIONS DEPARTMENT.

A. The Power Quality Solutions department is responsible for managing and reporting on distribution reliability programs and providing technical support for constructing and operating the distribution system. Three distinct teams function within the department: Power Quality, Distributed Energy Resources ("DER"), and Research and Development. The Power Quality group supports overall reliability performance of the distribution system by providing customer level and circuit level technical support to Service Consultants and individual customers, including primary metered and premium rollover services. The Power Quality group is responsible for administering the Company's infra-red program, hot fuse program, and root cause analysis program, analyzing results of these program efforts, and assisting operations departments in determining a course of action. The DER group is responsible for interfacing with both residential and commercial customers to facilitate the interconnection process for DER on the distribution system. DER group activities include the inspection and approval of the DER system before interconnection, as well as coordinating with distribution planning and system protection. Finally, the Research & Development group is responsible for the evaluation, development and implementation of pilots, proof of concept projects, and technologies focused on improving system reliability performance and technology advancement. When appropriate, they interface with the Institute of Electrical and Electronics Engineers, Electric Power Research Institute, Edison Electric Institute, Southeastern Electric Exchange, Distribution System Testing, Application, and Research, and similar organizations to further evaluate new initiatives.

Q. WHAT ARE THE MAIN FUNCTIONS OF THE SERVICE CONSULTANT DEPARTMENTS?

A. Service consultants serve as the frontline of communication for CenterPoint Houston's residential, commercial, or small industrial electric customers connecting to the distribution system. Their core job function entails being the customer's primary point of contact throughout the electric construction process at their new home, commercial business, or industrial job site. Service consultants work with developers, builders, electricians and individual customers to design needed distribution service facilities, obtain easements, issue work orders, collect customer contribution in aid of construction ("CIAC"), and schedule construction. Each consultant is assigned to a geographic area in either the North or South district, in which they are responsible for responding to any of their customer's questions. In addition to new construction requests, service consultants also respond to customer reliability inquiries and interface with distribution operations groups responsible for installation, maintenance, and repair of distribution systems. The Service Consultant Department is divided into two regions: North and South. The Service Consultant North department is responsible for customer interface at the Bellaire, Greenspoint, Cypress, Humble, Katy and Spring Branch service centers. The Service Consultant South department is responsible for customer interface at the South Houston, Galveston, Sugarland, Fort Bend, Baytown and Brazoria service centers.

Q. PLEASE DESCRIBE THE MAIN FUNCTIONS OF THE TRANSMISSION AND KEY ACCOUNTS DEPARTMENT.

A. The Transmission and Key Accounts Department is comprised of three distinct groups: Transmission Accounts and Support, Key Accounts, and Street Lighting Design. The Transmission Accounts and Support group is responsible for the interconnection of large industrial customers and generators to the transmission system, approval and payment of Transmission Cost of Service payments to other Transmission Service Providers, and coordination of regulatory filings for

CenterPoint Houston transmission projects including the monthly construction reports, final cost reports, and Certificate of Convenience and Necessity applications. The Key Accounts group is responsible for maintaining relationships with major distribution customers and coordinating special service arrangements with identified key accounts and major customers, as needed. Key Accounts consultants are each assigned specific distribution customers and serve as the customer's primary point of contact. They interface with other internal groups on the customer's behalf to address any issues the customer may have. The Street Lighting Design group designs lighting systems for roadways, bridges, walkways, hike and bike trails, and parks at the request of municipal governments and residential and commercial customers. They also assist customers with billing, material and inventory issues. The Street Lighting Design group interfaces regularly with the distribution operations groups responsible for installation, maintenance, and repair of street lighting systems.

III. POWER DELIVERY SOLUTIONS O&M EXPENDITURES

Q. WHAT PORTION OF THE COMPANY'S TOTAL TEST YEAR O&M EXPENDITURES WERE RELATED TO POWER DELIVERY SOLUTIONS?

A. Test year O&M expenditures for the Power Delivery Solutions Organization totaled approximately $8.8 million. Figure 2 shows the test-year expense for each department.

Figure 2. Test-Year O&M Expense by Department for Power Delivery Solutions

Power Delivery Solutions O&M by Department	Total Test Year Expense
Power Quality Solutions	$1,613,479
Service Consultants North	$2,140,797
Service Consultants South	$1,912,915
Transmission & Key Accounts	$2,034,463
Administrative & General	$1,090,980
Total	**$8,792,633**

Q. ARE ALL OF THE O&M EXPENDITURES ASSOCIATED WITH THE POWER DELIVERY SOLUTIONS DIVISION REASONABLE AND NECESSARY?

A. Yes. A utility must have operations that facilitate the interconnection process for customers and generators on both the transmission and distribution system. As such, the O&M expenses for Power Delivery Solutions are related to necessary functions that directly impact the reliability and operation of the distribution and transmission system to serve both existing and new customers. As the testimonies of Mr. Pryor, Mr. Narendorf, and Ms. Bodden detail, the Company's budgeting controls and processes further ensure the reasonableness of both O&M and capital investment projects. Additional examples of necessary programs and initiatives that are managed by Power Delivery Solutions are presented below.

IV. MAJOR PROGRAMS AND INITIATIVES

Q. HOW DOES CENTERPOINT HOUSTON ENSURE THE RELIABILITY OF ITS SYSTEM ON A DAY-TO-DAY BASIS?

A. CenterPoint Houston has a number of major programs and initiatives that are implemented to increase the reliability of the electric delivery system for

CenterPoint Houston customers. These programs include the Pole Maintenance Program, the Underground Residential Distribution Cable Life Extension Program, the Meter Maintenance Program, the Vegetation Management Program, the Feeder Inspection Program, the Pole Top Switch Inspection Program and the Service Restoration Process. These seven programs are discussed by Mr. Pryor. The Company also has a Power Factor Program and certain reliability standards, which Ms. Bodden addresses in her direct testimony. I address the Company's Infra-red Program, the Root Cause Analysis Program, the Hot Fuse Program and the Distribution Automation Program. All of these programs can result in capital improvements or O&M expenses, or in the case of some programs, a combination of both. For instance, the Pole Maintenance Program includes a combination of both O&M expenses for inspections and ground-line treatment of existing poles, and the capital investment for replacing poles. Regardless, the following programs are necessary to ensure the continued safe and reliable operation of the Company's transmission and distribution systems.

A. Infra-red Program

Q. WHAT IS THE INFRA-RED PROGRAM?

A. Infra-red technology allows the Company to see the heat generated by deteriorating components on the distribution system. These "Hot Spots" eventually result in equipment failure and a loss of service. Infra-red technology is a unique tool to find potential equipment outages before they occur, so that proactive repairs can be made prior to an outage. The Infra-red Program reduces the number of equipment failures and improves reliability by decreasing System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index

("SAIFI").

Q. WHAT IS THE INSPECTION CYCLE FOR THE INFRA-RED PROGRAM?

A. All circuits are inspected on an eight-year cycle. Seventy benchmark circuits, that are representative of the overall CenterPoint Houston system, are inspected every two years to ensure that the eight-year cycle is adequate to achieve the desired reliability results. If a circuit is identified as a repeating 10% circuit, meaning it's in the top 10% for SAIDI and SAIFI minutes, or a 300% circuit, meaning its SAIDI and SAIFI minutes are three times higher than the average circuit, then it is advanced on the infra-red schedule to the current year. This additional focus on the circuits with the highest SAIDI and SAIFI measurements are done to address performance issues. Also, circuits that are heavily loaded (greater than 500 amps) are inspected, as data has proven a higher failure rate of equipment when subjected to higher load.

Q. WHAT EQUIPMENT IS INSPECTED?

A. Infra-red scans are conducted on the terminal poles at the substation and major equipment on the circuit, including pole-top switches, reclosers, regulators, and capacitors. Scans are also performed on the fuse cutouts, jumpers, splices, and transformers along the circuit backbone. The identified hot spots are reported and repairs are made. If the problem is severe enough, and there is a danger of imminent failure, then procedures are taken to isolate the device and initiate immediate repairs.

B. Root Cause Analysis Program

Q. WHAT IS THE ROOT CAUSE ANALYSIS PROGRAM?

A. The Root Cause Analysis Program analyzes circuits that the Company projects will not perform as well as desired under the SAIDI and SAIFI metrics. A detailed evaluation of a circuit's outages for the current year is conducted. From this analysis, a recommendation and action plan is generated to address circuit issues. CenterPoint Houston uses outage causes, outage location, outage frequency, customer outage minutes, and the results of a field inspection to develop an action plan that can include a number of possible recommendations to address the root cause of the outages. The recommendations might include a protective coordination study, an infra-red inspection, enhanced lightning protection, reconfiguration to avoid vehicle collisions, reconfiguration of line fuses, tree trimming, and installation or relocation of automated devices. After corrective action is taken, the circuit performance is watched throughout the year to determine if the analysis was correct or if additional measures are necessary.

An essential element of the program is to create a proactive response to 10% circuit outages. It is designed to identify and initiate corrective actions on circuits with issues before they become a repeating 10% circuit. In order to accomplish this, a circuit's indices are analyzed against predictive data that indicates operational issues.

C. Hot Fuse Program

Q. WHAT IS THE HOT FUSE PROGRAM?

A. The Hot Fuse Program identifies line and transformer fuses that have experienced recurring outages. On a daily basis, fuses are identified and within approximately four weeks, corrective action is identified. There are two hot fuse criteria: (1) recurring hot fuse – a fuse that has had a minimum of three outages within a 90-day period, and (2) ultra hot fuse – a fuse that has had a minimum of three outages within a 30-day period. Hot fuses are less likely than an ultra hot fuse to have a high impact to the Company's indices if left unaddressed after the 90-day timeframe. These fuse outages are more closely associated with wind-related events that are caused by vegetation or slack span contacts. The ultra hot fuse is more likely to have a high impact to the Company's indices if left unaddressed after the 30-day timeframe. These fuse outages are more closely associated with ongoing issues, such as overloaded devices.

In addition, a third criterion applies for fuses that have large customer counts that affect the circuit's overall reliability. For those circuits with greater than four outages in 12 months, these fuses are also reviewed during the Root Cause Analysis process to verify a successful solution to the outages.

CenterPoint Houston field personnel inspects all the hot fuses meeting one of these criteria and research outage records to determine the cause of the outages causing the hot fuse. The Company then issues work orders to correct the problem. Typical remedies include tree trimming, the installation of wildlife protection devices, slack span adjustment, the installation of additional fuses to limit the impact of a fault, or the installation of smart fuses that only operate on permanent faults.

D. Distribution Automation

Q. WHAT IS CENTERPOINT HOUSTON'S DISTRIBUTION AUTOMATION PROGRAM?

A. The Distribution Automation Program implements remote switching automation on the distribution system in order to decrease outage times experienced by customers. Quick service restoration improves reliability and enhances customer satisfaction. Locations are chosen to allow for the greatest impact to the overall reliability of the service area.

Q. HOW DOES DISTRIBUTION AUTOMATION WORK?

A. Historically, remote control capability was added to line reclosers and pole-top switches. Line reclosers automatically sectionalize long circuits in the event of a fault. This isolates the outage to the section of the facilities that are directly affected. Reclosers attempt three times to reconnect the isolated section of a distribution line, but if the fault continues, the recloser will lock out. Once a recloser locks out, field personnel have to manually re-close it. The benefit of installing remote control capability on line reclosers is that it saves the travel time for utility personnel to go manually re-close the line reclosers after the fault has been resolved.

Q. WHAT IS THE COMPANY'S CURRENT APPROACH TO DISTRIBUTION AUTOMATION?

A. In 2011, the Company began utilizing Intelligent Grid Switching Devices ("IGSD") instead of installing automation on line reclosers and pole-top switches. These devices are state of the art equipment that allows for the functionality of the existing equipment coupled with enhanced features. The Company is able to program these devices to automatically sectionalize for a fault and then reclose if the fault has had one of the following occur: cleared, auto-sectionalize without a reclose, a remote command to operate, or a local command in the same device. Because one device can be programmed or re-programmed to perform the functionality of several devices, the device can be quickly modified in a distribution system that is changing. The devices are designed to interface with centralized control systems through state of the art communication protocols and network infrastructure. Monitoring stations are also installed to obtain voltage, current, and fault indicator information on the distribution system. This information is used to help locate permanent faults on the circuit and to help identify problems relating to customer issues.

Q. CURRENTLY, WHAT IS THE EXTENT OF AUTOMATION ON THE DISTRIBUTION SYSTEM?

A. CenterPoint Houston has installed remote control devices on 261 reclosers and 401 remote controlled pole top switches, and has installed 973 IGSDs and 68 monitoring stations on the distribution system.

Q. WHAT ARE CENTERPOINT HOUSTON'S FUTURE PLANS FOR DISTRIBUTION AUTOMATION?

A. The Company plans to continue to install IGSDs in strategic locations for reliability purposes.

V. VOLTAGE REGULATION BATTERY REQUEST

Q. PLEASE PROVIDE AN OVERVIEW OF CENTERPOINT HOUSTON'S REQUEST FOR PERMISSION TO INSTALL BATTERIES FOR VOLTAGE REGULATION PURPOSES.

A. CenterPoint Houston is requesting authority to install batteries, when necessary and cost effective, to provide voltage regulation associated with solar farms, wind generation, and other forms of distributed generation that are expected to be connected to the Company's facilities in the coming months and years. The request is a result of the Company's recent experience with the energization of a 5 megawatt ("MW") solar farm. As with any solar or wind generation project, the amount of load placed on the Company's system at any given time by the generation asset depends on weather. Following the energization of the solar facility in early 2019, 4MW of pump load was regularly being affected by voltage issues stemming from the solar farm's intermittency caused by cloud coverage. Cloud cover was inducing voltage deviations from the solar farm that occurred too quickly for the Company's traditional voltage regulation equipment to address.

Q. HOW DID THE COMPANY ADDRESS THE VOLTAGE ISSUES ASSOCIATED WITH THIS SOLAR PROJECT?

A. CenterPoint Houston studied various potential solutions to the voltage issues. Traditional utility fixes that were explored included the building of a new distribution line solely for the solar farm, the installation of a new substation for the solar farm, and making modifications to an existing substation to create an express distribution circuit to the solar installation. The Company also studied battery storage systems. Ultimately, the most cost effective solution for the issues caused by the solar facility was the creation of an express distribution circuit for the facility.

Q. IF THE COMPANY WAS ABLE TO ADDRESS THE VOLTAGE REGULATION ISSUES RELATED TO THIS SOLAR FACILITY WITH THE INSTALLATION OF TRADITIONAL TRANSMISSION AND DISTRIBUTION ASSETS, WHY IS IT REQUESTING PERMISSION TO INSTALL BATTERIES IN THIS PROCEEDING?

A. While it was most cost effective to address the voltage intermittency issues associated with the solar facility described above through the installation of an express distribution circuit, the Company is confident that each solar farm, wind asset, and distributed generation facility will present its own interconnection and voltage regulation issues. Depending on a solar or wind farm's location, distance from Company facilities, and any constraints on existing facilities, the installation of a battery for voltage regulation purposes may be the most cost-effective solution. For instance, the Company had space at its nearest substation to install the express distribution circuit for the solar facility. That space may not exist in substations located next to future solar generation installations, or there may be right of way constraints between the substation and the resource facility.

Q. HOW MANY SOLAR FARMS HAVE ASKED TO INTERCONNECT TO THE COMPANY'S DISTRIBUTION SYSTEM IN THE COMING YEARS?

A. At the time of this filing, the Company is aware of five new solar facilities that are currently under development. It has already executed interconnection agreements with four of these facilities. Each of the facilities is expected to create voltage regulation issues.

Q. WHAT PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION") ACTION IS CENTERPOINT HOUSTON REQUESTING AS IT RELATES TO VOLTAGE SMOOTHING BATTERIES?

A. The Company requests the authority to (1) install voltage smoothing battery systems, when necessary and cost effective, for voltage regulation purposes and (2) include the cost of the systems in rate base as depreciated consistent with the new rate noted in Mr. Watson's testimony.

Q. WHY IS THE COMPANY REQUESTING A COMMISSION RULING ON THIS ISSUE?

A. Battery materials and technologies have improved in recent years, and the proposed voltage smoothing battery system offers an opportunity to improve reliability for CenterPoint Houston's current customers. Wind and solar farms have a unique impact on electric distribution systems, and the demand for such facilities appears to be increasing. As the cost of energy storage systems continues to decline, the Company believes that it has a duty to explore how those systems may benefit its customers and the next generation of the utility electric grid. Similarly, the Company uses its best efforts to facilitate the interconnection of new generation to its transmission and distribution system for the benefit of all Electric Reliability Council of Texas customers. The installation of voltage smoothing technology further facilitates this interconnection, thus bringing more generation to market. However, given the fact that CenterPoint Houston's proposal is a first of its kind, and in light of stakeholder comments in the Commission's recent rulemaking related to energy storage (Project No. 48023), CenterPoint Houston determined that it would be prudent to request permission to install the voltage regulation assets in the context of this rate proceeding, where a depreciation rate for the asset can also be set.

Q. **WILL THE BATTERY FACILITIES BE CLASSIFIED AS TRANSMISSION OR DISTRIBUTION ASSETS?**

A. The Company anticipates that batteries installed for voltage regulation of solar and wind farms will qualify as distribution assets under Commission Substantive Rules and the Federal Energy Regulatory Commission Uniform System of Accounts.

Q. **COULD THE PROPOSED BATTERY SYSTEMS BE CONSIDERED GENERATION ASSETS?**

A. No. Section 35.151 of the Public Utility Regulatory Act, "Electric Energy Storage," defines electric energy storage facilities that are to be used to sell energy or ancillary services as "generation assets." The battery systems at issue in this filing will not be used to sell energy or ancillary services. CenterPoint Houston will purchase any energy needed to charge the batteries, but will not sell energy expended by the batteries during dips in voltage that might result in outages for customers when the dip is followed by a corresponding spike.

Q. **COULD THE COMPETITIVE MARKET PROVIDE A VOLTAGE SOLUTION EQUIVALENT TO THE COMPANY'S REQUEST?**

A. It could, and CenterPoint Houston anticipates that, in some instances, solar, wind, or other distributed generation generators will install energy storage facilities that could manage voltage intermittency. However, there is no existing requirement for a generator to install smoothing facilities on its side of the meter. CenterPoint Houston nevertheless has a responsibility to maintain reliable delivery service to all customers, and downstream customers are being impacted by the operation of this solar facility. To this end, if the circuit continues to fail to perform within the range of system-wide reliability standards due to the impact of the solar farm, a customer could allege through an enforcement action that the Company is not properly operating and maintaining its distribution system.

Q. WHAT IS THE ANTICIPATED COST OF A TYPICAL VOLTAGE SMOOTHING BATTERY INSTALLATION?

A. The Company estimates that battery systems necessary to assist with voltage intermittency will generally cost approximately $4.2 million to install and $30,000 per year to operate and maintain.

VI. DISTRIBUTED ENERGY RESOURCE TECHNOLOGY

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE DER INTERCONNECTION PROCESS?

A. Yes. The Company is chiefly concerned with the safety and reliability of the grid for all its customers while actively seeking solutions to facilitate the interconnection of DER. Currently, the Company requires transfer trip anti-islanding protection for all generators over 2MW connected to the distribution system. The Company also requires transfer trip anti-islanding protection for distribution connected generators greater than 300kW but less than or equal to 2MW if the generator creates an islanding risk as determined by the Company's pre-interconnection study. Going forward, the Company seeks the flexibility to offer additional islanding protection solutions. In the short-term, this will allow the Company to offer reverse power flow in lieu of transfer trip for distribution connected generators greater than 300kW but less than or equal to 2MW, if the solution is more cost effective and offers equal protection of Company assets. Please see the direct testimony of Mr. Troxle.

VII. REQUEST TO ADD AN ADDITIONAL ALLOWANCE FOR FACILITY EXTENSIONS TO ELECTRIC VEHICLE CHARGING STATIONS

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO ADD AN ADDITIONAL ALLOWANCE FOR FACILITY EXTENSIONS TO ELECTRIC VEHICLE CHARGING STATIONS?

A. The Company is proposing to add an additional allowance in Section 2 of its Construction Services Policy (governing facility extensions to permanent retail customer electrical installations), on top of the existing standard allowance, for facility extensions to EV public charging stations. The purpose of this additional allowance is to better facilitate the growth of EV charging stations in the Company's service territory. Specifically, the Company seeks to reduce the amount of the CIAC required from a customer who requests a facility extension to a public EV charging station to be located on the customer's premises.

Q. PLEASE DESCRIBE THE ADDITIONAL ALLOWANCE PROPOSED FOR PUBLIC EV CHARGING STATIONS.

A. The terms and conditions for the additional allowance proposed for facility extensions to public EV charging stations are contained in new Subsection 2.5 of the Company's Construction Services Policy (located in Chapter 6.1.2.2 of the Company's tariff). See Exhibit MAT-8 to the direct testimony of Mr. Troxle. In addition to the standard allowance currently provided by the Company for all facility extensions to permanent retail customer electrical installations as described in Subsection 2.2 of the Construction Services Policy, CenterPoint Houston is proposing in new Subsection 2.5 to provide another allowance toward the cost of a facility extension to a public EV charging station to cover up to $18,000 of the remaining facility extension costs not covered by the standard allowance.

Q. WHAT IS THE BASIS FOR THE ADDITIONAL ALLOWANCE AMOUNT OF UP TO $18,000 TOWARD THE COST OF AN EV CHARGING STATION FACILITY EXTENSION?

A. $18,000 represents the approximate cost per foot for a typical underground facility extension of 1,000 feet of single phase electrical facilities, or $18 per foot. The Company anticipates that most public EV charging stations will require 3-phase underground facilities, and the cost for constructing 3-phase underground facilities is significantly higher than $18 per foot, because of the requirement for concrete encased ducts and manhole access to the underground facilities along the route of the extension for 3-phase underground facilities, which are not required for single-phase underground facilities. Nonetheless, the Company believes this relatively small additional allowance may be enough to facilitate wider availability of public EV charging stations in the communities we serve.

Q. HOW WOULD THE COMPANY CHARGE A CUSTOMER FOR AN UNDERGROUND FACILITY EXTENSION TO A PUBLIC EV CHARGING STATION WITHOUT THE ADDITIONAL ALLOWANCE CENTERPOINT HOUSTON IS PROPOSING?

A. For an underground facility extension, the Company estimates the cost it will incur to install the underground extension from the nearest existing delivery system facility of suitable voltage, phase and capacity to the point of delivery for the customer's charging station as designated by the Company. The Company then deducts the standard allowance—which is the estimated cost the Company would incur to install an overhead extension between those same points but limited to 1,000 feet for 3-phase facilities and 2,000 feet for single phase facilities—from that estimated cost, and the difference is the CIAC the customer must pay for the extension. With the additional EV construction allowance the Company is proposing, if that difference is $18,000 or less, the customer would not be required to pay a CIAC for the extension, and if that difference is greater than $18,000, the customer's CIAC requirement for the extension would be reduced by $18,000. Any cost incurred by the Company for the extension not covered by a customer CIAC, whether due to the existing standard allowance or a combination of the existing standard allowance and the proposed EV construction allowance, would get included in the Company's rate base at that cost.

Q. WHAT CIRCUMSTANCES HAVE LED TO THE COMPANY'S EV CHARGING STATION REQUEST?

A. The growth of public EV charging stations is consistent with encouraging the use of electric vehicles. Planning for electric vehicles and incentivizing their adoption is part of an increasing trend at the local, state, and national levels to promote better air quality through an increase in low-to-zero emission transportation. In 2017, the Texas Legislature passed, and the Governor signed, a $2,500 tax rebate program for Texas residents who purchase electric or hybrid vehicles. The program is administered by the Texas Commission for Environmental Quality.

A sufficient network of EV charging stations helps to reduce consumer "range anxiety," that is the fear of being unable to charge the vehicle when necessary. In addition, commercial industries operating high-mileage fleets will have lower barriers to fleet conversion when sufficient fast charging infrastructure is readily available.

The Company also attempts to be sensitive to the planning and initiatives of municipalities within its service territory and the City of Houston recently launched an electric vehicle initiative that has support from industries such as airlines, rideshare, academia, energy, and transit. The companies aligned with the City of Houston initiative are looking for a planned approach to widespread adoption of public charging stations to support their infrastructure needs. In sum, CenterPoint Houston's request attempts to respond to a growing need of our customers, cities, and businesses. Utility involvement in promoting EV adoption typically takes the form of either the utility (a) installing and owning the charging stations or (b) supporting the interconnection of third-party owned stations. With its facility extension proposal for public EV charging stations, the Company is pursuing the latter type of involvement.

VIII. REQUEST TO MODIFY THE COMPANY'S LIGHTING SERVICES POLICY

Q. PLEASE DESCRIBE THE LIGHTING SERVICES CENTERPOINT HOUSTON PROVIDES.

A. Lighting Services are available to cities, governmental agencies, real estate developers, and other groups requesting the installation of street lighting. Lighting Services provides for the installation, ownership, O&M of the necessary ornamental standard (if any) and fixtures, including the replacement of lamps. The majority of the cost for providing this service relates directly to CenterPoint Houston's capital investment, and O&M of the specific fixture and ornamental standard (if any). The Tariff contains the provisions governing the terms of service and the type of service, the Monthly Rate consisting of Transmission and Distribution Charge per lamp type (i.e., mercury vapor, high pressure sodium vapor, metal halide, or light emitting diode), and references to applicable service riders.

Q. WHAT CHANGES IS CENTERPOINT HOUSTON PROPOSING TO ITS LIGHTING SERVICES TARIFF?

A. The Company proposes to establish Light Emitting Diode ("LED") Luminaires as the new street light standard lamp type for Street Lighting Services and Miscellaneous Lighting Services under Lighting Services section 6.1.1.1.6 of the Tariff. Recent advances in LED technology and declining LED prices have resulted in LED for street lighting as an attractive alternative to existing street lighting options due to the potential customer and energy savings that could be achieved with more efficient light technology. CenterPoint Houston will continue to install LED lighting in place of the other non-LED lamp types under its normal replacement cycle (i.e., as lights fail and reach the end of their useful lives). Consequently, installation of a non-LED lamp type (e.g., metal halide, high pressure sodium) will be only in circumstances where LED lighting lamp installation is not possible or cost effective. Please see the direct testimony of Mr. Troxle for the tariff language proposed by the Company.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. For the test year, the Power Delivery Solutions division O&M expenditures were \$8.8 million. The O&M expenditures incurred by the Power Delivery Solutions division during the test year are reasonable and necessary expenses that should be recovered in the Company's rates. My testimony demonstrates that the Power Delivery Solutions division is properly structured to accomplish the goal of providing a reliable power delivery system at a reasonable cost. Costs associated with this organization are effectively managed and maintained at reasonable levels through the entire process of business planning, budget plan review and ongoing budget plan monitoring. These costs are reasonable, prudent and necessary. Moreover, the activities performed by the Power Delivery Solutions division are a reasonable and necessary part of providing electric utility service. Finally, the Company requests approval of its proposals related to voltage regulation batteries, DER interconnections, facilities extensions for EV charging stations, and street lighting services.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF HARRIS §

AFFIDAVIT OF JULIENNE SUGAREK

BEFORE ME, the undersigned authority, on this day personally appeared Julienne Sugarek who having been placed under oath by me did depose as follows:

1. "My name is Julienne Sugarek. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Julienne Sugarek
Julienne Sugarek

SUBSCRIBED AND SWORN TO BEFORE ME on this 5th day of March 2019, 2019.

SONIA VELA
Notary Public, State of Texas
My Commission Expires 08-30-2019

Sonia Vela
Notary Public in and for the State of TX

My commission expires: 08-30-2019

JULIENNE P. SUGAREK WORKPAPERS:

- WP JPS-1 EEI Electric Transport Oct18.pdf
- WP JPS-2 Solar Smoothing.pdf
- WP JPS-3-CONFIDENTIAL DER map.pdf

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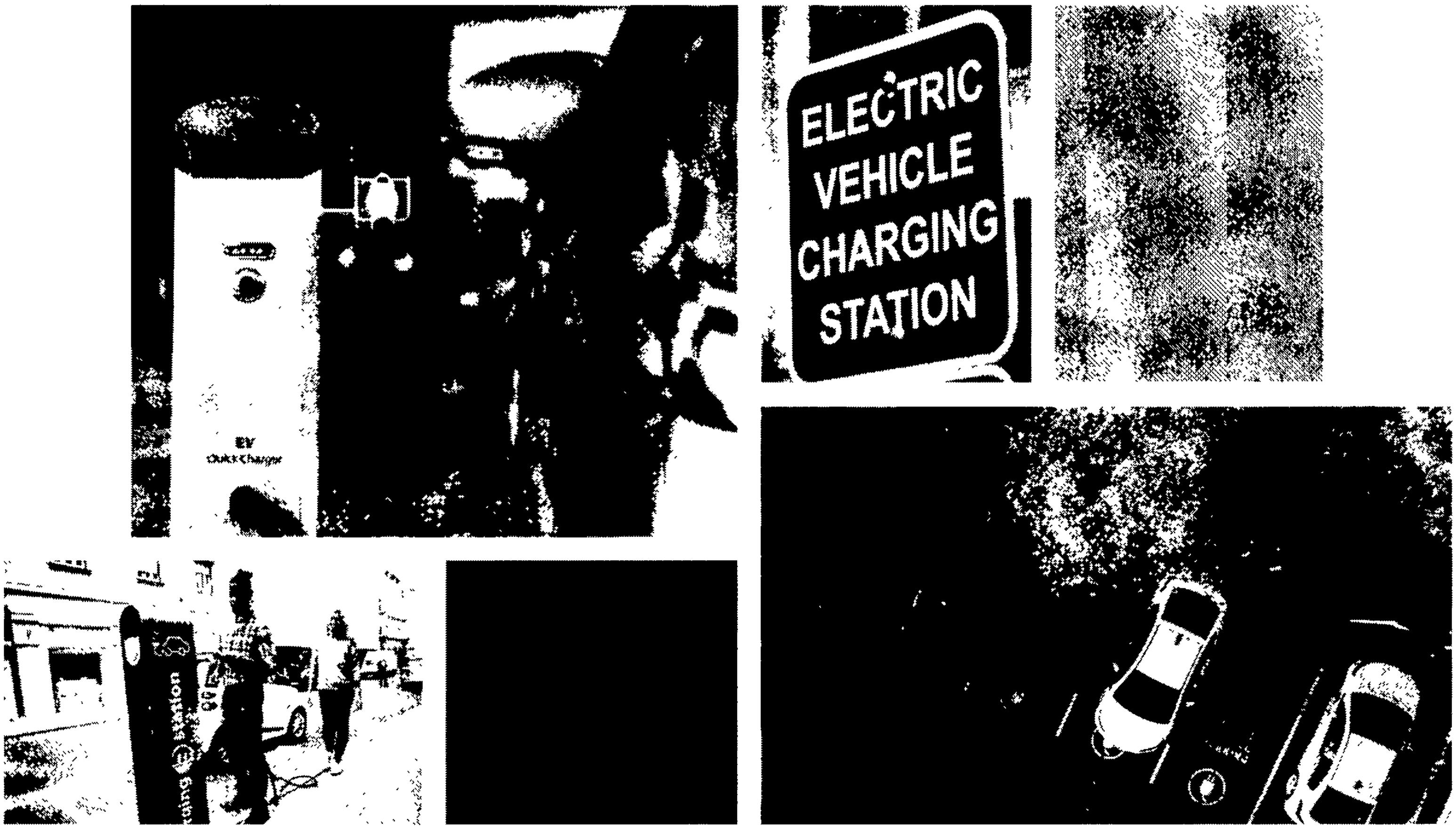

Electric Transportation State Regulatory Overview and Framework

October 2018

Many individuals at EEI and EEI member companies contributed to this document. In particular, thank you to the EEI Electric Transportation CEO Task Force Co-Chairs Patti Poppe, President and CEO, CMS Energy; John Pettigrew, CEO, National Grid; and Pedro Pizarro, President and CEO, Edison International; members of the EEI Customer Solutions Executive Advisory Committee; individual member contributors: Laura Renger, Southern California Edison; Chris Budzynski, Exelon; Rishi Sondhi, National Grid; Lang Reynolds, Duke Energy; David Owen, CenterPoint Energy; and Sarah Barbo, CMS Energy; as well as all the individual member companies that provided content to this paper.

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CUSTOMER SOLUTIONS

ELECTRIC TRANSPORTATION

Electric Transportation State Regulatory Overview And Framework

Prepared for:

EEI's Electric Transportation CEO Task Force

Prepared by:

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Becky Knox

October 2018

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Electric Transportation State Regulatory Framework: Overview

In March 2018, the Electric Transportation CEO Task Force directed the Edison Electric Institute (EEI)—in collaboration with member companies—to develop this Electric Transportation State Regulatory Framework. This framework highlights five key components of an electric transportation state regulatory filing: customer education and electric vehicle (EV) experience; stakeholder engagement; charging infrastructure deployment; residential managed charging; and commercial charging.

The Electric Transportation State Regulatory Framework is an executive-level document that is designed to provide the state of play and targeted guidance to electric companies as they contemplate electric transportation filings. The framework captures emerging practices and highlights examples from those electric companies that have made electric transportation filings to date.

The framework was informed by extensive engagement with the major stakeholders that have participated in electric transportation filings. The framework will allow all EEI members to benefit from the learnings of early movers, will help establish a baseline of understanding across the industry, and ultimately will help all members with their electric transportation filings.

Electric Transportation Regulatory Filings: Five Key Components

1. **Customer Education and EV Experience**
   Electric companies are uniquely suited to help provide customers with information and education regarding EVs and the benefits that electric transportation can provide. Customers already view electric companies as energy experts and expect them to provide information on energy-related technologies and solutions, including EVs. Electric companies can provide advisory services and customer support to potential EV buyers and owners. Having a designated customer service representative or EV account team can help educate customers about EVs. Additionally, electric companies can assist in creating a seamless customer experience for EV purchasers, including identifying EV-knowledgeable car dealers, providing assistance with charging station installations at residences, and offering information about public charging locations.
2. **Stakeholder Engagement**
   Stakeholder engagement and support are critical to the success of electric transportation. It is important to begin early in the state regulatory process (well in advance of an actual regulatory filing) to obtain initial feedback and input from key stakeholders. In addition, implementing a process that allows for ongoing stakeholder input throughout the execution of an electric transportation initiative is important (e.g., a formal advisory board to provide ongoing feedback on program elements and outcomes). Key metrics for success should be agreed upon and tracked for regular public reporting. These metrics could include cost per charger installed, number of stations installed, charging behavior, and others.

3. **Charging Infrastructure Deployment**
   Electric companies can help address the lack of charging infrastructure, which has been identified as one of the primary barriers to greater EV adoption. A charging infrastructure deployment strategy should be designed to address the needs in a company's service territory, including those in a variety of target segments (e.g., national highway corridors, multi-unit dwellings, workplaces, long-dwell public locations, etc.), and ownership models. Charging deployments should promote interoperability and open communication standards to create a positive customer experience, to drive innovation, and to foster competition in the market. Charging infrastructure should be well-maintained to ensure availability. Coordination among the electric company, site hosts, and third parties (including local governments) is essential to ensure that planning and siting for charging infrastructure are done in a way that not only leverages existing deployment projects (e.g., Electrify America), but also optimizes the location of and time required for planned deployments to help keep costs down.
4. **Residential Managed Charging**
   Pricing programs that encourage customers to charge EVs when the energy grid has available capacity or excess energy could minimize potential distribution system upgrades and result in more efficient operation of the energy grid, potentially lowering the average system cost for all electric customers. A managed charging strategy can include smart pricing (e.g., time-of-use rates and other types of dynamic rates) to send price signals that encourage customers to charge during certain times of the day (e.g., off-peak). Managed charging strategies will depend on both energy grid needs and customer needs.
5. **Commercial Charging**
   Commercial charging is also an important consideration for EV filings. For individual EV drivers, the availability of charging infrastructure outside the home has been identified as a critical element in encouraging widespread EV adoption. And, as costs decrease, more fleets are electrifying. A variety of charging strategies likely will be needed for different types of commercial applications and charging durations, such as workplace charging, fleet charging, and direct current fast charging (DCFC). Smart charging strategies are under development for commercial customer applications.

In addition to the five key components listed above, the following four issue areas have emerged as major considerations in state regulatory proceedings. Although these are not strategies or action items, it is essential to address these four issues in any electric transportation state regulatory filing.

Benefits of Electric Transportation
EVs provide major benefits for the environment, for all customers, for the nation's energy grid, and for national security. It is critical to emphasize these benefits (as appropriate) in regulatory filings.

- *Customer benefits*: EVs are typically cheaper to operate than gasoline-fueled vehicles due to lower fuel and maintenance costs. As battery costs fall, the EV price premium will decline. Already today, the low price of EVs on the secondary market makes them an affordable driving option. Electric company investment can make charging infrastructure more affordable for customers to install, and time-varying rates can benefit customers and the energy grid.
- *Environmental benefits*: Based on the average electricity generation mix nationwide, EVs emit less than half the greenhouse gas emissions of conventional vehicles and significantly reduce

other emissions, including nitrogen oxides (NOx) and particulates. The carbon and air quality benefits will grow as electricity generation continues to get even cleaner.[1]

- *Energy grid benefits*: EV charging that occurs when the energy grid has available capacity improves the efficiency of the energy grid—potentially lowering the average cost to serve all customers.
- *National security benefits*: EVs are powered by a domestic mix of energy sources, unlike gasoline-fueled vehicles that depend solely on oil, only 40 percent of which is domestically produced.

Access and Equity

Electric companies can help expand electric transportation access to underserved communities. Program design strategies should include careful consideration of where additional infrastructure will benefit more customers in a variety of communities. Programs also can promote applications beyond individually owned passenger vehicles, including mass transit, commercial fleets, school buses, ridesharing, medium- and heavy-duty applications, and eventually automated vehicle fleets, to ensure that all customers can realize the benefits of increased transportation electrification. For example, electric companies can support the build-out of public charging infrastructure that can be used by ridesharing programs and mass transit, providing the benefits of EVs to those who may not even own a car.

Energy Grid Readiness

The energy grid can accommodate EVs. Even as EV adoption increases, the ability to shape load through pricing and other charging management strategies will help to mitigate any potential impacts to the energy grid. Providing more information to regulators and stakeholders about the planning and preparations already underway to integrate increased EV adoption and additional charging infrastructure into the energy grid will help ease uncertainty about the grid's readiness for the advancing EV market.

Industry Leadership

Leadership by example is an important component of an electric transportation program. Companies can commit to transitioning their own fleets to electric through EEI's Fleet Electrification Initiative.[2] They also can invest in employee engagement programs that provide education and workplace charging to encourage employees to make the change to electric vehicles through EEI's Employee EV Engagement Initiative.[3] Companies even can encourage their direct suppliers and contractors to electrify their fleets and engage their employees.

[1] See http://www.edisonfoundation.net/iei/publications/Documents/IEI_Clean%20Energy%20Top%2010_September%20 2018%20update.pdf
[2] See http://www.eei.org/issuesandpolicy/electrictransportation/FleetVehicles/Resources/Pages/default.aspx.
[3] See http://www.eei.org/issuesandpolicy/electrictransportation/PEVengagement/Pages/default.aspx.