2019 JUN -6 PM 2:27

PUBLIC UTILITY COMMISSION
FILING CLERK

SOAH DOCKET NO. 473-19-3864
PUC DOCKET NO. 49421

| | | |
|---|---|---|
| APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES | §<br>§<br>§ | PUBLIC UTILITY COMMISSION OF TEXAS |

# DIRECT TESTIMONY

# OF

# SCOTT NORWOOD

ON BEHALF OF

CITY OF HOUSTON

AND HOUSTON COALITION OF CITIES

JUNE 6, 2019

412

## DIRECT TESTIMONY OF SCOTT NORWOOD

## TABLE OF CONTENTS



**EXHIBITS:**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.**

A. My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. My business address is P.O. Box 30197, Austin, Texas 78755-3197.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am an energy consultant specializing in the areas of electric utility regulation, resource planning and energy procurement.

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. I am an electrical engineer with over 35 years of experience in the electric utility industry. I began my career as a power plant engineer for the City of Austin's Electric Utility Department where I was responsible for electrical maintenance and design projects for the City's three gas-fired power plants. In January 1984, I joined the staff of the Public Utility Commission of Texas, where I was responsible for addressing resource planning, fuel, and purchased power cost issues in electric rate and plant certification proceedings before the Texas PUC. Since 1986 I have provided utility regulatory consulting, resource planning, and power procurement services to public utilities, electric consumers, industrial interests, municipalities, and state government clients. I have testified in over 200 utility regulatory proceedings over the last 20 years, before state regulatory commissions in Alaska, Arkansas, Florida, Georgia, Illinois, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, Ohio, Oklahoma, Texas, Virginia, Washington, and Wisconsin.[1]

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

A. I am testifying on behalf of the City of Houston and Houston Coalition of Cities ("COH/HCC").

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS?**

A. Yes. I have filed testimony in numerous past regulatory proceedings before the PUC as a consultant and former member of the PUC's Staff. I have represented the City of Houston as an expert witness on regulatory matters involving CenterPoint and its predecessor Houston Lighting and Power Company in proceedings before the PUC dating back to 1990. I filed testimony on behalf of COH/HCC in PUC Docket Nos. 47032, 45747 and 4572, involving CenterPoint Energy Houston Electric, LLC's ("CEHE" or "Company") past Distribution Cost Recovery Factor ("DCRF") proposals. I also filed testimony on behalf of the COH/HCC in PUCT Docket No. 38339, CEHE's last general base rate case.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

---

[1] See Exhibit SN-1 for additional details on my background and experience.

A. The purpose of my testimony is to present my evaluation and recommendations regarding certain issues underlying CEHE's application for authority to increase base rates, including the level of the Company's requested operations and maintenance ("O&M") expenses, the prudence of capital investments, and final reconciliation of past Distribution Cost Recovery Factor ("DCRF") charges and revenues.

**Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?**

A. Yes. I have prepared 14 exhibits, which are attached to my testimony.

## II. SUMMARY OF TESTIMONY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.**

A. My testimony focuses on the reasonableness, necessity and prudence of CEHE's requests for O&M expenses and capital additions for the test year ending December 31, 2018, as well as final reconciliation of the Company's past DCRF charges and revenues. My primary conclusions and recommendations are as follows:

1) CEHE's O&M request reflects an extraordinary and unjustified increase of approximately $70 million when compared to the average O&M expense incurred over the previous three years. Approximately 80% of the total O&M increase proposed by CEHE occurs in seven FERC accounts that increased by an average of 18.7% when compared to expenses for the previous three years. The Company has not shown that these cost increases are reasonable, necessary or likely to recur. I

recommend that the total amount of O&M expenses allowed in base rates be no more than $43.58 million, which is $44.3 million less than the amount requested by CEHE. My recommendation is based on reducing the extraordinary level of O&M expense requested by CEHE for the 2018 adjusted test year to reflect a reasonable normalized level of expense based on increasing the actual level of 2017 O&M expense by 2.6%, which is two times the average annual rate of increase (1.3% per year) in O&M expenses incurred by CEHE from 2014 through 2017.

2) CEHE has not provided evidence to demonstrate that its investments in the Underground Cable Assessment and Life Extension Program and the Major Underground Rehabilitation project were reasonable and necessary or prudently incurred. The gross plant in service amounts for these two projects were $59.6 million, and $57.7 million, respectively, as of the test year end. Based on CEHE's failure to demonstrate these projects were reasonable, necessary or prudent, and the results of analyses conducted by the Company that indicate the projects provide negligible benefits to customers, I recommend that CEHE's request for approval of the investments in both projects be disallowed. My recommendation to disallow these two projects reduces the Company's base revenue requirement by approximately $15 million. I further recommend that the PUC order CEHE to refund through a DCRF credit rider all costs for these two projects that have been collected through the Company's past DCRF charges, along with associated carrying charges, as provided by the PUC's DCRF Rule.

3) CEHE improperly included approximately $2.6 million of indirect corporate costs in the Company's past DCRF charges. The PUC's DCRF Rule explicitly states that indirect corporate costs shall not be included in DCRF charges. In addition, CEHE recovered approximately $31.8 million through past DCRF charges for the two unreasonable and unnecessary underground projects. In addition to recommending that these two projects be removed from the Company's rate base and new base rates, I recommend that the Commission order CEHE to refund these ineligible, unnecessary and unreasonable costs previously recovered through the Company's DCRF charges over a one-year period, through a DCRF credit rider. I further recommend that the amounts refunded include carrying charges based on CEHE's cost of long-term debt during the periods that the improper DCRF charges were made. The total amount that I recommend be refunded through my proposed DCRF credit rider is approximately $32.5 million.

## III. OPERATIONS AND MAINTENANCE EXPENSES

**Q. HOW HAS CEHE'S OPERATIONS AND MAINTENANCE ("O&M") EXPENSES CHANGED SINCE 2010?**

A. As summarized in Table 1 below, CEHE's O&M expenses, excluding ERCOT transmission charges from third parties, have increased by $177 million (37.4%) since 2010.

Table 1

CEHE O&M Expense
2010 vs 2018
($Millions)

| | 2010 | 2018 | Increase | %Increase |
|---|---|---|---|---|
| Transmission O&M** | $30.3 | $53.8 | $23.5 | 77.5% |
| Distribution O&M | $212.7 | $278.0 | $65.2 | 30.7% |
| Administrative & General | $230.7 | $319.0 | $88.2 | 38.2% |
| Total O&M | $473.7 | $650.7 | $177.0 | 37.4% |

Source: CEHE's 2010 and 2018 FERC Form 1 filings, Pages 320-323.
**T ransmission operations expense excludes ERCOT charges (Acct 565).

**Q. WHAT IS CEHE'S EXPLANATION FOR THE GROWTH IN O&M EXPENSES ON ITS SYSTEM SINCE 2010?**

A. CEHE states that customer growth and the need to address various reliability concerns have been primary factors driving the increase in O&M expenses since Docket 38339.[2]

**Q. DO CUSTOMER GROWTH AND/OR THE NEED TO ADDRESS RELIABILITY CONCERNS JUSTIFY THE INCREASE IN CEHE'S O&M SINCE 2010?**

A. No. CEHE's O&M expenses have increased at a rate of approximately 4.6% per year since 2010. As summarized in Table 2 below, CEHE's customer and sales growth since 2010 has been just over 2.1% per year, which is relatively low.

Table 2

CEHE Customer Growth
2010 vs 2018
(Number of Customers by Class)

| | 2010 | 2018 | Increase | %/Yr Incr |
|---|---|---|---|---|
| Residential | 1,864,611 | 2,181,689 | 317,078 | 2.1% |
| Commercial | 265,044 | 299,525 | 34,481 | 1.6% |
| Industrial | 2,043 | 2,038 | -5 | 0.0% |
| Municipal | 782 | 833 | 51 | 0.8% |
| Total Customers | 2,132,480 | 2,484,085 | 351,605 | 2.1% |
| Total Sales (MWh) | 76,973,115 | 90,408,836 | 13,435,721 | 2.2% |

Moreover, CEHE's system reliability performance, as measured by System Average Interruption Duration Index ("SAIDI"), has been generally been good since 2010, although the Company's SAIDI increased significantly in 2015 and has remain somewhat higher than SAIDI levels before 2015.[3]

**Q. WHY DID CEHE'S SAIDI INCREASE SIGNIFICANTLY AFTER 2015?**

A. As recognized by the PUC in PUC Docket No. 48426, the increase in CEHE's SAIDI after 2015 was primarily due to the Company's implementation of a new outage management system ("OMS") which resulted in more detailed and accurate outage recording and, consequently, higher reported customer outage rates.[4]

---

[2] See the Direct Testimony of CEHE witness Pryor at 7.
[3] See Exhibit SN-2. SAIDI measures the average minutes per year of customer interruption due to unplanned distribution outages.
[4] See PUC Docket No. 48426 Final Order.

**Q. IS THE SOMEWHAT ELEVATED SAIDI LEVEL REPORTED BY CEHE SINCE 2014 A REASON FOR CONCERN?**

A. No. For example, CEHE's SAIDI excluding scheduled outages and major events has averaged 119 minutes per year over the last three years. This performance translates to average customer service reliability of approximately <u>99.98%, which is very good</u>.

**Q. ARE THERE OTHER WAYS TO GAUGE CEHE'S DISTRIBUTION SERVICE RELIABILITY PERFORMANCE?**

A. Yes. The number of customer complaints, and the number of customer requests for higher reliability performance are indicators of the extent to which customers are dissatisfied with service reliability.

**Q. IS THERE ANY INDICATION THAT CEHE'S CUSTOMERS ARE DISSATISFIED WITH THE COMPANY'S SERVICE RELIABILITY?**

A. No. For example, over the last five years CEHE has received only approximately 120 customer complaints per year related to outages or adequacy of service.[5] This number of complaints represents less than <u>0.005%</u> of the Company's 2.5 million customers, which indicates a high level of customer satisfaction with CEHE's service reliability. Moreover, although the Company offers an optional Premium Rollover Service tariff that provides two separate sources of power to customers who want higher service reliability,

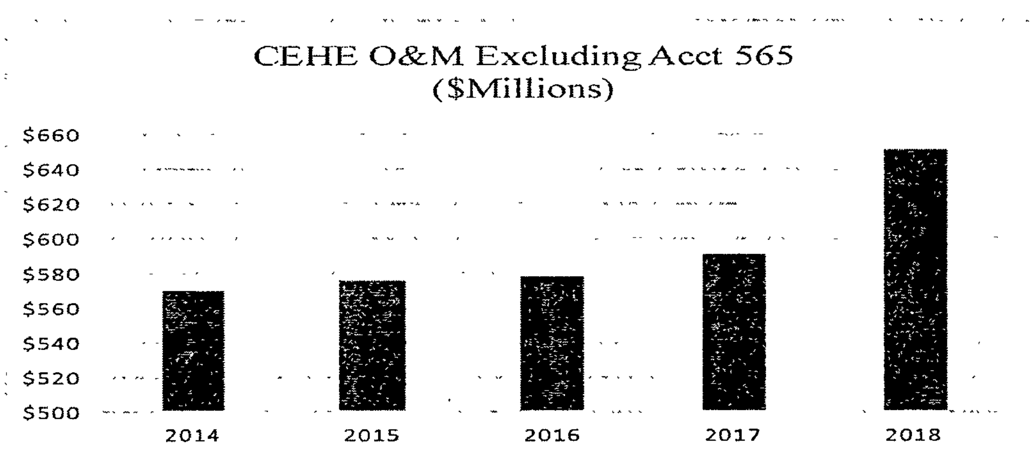
[5] See Exhibit SN-3, CEHE's response to City of Houston's RFI No. 1-23.

only 13 customers, or approximately <u>0.0005%</u> of the Company's 2.5 million customers, have elected to acquire such service.[6]

**Q. TURNING TO BACK TO CEHE'S O&M REQUEST IN THIS CASE, HOW DOES THE COMPANY'S REQUEST COMPARE TO O&M EXPENDITURES INCURRED OVER THE LAST SEVERAL YEARS?**

A. As shown below in Figure 1, excluding ERCOT transmission charges, the Company's 2018 Test Year O&M request (~$650.7 million) is approximately $72.2 (12.5%) higher than average O&M expenses over the previous four years.

Figure 1




**Q. WHAT ARE THE MAJOR AREAS CONTRIBUTING TO THE $72 MILLION INCREASE IN O&M EXPENSES REQUESTED BY CEHE WHEN COMPARED**

[6] See Exhibit SN-4, CEHE's response to COH 1-30.

**TO THE AVERAGE LEVEL OF O&M EXPENDED OVER THE PREVIOUS FOUR YEARS?**

A. As summarized in Table 3 below, $56.7 million (~79%) of the O&M increase requested by CEHE in this case occurs in seven FERC accounts:

Table 3

CEHE O&M Expense
2014-17 Average vs 2018 Request
($Millions)

| FERC Acct | Description | 2014-17 Avg | 2018 Request | Increase | %Increase |
|---|---|---|---|---|---|
| 560 | Trans. Operation Super. & Engin. | $9.5 | $13.3 | $3.8 | 40.7% |
| 570 | Trans. Maint. of Station Equipment | $7.2 | $10.8 | $3.6 | 50.0% |
| 580 | Distr. Operation Super. & Engin. | $44.1 | $54.2 | $10.1 | 23.0% |
| 588 | Misc. Distribution Expenses | $29.9 | $36.2 | $6.3 | 21.0% |
| 593 | Distr. Maint. of Overhead Lines-Primary | $72.7 | $85.3 | $12.5 | 17.3% |
| 594 | Distr. Maint. of Underground Lines-Primary | $9.3 | $13.2 | $3.9 | 41.9% |
| 930.2 | Miscellaneous General Expense | $129.4 | $146.2 | $16.8 | 13.0% |
| | Subtotal | $302.1 | $359.2 | $57.1 | 18.9% |

Source: CEHE's 2010 and 2018 FERC Form 1 filings, Pages 320-323

Q. **HAS CEHE PROVIDED EVIDENCE THAT ESTABLISHES THE REQUESTED COST INCREASES IN THE ABOVE ACCOUNTS ARE REASONABLE, NECESSARY AND RECURRING IN NATURE?**

A. No. CEHE's testimony does not address the specific reasons for the above cost increases, or why the higher O&M costs requested by the Company are reasonable, necessary, prudently incurred, or likely to recur in the future. Moreover, CEHE's discovery responses indicate that the Company does not maintain variance reports that address the reasons why the test year O&M costs in Distribution or Transmission FERC accounts are much higher than O&M expenditures over the previous four years.[7]

**Q. WHY SHOULD CEHE BE HELD ACCOUNTABLE FOR ESTABLISHING THE REASONABLENESS OF REQUESTED O&M COSTS?**

A. The Commission has traditionally held utilities responsible to demonstrate that costs recovered through rates are reasonable, necessary, prudently incurred, and reflective of a normal and recurring level of expense. The $59.5 million (10.1%) increase in O&M costs requested by CEHE is nearly 8 times the 1.3% per year average increase in O&M expenses incurred by the Company over the previous four years (2014-2017), which is extraordinary. The Company has not explained the reasons for this increase in its testimony or discovery responses, or otherwise proved that the extraordinary proposed increase is likely to continue in the future. It is not appropriate to set rates based on test year expenses that are unreasonably high, non-recurring in nature, or that are otherwise unnecessary. Moreover, as discussed later in my testimony, CEHE invested more than $3.7 billion for improvements to the Company's transmission and distribution grid since 2010. In many cases, such investments were justified based on projected reliability improvements that ultimately should be reflected in fewer outages and reduced maintenance costs. Given CEHE's large investments for improvements to the grid, the Company should be held accountable for explaining promised O&M savings have not materialized and why the requested O&M costs in this case are 12.5% higher (rather than lower) than O&M costs incurred over the previous four years.

---

[7] See Exhibit SN-5, CEHE's responses to COH 1-5 and COH 1-7.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING CEHE'S O&M REQUEST IN THIS CASE?**

A. CEHE's O&M request reflects an extraordinary and unjustified increase of approximately $72 million when compared to the average O&M expense incurred over the previous four years. Approximately 79% of the total O&M increase requested by CEHE occurs in seven FERC accounts that increased by an average of 18.9% over the average level of expenses incurred during the previous four years. The Company has not shown that these cost increases are reasonable, necessary or likely to recur. Given these facts, I recommend that the level of O&M requested by CEHE be reduced by <u>$44.3 million</u>. My recommendation is based on the Company's actual 2017 O&M level, increased by 2.6% to account for escalation, which is double the average annual increase in O&M (1.3%/year) incurred by CEHE over the previous four years. Under my recommendation, CEHE's total allowed O&M costs (excluding ERCOT charges) would be approximately $606.4 million.

## IV. <u>CEHE CAPITAL INVESTMENTS</u>

**Q. HOW HAVE CEHE'S PLANT IN SERVICE BALANCES CHANGED SINCE THE COMPANY'S LAST BASE RATE CASE?**

A. As summarized in Table 4 below, CEHE's Plant in Service balances at the end of 2018 test year are $4.3 billion more (58.7% higher) than at the end of 2010, 2010 being the year following the Company's test year in its last base rate case PUC Docket No. 38339.

Table 4

CEHE Plant In Service Balance
2010 vs 2018 Year End
($Millions)

| | 2010 | 2018 | Increase | %Increase | %Increase/Yr |
|---|---|---|---|---|---|
| Intangible Plant | $193.5 | $294.7 | $101.2 | 52.3% | 6.5% |
| Transmission Plant | $1,591.5 | $3,062.4 | $1,470.9 | 92.4% | 11.6% |
| Distribution Plant | $5,044.0 | $7,316.3 | $2,272.3 | 45.0% | 5.6% |
| General Plant | $553.9 | $1,041.0 | $487.1 | 87.9% | 11.0% |
| Total | $7,382.9 | $11,714.4 | $4,331.5 | 58.7% | 7.3% |

Source: CEHE's 2010 and 2018 FERC Form 1 filings, Pages 204-207.

**Q. WHAT INFORMATION HAS CEHE PROVIDED TO SUPPORT THE PRUDENCE OF THE CAPITAL INVESTMENTS AT ISSUE IN THIS CASE?**

A. CEHE has provided limited testimony and summary results of analyses of major projects developed with the Company's Asset Investment Strategy ("AIS") software to support the prudence of major projects in this case.

**Q. HOW DOES THE AIS PROGRAM EVALUATE WHETHER AN INVESTMENT IS JUSTIFIED AND BENEFICIAL TO CUSTOMERS?**

A. According to documentation provided by CEHE in response to discovery, the AIS software evaluates and ranks capital investment projects on a Value-to-Cost ("V/C") Ratio basis.[8] The AIS determines the "value" of projects based on estimates of four types of project benefits: 1) Load at Risk, 2) Reliability Benefits, 3) Design Criteria and 4) Supplemental Benefits. The primary benefit considered by the AIS analysis is the

"Load at Risk" benefit, which is an estimate of the amount of load that would theoretically be at risk of not being served if the project is not conducted.

**Q. DO THE BENEFITS CALCULATED BY THE AIS REPRESENT ECONOMIC BENEFITS TO CUSTOMERS?**

A. No. The Company admits that none of the four categories of benefits calculated by the AIS software represent expected monetary (economic) benefits to customers.[9] Thus, unlike cost/benefit analysis techniques that the PUC has traditionally relied upon to judge whether major utility investments are economically beneficial to customers, and the lowest reasonable cost alternative, the AIS software results do not measure whether any investment will be economically beneficial to customers. In fact, the AIS load at risk values would be difficult to verify and, unlike the cost of the projects, have little or no direct impact on customer electric bills. For these reasons, it would be unreasonable to rely on the AIS software results as a primary indicator of the prudence of capital projects under review in this case, as CEHE has done.

**Q. DOES THE INFORMATION CEHE HAS PROVIDED ESTABLISH THAT THE MAJOR CAPITAL PROJECT INVESTMENTS UNDER REVIEW IN THIS CASE WERE REASONABLE, NECESSARY AND PRUDENTLY INCURRED?**

A. Yes. I have been able to affirmatively determine that a significant number of the capital projects for which CEHE is seeking approval in this case are reasonable and necessary; however, in other instances the Company has not provided cost/benefit analyses or other

---

[8] See Exhibit SN-6, CEHE's response to COH 13-6.

information required to support capital investments. Because of the large number of projects under consideration, I focused my review on CEHE distribution capital projects that had a total cost of more than $5 million, and which were initiated by CEHE primarily as proactive efforts to improve the condition or reliability of existing distribution system assets.

**Q. WHAT PORTION OF CEHE'S DISTRIBUTION CAPITAL PROJECTS WERE FOCUSED PRIMARILY ON RELIABILITY IMPROVEMENT?**

A. CEHE indicates that investments for distribution system reliability improvement totaled approximately $866 million, or nearly 37% of the Company's $2.34 billion total capital investment in distribution assets from 2010 through 2018.[10]

**Q. HAS CEHE PROVIDED INFORMATION THAT ESTABLISHES THAT MAJOR DISTRIBUTION SYSTEM AND RELIABILITY IMPROVEMENT PROJECTS WERE REASONABLE, NECESSARY AND COST-BENEFICIAL TO CUSTOMERS5?**

A. No. While there are several major CEHE distribution reliability improvement projects that are not well-supported in CEHE's testimony or discovery responses, the support provided for Company's investments in the Underground Cable Assessment and Life Extension Program (Project No. ABCA) and the Major Underground Rehabilitation Program (Project No. CE1B) is superficial and deficient. CEHE's investments in these two projects over the 2010-2018 period totaled approximately $54 million and $57.5

[9] See Exhibit SN-7, CEHE's responses to COH RFIs Nos. 13-1, 13-3 and 13-4.

million, respectively.[11] Both programs were evaluated by CEHE's AIS program to have very low V/C ratios of 0.02 and 0.04, respectively, which indicates they are expected to provide very little Load-at-Risk benefit for the cost invested.[12] Therefore, even under CEHE's AIS analysis, which does not measure economic benefits of the projects to customers, the V/C ratios are so low that they do not justify the projects or otherwise demonstrate prudence of projects. In fact, The Company has acknowledged that "there is not a direct correlation between the capital dollars spent and SAIDI impact" of these two programs.[13]

**Q. WOULD THE TWO PROJECTS MATERIALLY IMPROVE THE EXISTING LEVEL OF SERVICE RELIABILITY PROVIDED BY CEHE?**

A. No. It is questionable whether customers would even notice the reliability effects of the two underground projects, since CEHE indicates that underground cable failures contributed only approximately 5 minutes per year to the Company's SAIDI over the 2010-2018 period, and there has been no discernible improvement in the already high reliability of underground circuits as a result of CEHE's investments in these two underground programs.[14] Moreover, CEHE's direct testimony provides only very short summary discussions of these two underground programs and does not address the prudence of the Company's investments in either program in any detail.[15] In short, the

---

[10] See the Direct Testimony of CEHE witness Pryor, at 16.
[11] See Exhibit SN-8, CEHE's response to COH 13-2, Attachment 1.
[12] See Exhibit SN-9, Excerpts from CEHE's response to COH 1-22.
[13] See Exhibit SN-10, CEHE's response to COH 10-23.
[14] See Exhibit SN-11, CEHE's response to COH 10-27.
[15] See Exhibit SN-12, CEHE's response to COH 15-2, and the Direct Testimonies of CEHE witness Pryor at 15-22 and 34-35, witness Sugarek at 9-15 and witness Narendorf at 15.

very limited information provided by CEHE does not support the prudence of the two underground projects and indicates that the Company's $111.5 million investment in the two projects is not justified by reliability or monetary benefits to customers.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONAND RECOMMENDATIONS REGARDING CEHE'S INVESTMENTS IN THE TWO UNDERGROUND RELIABILITY PROJECTS.**

A. CEHE has not justified its investments in the Underground Cable Assessment and Life Extension Program or the Major Underground Rehabilitation project. Based on CEHE's failure to demonstrate the prudence of these projects, and information provided in discovery that indicates the investments for these projects are not beneficial to customers, I recommend that CEHE's request for approval of the investments in both projects be disallowed and removed from rate base. I further recommend that the PUC order CEHE to refund all costs for these two unnecessary and unjustified projects that have been collected through the Company's past DCRF charges, along with associated carrying charges, through a DCRF credit rider.

## V. RECONCILIATION OF DCRF COSTS

**Q. IS CEHE SEEKING FINAL APPROVAL OF COSTS OF CAPITAL PROJECTS THAT HAVE BEEN RECOVERED THROUGH THE COMPANY'S DCRF THROUGH THE END OF THE TEST YEAR IN THIS CASE?**

A. Yes. CEHE witness Pryor addresses the reasonableness and prudence of capital projects whose costs have been recovered through the Company's DCRF since the last base rate case.

**Q. WHAT ISSUES ARE TO BE DECIDED IN FINAL RECONCILIATION OF CEHE'S DCRF COSTS AND REVENUES?**

A. The PUC's DCRF Rule (PUC S.R. 25.243(f)) provides the following with regard to scope of the DCRF reconciliation process:

> The reconciliation shall be limited to the issues of the extent to which the investments complied with PURA, including §36.053 and §36.058, and this section and were prudent, reasonable, and necessary. To the extent that the PUC determines that the investments did not comply with PURA and this section or were not prudent, reasonable, and necessary, the electric utility shall refund all revenues related to the investments that it improperly recovered through rates, and shall also pay its customers carrying charges on these revenues.

**Q. HAS CEHE RECOVERED ANY COSTS THROUGH PAST DCRF CHARGES THAT WERE IMPRUDENTLY INCURRED OR OTHERWISE INELIGIBLE FOR RECOVERY THROUGH THE DCRF?**

A. Yes. The DCRF Rule specifies that distribution investment costs that are recoverable through the DCRF must meet the following criteria:

> Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to transmission service rates), §25.193 of this

> title (relating to distribution service provider transmission cost recovery factors (TCRF)), or §25.239 of this title (relating to transmission cost recovery factor for certain electric utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism.

As noted in the previous section of my testimony, CEHE's investments in the Underground Cable Assessment and Life Extension Program and the Major Underground Rehabilitation project did not meet the "prudent, reasonable and necessary" criterion for recovery through CEHE's DCRF. I therefore recommend that all costs of these projects recovered through CEHE's past DCRF charges be refunded to customers along with associated carrying charges as required by the PUC's DCRF Rule.

**Q. WERE ANY OTHER COSTS INCLUDED IN CEHE'S PAST DCRF CHARGES THAT ARE NOT ELIGIBLE FOR RECOVERY THROUGH THE DCRF?**

A. Yes. As I noted above, the DCRF Rule states that "indirect corporate costs" are not includable in distribution investments that are recovered through the DCRF. Nevertheless, as acknowledged by CEHE, it indirectly charged approximately $2.6 million in corporate costs to distribution capital investments and included the same in the Company's last DCRF charges.[16]

[16] See Exhibit SN-13, CEHE's response to COH 15-6, Attachment 2.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING INDIRECT CORPORATE COSTS THAT HAVE BEEN RECOVERED THROUGH CEHE'S PAST DCRF CHARGES?**

A. I recommend that the PUC order CEHE to refund all amounts it has collected for the $2.6 million of indirect corporate costs that are not eligible for recovery through the Company's DCRF charges, along with associated carrying charges as required by the PUC's DCRF Rule.

**Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS FOR COSTS IMPROPERLY RECOVERED THROUGH CEHE'S DCRF?**

A. My recommended adjustments for the two underground projects and for indirect corporate charges represent a total refund balance of approximately $32.5 million, for amounts that have been recovered through CEHE's DCRF dating back to 2015, along with associated interest. [17]

**Q. HOW DO YOU RECOMMEND THAT THESE AMOUNTS BE REFUNDED TO CUSTOMERS?**

A. I recommended that the $32.5 million of unreasonable and ineligible costs recovered through CEHE's DCRF be refunded over one year using DCRF credit factors that reflect cost allocations and billing units consistent with the Company's approved DCRF. My proposed credits for each rate class are attached as Exhibit SN-14 of my testimony. I further recommend that any over- or under-recovery balance that remains after the one-

---

[17] See Exhibit SN-14.

year DCRF credit period should be included in setting charges in the Company's next DCRF proceeding after the one-year credit rider effective period.

**Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

A. Yes.

# RESUME OF DON SCOTT NORWOOD

**Norwood Energy Consulting, L.L.C.**

P. O. Box 30197
Austin, Texas 78755-3197
scott@scottnorwood.com
(512) 297-1889

## SUMMARY

Scott Norwood is an energy consultant with over 37 years of utility industry experience in the areas of regulatory consulting, resource planning and energy procurement. His clients include government agencies, publicly-owned utilities, public service commissions, municipalities and various electric consumer interests. Over the last 15 years Mr. Norwood has presented expert testimony on electric utility ratemaking, resource planning, and electric utility restructuring issues in over 200 regulatory proceedings in Arkansas, Georgia, Iowa, Illinois, Michigan, Missouri, New Jersey, Oklahoma, South Dakota, Texas, Virginia, Washington and Wisconsin.

Prior to founding Norwood Energy Consulting in January of 2004, Mr. Norwood was employed for 18 years by GDS Associates, Inc., a Marietta, Georgia based energy consulting firm. Mr. Norwood was a Principal of GDS and directed the firm's Deregulated Services Department which provided a range of consulting services including merchant plant due diligence studies, deregulated market price forecasts, power supply planning and procurement projects, electric restructuring policy analyses, and studies of power plant dispatch and production costs.

Before joining GDS, Mr. Norwood was employed by the Public Utility Commission of Texas as Manager of Power Plant Engineering from 1984 through 1986. He began his career in 1980 as Staff Electrical Engineer with the City of Austin's Electric Utility Department where he was in charge of electrical maintenance and design projects at three gas-fired power plants.

Mr. Norwood is a graduate of the college of electrical engineering of the University of Texas.

## EXPERIENCE

The following summaries are representative of the range of projects conducted by Mr. Norwood over his 30-year consulting career.

### Regulatory Consulting

*Oklahoma Industrial Energy Consumers* - Assisted client with technical and economic analysis of proposed EPA regulations and compliance plans involving control of air emissions and potential conversion of coal-to-gas conversion options.

*Cities Served by Southwestern Electric Power Company* – Analyzed and presented testimony regarding the prudence of a $1.7 billion coal-fired power plant and related settlement agreements with Sierra Club.

*New York Public Service Commission* - Conducted inter-company statistical benchmarking analysis of Consolidated Edison Company to provide the New York Public Service Commission with guidance in determining areas that should be reviewed in detailed management audit of the company.

*Oklahoma Industrial Energy Consumers* - Analyzed and presented testimony on affiliate energy trading transactions by AEP in ERCOT.

*Virginia Attorney General* – Analyzed and presented testimony regarding distribution tap line undergrounding program proposed by Dominion Virginia Power Company.

*Cities Served by Southwestern Electric Power Company* – Analyzed and presented testimony regarding the prudence of the utility's decision to retire the Welsh Unit 2 coal-fired generating unit in conjunction with a litigation settlement agreement with Sierra Club.

*Georgia Public Service Commission* - Presented testimony before the Georgia Public Service Commission in Docket 3840-U, providing recommendations on nuclear O&M levels for Hatch and Vogtle and recommending that a nuclear performance standard be implemented in the State of Georgia.

*Oklahoma Industrial Energy Consumers* - Analyzed and presented testimony addressing power production and coal plant dispatch issues in fuel prudence cases involving Oklahoma Gas and Electric Company.

*Georgia Public Service Commission* - Analyzed and provided recommendations regarding the reasonableness of nuclear O&M costs, fossil O&M costs and coal inventory levels reported in GPC's 1990 Surveillance Filing.

*City of Houston* - Analyzed and presented comments on various legislative proposals impacting retail electric and gas utility operations and rates in Texas.

*New York Public Service Commission* - Conducted inter-company statistical benchmarking analysis of Rochester Gas & Electric Company to provide the New York Public Service Commission with guidance in determining areas which should be reviewed in detailed management audit of the company.

*Virginia Attorney General* – Analyzed and presented testimony regarding an accelerated vegetation management program and rider proposed by Appalachian Power Company.

*Oklahoma Attorney General* – Analyzed and presented testimony regarding fuel and purchased power, depreciation and other expense items in Oklahoma Gas & Electric Company's 2001 rate case before the Oklahoma Corporation Commission.

*City of Houston* - Analyzed and presented testimony regarding fossil plant O&M expense levels in Houston Lighting & Power Company's rate case before the Public Utility Commission of Texas.

*City of El Paso* - Analyzed and presented testimony regarding regulatory and technical issues related to the Central & Southwest/El Paso Electric Company merger and rate proceedings before the PUCT, including analysis of merger synergy studies, fossil O&M and purchased power margins.

*Residential Ratepayer Consortium* - Analyzed Fermi 2 replacement power and operating performance issues in fuel reconciliation proceedings for Detroit Edison Company before the Michigan Public Service Commission.

*Residential Ratepayer Consortium* - Analyzed and prepared testimony addressing coal plant outage rate projections in the Consumer's Power Company fuel proceeding before the Michigan Public Service Commission.

*City of El Paso* - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1991 rate case before the Public Utility Commission of Texas.

*City of Houston* - Analyzed and developed testimony regarding the operations and maintenance expenses and performance standards for the South Texas Nuclear Project, and operations and maintenance expenses for the Limestone and Parish coal-fired power plants in HL&P's 1991 rate case before the PUCT.

*City of El Paso* - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1990 rate case before the Public Utility Commission of Texas. Recommendations were adopted.

**Energy Planning and Procurement Services**

*Virginia Attorney General* – Review and provide comments or testimony regarding annual integrated resource plan filings made by Dominion Virginia Power and Appalachian Power Company.

*Dell Computer Corporation* – Negotiated retail power supply agreement for Dell's Round Rock, Texas facilities producing annual savings in excess of $2 million.

*Texas Association of School Boards Electric Aggregation Program* – Serve as TASB's consultant in the development, marketing and administration of a retail electric aggregation program consisting of 2,500 Texas schools with a total load of over 300 MW. Program produced annual savings of more than $30 million in its first year.

*Oklahoma Industrial Energy Consumers* - Analyzed and drafted comments addressing integrated resource plan filings by Public Service Company of Oklahoma and Oklahoma Gas and Electric Company.

*S.C. Johnson* - Analyzed and presented testimony addressing Wisconsin Electric Power Company's $4.1 billion CPCN application to construct three coal-fired generating units in southeast Wisconsin.

*Oklahoma Industrial Energy Consumers* - Analyzed wind energy project ownership proposals by Oklahoma Gas and Electric Company and presented testimony addressing project economics and operational impacts.

*City of Chicago, Illinois Attorney General, Illinois Citizens' Utility Board* - Analyzed Commonwealth Edison's proposed divestiture of the Kincaid and State Line power plants to SEI and Dominion Resources.

*Georgia Public Service Commission* - Analyzed and presented testimony on Georgia Power Company's integrated resource plan in a certification proceeding for an eight unit, 640 MW combustion turbine facility.

*South Dakota Public Service Commission* - Evaluated integrated resource plan and power plant certification filing of Black Hills Power & Light Company.

*Shell Leasing Co.* - Evaluated market value of 540 MW western coal-fired power plant.

*Community Energy Electric Aggregation Program* – Served as Community Energy's consultant in the development, marketing and start-up of a retail electric aggregation program consisting of major charitable organizations and their donors in Texas.

*Austin Energy* – Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

*Austin Energy* - Provided technical assistance in the evaluation of the economic viability of the City of Austin's ownership interest in the South Texas Project.

*Austin Energy* - Assisted with regional production cost modeling analysis to assess production cost savings associated with various public power merger and power pool alternatives.

*Sam Rayburn G&T Electric Cooperative* - Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

*Rio Grande Electric Cooperative, Inc.* - Directed preparation of power supply solicitation and conducted economic and technical analysis of offers.

*Virginia Attorney General* – Review and provide comments or testimony regarding annual demand-side management program programs and rider proposals made by Dominion Virginia Power and Appalachian Power Company.

*Austin Energy* – Conducted modeling to assess potential costs and benefits of a municipal power pool in Texas.

**Electric Restructuring Analyses**

*Electric Power Research Institute* - Evaluated regional resource planning and power market dispatch impacts on rail transportation and coal supply procurement strategies and costs.

*Arkansas House of Representatives* – Critiqued proposed electric restructuring legislation and identified suggested amendments to provide increased protections for small consumers.

*Virginia Legislative Committee on Electric Utility Restructuring* – Presented report on status of stranded cost recovery for Virginia's electric utilities.

*Georgia Public Service Commission* – Developed models and a modeling process for preparing initial estimates of stranded costs for major electric utilities serving the state of Georgia.

*City of Houston* – Evaluated and recommended adjustments to Reliant Energy's stranded cost proposal before the Public Utility Commission of Texas.

*Oklahoma Attorney General* – Evaluated and advised the Attorney General on technical, economic and regulatory policy issues arising from various electric restructuring proposals considered by the Oklahoma Electric Restructuring Advisory Committee.

*State of Hawaii Department of Business, Economics and Tourism* – Evaluated electric restructuring proposals and developed models to assess the potential savings from deregulation of the Oahu power market.

*Virginia Attorney General* - Served as the Attorney General's consultant and expert witness in the evaluation of electric restructuring legislation, restructuring rulemakings and utility proposals addressing retail pilot programs, stranded costs, rate unbundling, functional separation plans, and competitive metering.

*Western Public Power Producers, Inc.* - Evaluated operational, cost and regional competitive impacts of the proposed merger of Southwestern Public Service Company and Public Service Company of Colorado.

*Iowa Department of Justice, Consumer Advocate Division* - Analyzed stranded investment and fuel recover issues resulting from a market-based pricing proposal submitted by MidAmerican Energy Company.

*Cullen Weston Pines & Bach/Citizens' Utility Board* - Evaluated estimated costs and benefits of the proposed merger of Wisconsin Energy Corporation and Northern States Power Company (Primergy).

*City of El Paso* - Evaluated merger synergies and plant valuation issues related to the proposed acquisition and merger of El Paso Electric Company and Central & Southwest Company.

*Rio Grande Electric Cooperative, Inc.* - Analyzed stranded generation investment issues for Central Power & Light Company.

**Power Plant Management**

*City of Austin Electric Utility Department* - Analyzed the 1994 Operating Budget for the South Texas Nuclear Project (STNP) and assisted in the development of long-term performance and expense projections and divestiture strategies for Austin's ownership interest in the STNP.

*City of Austin Electric Utility Department* - Analyzed and provided recommendations regarding the 1991 capital and O&M budgets for the South Texas Nuclear Project.

*Sam Rayburn G&T Electric Cooperative* - Developed and conducted operational monitoring program relative to minority owner's interest in Nelson 6 Coal Station operated by Gulf States Utilities.

*KAMO Electric Cooperative, City of Brownsville and Oklahoma Municipal Power Agency* - Directed an operational audit of the Oklaunion coal-fired power plant.

*Sam Rayburn G&T Electric Cooperative* - Conducted a management/technical assessment of the Big Cajun II coal-fired power plant in conjunction with ownership feasibility studies for the project.

*Kamo Electric Power Cooperative* - Developed and conducted operational monitoring program for client's minority interest in GRDA Unit 2 Coal Fired Station.

*Northeast Texas Electric Cooperative* - Developed and conducted operational monitoring program concerning NTEC's interest in Pirkey Coal Station operated by Southwestern Electric Power Company and Dolet Hills Station operated by Central Louisiana Electric Company.

*Corn Belt Electric Cooperative/Central Iowa Power Cooperative* - Perform operational monitoring and budget analysis on behalf of co-owners of the Duane Arnold Energy Center.

## PRESENTATIONS

*Quantifying Impacts of Electric Restructuring: Dynamic Analysis of Power Markets,* 1997 NARUC Winter Meetings, Committee on Finance and Technology.

*Quantifying Costs and Benefits of Electric Utility Deregulation: Dynamic Analysis of Regional Power Markets,* International Association for Energy Economics, 1996 Annual North American Conference.

*Railroad Rates and Utility Dispatch Case Studies,* 1996 EPRI Fuel Supply Seminar.

**Exhibit SN-2**

CEHE Historical SAIDI Performance (Average Outage Minutes per Customer per Year)

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Major Event | 9 32 | 51 06 | 32.36 | 14.2 | 0.23 | 59.65 | 63 46 | 312 17 | 4.85 | |
| Forced Interruptions | 81 67 | 94.36 | 102 54 | 92.59 | 85 71 | 154.61 | 119 81 | 102.73 | 116 46 | |
| Scheduled Interruptions | 15.24 | 18.6 | 17 92 | 29.09 | 32.04 | 36.8 | 34 12 | 36.84 | 50.05 | |
| Outside Causes | 4 49 | 5.76 | 4.3 | 4.57 | 2 5 | 8.22 | 8.45 | 2 62 | 7.23 | |
| Outside Causes - Substation | 4 48 | 3.92 | 4 3 | 4.54 | 2.39 | 7 72 | 8.28 | 2.2 | 4.25 | |
| Outside Causes - Transmission | 0 | 1.84 | 0 | 0.03 | 0.11 | 0.5 | 0.16 | 0 42 | 2.98 | |
| | | | | | | | | | | |
| Total Incl Major Events | 110.7 | 169.8 | 157.1 | 140.5 | 120.5 | 259.3 | 225.8 | 454.4 | 178.6 | |
| Total Excl Major Events | 101.4 | 118.7 | 124.8 | 126.3 | 120.3 | 199.6 | 162 4 | 142.2 | 173.7 | |
| Total Excl Scheduled Interruptions | 86.2 | 100.1 | 106.8 | 97 2 | 88 2 | 162.8 | 128.3 | 105.4 | 123.7 | |
| | | | | | | | 2010-2014 Avg: | | 95.7 | |
| | | | | | | | 2015· | | 162.8 | 70.1% |
| | | | | | | | 2016-2018 Avg: | | 119.1 | 24.5% |
| | | | | | | | | | 99.98% | |

Source· COH 1-13

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH01-23**

**QUESTION:**

Provide the total number of CEHE's customer complaints by class and type of complaint (including service reliability) over each of the last five years.

**ANSWER:**

Consistent with clarification provided by counsel for the City of Houston, CenterPoint Energy is providing COH01-23 Summary of Complaints (Confidential), a 5 year history of formal escalated complaints received and resolved within Customer Operations.

**The attachment is confidential and is being provided pursuant to the Protective Order issued in Docket No. 49421.**

**SPONSOR (PREPARER):**
Rebecca Demarr (Rebecca Demarr)

**RESPONSIVE DOCUMENTS:**
COH01-23 Summary of Complaints (Confidential).xlsx

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH01-30**

**QUESTION:**

Does CEHE currently offer any tariffs or other means for customers to obtain enhanced distribution system reliability service? If so, provide the tariffs, describe the services provided, and indicate the number of customers that have elected to purchase such services. If not, explain why not.

**ANSWER:**

Yes. CEHE offers Premium Rollover Service that provides two separate sources of power to customers on the overhead distribution system. If the primary source of power fails, the customer's load will automatically be switched to the backup source. The second source of power is obtained by extending a second circuit to the customer. The speed at which a customer can switch to the backup source depends on the switching device (30 seconds for a switch or 25 cycles or 0.417 seconds for a recloser). The policy is to offer rollover service in a manner that the extension of the second circuit will not cause a bottleneck with regards to the expansion of the distribution system for future customers and new loads. The customer must pay for a study by Electric Distribution Planning to determine the upfront costs to extend the second circuit, the cost of the switch/breaker and the cost of any additional transformers, if required. There is also a monthly payment that depends on the amount of KVA the customer intends to roll over because CEHE must maintain this reserve capacity on the backup circuit, as well as monthly expenses for planning and dispatching around the rollover location. There are approximately 13 customers with this service. See attached copy of the tariff.

**SPONSOR (PREPARER):**
Matthew Troxle/Dale Bodden/Julienne Sugarek (Matthew Troxle/Dale Bodden/Julienne Sugarek)

**RESPONSIVE DOCUMENTS:**
COH01-30 PRS Tariff Attachment 1.pdf

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH01-05**

**QUESTION:**

Provide CEHE's budgeted and actual distribution O&M expenses for each year since 2016.

**ANSWER:**

CEHE does not budget O&M at the distribution level and therefore does not have budgeted distribution O&M available for the time period requested. Please see response to COH01-01 for references to the actual distribution O&M expenses.

**SPONSOR (PREPARER):**
Kristie Colvin (Kristie Colvin)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH01-07**

**QUESTION:**

Provide CEHE's budgeted and actual transmission O&M expenses for each year since 2016.

**ANSWER:**

CEHE does not budget O&M at the transmission level and therefore does not have budgeted transmission O&M available for the time period requested. Please see response to COH01-03 for references to the actual transmission O&M expenses.

**SPONSOR (PREPARER):**
Kristie Colvin (Kristie Colvin)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH13-06**

**QUESTION:**

Reference CEHE's response to City of Houston's Request for Information 01-22 and provide definitions for each criterion included in the Project Valuation score of each project and indicate whether values for each criterion represent monetary benefits, estimated value or some other basis.

**ANSWER:**

Please refer to the response to COH01-22 for a copy of the attachment, COH01-22 Project Evaluation Forms Attachment 2.pdf. Each of the Project Evaluation Forms (PEFs) includes the assumptions and explanations for the load at risk calculation for that project. The definitions for the load at risk criterion are:

- Base load at risk (Mw): The megawatts on the distribution/transmission circuit or substation component that is at risk of an outage if the project is not built.
- Number of Components at Risk: The number of components involved in a project. If there are 8 substation breakers involved in the project, then the number of components is 8.
- Probability of Failure: The historical outage rate or failure rate for each component.
- Days to Restore Operations, which is converted to hours: The typical number of days to restore service in the event of a failure or outage. This may range from 1 day for a distribution circuit to 14 days for a substation power transformer.
- Qualitative Adjustments (Reliability or Design Criteria Benefit): Additional credit is given for design criteria or reliability criteria justification for a project.
- Supplemental Benefits: Added credit for a number of supplemental categories including leverages existing technology, enables additional technology, contributes to overall infrastructure performance/improvement, increases infrastructure for future use, provides improved service quality to clients/customers, or provides benefits to other departments.
- Corporate Risk Alignment, if applicable: Additional credit if the project aligns with a stated corporate risk.

Monetary benefits are not calculated for a project or program as a part of its value calculation. Please see attachment COH13-06 AIS Benefit Training Guide.pdf for additional discussion for each criterion.

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
COH13-06 AIS Benefit Training Guide.pdf

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH13-01**

**QUESTION:**

Reference CEHE's response to City of Houston's Request for Information 01-22 and provide documentation that explains the capabilities of the AIS decision tool and explain what is meant by the referenced "non-monetized benefit/cost information" produced by the AIS.

**ANSWER:**

As discussed in COH 1-22, the AIS decision tool produces non-monetized benefit/cost information for selected projects and programs as a way to optimize the Company's annual capital portfolio. This includes distribution, transmission, substation, telecommunications and major underground projects. The benefit/cost information is based on a metric that is determined by the "benefits" divided by the "cost" of the project to give a cost-weighted value. The benefits are determined by a calculation based on megawatts at risk, probability of outage, number of components involved, and the duration of exposure as measured by repair time, plus additional multipliers, based on drivers for the project such as design criteria, reliability, supplemental benefits and corporate risk alignment.

Regarding documentation of the AIS decision tool, please see attachment COH13-01 - AIS User Manual v3.0.1404, pp 9-11, Davies Consulting LLC Attachment 1 (confidential).pdf for information about the AIS process and toolset. AIS is configurable, based upon the needs of the organization implementing it.

CEHE's configuration facilitates an operations-based project (or program) risk evaluation, and all criteria and evaluation elements were developed by CEHE operations and engineering subject matter experts. A project's benefit (value) is determined by calculating the load that is at risk (expressed in Mwh) if the project is not executed. It is a "non-monetized" benefit/cost calculation in that "monetary" benefits are not calculated for a project in determining its value. Additional value may result from the project's alignment with CEHE's corporate risks. Accordingly, the benefit/cost ratio, or the AIS value/cost ratio, is expressed as Mwh/Estimated Cost ($).

**The attachment is confidential and is being provided pursuant to the Protective Order issued in Docket No. 49421.**

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
COH13-01 - AIS User Manual v3.0.1404 pp 9-11 Attachment 1 (confidential).pdf

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH13-03**

**QUESTION:**

Reference CEHE's response to City of Houston's Request for Information 01-22 and provide the definition of the Load at Risk criterion use for project valuation, provide the formula and assumptions for calculating this criterion, and explain whether the score for this criterion reflects estimated monetary benefit to customers or some other value.

**ANSWER:**

Load at Risk is a calculated value that quantifies the risk of not serving electric load. If a project is not built, there is a risk that load, or redundancy for serving that load (measured in Mw), will be lost, placing the existing system at risk for a period of time (Days, which is converted to hours) until the system is restored to a normal state.

The basic equation to quantify Load at Risk =

(Base load at risk (Mw) x Number of Components at Risk x Probability of Failure x Days to Restore Operations) +

Qualitative Adjustments (Reliability or Design Criteria Benefit and Supplemental Benefits) +

Corporate Risk Alignment, if applicable.

Please refer to the response to COH 1-22 for a copy of the attachment, COH 1-22 Project Evaluation Forms Attachment 2.pdf. Each of the Project Evaluation Forms (PEFs) includes the assumptions and explanations for the load at risk for that project. The load at risk is not a monetary benefit.

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH13-04**

**QUESTION:**

Reference CEHE's response to City of Houston's Request for Information 01-22 and provide forecasted monetary benefits and actual realized monetary benefits for each of the projects along with assumptions and other workpapers supporting these calculations.

**ANSWER:**

Monetary benefits are not calculated for a project or program as a part of its value calculation. Please see response for COH13-01 and COH13-03.

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH13-02**

**QUESTION:**

Reference CEHE's response to City of Houston's Request for Information 01-22 and provide the approved budget and actual cost for each of the listed projects.

**ANSWER:**

The approved budget and actual cost for the projects and programs listed in CEHE's response to COH01-22 is provided in attachment COH13-02 Costs for AIS Projects Attachment 1.xlsx. The projects and programs listed covered the time period from 2010 to 2018, so the costs that are provided are for 2010 to 2018.

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
COH13-02 Costs for AIS Projects Attachment 1.xlsx

**COH 13-2 Costs for AIS Projects Attachment 1.xlsx**
**Budget and Actual Cost for Years 2010-2018**
Figures exclude Capital Overhead

| Project Number | Short Title | Budget | Actual |
|---|---|---|---|
| AB1C | 300% and 10% Circuit Reliability Program | 124,482,860 | 112,011,466 |
| AB2G | Pole Maintenance Program (Poles) | 114,709,794 | 90,455,421 |
| AB48 | Pole Maintenance Program (Bracing) | 23,121,104 | 17,765,754 |
| ABCA | Cable Assessment/Life Extension Program (CAP/CLEP) | 61,763,854 | 53,997,986 |
| CE1B | Major Underground Rehab | 54,845,865 | 57,506,694 |
| DB18 | City of Houston LED Streetlight Conversion | 69,512,058 | 65,874,384 |
| HLP/00/0014 | Replace SCADA Logic Cages/RTUs | 21,166,379 | 16,894,658 |
| HLP/00/0075 | Replace Failed Major Equip and Purchase Spares | 131,990,767 | 127,517,913 |
| HLP/00/0484 | Substation Security Upgrades | 15,078,130 | 19,425,611 |
| HLP/00/0612 | Fry Substation: Build 35kV Sub w/6 35kV Feeders | 8,745,000 | 9,533,912 |
| HLP/00/0875 | Springwoods Substation: Build 35kV Sub w/8 Feeders | 11,660,000 | 13,505,096 |
| HLP/00/0884 | Replace 12/35kV Square D Type FBS Breakers | 13,835,984 | 8,836,030 |
| HLP/00/0909 | Replace 35/12kV Breakers | 5,936,532 | 7,684,302 |
| HLP/00/0941 | Alexander Island Substation: Upgrade Transformers to 50MVA | 5,973,958 | 6,001,653 |
| HLP/00/0953 | South Channel: New Substation 2-50MVA Trfs w/6 Feeders | 6,290,445 | 5,916,905 |
| HLP/00/0954 | Sandy Point: New Substation 2-50MVA Trfs w/4-12kV Feeders | 6,160,000 | 11,042,088 |
| HLP/00/0956 | Willow Substation: Add 2-100MVA Transformers w/4-35kV Feeders | 8,529,150 | 10,352,445 |
| HLP/00/0963 | Springwoods Substation: Add 3rd 100MVA Trf and 4-35kV Feeders | 6,027,757 | 3,591,424 |
| HLP/00/0974 | Tomball Substation: Add 3rd Transformer and 2 Feeders | 2,226,809 | 4,008,100 |
| HLP/00/0977 | Jordan: New 35kV Substation | 6,434,799 | 6,906,746 |
| HLP/00/0978 | Trinity Bay: Install 35kV Facilities (2 Trfs and 4-35kV Feeders) | 2,755,418 | 5,051,002 |
| HLP/00/1036 | Tanner: New Substation w/2-100MVA Trfs and 6-35kV Feeders | 11,000,000 | 12,790,474 |
| HLP/00/1084 | Village Creek: New Substation w/2-100MVA Trfs and 4-35kV Feeders | 11,880,000 | 12,783,585 |
| HLP/00/1087 | Arcola Substation: Install 3rd 100MVA Trf and 3-35kV Feeders | 3,867,088 | 3,685,348 |
| S/101785/CE/FIBER | Fiber Rehabilitation, Telecom Core Network | 17,724,792 | 19,126,318 |
| S/101785/CN/FIBER | Post Ams WiMax and WiMax "Backhaul" Transport Growth | 30,959,107 | 8,058,773 |
| S/101785/CN/MPLS | Telcom Services MPLS Network Optimization | 8,759,348 | 7,844,371 |
| S/101785/CN/OPENSKY | Opensky VMDRS: Console Repl; Sys Growth; Post-project enhancements | 31,069,611 | 26,414,890 |
| S/101785/CN/TFSY | Fiber Expansion, v.10 | 5,884,797 | 6,069,750 |
| S/101785/CN/TMSY | Microwave: New licensed sites; OC3 MW repl; Licensed network deployment | 10,894,164 | 9,676,192 |

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH01-22**

**QUESTION:**

Provide cost/benefit analyses and other information supporting the prudence of each CEHE distribution capital project having a total cost of more than $5 million that was placed in service since 2009.

**ANSWER:**

See attachment COH01-22 Index Attachment 1.xlsx for an index of the benefit/cost analysis that has been performed for a number of the CEHE distribution capital projects that have a total cost of more than $5 million that have been placed into service since 2009.

The index will provide the Project Number and Description similar to what was provided in previous DCRF's, a simplified description that closely corresponds to the terminology utilized by the Company's Asset Investment Strategy ("AIS") decision tool, and the page number in the attached pdf that provides the corresponding Project Evaluation Forms ("PEFs") that are produced by the AIS tool. See COH01-22 Project Evaluation Forms Attachment 2.pdf.

The AIS decision tool produces non-monetized benefit/cost information for selected projects and programs as a way to optimize the Company's annual capital portfolio. This includes distribution, transmission, substation, telecommunications and major underground projects. The benefit/cost information is based on a metric that is determined by the "benefits" divided by the "cost" of the project to give a cost-weighted value. The benefits are determined by a calculation based on megawatts at risk, probability of outage, number of components involved, and the duration of exposure as measured by repair time, plus additional multipliers, based on drivers for the project such as design criteria, reliability, supplemental benefits and corporate risk alignment. Please note that not all investments are modeled in the optimization process, such as public improvements (facility relocations), service restoration, distribution revenue, non-program corrective maintenance, fleet/facilities, information technology projects, and other non-T&D capital work.

The attached file includes PEFs for work that meets the $5M threshold for those distribution projects and programs that were sponsored in 2014-2018. In cases where multiple years are involved, such as in a recurring program, PEFs are included for each year's submission.

Attachment 2 is voluminous and is provided as discussed below.

**The requested information is voluminous and will be provided to the propounding party only in electronic format on CD. Please contact Alice Hart at (713) 207-5322 to request a copy of the CD. Please see index of voluminous material below.**

| Date | Project Number | Short Title | Preparer | Page # |
|---|---|---|---|---|
| Undated | AB1C | 300% and 10% Circuit Reliability Program | Dale Bodden | 1-35 |
| Undated | AB2G | Pole Maintenance Program (Poles) | Dale Bodden | 36-57 |
| Undated | AB48 | Pole Maintenance Program (Bracing) | Dale Bodden | 36-57 |
| Undated | ABCA | Cable Assessment/Life Extension Program (CAP/CLEP) | Dale Bodden | 58-74 |

| | | | | |
|---|---|---|---|---|
| Undated | CE1B | Major Underground Rehab | Dale Bodden | 75-98 |
| Undated | DB18 | City of Houston LED Streetlight Conversion | Dale Bodden | 99-116 |
| Undated | HLP/00/0014 | Replace SCADA Logic Cages/RTUs | Dale Bodden | 117-133 |
| Undated | HLP/00/0075 | Replace Failed Major Equip and Purchase Spares | Dale Bodden | 134-152 |
| Undated | HLP/00/0484 | Substation Security Upgrades | Dale Bodden | 153-169 |
| Undated | HLP/00/0612 | Fry Substation: Build 35kV Sub w/6 35kV Feeders | Dale Bodden | 170-172 |
| Undated | HLP/00/0875 | Springwoods Substation: Build 35kV Sub w/8 Feeders | Dale Bodden | 173-175 |
| Undated | HLP/00/0884 | Replace 12/35kV Square D Type FBS Breakers | Dale Bodden | 176-181 |
| Undated | HLP/00/0909 | Replace 35/12kV Breakers | Dale Bodden | 182-200 |
| Undated | HLP/00/0941 | Alexander Island Substation: Upgrade Transformers to 50MVA | Dale Bodden | 201-204 |
| Undated | HLP/00/0953 | South Channel: New Substation 2-50MVA Trfs w/6 Feeders | Dale Bodden | 205-207 |
| Undated | HLP/00/0954 | Sandy Point: New Substation 2-50MVA Trfs w/4-12kV Feeders | Dale Bodden | 208-219 |
| Undated | HLP/00/0956 | Willow Substation: Add 2-100MVA Transformers w/4-35kV Feeders | Dale Bodden | 220-223 |
| Undated | HLP/00/0963 | Springwoods Substation: Add 3rd 100MVA Trf and 4-35kV Feeders | Dale Bodden | 224-227 |
| Undated | HLP/00/0974 | Tomball Substation: Add 3rd Transformer and 2 Feeders | Dale Bodden | 228-230 |
| Undated | HLP/00/0977 | Jordan: New 35kV Substation | Dale Bodden | 231-233 |
| Undated | HLP/00/0978 | Trinity Bay: Install 35kV Facilities (2 Trfs and 4-35kV Feeders) | Dale Bodden | 234-236 |
| Undated | HLP/00/1036 | Tanner: New Substation w/2-100MVA Trfs and 6-35kV Feeders | Dale Bodden | 237-247 |
| Undated | HLP/00/1084 | Village Creek: New Substation w/2-100MVA Trfs and 4-35kV Feeders | Dale Bodden | 248-255 |
| Undated | HLP/00/1087 | Arcola Substation: Install 3rd 100MVA Trf and 3-35kV Feeders | Dale Bodden | 256-259 |
| Undated | S/101785/CE/FIBER | Fiber Rehabilitation, Telecom Core Network | Dale Bodden | 260-281 |
| Undated | S/101785/CN/FIBER | Post Ams WiMax and WiMax "Backhaul" Transport Growth | Dale Bodden | 282-286 |
| Undated | S/101785/CN/MPLS | Telcom Services MPLS Network Optimization | Dale Bodden | 287-291 |
| Undated | S/101785/CN/OPENSKY | Opensky VMDRS: Console Repl; Sys Growth; Post-project enhancements | Dale Bodden | 292-308 |
| Undated | S/101785/CN/TFSY | Fiber Expansion, v.10 | Dale Bodden | 309-336 |

| | | | | |
|---|---|---|---|---|
| Undated | S/101785/CN/TMSY | Microwave: New licensed sites; OC3 MW repl; Licensed network deployment | Dale Bodden | 337-352 |

**SPONSOR (PREPARER):**
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

**RESPONSIVE DOCUMENTS:**
COH01-22 Index Attachment 1.xls
COH01-22 Project Evaluation Forms Attachment 2.pdf

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH10-23**

**QUESTION:**

Reference page 19, Figure 5 of witness Pryor's direct testimony and provide the estimated improvement to CEHE's SAIDI performance (minutes per year) associated with each listed category of reliability improvements.

**ANSWER:**

As discussed in the response to COH 10-13, CenterPoint Houston has a number of reliability improvement programs that will result in many of the capital reliability improvements for the categories listed in Figure 5 of witness Pryor's direct testimony. For the capital improvement categories Overhead Service Rehabilitation, Pole and URD Replacement, there are benefits to the capital investments, especially since these were necessary improvements to resolve an equipment or facility issue, but there is not a direct correlation between the capital dollars spent and SAIDI impact.

IGSD installations facilitate the isolation of faults on distribution feeders by remote control and thus provide a benefit to system SAIDI. See the chart below for the annual system SAIDI savings for these devices since 2014. To be clear, the $7.3 million in Figure 5 for IGSD installations is not the total investment over the last 9 years because for much of that time the capital dollars for IGSD installations were not separately accounted for, but were attributed to other accounts. A rough estimate of the capital dollars invested in IGSD installations for 2010-2018 is approximately $79 million, and as a result the cumulative SAIDI savings for 2014-2018 is 62.19 minutes.

(Millions of Dollars)

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| IGSD System SAIDI Savings | 6.32 | 8.28 | 18.74 | 18.93 | 9.92 |

For the Street Lighting and Capacitor categories, the capital investments items do not have an impact on system SAIDI.

**SPONSOR (PREPARER):**
Dale Bodden (Dale Bodden)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH10-27**

**QUESTION:**

Reference page 35 of witness Pryor's direct testimony and provide the annual SAIDI contribution of URD cable failure outages for each year since 2010.

**ANSWER:**

The annual SAIDI contribution of URD cable failure outages to system SAIDI is provided in the following chart.

| Year | SAIDI |
|---|---|
| 2010 | 1.932 |
| 2011 | 5.477 |
| 2012 | 5.134 |
| 2013 | 6.678 |
| 2014 | 6.827 |
| 2015 | 5.412 |
| 2016 | 5.575 |
| 2017 | 5.230 |
| 2018 | 5.035 |

**SPONSOR (PREPARER):**
Dale Bodden (Dale Bodden)

**RESPONSIVE DOCUMENTS:**
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH15-02**

**QUESTION:**

Reference CEHE's response to COH01-22, for each capital project identified, identify the specific portions of CEHE's testimony, exhibits and workpapers supporting the prudence of costs incurred for each such project.

**ANSWER:**

Several Company witnesses support the prudence of and necessity of the capital projects identified in response to COH 1-22. Specifically, Company witness Randal Pryor's testimony describes programs designed to ensure the reasonableness and prudence of distribution investment, as well as cost control and budgeting processes implemented by CenterPoint Houston on an ongoing basis. Company witness Martin Narendorf, likewise, describes programs designed to ensure the reasonableness and prudence of transmission investment, as well as cost control and budgeting processes implemented by CenterPoint Houston. Ms. Dale Bodden describes planning processes that ensure capital investment projects are consistently and thoroughly evaluated prior to and during construction. Ms. Julienne Sugarek testifies to how the Company's 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. And, Ms. Shachella James explains the structure and services provided by Service Company's Technology Operations group and demonstrates the reasonableness and necessity of Technology Operations capital investment deployed by CenterPoint Houston. These witnesses describe how all projects, including the projects identified in response to COH 1-22, are managed on a daily basis to ensure prudence and reasonableness of costs.

See attachment COH15-02 Testimony Pages for Capital Projects.xlsx for a listing of the capital projects identified in CEHE's response to COH 1-22 and specific portions of CEHE's testimony, exhibits and workpapers that are relevant to and supporting of the prudence and necessity for the referenced projects.

**SPONSOR (PREPARER):**
Randal Pryor/Martin Narendorf/Dale Bodden/Julienne Sugarek/Shachella James (Randal Pryor/Martin Narendorf/Dale Bodden/Julienne Sugarek/Shachella James)

**RESPONSIVE DOCUMENTS:**
COH15-02 Testimony Pages for Capital Projects.xlsx

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC**
**2019 CEHE RATE CASE**
**DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**CITY OF HOUSTON**
**REQUEST NO.: COH15-06**

**QUESTION:**

Reference CEHE's response to COH01-22, for each capital project identified, provide the corporate costs that were allocated to each project, along with the basis for such allocations, and the portion of such costs included in each CEHE DCRF filing.

**ANSWER:**

Please see the response to PUC02-20U explaining capital work billed directly or allocated to capital work orders.
Please refer to Ms. Kristie Colvin's direct testimony Exhibit KLC-11 for the capitalization of computer software policy and capitalization policy. Refer to COH15-06 Attachment 1.pdf for the construction overhead policy.
Please see the response to COH15-06 Attachment 2.xlsx for the corporate costs that were included in CenterPoint Houston's DCRF filing. A DCRF application was not filed for calendar year ended 2018.

**SPONSOR (PREPARER):**
Kristie Colvin / Michelle Townsend (Kristie Colvin / Michelle Townsend)

**RESPONSIVE DOCUMENTS:**
COH15-06 Attachment 1.pdf
COH15-06 Attachment 2.xlsx

**CenterPoint Energy Houston Electric**
**Calculation of Capitalized Overhead for Distribution**

| | Docket No. 44572 | Docket No. 45747 | Docket No. 47032 | Docket No 48226 | Total |
|---|---|---|---|---|---|
| Accounts Payable | 128,518 | 119,816 | 163,906 | 165,372 | 577,612 |
| Property Accounting | 270,355 | 274,830 | 201,733 | 350,599 | 1,097,517 |
| Call Center | - | 210,013 | 328,916 | 388,523 | 927,451 |
| Total | 398,874 | 604,658 | 694,555 | 904,494 | 2,602,580 |

**Exhibit SN-14**

Recommended DCRF Reconciliation Adjustment and DCRF Credit Rider

| Rate Class | Billing Units | Class Alloc | Proj ABCA Adjustment | Proj CE1B Rev Adj | Indirect Corp Chg Adj | Total DCRF Credit | Total DCRF Credit | |
|---|---|---|---|---|---|---|---|---|
| Residential | 29,513,574,664 | 53.07% | $7,632,396 | $9,229,859 | $382,082 | $17,244,336 | $0.000584 | per kWh |
| Secondary<=10 | 928,256,194 | 2.11% | $303,497 | $367,019 | $15,193 | $685,709 | $0.000739 | per kWh |
| Secondary > 10 | 116,423,346 | 35.12% | $5,050,125 | $6,107,118 | $252,812 | $11,410,056 | $0.098005 | per billing KVA |
| Primary | 12,059,474 | 1.64% | $236,528 | $286,033 | $11,841 | $534,402 | $0.044314 | per billing KVA |
| Transmission | 26,426,924 | 0.14% | $19,894 | $24,058 | $996 | $44,949 | $0.001701 | per 4CP kVA |
| Lighting | 267,155,948 | 7.92% | $1,138,906 | $1,377,279 | $57,014 | $2,573,199 | $0.009632 | per kWh |
| | | | $14,381,345 | $17,391,366 | $719,938 | **$32,492,649** | | |