ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Molly Holland Sponsoring Witness: N/A Beginning Sequence No. EV190 Ending Sequence No. EV190

Question No.: TIEC 1-40 Part No.: Addendum:

The following discovery requests pertain to the Direct Testimony of Kristin Sasser.

Question:

Did ETI's customers experience outages during Winter Storm Uri? If so, provide ETI's assessment of the kWh sales that ETI was unable to supply to its customers.

Response:

Yes, ETI's customers experienced outages during Winter Storm Uri. Based on a comparison of 2019 to 2020 data, ETI sales were lower by approximately 44,290,000 kWh.

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Kyle Sannino Sponsoring Witness: Kristin Sasser Beginning Sequence No. PI24 Ending Sequence No. PI24

Question No.: TIEC 1-41 Part No.: Addendum:

The following discovery requests pertain to the Direct Testimony of Kristin Sasser.

Question:

Explain how the weather adjustment adjusts kWh sales for the period that Winter Storm Uri impacted ETI's service territory.

Response:

The calculations of the weather adjustment for the period that Winter Storm Uri impacted Entergy Texas, Inc.'s service territory were performed under the same weather normalization process as described in the Direct Testimony of Kristin Sasser at page 7 (Q14), including obtaining actual measured hourly temperatures from the National Weather Service stations at Beaumont and Houston, Texas.

ENTERGY TEXAS, INC.
TEST YEAR DATA BY RATE CLASS
FOR TWELVE MONTHS ENDING DECEMBER 31, 2021

		TEXAS							
		Number of Customers			kWh Sales & Adjustments				
Line No.	Rate Class	Per Books Average	Per Books Year End	Adjusted Year End	Per Books	Weather Adjustment	Yr-End Cust Adjustment	Reclassification/ Annualization Adjustment	Test Year Adjusted
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential Service	418,772	422,815	422,815	6,172,928,238	34,473,050	60,448,785	-	6,267,850,073
2	Small General Service	37,662	38,207	38,207	484,196,258	890,819	6,069,154	-	491,156,231
3	General Service	20,031	20,085	20,085	3,159,909,052	6,106,033	9,759,809	(3,134,114)	3,172,640,780
4	Large General Service	390	390	390	1,310,438,327	2,026,373	0	(15,059,054)	1,297,405,646
5	Large Industrial Power Service	124	124	124	7,614,546,923	740,031	0	348,487,016	7,963,773,970
6	Lighting Service	2,744	2,763	2,744	90,885,214	0	0	-	90,885,214
7	Total Retail	479,723	484,384	484,365	18,832,904,012	44,236,306	76,277,748	330,293,848	19,283,711,914

Sponsored by Crystal K. Elbe

PUC DOCKET NO. 16705
SOAH DOCKET NO. 473-96-2285

APPLICATION OF ENTERGY TEXAS FOR APPROVAL OF ITS TRANSITION TO COMPETITION PLAN AND THE TARIFFS IMPLEMENTING THE PLAN, AND FOR THE AUTHORITY TO RECONCILE FUEL COSTS, TO SET REVISED FUEL FACTORS, AND TO RECOVER A SURCHARGE FOR UNDER-RECOVERED FUEL COSTS	§ § § § § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

SECOND ORDER ON REHEARING

This Second Order on Rehearing (Order) addresses the application filed by Entergy Gulf States, Inc. (EGS or the Company) on November 27, 1996, in accordance with Paragraph 9b of the Stipulation and Agreement approved by the Commission in Docket No. 11292.[1] Through this Order, the Commission adopts in part and modifies in part the Proposal for Decision (PFD) as corrected and the Supplemental Proposal for Decision (SPFD) issued by the State Office of Administrative Hearings (SOAH) Administrative Law Judges (ALJs) in late March 1998.[2]

I. Introduction

The SOAH ALJs conducted separate evidentiary hearings on the four component parts of this docket: fuel, revenue requirement, cost allocation/rate design, and competitive issues. After completion of the hearings and review of the record evidence, the ALJs recommended that the Commission order EGS to reduce its current Texas retail base rates by $137 million, which

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[1] *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer or Merger,* Docket No. 11292, 19 P.U.C. BULL. 2040, 2041 (Ordering Paragraph 5) (Dec. 29, 1993).

[2] The ALJs issued the PFD on March 25, 1998, as revised by clarifications, revised text, and revised schedules filed on June 4, 12, and 16, 1998. The ALJs issued the SPFD, which addresses supplemental fuel-related issues, on March 27, 1998. The Commission considered the matters addressed in this Order at its open meetings convened on June 30, July 8 through 10, July 13, July 16, and July 22, 1998. The Commission issued its "final" order in this docket on July 22, 1998. The Commission considered motions for rehearing at its open meetings convened on August 26, and October 8, 1998. A more detailed procedural history of this case is contained in Attachment A to the PFD and the Findings of Fact (FoF) and Conclusions of Law (CoL), as modified, contained in this Order.

in SO_2 emission revenues from FERC Account 411.8 - Gains from Disposition of Allowances - and record them in FERC Suspense Account 254.

Rate Design

209. EGS' cost allocation and rate design proposals reflect changes stemming from the merger of Entergy Corporation and Gulf States Utilities Company. EGS used a cost allocation methodology different from GSU's prior cases. The Company also proposed structural changes to its tariffs and has unbundled its rates in preparation for competition. The Company proposes no overall base rate increase.

210. The Company should use weighted billing cycle data for each day of the month to match exactly weather and sales.

211. EGS' weather adjustment for the commercial classes is unreasonable because the Company did not use a uniform method of weather adjustment.

212. An adjustment based on number of customers and weather should be made to demand. Although energy sales and peak demands are not necessarily affected by weather in the same degree, there is also no indication that the difference is substantial. It would be inconsistent to allow EGS to adjust revenues for weather but not demand.

213. EGS' adjustments to the Residential Service (RS), Small General Service (SGS), and General Service (GS) classes based on the number of customers at the end of the test year, the several reclassification adjustments caused by customer transfers between classes, and the miscellaneous adjustments are reasonable.

214. The 12 Coincident Peak (CP) values used by EGS should be replaced with the actual 12 CP, average (54,092 kW).

215. The CP method allocates costs on the basis of system peak. This method assumes that the system-peak drives all production capacity-related costs and assigns costs to customer classes based on each class' relative contribution to the system coincident peak demand.

216. The 12CP method is based on the twelve monthly peaks of EGS' various jurisdictions, thus reflecting, to a degree, the kWh load patterns of EGS' jurisdictions.

217. The use of the 12 CP method reasonably allocates production capacity-related and transmission capacity-related costs at the jurisdictional level.

217A. Special-rate revenue (for LQF, SMQ, MSS, and EAPS) should be directly assigned to the jurisdiction of origin. This will preclude a $396,000 subsidy from Texas to Louisiana.

218. Wheeling expenses should be accorded base rate treatment. Wheeling revenues should be treated as base rate revenues.

219. The wheeling classes should be included as separate classes in the cost of service studies. The service transmission tariff should be treated separately from the access service transmission tariff.

220. Deleted.

221. The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year.

222. The A&E 4CP method is also preferable because it is devoid of any double counting problem.

223. The Company's methodology for allocating distribution plant is the most reasonable because distribution substation and primary line costs are localized in nature; that is, they are designed and constructed to handle loads close to the point of ultimate use. The Company used the simultaneous peak load of each customer class Maximum Diversified Demand (MDD) as the basis for allocating those costs.

224. Current cost of services studies are not based on geographical differences. Classes are not divided based on geography, and industrial sites are not self-sufficient islands. The use of city streets and property enables EGS to have an integrated utility system from which all ratepayers benefit.

225. EGS' allocation of local gross receipt and franchise taxes to the classes based on total rate schedule revenues is reasonable.

226. The decommissioning expense does not vary with the amount of energy the plant consumes or produces. The costs are fixed and do not vary with the level of generation.

227. The allocation of decommissioning expense to both the Texas jurisdictional and class levels on the basis of production capacity-related costs is reasonable.

228. The Company allocates Cash Working Capital and other non-investor-supplied capital that serves as a general source of funds by a composite factor that recognizes that CWC is fungible, which is reasonable.

228A EOI expense should be allocated consistent with the Commission-approved rate design allocation in this docket.

229. Synchronizing fuel revenues and expenses in the compliance cost of service study by using the rate-year fuel expense and fuel revenues will ensure compliance with P.U.C.

TAX CODE

TITLE 2. STATE TAXATION

SUBTITLE G. GROSS RECEIPTS AND MIXED BEVERAGE TAXES

CHAPTER 182. MISCELLANEOUS GROSS RECEIPTS TAXES

SUBCHAPTER B. UTILITY COMPANIES

Sec. 182.021. DEFINITIONS. In this subchapter:

(1) "Utility company" means a person:

(A) who owns or operates a gas or water works, or water plant used for sale and distribution within an incorporated city or town in this state; or

(B) who owns or operates an electric light or electric power works, or light plant used for sale and distribution within an incorporated city or town in this state, or who is a retail electric provider, as that term is defined in Section 31.002, Utilities Code, that makes sales within an incorporated city or town in this state; provided, however, that a person who owns an electric light or electric power or gas plant used for distribution but who does not make retail sales to the ultimate consumer within an incorporated city or town in this state is not included in this definition.

(2) "Business" means the providing of gas, electric light, electric power, or water.

(3), (4) Repealed by Acts 1991, 72nd Leg., 1st C.S., ch. 5, Sec. 17.06, eff. Sept. 1, 1991.

Acts 1981, 67th Leg., p. 1715, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1991, 72nd Leg., 1st C.S., ch. 3, Sec. 5.02, eff. Sept. 1, 1991; Acts 1991, 72nd Leg., 1st C.S., ch. 5, Sec. 17.06, eff. Sept. 1, 1991; Acts 1999, 76th Leg., ch. 405, Sec. 55, eff. Sept. 1, 1999.
Amended by:

Acts 2017, 85th Leg., R.S., Ch. 102 (S.B. 559), Sec. 1, eff. May 23, 2017.

Sec. 182.022. IMPOSITION AND RATE OF TAX. (a) A tax is imposed on each utility company that makes a sale to an ultimate consumer in an incorporated city or town having a population of more than 1,000, according to the last federal census next preceding the filing of the report.

(b) The tax rates are:

(1) .581 percent of the gross receipts from business done in an incorporated city or town having a population of more than 1,000 but less than 2,500, according to the last federal census next preceding the filing of the report;

(2) 1.07 percent of the gross receipts from business done in an incorporated city or town having a population of 2,500 or more but less than 10,000, according to the last federal census next preceding the filing of the report; and

(3) 1.997 percent of the gross receipts from business done in an incorporated city or town having a population of 10,000 or more, according to the last federal census next preceding the filing of the report.

(c) Notwithstanding any other provision of this chapter, a tax under this chapter may not be imposed on gross receipts from the sale of electricity generated by an advanced clean energy project, as defined by Section 382.003, Health and Safety Code.

Text of subsection effective on January 01, 2024

(d) Notwithstanding any other provisions of this chapter, a tax under this chapter may not be imposed on the gross receipts from the sale of electricity to a public school district customer.

Acts 1981, 67th Leg., p. 1715, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1991, 72nd Leg., 1st C.S., ch. 3, Sec. 5.03, eff. Sept. 1, 1991; Acts 1991, 72nd Leg., 1st C.S., ch. 5, Sec. 17.07, eff. Sept. 1, 1991.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1277 (H.B. 3732), Sec. 6, eff. September 1, 2007.

Acts 2017, 85th Leg., R.S., Ch. 102 (S.B. 559), Sec. 2, eff. May 23, 2017.

Acts 2019, 86th Leg., R.S., Ch. 53 (H.B. 2263), Sec. 4, eff. January 1, 2024.

Sec. 182.023. PAYMENT OF TAX. Only one utility company pays the tax on a commodity. If the commodity is produced by one utility company and distributed by another, the distributor pays the tax.

Acts 1981, 67th Leg., p. 1715, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.024. POLITICAL SUBDIVISIONS. No city or other political subdivision of this state may impose an occupation tax or charge of any sort on a utility company taxed under this subchapter.

Acts 1981, 67th Leg., p. 1715, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.025. CHARGES BY A CITY. (a) An incorporated city or town may make a reasonable lawful charge for the use of a city street, alley, or public way by a public utility in the course of its business.

(b) The total charges, however designated or measured, may not exceed two percent of the gross receipts of the public utility for the sale of gas or water within the city.

(c) The total charges, however designated or measured, relating to distribution service of an electric utility or transmission and distribution utility within the city may not exceed the amount or amounts prescribed by Section 33.008, Utilities Code. The charges paid by an electric utility or transmission and distribution utility under this subsection may be only for distribution service.

(d) If a public utility taxed under this subchapter pays a special tax, rental, contribution, or charge under a contract or franchise executed before May 1, 1941, the city shall credit the payment against the amount owed by the public utility on any charge allowable under Subsection (a) of this section.

(e) In this section:

(1) "Distribution service" has the meaning assigned by Section 33.008, Utilities Code.

(2) "Electric utility" has the meaning assigned by Section 31.002, Utilities Code.

(3) "Public utility" means:

(A) a person who owns or operates a gas or water works or water plant used for local sale and distribution located within an incorporated city or town in this state; or

(B) an electric utility or transmission and distribution utility providing distribution service within an incorporated city or town in this state.

(4) "Transmission and distribution utility" has the meaning assigned by Section 31.002, Utilities Code.

Acts 1981, 67th Leg., p. 1716, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1999, 76th Leg., ch. 405, Sec. 56, eff. Jan. 1, 2002.

Sec. 182.026. SUBCHAPTER NOT APPLICABLE. (a) This subchapter does not apply to a utility company owned and operated by a city, town, county, water improvement district, or conservation district.

(b) This subchapter does not:

(1) affect collection of ad valorem taxes; or

(2) impair or alter a provision of a contract, agreement, or franchise made between a city and a public utility company relating to a payment made to the city.

Acts 1981, 67th Leg., p. 1716, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1991, 72nd Leg., 1st C.S., ch. 3, Sec. 5.04, eff. Sept. 1, 1991; Acts 1991, 72nd Leg., 1st C.S., ch. 5, Sec. 17.08, eff. Sept. 1, 1991.

Sec. 182.027. NO EXEMPTION. Notwithstanding anything to the contrary in Chapter 161, Utilities Code, this subchapter applies to a retail electric provider as defined in Section 31.002(17), Utilities Code, that is owned, operated, or controlled by an electric cooperative.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 57, eff. Sept. 1, 1999.

SUBCHAPTER E. TAX COLLECTIONS AND BUSINESS PERMITS

Sec. 182.081. REPORTS. (a) A person required to pay a tax under this chapter shall report to the comptroller on the last day of January, April, July, and October of each year.

(b) A report must include a statement of the gross receipts from business done, as defined in this chapter for each taxpayer, during the preceding quarterly period.

Acts 1981, 67th Leg., p. 1717, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1983, 68th Leg., p. 1379, ch. 284, Sec. 10, eff. Sept. 1, 1983.

Sec. 182.082. TAX PAYMENTS: DUE DATE. Except as provided in Section 182.083 of this code, the taxes imposed by this chapter are due and payable to the comptroller on the last day of January, April, July, and October of each year.

Acts 1981, 67th Leg., p. 1717, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1983, 68th Leg., p. 1379, ch. 284, Sec. 10, eff. Sept. 1, 1983; Acts 1997, 75th Leg., ch. 1423, Sec. 19.117, eff. Sept. 1, 1997.

Sec. 182.083. PAYMENT OF TAX IF BUSINESS BEGUN AFTER BEGINNING OF QUARTER. (a) Except as provided in Subsection (b) of this section, if a person taxed under this chapter begins business on or after the first day of the quarter, then in lieu of the gross receipts tax provided for in this chapter, the tax for that quarter is $50, payable to the comptroller in advance.

(b) If a person that begins business on or after the first day of the quarter is an incorporation, reincorporation, or survivor of a merger of a person or persons that were previously subject to a tax under this chapter, its report required under Section 182.081 of this code must show the combined gross receipts during the preceding quarterly period of the person or persons that were incorporated, reincorporated, or merged to form the new entity. The gross receipts tax provided for in this chapter must be paid on the reported combined gross receipts required under this subsection.

Acts 1981, 67th Leg., p. 1717, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1985, 69th Leg., ch. 31, Sec. 2, eff. Aug. 26, 1985; Acts 1997, 75th Leg., ch. 1423, Sec. 19.118, eff. Sept. 1, 1997.

Sec. 182.084. ADDITIONAL REPORTS. The comptroller may require a person required to report under this chapter to supply additional or supplemental reports containing information necessary to compute the tax due.

Acts 1981, 67th Leg., p. 1717, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.085. FORMS. The comptroller shall prepare forms for use in making the reports required by this chapter.

Acts 1981, 67th Leg., p. 1718, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.086. PERMIT REQUIRED; FORM OF PERMIT. (a) Each person taxed under this chapter must have a permit to transact business.

(b) The comptroller shall issue the permit in a form prescribed by the attorney general.

(c) A permit shows:

(1) the name of the person to whom it is issued;

(2) the business to be transacted; and

(3) that the holder has complied with this chapter.

(d) The permit must be publicly displayed at the principal office of the person to whom it is issued.

Acts 1981, 67th Leg., p. 1718, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.087. APPLICATION AND ISSUANCE OF PERMIT. (a) The comptroller shall prescribe the form of the application for the permit to transact business.

(b) The application must show:

(1) to the satisfaction of the comptroller the facts required under Section 182.086 of this code; and

(2) that the applicant has paid the taxes required by this chapter or, if the applicant is the buyer of a going business, that the seller has paid all taxes due or to become due under this chapter.

(c) After determining that all taxes due under this chapter have been paid, the comptroller shall issue the permit to transact business.

(d) Repealed by Acts 1993, 73rd Leg., ch. 587, Sec. 35, eff. Oct. 1, 1993.

(e) Repealed by Acts 1983, 68th Leg., p. 4769, ch. 840, Sec. 1, eff. Aug. 29, 1983.

Acts 1981, 67th Leg., p. 1718, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1983, 68th Leg., p. 4769, ch. 840, Sec. 1, eff. Aug. 29, 1983; Acts 1993, 73rd Leg., ch. 587, Sec. 35, eff. Oct. 1, 1993.

Sec. 182.088. SUSPENSION OF PERMIT. (a) If taxes due under this chapter are not paid before the expiration of 30 days after the due date, the comptroller shall mail a written notice to the delinquent taxpayer at the last known address stating that:

(1) the tax is unpaid; and

(2) the comptroller will suspend the permit to transact business if the tax is not paid within 10 days of the date of the notice.

(b) The mailing of the notice is sufficient compliance with this law.

(c) If the tax and accrued penalties are not paid before the expiration of 15 days after the mailing of the notice, the comptroller shall:

(1) Note on the records that the permit to transact business of the delinquent taxpayer has been suspended, giving the date of suspension;

(2) immediately certify the suspension to the attorney general; and

(3) have published a notice of suspension of the permit in a daily or weekly newspaper published in the county of the delinquent taxpayer's business or, if there is no newspaper published in that county, in a daily newspaper with statewide circulation.

Acts 1981, 67th Leg., p. 1718, ch. 389, Sec. 1, eff. Jan. 1, 1982.

SUBCHAPTER F. PENALTIES

Sec. 182.102. PENALTY FOR FAILURE TO FILE REPORT OR TO PAY TAX. (a) A person who fails to file a report as required by this chapter or who fails to pay a tax imposed by this chapter when due forfeits five percent of the amount due as a penalty, and if the person fails to file the report or pay the tax within 30 days after the day on which the tax or report is due, the person forfeits an additional five percent.

(b) The minimum penalty imposed by this section is $1.

Acts 1981, 67th Leg., p. 1719, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1983, 68th Leg., p. 452, ch. 93, Sec. 5, eff. Sept. 1, 1983.

Sec. 182.103. SUITS. (a) The attorney general shall bring suits to collect penalties under this chapter.

(b) The courts of Travis County have concurrent jurisdiction of a violation under this chapter.

Acts 1981, 67th Leg., p. 1719, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.104. TRANSACTING BUSINESS WITHOUT A PERMIT: PENALTY. (a) A person commits an offense if the person is required by Section 182.086 of this code to have a permit and the person transacts business without a valid permit.

(b) An offense under Subsection (a) of this section is punishable by a fine of not less than $50 nor more than $500. Each day on which a violation occurs is a separate offense.

Acts 1981, 67th Leg., p. 1719, ch. 389, Sec. 1, eff. Jan. 1, 1982.

SUBCHAPTER G. NATURE AND ALLOCATION OF TAX

Sec. 182.121. NATURE OF TAX. A tax imposed by this chapter is an occupation tax.

Acts 1981, 67th Leg., p. 1719, ch. 389, Sec. 1, eff. Jan. 1, 1982.

Sec. 182.122. ALLOCATION OF TAX. Revenues collected under this chapter are allocated:

(1) one-fourth to the foundation school fund; and

(2) three-fourths to the general revenue fund.

Acts 1981, 67th Leg., p. 1719, ch. 389, Sec. 1, eff. Jan. 1, 1982. Amended by Acts 1981, 67th Leg., p. 2778, ch. 752, Sec. 9(h), eff. Jan. 1, 1982; Acts 1984, 68th Leg., 2nd C.S., ch. 28, art. II, part B, Sec. 5, eff. Sept. 1, 1984.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1277 (H.B. 3732), Sec. 7, eff. September 1, 2007.

Acts 2007, 80th Leg., R.S., Ch. 1277 (H.B. 3732), Sec. 8, eff. September 1, 2020.

PUC DOCKET NO. 40443
SOAH DOCKET NO. 473-12-7519

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ON REHEARING

This Order addresses the application filed on July 27, 2012 by Southwestern Electric Power Company (SWEPCO) for authority to change its rates and reconcile its fuel costs. The primary contested issue regarding the proposed increase involves the portion of SWEPCO's share of the costs of the Turk coal plant in Hempstead, Arkansas that are allocated to Texas.

SWEPCO's application sought a total-company revenue requirement of $1.033 billion, exclusive of fuel revenues. The requested Texas retail revenue requirement exclusive of fuel revenues was $329 million, which reflected an increase in annual Texas retail revenues of $83.37 million over its adjusted test-year revenues.[1] The increase primarily consists of the inclusion of the newly constructed Turk coal plant and Stall gas plant. For the fuel reconciliation period from April 1, 2009 through December 31, 2011, SWEPCO sought to reconcile a cumulative fuel under-recovery balance of $3,936,492, including interest, and proposed no surcharge. SWEPCO's reconciliation included proposed revisions to Dolet Hills Lignite Company benchmark price.

The State Office of Administrative Hearings' administrative law judges (ALJs) issued a proposal for decision on May 20, 2013. The ALJs' recommended approval of the application, with certain adjustments. Regarding the Turk plant, the ALJs recommended the disallowance of all Turk costs over approximately $934 million as being imprudently incurred in continuing construction after June 2010. The ALJs further recommended that approximately $260 million be allowed for the estimated costs to retrofit the Welsh Unit 2 coal plant that SWEPCO should have undertaken instead of completing the Turk plant. However, the ALJs recommended in the

[1] Rebuttal Testimony of Jennifer L. Jackson, SWEPCO Ex. 88, JLJ-1R at 2.

residential sales post-test-year adjustment with the actual weather-adjusted 2012 sales. SWEPCO should use the 10-year weather normalization.

Lighting Allocation

264. SWEPCO's rebuttal production demand allocator appropriately reflects 8,760 hours for all classes.

Residential Customer Unit Costs

265. SWEPCO's class cost-of-service study appropriately functionalizes and allocates all costs incurred by SWEPCO in support of its utility operations following established cost-causative factors and practices. A component of these costs includes general overhead costs, which are properly recorded in support of SWEPCO's overall utility operations, including customer costs.

266. SWEPCO proposes to allocate transmission costs to retail classes based on the 12 Coincident Peak (12CP) demand allocator.

267. The 12CP method allocates costs based on peak demands in all twelve months, with no distinction between the on-peak summer months and the off-peak months.

268. SWEPCO is a summer peaking utility. The electricity demands in the spring and fall months are much lower and not relevant in determining the amount of capacity needed for SWEPCO to provide reliable service.

269. The June through September summer peak demands determine the amount of transmission capacity that SWEPCO must build. SWEPCO's use of the 12CP method is inconsistent with cost causation.

270. The Commission has a longstanding policy of allocating transmission costs based primarily on peak demands in the four summer months.

271. The Average and Excess/4 Coincident Peak (A&E/4CP) method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

272. SWEPCO should use the A&E/4CP method for allocating transmission costs to the retail classes.

Municipal Franchise Fees

273. Municipal franchise fees are taxes levied by municipalities based on the amount of electricity sold within the municipal boundaries.

274. SWEPCO proposes to allocate and collect municipal franchise fees from customer classes based on in-city kWh sales.

275. Municipal franchise fees are caused by the kWh delivered within incorporated municipalities that levy these costs. The cost of municipal franchise fees should be directly allocated to customer classes based on kWh delivered within the municipal boundaries.

276. Collection of municipal franchise fees under the spread collection method is appropriate.

Miscellaneous Gross Receipts Taxes

277. The miscellaneous gross receipts tax is imposed on each utility company's taxable gross receipts derived from business done in an incorporated city with a population over 1,000.

278. Miscellaneous gross receipts taxes are caused by taxable receipts from business done within incorporated municipalities. The cost of miscellaneous gross receipts taxes should be directly allocated to customer classes based on inside-city revenues.

279. Collection of miscellaneous gross receipts taxes under the spread collection method is appropriate.

Primary Distribution Substation and Line Services

280. Primary distribution substation customers take service at the substation bus and do not use SWEPCO's distribution lines.

281. Primary distribution substation demands associated with the customers taking such service should be removed from the allocation factors related to the distribution investments that should not be allocated to primary distribution substation customers.

Appropriate Load Factor for Use in Average Component of A&E/4CP

282. SWEPCO proposed the use of the Texas retail load factor in its A&E/4CP methodology for allocating capacity-related production costs.

283. Because SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor. The appropriate load factor for use in the A&E/4CP methodology is the system load factor.

284. The system load factor is calculated based on the annual energy use and four coincident peaks.

285. SWEPCO's system load factor during the test year was 58%.

286. DELETED.

Revenue Distribution

287. SWEPCO's proposed revenue distribution is reasonable because having few customers can make the class cost-of-service results for a particular class susceptible to unusual circumstances in a particular test year.

288. Grouping rate classes together may mitigate unusual pricing circumstances.

289. SWEPCO's proposed revenue distribution incorporates the major class groupings that were acceptable to parties to SWEPCO's last rate case settlement.

290. SWEPCO's proposed major class groupings isolate any rate class subsidies to affect rate classes within the major class groupings.

Class Cost Allocation and Rate Design
Residential

291. SWEPCO's residential service is composed of two elements: a customer charge and a consumption-based energy charge. SWEPCO has an on-peak energy charge imposed in the months of May through October (summer) for all kWh. SWEPCO has a two-tiered off peak energy charge during the months of November through April (winter) that includes a declining block rate for usage in excess of 600 kWh, in which the price of each unit is reduced after a defined level of usage.

292. It is reasonable to increase the Residential customer charge to $8.00.

293. A slight increase in the customer charge considers SWEPCO's concern that the current customer charge under-recovers the customer costs shown in the class cost-of-service

DOCKET NO. 53719

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY TO	§	
CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

KHAMSUNE VONGKHAMCHANH

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

Utilities cannot measure the instantaneous demand of all customers and do not have instantaneous demand meters on all components of the transmission and distribution network. Therefore, energy loss factors are estimated by using load descriptors such as the peak responsibility factor,[26] the coincidence factor,[27] the load factor,[28] and the loss factor.[29]

A. Development of Transmission and Distribution Demand Losses

Q130. PLEASE PROVIDE AN OVERVIEW OF HOW ETI DEVELOPED ITS DEMAND LOSS FACTORS.

A. ETI utilizes a top-down approach to estimate its demand loss; that is, it analyzes demand losses for the highest voltage level in the system and then for each successively lower voltage level. ETI calculated demand loss factors for the analysis period, July 1, 2020 through June 30, 2021. The demand loss analysis that I sponsor estimates demand losses for four voltage levels: (1) the transmission system at 230 kV and above ("bulk transmission system"); (2) the transmission system below 230 kV and above or equal to 69 kV ("local

[26] The peak responsibility factor is the ratio of the on-peak load for each component of the transmission and distribution system to the peak design ("rated") load for each component of the transmission and distribution system.

[27] The coincidence factor is a ratio of the maximum demand coincident with the company's system peak for a specified group of customers to the sum of the individual maximum non-coincident demands of the members of such group.

[28] Load factor is calculated by dividing the energy consumed for a specified time period by the product of the number of time units for such specified time period and the peak demand that occurred during such time period.

[29] Loss factor is defined as the energy loss during a specific time period divided by the product of the specific time period and the peak demand loss.

transmission system"); (3) the primary distribution system; and (4) the secondary distribution system.

ETI analyzes measured on-peak generation and net power interchange on the supply-side and the on-peak power demands of its customers for comparable time periods. On-peak power deliveries were estimated by using demand data for all locations equipped with interval recording demand meters installed for billing purposes and by using estimated hourly demands of customers who normally do not have hourly demand meters at their service location.

The average of the 12 monthly coincident peaks ("12 CP") during the analysis period is used to estimate demand losses. The Company's average 12 CP generation plus net power interchange ("Total Input") for the analysis period was 3,721 MW and the average 12 CP demand ("Total Delivery to Customers") for the analysis period was 3,647 MW.

Q131. PLEASE DESCRIBE HOW ETI CALCULATES DEMAND LOSS FACTORS.

A. Transmission demand losses are determined by performing transmission load-flow simulations using the Power System Simulator for Engineering ("PSS/E") model for ETI's 12 CP in the analysis period. The demand losses of the bulk and local transmission systems are derived from the sum of average demand losses. Distribution demand losses are calculated by the Simplified Calculation of Loss Equations ("SCALE") model developed by the Electric Power Research Institute ("EPRI"). SCALE uses the observed customer demand patterns to calculate demand losses for substation transformers, distribution primaries (feeders and laterals), distribution secondaries, and distribution transformers.

After the demand losses are estimated for all voltage levels, loss ratios for each voltage level are determined as the ratio of input power to the input power, less the demand loss calculated for each voltage level. The cumulative demand loss factor for a given voltage level is determined as the product of the loss ratio for each voltage level and the cumulative demand loss factor for the next lower voltage level.

Q132. HOW DID ETI ESTIMATE TRANSMISSION DEMAND LOSSES?

A. ETI uses the PSS/E transmission network load-flow analysis software to estimate demand losses for the transmission system. The results from the PSS/E software show that transmission system losses ("Transmission Delivery") accounted for 34 MW of the total system losses: 9 MW were lost in the bulk transmission system, and 25 MW were lost in the local transmission system (rounded and as reflected on Exhibit KV-12). Therefore, the remaining 142 MW of losses were attributable to losses in the substation (33 MW), distribution primary (69 MW), and distribution secondary systems (40 MW). These losses are reflected on Exhibit KV-12.

Q133. PLEASE DESCRIBE THE PSS/E MODEL.

A. The PSS/E software, created by Power Technologies, Inc., is an electric transmission system network simulation software used by many of the major

ENTERGY TEXAS, INC. Electric Service SCHEDULE IS	Sheet No.: 28 Effective Date: Service on and after 10-17-18 Revision: 10 Supersedes: IS Effective 12-19-13 Schedule Consists of: Three Sheets

RIDER TO SCHEDULES LIPS, LIPS-TOD,
INTERRUPTIBLE SERVICE

I. APPLICABILITY

This rider is applicable under the regular terms and conditions of the Company to existing interruptible load as of the effective date of this schedule and to new load from existing or new LIPS and LIPS-TOD Customers who contract for not less than 2,500 kW of Firm Contract Power and who contract for not less than 2,000 kW of Interruptible Contract Power.

II. AVAILABILITY

The availability of total Interruptible Service supplied by the Company under all Interruptible Service Riders will be limited to an amount equal to 5.3% of the projected Retail Company peak demand. The Company reserves the right to refuse service under Section III (A) of this rider if, in the opinion of the Company, such service could cause damage to property or persons or adversely affect the public health, safety and welfare. Interruptible loads may be served by Customer's auxiliary sources during times of interruption by Company, but must be returned to Company service as soon as practical after such service is restored.

This schedule is available only to customers who are annually registered by the Company each MISO Planning Year and who qualify for, and are accepted as a Midcontinent Independent System Operator, Inc. (MISO) Load Modifying Resource (LMR) as defined in MISO's currently effective FERC tariff and as described in the associated MISO Business Practice Manuals. Customer must provide Company with all necessary assistance, information, data and documentation required for such annual registration including, but not limited to, 1) MISO-required documentation indicating Customer's capability to reduce demand to firm service level within the prescribed time limit when instructed to do so, 2) confirmation that Customer has the capability to be interrupted at least five times during the calendar months of June, July and August and 3) confirmation that Customer has the ability and is willing to sustain such an interruption to firm service level for a minimum of four consecutive hours.

The Company may terminate Customer's participation in this rider schedule if MISO precludes the Customer from participating as an LMR for failure to reduce load or failure to pay penalties as described in this schedule. The Company may terminate Customer's participation in this rider schedule if Customer fails to qualify as a LMR after providing written notice and a reasonable opportunity for Customer to requalify following a decision by MISO rejecting the registration of Customer's load. Service under this rider schedule cannot be terminated if the failure to qualify as a LMR is due to the Company's failure to collect the required information and submit the registration in a timely manner.

(Continued on reverse side)

III. **BILLING AMOUNTS**

All service rendered through the meter shall be billed as Billing Load at the rates established in the applicable rate schedule, with the exception that the minimum Billing Load shall be the Customer's Firm Contract Power, plus 20% of Customer's Interruptible Contract Power under (A), and/or (B) below as defined in Sections VI A and VI B below. The minimum billing load (20% of Contract Power) for the Customer's Interruptible load will be applied to the amount of load contracted for under each of the three options stated below.

The Interruptible Credit shall be applied to the Interruptible Power Billing Load which is the difference between the maximum demand registered on the meter during the billing period and the amount of Firm Contract Power, subject to the minimum provision as stated above. Such Firm Contract Power is subject to the off-peak provision included in Section V of the applicable rate schedule. If at any time the maximum demand in a month exceeds Total Contract Power, which shall be the sum of Firm Contract Power and Interruptible Contract Power, the increment shall serve to increase Firm Contract Power.

Interruptible Credit and Notice Requirement:

(A) No notice requirement: $4.88 credit per billing kW per month for all interruptible power as determined above.

(B) Five (5) minute notice requirement: $3.75 credit per billing kW per month for all interruptible power as determined above.

The total amount of Interruptible Contract Power (as defined in Section VI A) must be designated as subject to (A) and/or (B) above. In any billing month when the Interruptible Billing Load is less than the Interruptible Contract Power the amount of Interruptible Credit will be calculated as follows, subject to minimum requirements in Section III:

(1) 5-minute notice requirement - Section III (B)
(2) no notice requirement - Section III (A)

Energy Charges, fixed fuel factors, minimum charges, and delivery voltage credits are unchanged from the applicable rate schedule. Delivery voltage credits shall be applied to the total Billing Load.

IV. **NON-COMPLIANCE**

If at any time during the MISO Planning Year, Company directs the Customer to interrupt load and Customer fails to interrupt all load in excess of firm load for the entire period of interruption and within the time specified in Section III (B) following request by Company, the Customer will not receive the Interruptible credit for the billing month and Customer will be assessed the following penalties:

 (Continued on next page)

ENTERGY TEXAS, INC. Electric Service SCHEDULE IS (Cont.)	Sheet No.: 29 Effective Date: Service on and after 10-17-18 Revision: 10 Supersedes: IS Effective 12-19-13 Schedule Consists of: Three Sheets

RIDER TO SCHEDULES LIPS AND LIPS-TOD FOR INTERRUPTIBLE SERVICE

Penalty Rates:

A. The amount of the specified demand reduction not achieved times the MISO defined Locational Marginal Price (LMP), plus

B. Any Revenue Sufficiency Guarantee (RSG) charges imposed on the Company by MISO pursuant to the terms of MISO's currently effective FERC tariff , plus

C. Any other penalties or fees imposed on the Company by MISO pursuant to the terms of MISO's currently effective FERC tariff for failure to reduce load as directed by MISO, plus

D. $500 to recover the Company's administrative costs for determination and payment of each penalty occurrence.

In the event that Customer fails to interrupt as instructed, Customer will be required to provide documentation for the specific circumstances that would justify exemption from such penalties. If MISO determines that failure to interrupt was justified, Customer will not be penalized.

Effective with the billing month following the second non-compliance by Customers (as described in B above), the total service contracted for under this rider will be transferred to and billed under the applicable rate schedule for at least the next 12 months. Customer may only return to this rider if the Company agrees that there is interruptible load that may be contracted for pursuant to Section II of this rider.

If Customer failed, in whole or part, to comply with any Company requested interruptions, the duration of such period of interruption shall not be considered an interruption for purposes of this rider. Instances where Company requests interruptible loads be kept off beyond the 10-hour daily limit, as in System emergencies, shall not be counted toward the Annual Interrupted Hours.

V. INTERRUPTIONS

Interruptions shall be requested by Company at the discretion of the Company as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, maintaining service integrity in the area or other situations when reduction in load on the Company's system is required. To the extent possible interruptible loads will be interrupted before any curtailment of firm loads is requested or required. For loads requiring 5-minute notice, Customer is responsible for interrupting loads. For loads requiring no notice, interruptions will be made by Company via electronic data transmission equipment from Customer's location to the Company's system operator.

(Continued on reverse side)

Normally, the required notice, if any, will be given to Customer before load must be interrupted. Longer or shorter notice will be given at Company's option at the time of notice. Service may be restored immediately upon notification by Company.

For loads requiring 5-minute notice, interruptions will be limited to no more than ten (10) hours per day (midnight to midnight) and to no more than two (2) interruptions per day. Interruptions will also be limited to a maximum of fifty (50) hours in a single week (12:01 a.m. Monday to 12:00 p.m. Sunday). Annual Interrupted Hours shall not exceed 600 hours in any MISO Planning Year. For loads requiring no notice, the hours of interruption are unlimited. Periods when the Interruptible Service is interrupted due to general system curtailment shall not be counted when Annual Interrupted Hours are determined.

VI. **DEFINITIONS**

A. Interruptible Contract Power - The maximum amount of Kilowatts (kW) Customer has designated as subject to interruptions. This amount of Kilowatts is subject to interruptions in both on-peak and off-peak periods.

B. Firm Contract Power - the amount of Kilowatts (kW) Customer intends to exclude from interruptions as defined herein. Nothing herein excludes such loads from the normal operating outages inherent to an electrical power system, nor from outages due to a System emergency. Firm Contract Power will be the amount of Kilowatts (kW) contracted for under this rider schedule or subsequently established per Section III above. Customer may modify its Firm Contract Demand in accordance with the currently effective MISO FERC tariff as described in associated MISO Business Practice Manuals. Such modification must remain consistent with the Customer’s existing contracts with the Company for firm and interruptible capacity limitations.

C. Total Contract Power - the sum of Interruptible Contract Power and Firm Contract Power, as defined above.

D. Excess Demand - the amount of Kilowatt (kW) demand occurring during a Period of Interruption which is in excess of Firm Contract Power, in either on-peak or off-peak periods.

E. Period of Interruption - that span of time during which Customer's interruptible loads shall not be served by the Company. This shall begin at the time designated by Company to shed interruptible loads and shall terminate when Company notifies Customer the Period of Interruption is over.

F. MISO Planning Year – The period of time from June 1st of one year to May 31st of the following year that is used for developing MISO Resource Plans.

G. Annual Interrupted Hours - the total number of hours Company has interrupted service during the current MISO Planning Year.

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RIDER TO SCHEDULES LIPS AND LIPS-TOD FOR INTERRUPTIBLE SERVICE

VII. **CONTRACTS**

A. A Contract is required for this rider.

B. Term of Contract:

1. Within the first two years of service under this rider, Customer may elect to have all, or portions of, his Interruptible Contract Power converted to Firm Contract Power upon ninety (90) days written notice to Company, subject to the availability of new firm power service. If the election occurs during the first year of service under this schedule, the Customer shall return all monthly credits provided by this tariff until the date that the interruptible service is converted to firm service.

2. After two years (twenty-four consecutive months) of service under this rider, Customer may elect to have all, or portions of, his Interruptible Contract Power converted to Firm Contract Power, upon three (3) years written notice to Company, subject to the availability of new firm power service.

3. Upon conversion of loads under (1) or (2) above, or upon termination of Interruptible Service under this rider, Customer may not increase his remaining Interruptible Contract Power, or initiate new service under this rider, for a period of twelve (12) months following such conversion or termination, and then only subject to the availability of new Interruptible Service.
4. Any additions of Interruptible Contract Power will be considered increases to existing loads, rather than new blocks requiring separate contracts, and will be subject to the same conditions outlined in (1), (2), or (3) above that are then relevant to the existing service.

VIII. **METERING**

A. All interruptible service will be served through the total service meter. Company may require telemetering of the Customer's loads to the Company's system operator.

B. Costs of telemetering facilities, including rental or investment costs of communications circuits, may be included in the Facilities Charge, or Customer may elect to pay a lump sum to offset the additional investment by Company.

In the case of Facilities Charges, such charges will continue beyond the date of termination or conversion of Interruptible loads (as discussed in Section VII) until the Company's investment has been recovered. A separate contract for such Facilities Charges may be required.

(Continued on reverse side)

IX. CONDITIONS OF SERVICE

Customers contracting for service under Section III (A) of this Schedule will provide, at Customer's expense, Company specified electronic data transmission equipment from Customer's location to the Company's system operator. Specifications for electronic data equipment are available from Company upon request.

X. USE OF SERVICE

Electric service furnished under this rate shall not be used by the Customer as an Auxiliary or Standby Service. Customer shall not resell nor share any energy purchased under this rate.

ENTERGY TEXAS, INC. Electric Service SCHEDULE LIPS	Sheet No.: 26 Effective Date: Service on and after 10-17-18 Revision: 7 Supersedes: LIPS Effective 4-1-14 Schedule Consists of: Two Sheets

LARGE INDUSTRIAL POWER SERVICE

I. **APPLICABILITY**

This Schedule is applicable under the regular terms and conditions of the Company to Customers who contract for not less than 2,500 kW of electric service at Company's available line voltage.

II. **NET MONTHLY BILL**

A. Customer Charge $2,500.00 per month

		Billing Months of	
		May-October	November-April
B.	Billing Load Charge All kW per month	$8.15 per kW	$ 7.58 per kW
C.	Energy Charge* 1st 584 kWh/kW of Billing Load Additional kWh	 $ 0.004867 per kWh $ 0.003262 per kWh	 $ 0.004867 per kWh $ 0.003262 per kWh

*Plus the Fixed Fuel Factor per Schedule FF and all applicable riders.

D. Delivery Voltage Adjustment

The Delivery Voltage below represents the voltage of the line from which service is delivered or, if applicable, the voltage used in determining the facilities charge under Schedule AFC. When service is metered at a voltage other than the Delivery Voltage, metered quantities will be adjusted by 1.5% for each transformation step to the Delivery Voltage.

Delivery Voltage	Adjustment
Less than Transmission (69kV)	$1.42 per kW of Billing Load
Transmission (69kV)	$0.05 per kW of Billing Load
Transmission (138kV)	($0.29) per kW of Billing Load
Transmission (230kV)	($0.75) per kW of Billing Load

E. Minimum Charge

The monthly minimum charge will be the sum of the Customer Charge, Billing Load Charge and the Delivery Voltage Adjustment. Where the installation of excessive new facilities is required or where there are special conditions affecting the service, Company may require, in the Contract, a higher minimum charge and/or Facilities Agreement pursuant to Schedule AFC, to compensate for additional costs.

(Continued on reverse side)

III. **METERING**

Where the available line voltage is Transmission (69kV) or higher, metering will be at such Transmission Voltage or at Company's option, metering may be on the low side of the transformer. In such case the metered quantities will be adjusted pursuant to § II. D and Customer will receive a Delivery Voltage Adjustment as though the metering was at the Transmission Voltage.

Where the available line voltage is less than Transmission (69KV), the metered quantities will be adjusted pursuant to § II. D.

Where service is taken at multiple voltage levels and Customer requests totalizing arrangements for billing purposes, the Delivery Voltage Adjustment will be computed based upon demand, but weighted by kWh consumption at each voltage level.

Where service is of extremely fluctuating or intermittent type, Company may specify shorter intervals of load measurement than 30-minute intervals.

IV. **POWER FACTOR ADJUSTMENT**

Where Customer's power factor of total service supplied by Company is such that 90% of measured monthly maximum kVA used during any 30-minute interval exceeds corresponding measured kW, Company will use 90% of such measured maximum kVA as the number of kW for all purposes that measured maximum kW demand is specified herein. However, where Customer's power factor is regularly 0.9 or higher, Company may at its option omit kVA metering equipment or remove same if previously installed.

V. **OFF-PEAK PROVISIONS**

In case the monthly maximum measured 30-minute demand occurs during an off-peak period and is greater than Contract Power, such monthly maximum kW load will be reduced by 33-1/3% but will not be thereby reduced to a smaller number of kW than Contract Power, nor less than stipulated in §§ VI (C). Where the maximum kW load during off-peak periods does not exceed Contract Power, no reduction in off-peak maximum load will be made for billing purposes.

Off-peak hours, for purposes of this schedule, are all hours of the year not specified as on-peak hours.

On-peak hours, for purposes of this schedule, are designated as 8:00 a.m. to 10:00 p.m. Monday through Friday of each week beginning on May 15 and continuing through October 15 of each year except that Memorial Day, Labor Day and Independence Day (July 4 or the nearest weekday if July 4 is on a weekend) are not on-peak.

VI. **DETERMINATION OF BILLING LOAD**

The kW of Billing Load will be the greatest of the following:

(A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or

(B) 75% of Contract Power as defined in § VII; or

(C) 2,500 kW.

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ENTERGY TEXAS, INC. Electric Service SCHEDULE LIPS (Cont.)	Sheet No.: 26A Effective Date: Service on and after 10-17-18 Revision: 7 Supersedes: LIPS Effective 4-1-14 Schedule Consists of: Two Sheets

LARGE INDUSTRIAL POWER SERVICE

VII. **DETERMINATION OF CONTRACT POWER**

Unless Company gives Customer written notice to the contrary, Contract Power will be as defined below:

Contract Power shall be the highest load established under § VI (A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.

VIII. **PHASE AND VOLTAGE OF SERVICE**

At the option of the Company, service will be delivered at the Customer's utilization voltage or at available Transmission line voltage (69kV or higher). Service will be metered at, or corrected to, the Transmission line voltage at the point of delivery, or at Company's option, at the nearest transmission station supplying Customer's load.

IX. **USE OF SERVICE**

Electric service furnished under this rate shall not be used by Customer as an auxiliary or supplementary service to engines or other prime movers or to any other source of power except in conjunction with rider for Standby and Maintenance Service. Customer shall not resell nor share any energy purchased under this rate.

X. **AMOUNT DUE AND PAYMENT**

The past due amount for service furnished for which payment is not made within sixteen (16) days of the billing date shall be the monthly bill, including all adjustments under the rate schedule and applicable riders, plus 5%. The 5% penalty on delinquent bills shall not be applied to any balance to which the penalty has already been applied. If the amount due when rendered is paid prior to such date, the monthly bill, including all adjustments under the rate schedule and applicable riders, shall apply. If providing service to the State of Texas or to municipalities or other political subdivisions of this state, Company shall not assess a fee, penalty, interest or other charge to these entities for delinquent payment of a bill.

ENTERGY TEXAS, INC. Electric Service SCHEDULE SMS	Sheet No.: 58 Effective Date: 4-1-14 Revision: 8 Supersedes: SMS Effective 6-30-12 Schedule Consists of: Two Sheets

STANDBY AND MAINTENANCE SERVICE

I. **APPLICABILITY**

This rider is applicable to customers who have their own generation equipment and who contract for Standby and Maintenance Service from the Company.

II. **MODIFICATION OF REGULAR RATE SCHEDULE**

Service taken under this schedule may be in addition to service provided by the Company under other rate schedules. The regular rate schedule in such case, if applicable, will be modified by the addition of §§ III and IV of this Schedule. In consideration of these modifications, the first sentence of the "Use of Service" Section of the regular rate schedule is eliminated.

III. **DETERMINATION OF BILLING DEMANDS AND ENERGY QUANTITIES**

A. Standby Service:

(1) The monthly billing demand for Standby Service shall be the greater of the contracted Standby Service demand or the actual Standby Service demand taken during the 12 month period ending with the current month. The Company is not obligated to furnish Standby Service power in excess of the nameplate rating of the Customer's largest generator. Requirements purchased from Company in excess of this amount shall be purchased under Maintenance Service (§ IV) or the appropriate firm power rate schedule.

(2) In the case where a Customer purchases firm power or interruptible power from the Company under another rate schedule in addition to selling power to the Company, the actual standby service demand shall be the difference between the Customer's maximum demand registered on the meter during the standby period and contract power as established under contract for firm power. The Customer is required to notify the Company of the time periods when standby service is being taken. This notification must be made within 24 hours of the beginning and end of usage to avoid increasing the Customer's contract power for firm load.

(Continued on reverse side)

(3) The energy associated with the actual Standby Service demand taken shall be:

a. As metered, or

b. For Customers who purchase firm power from the Company under another rate schedule, as computed by taking the total energy used during each hour of the standby period and subtracting the average energy used for the five hours prior to the beginning of the standby period.

B. Maintenance Service

Maintenance Service will be available on 24-hour prior notice only during such times and at such locations that, in Company's sole opinion, will not result in affecting adversely or jeopardizing firm service to other Customers, prior commitments for Maintenance Service to other Customers, or commitments to other utilities. Arrangements and scheduling of Maintenance Service will be agreed in writing in advance of use or confirmed in writing if arranged verbally. Where there are applications from more than one Customer, or Service applied for is more than Company has available, Company will allocate and schedule available service, in its final judgment, and curtail or cancel application. Where Maintenance Service stands requested, agreed and scheduled, but not taken, Customer will be obligated to pay for such service same as scheduled, if Company has refused to supply some other Customer similar service in order to limit total Maintenance Service to that which Company considers available. Maintenance Service will be scheduled for a continuous period of not less than one day.

(1) The billing demand for Maintenance Service will be the greater of 90% of the scheduled Maintenance Service demand or the actual Maintenance Service demand taken. The Company is not obligated to furnish Maintenance Service power in excess of that which is scheduled. Where Maintenance Service was scheduled to begin or end on other than a regular monthly meter reading date, the monthly bill will be computed on a prorated basis with the Billing Load which includes Maintenance Service effective only for the days Maintenance Service was scheduled.

(2) In the case where a Customer purchases firm power from the Company under another rate schedule, the actual Maintenance Service demand shall be the difference between the Customer's maximum demand registered on the meter during the maintenance period and contract power as established under contract for firm power.

(3) The energy associated with the actual maintenance service demand taken shall be:

a. As metered, or

b. For Customers who purchase firm power from the Company under another rate schedule, as computed by taking the total energy used during each hour of the maintenance period and subtracting the average energy used for the five hours prior to the beginning of the maintenance period.

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STANDBY AND MAINTENANCE SERVICE

IV. **NET MONTHLY CHARGES**

A. Customer Charge $950.00 (Applies to customers that take only SMS service)

B. Monthly Load Charge

Delivery Voltage	Billing Demand Charges ($/kW) Standby Service (1)	Maintenance Service (2)
Distribution (less than 69 kV)	$2.21	$2.03
Transmission (69 kV and greater)	$0.74	$0.55

(1) The Billing Demand for Standby Service shall be as determined in §§ III.A.1 and III.A.2.
(2) The Billing Demand for Maintenance Service shall be as determined in §§ III.B.1 and III.B.2.

C. The Monthly Energy Charge shall be the kWh as determined in §§ III.A.3 and/or III.B.3 times the total of the applicable charges shown below plus the Fixed Fuel Factor per Schedule FF

Delivery Voltage	Energy Charges ($/kWh) On-Peak	Off-Peak
Distribution (less than 69 kV)	$0.04334	$0.00476
Transmission (69 kV and greater)	$0.04147	$0.00455

Summer: On-peak hours, for purposes of this schedule, are 1:00 p.m. to 9:00 p.m. Monday through Friday of each week beginning on May 15 and continuing through October 15 of each year except that Memorial Day, Labor Day and Independence Day (July 4 or the nearest weekday if July 4 is on a weekend) are not on-peak.

Winter: On-peak hours for each week of Monday through Friday beginning October 16 and continuing through May 14 of each year are 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m., except that Thanksgiving Day, Christmas Day and New Year's Day (or the nearest weekday if the holiday should fall on a weekend) are not on-peak.

Off-peak hours, for purposes of this schedule, are all hours of the year not specified as on-peak hours. With approval of the Commission, Company may at its sole discretion change the on-peak hours and season from time to time.

(Continued on reverse side)

V. CONDITIONS OF SERVICE

A. Customer and Company will agree on operating procedures, and control and protective devices which will limit the taking of power from Company's system to amounts which will not adversely affect service to Company's other Customers. When Customer's generating equipment is operated in parallel with Company's suitable relays, control and protective apparatus will be furnished and maintained by Customer in accordance with specifications agreed to by Company, and subject to inspection by Company's authorized representatives at all reasonable times.

B. The term for service under this rider schedule shall be such as may be agreed upon but not less than one year.

C. Where Customer's power factor of total service supplied by Company is such that 90% of measured monthly maximum kVA used during any 30-minute interval exceeds corresponding measured kW, Company will use 90% of such measured maximum kVA as the number of kW for all purposes that measured maximum kW demand is specified herein. However, where Customer's power factor is regularly 0.9 or higher Company may at its option omit kVA metering equipment or remove same if previously installed.

D. Schedule SMS will normally be billed on a monthly basis or such other period as determined by Company. However, where use of service includes recurring switching of load to Company's system, normally supplied from Customer's generating facilities, for intervals shorter than so stipulated above, Company may determine billing load by metering having shorter intervals.

VI. GROSS MONTHLY BILL AND PAYMENT

The gross monthly bill for service furnished for which payment is not made within sixteen (16) days of the billing date shall be the net monthly bill, including all adjustments under the rate schedule and applicable riders, plus 5%. The 5% penalty on delinquent bills shall not be applied to any balance to which the penalty has already been applied. If the monthly bill is paid prior to such date, the net monthly bill, including all adjustments under the rate schedule and applicable riders, shall apply. If providing service to the State of Texas or to municipalities or political subdivisions of this state, Company shall not assess a fee, penalty, interest or other charge to these entities for delinquent payment of a bill.

§25.242. Arrangements Between Qualifying Facilities and Electric Utilities.

(a) **Purpose.** The purpose of this section is to regulate the arrangements between qualifying facilities, retail electric providers with the price to beat obligation (PTB REPs), and electric utilities as required by federal and state law in a manner consistent with the development of a competitive wholesale power market.

(b) **Application.** This section applies to all PTB REPs and to all electric utilities, including transmission and distribution utilities. The provisions of this section concerning purchase or sale of electricity between an electric utility and a qualifying facility do not apply to a transmission and distribution utility. This section does not apply to municipal utilities, river authorities, or electric cooperatives.

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

(1) **Avoided costs** -- The incremental costs to a PTB REP, or electric utility of electric energy, which, but for the purchase from the qualifying facility or qualifying facilities, such PTB REP or electric utility would generate itself or purchase from another source.

(2) **Back-up power** -- Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

(3) **Cost of decremental energy** -- The cost savings to a utility associated with the utility's ability to back-down some of its units or to avoid firing units, or to avoid purchases of power from another source because of purchases of power from qualifying facilities.

(4) **Electric utility** -- For purposes of this section, an integrated investor-owned utility that has not unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Firm power** -- From a qualifying facility, power or power-producing capacity that is available pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(6) **Host utility** -- The utility with which the qualifying facility is directly interconnected.

(7) **Maintenance power** -- Electric energy or capacity supplied during scheduled outages of the qualifying facility.

(8) **Market price** -- The market-clearing price of energy (MCPE) in the balancing energy market for the Electric Reliability Council of Texas (ERCOT) congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties and fees typically applied to power generators.

(9) **Non-firm power from a qualifying facility** -- Power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(10) **Parallel operation** -- A mode of operation which enables a qualifying facility to export automatically any electric capacity which is not consumed by the qualifying facility or the user of the qualifying facility's output. Parallel operation results in three possible states of operation at any point in time:

(A) The qualifying facility is generating an amount of capacity that is less than the customer's load. The customer is therefore a net consumer.

(B) The qualifying facility is generating an amount of capacity that is more than the customer's load. The customer is therefore a net producer.

(C) The qualifying facility is generating an amount of capacity that is equal to the customer's load. The customer is therefore neither a net producer nor a net consumer.

(11) **Purchase** -- The purchase of electric energy or capacity or both from a qualifying facility by a PTB REP or electric utility.

§25.242(c) continued

(12) **Purchasing utility** -- The electric utility that is purchasing a qualifying facility's capacity and/or energy.

(13) **Quality of firmness of a qualifying facility's power** -- The degree to which the capacity offered by the qualifying facility is an equivalent quality substitute for firm purchased power or an electric utility's own generation. At a minimum the following factors should be considered in determining quality of firmness:

(A) reliability of generation and interconnection;

(B) forced outage rate;

(C) availability during peak periods;

(D) the terms of any contract or other legally enforceable obligation, including, but not limited to, the duration of the obligation, performance guarantees, termination notice requirements, and sanctions for noncompliance;

(E) maintenance scheduling;

(F) availability for system emergencies, including the ability to separate the qualifying facility's load from its generation;

(G) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(H) other dispatch characteristics;

(I) reliability of primary and secondary fuel supplies used by the qualifying facility; and

(J) impact on utility system stability.

(14) **Retail electric provider with the price to beat obligation (PTB REP)** -- A REP that makes available a PTB pursuant to PURA §39.202.

(15) **Sale** -- The sale of electric energy or capacity or both supplied to a qualifying facility.

(16) **Supplementary power** -- Electric energy or capacity regularly used by a qualifying facility in addition to that which the facility generates itself.

(17) **System emergency** -- A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(18) **Transmission and distribution utility (TDU)** -- As defined in §25.5 of this title (relating to Definitions).

(d) **Negotiation and filing of rates.**

(1) **Negotiated rates or terms.** Nothing in this section shall:

(A) limit the authority of any PTB REP or electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differs from the rate or terms or conditions that would otherwise be required by this section; or

(B) affect the validity of any contract entered into between a qualifying facility and a PTB REP or electric utility for any purchase before the adoption of this section.

(2) **Filing of rates.** All rates for sales to qualifying facilities, contractual or otherwise, shall be contained in the schedule of rates of the electric utility filed with the commission.

(e) **Availability of electric utility system cost data.**

(1) **Applicability.** Paragraph (2) of this subsection applies to large electric utilities whose total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. Paragraph (3) of this subsection applies to all other electric utilities.

§25.242(e) continued

(2) **Data request for large electric utilities.** Large utilities shall file the following data:

(A) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one, ten and 100 megawatts or not more than 10% of the system peak demand for systems of less than 1,000 megawatts. The avoided cost shall be stated on a cents-per-kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next nine years.

(B) the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding nine years.

(C) for the current year and each of the next nine years, the estimated capacity costs at completion of the planned capacity additions and planned capacity purchases, on the basis of dollars-per-kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. Such information shall be submitted in accordance with the Federal Energy Regulatory Commission Regulations, 18 Code of Federal Regulations, §292.302 and shall be sufficient for qualifying facilities to reasonably estimate the utility's avoided cost. Accompanying each filing pursuant to this rule shall be a detailed explanation of how the data was determined, including sources and assumptions employed.

(3) Special requirements for small electric utilities. Affected utilities shall, upon request:

(A) provide to an interested person comparable data to that required under paragraph (2) of this subsection to enable qualifying facilities to estimate the electric utility's avoided costs; or

(B) with regard to an electric utility that is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide to an interested person the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(4) **Filing date.** By February 15 each year, large electric utilities shall file with the commission and shall maintain for public inspection the data set forth in paragraph (2) of this subsection.

(f) **PTB REP and electric utility obligations.**

(1) Obligation to purchase from qualifying facilities.

(A) In accordance with this subsection and subsection (g) of this section, each PTB REP and electric utility shall purchase any energy that is made available from a qualifying facility:

(i) directly to the PTB REP or electric utility; or

(ii) indirectly to the PTB REP or electric utility in accordance with paragraph (4) of this subsection.

(B) Each electric utility shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within 90 days of being notified by the qualifying facility that such energy is or will be available, provided that the electric utility has sufficient interconnection facilities available. If an agreement to purchase energy is not reached within 90 days after the qualifying facility provides such notification, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the 90th day following such notice. If the electric utility determines that adequate interconnection facilities are not

§25.242(f)(1)(B) continued

available, the electric utility shall inform the qualifying facility within 30 days after being notified for distribution interconnection, or within 60 days for transmission interconnection, giving the qualifying facility a description of the additional facilities required as well as cost and schedule estimates for construction of such facilities. If an agreement to purchase energy is not reached upon completion of construction of the interconnection facilities or 90 days after notification by the qualifying facility that such energy is or will be available, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the time of interconnection or the 90th day, whichever is later. Nothing in this subsection shall be construed in a manner that would preclude a qualifying facility from notifying and contracting for energy with a utility for sale of energy prior to 90 days before delivery of such energy.

(C) Each PTB REP shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within a timely fashion after being notified by the qualifying facility that such energy is or will be available.

(2) **Obligation to sell to qualifying facilities.** In accordance with subsection (k) of this section, each electric utility shall sell any energy and capacity requested to any qualifying facility located within the electric utility's service area. Each PTB REP shall also sell any energy requested to any qualifying facility; however, those sales shall be at market based rates. Nothing shall restrict the ability of any qualifying facility to purchase energy from any REP.

(3) **Interconnection.** Interconnection by a qualifying facility is addressed by Subchapter I, Division 1, of this chapter (relating to Transmission and Distribution) if the interconnection is to a transmission system and by §25.211 of this title (relating to Interconnection of On-site Distributed Generation) if the interconnection is to a distribution system, except if the interconnection is regulated by the Federal Energy Regulatory Commission.

(4) **Transmission to other electric utilities.** Transmission service provided by an electric utility in the ERCOT power region to a qualifying facility shall be governed by Subchapter I of this chapter.

(5) **PTB REP and scheduling with qualifying facilities.** A PTB REP shall use dynamic resource scheduling or responsibility transfer in ERCOT with any qualifying facility that requests such scheduling, as permitted by ERCOT. The PTB REP's cost of using dynamic resource scheduling or responsibility transfer attributable solely to purchases from qualifying facilities shall be charged to qualifying facilities that use such scheduling. If a qualifying facility uses static scheduling, the qualifying facility shall bear the costs for any imbalances resulting from the qualifying facility's failure to submit a schedule or to comply with the schedule.

(g) **Rates for purchases from a qualifying facility.**

(1) Rates for purchases of energy and capacity from any qualifying facility shall be just and reasonable to the customers of the electric utility or PTB REP and in the public interest, and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided cost. Rates for purchase shall be based upon a market-based determination of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchase do not violate this subsection if the rates for such purchase differ from avoided cost at the time of delivery. Payments which do not exceed avoided cost shall be found to be just and reasonable operating expenses of the electric utility.

§25.242(g) continued

(3) A QF may agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. Rates for purchase of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products.

(h) **Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.**

(1) There shall be included in the tariffs of each electric utility standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The rates for purchases under this paragraph:

(A) shall be consistent with subsection (g) of this section, as it concerns purchases from a qualifying facility;

(B) shall consider the aggregate capacity value provided by multiple qualifying facilities with a design capacity of 100 kilowatts or less; and

(C) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(2) Terms and conditions unique to qualifying facilities with a design capacity of 100 kilowatts or less such as metering arrangements, safety equipment requirements, liability for injury or equipment damage, access to equipment and additional administrative costs, if any, shall be included in a standard tariff.

(3) The standard tariff shall offer at least the following options:

(A) parallel operation with interconnection through a single meter that measures net consumption;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production will not be metered or purchased by the utility and therefore there will be no additional customer charge imposed on the qualifying facility;

(B) parallel operation with interconnection through two meters with one measuring net consumption and the other measuring net production;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection;

(C) interconnection through two meters with one measuring all consumption by the customer and the other measuring all production by the qualifying facility;

(i) all consumption by the customer for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the customer would belong in the absence of the qualifying facility;

(ii) all production by the qualifying facility for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection.

§25.242(h) continued

(4) In addition, each electric utility shall offer qualifying facilities using renewable resources with an aggregate design capacity of 50 kilowatts or less the option of interconnecting through a single meter that runs forward and backward.

(A) Any consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs.

(B) Any production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) of this subsection.

(C) This option is not available if a contract for interconnection or the purchase of electricity is executed after December 31, 2008.

(5) Interconnection requirements necessary to permit interconnected operations between the qualifying facility and the utility and the costs associated with such requirements shall be dealt with in a manner consistent with Subchapter I of this chapter.

(6) The rates, terms and conditions contained in the standard tariff for qualifying facilities with a design capacity of 100 kilowatts or less shall be subject to review and revision by the commission.

(7) Except for qualifying facilities subject to §25.217 of this title (relating to Distributed Renewable Generation) requirements for the provision of insurance under this subsection shall be of a type commonly available from insurance carriers in the region of the state where the customer is located and for the classification to which the customer would belong in the absence of the qualifying facility. An enhancement to a standard homeowner's or farm and ranch owner's policy containing adequate liability coverage and having the effect of adding the electric utility as an additional insured or named insured is one means of satisfying the requirements of this paragraph. Such policies shall in each instance be on a form approved or promulgated by the Texas Department of Insurance and issued by a property or casualty insurer licensed to do business in the State of Texas.

(i) **Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility.** Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility shall be filed with the commission based on one of the following approaches:

(1) Rates for purchases of nonfirm power may, by agreement of both the electric utility and the qualifying facility, be based on the utility's average avoided energy costs. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(2) PTB REPs and QFs may mutually agree to rates for purchases of nonfirm power that differ from the rates described in paragraph (4) of this subsection. Any such agreements shall be made on a nondiscriminatory basis. Such agreements may include provisions to prevent the potential for arbitrage.

(3) Rates for purchases of nonfirm power may, at the option of the qualifying facility, be based on the full cost at the time of delivery of decremental energy that would have been incurred by the electric utility had the qualifying facility not been in operation.

(A) The following factors should be considered in the calculation of the cost of decremental energy:

(i) fuel costs;

(ii) variable operating and maintenance costs;

(iii) line losses;

(iv) heat rates;

§25.242(i)(3)(A) continued

(v) cost of purchases from other sources;
(vi) other energy-related costs;
(vii) capacity costs, if, as a class, qualifying facilities providing nonfirm energy offer some predictable capacity; and
(viii) for short term energy purchases, the time and quantity of energy furnished.

(B) If practical, the avoided cost should be determined by calculating by time period, using the utility's economic dispatch model (or comparable methodology), the difference between the cost of the total energy furnished by both the qualifying facility and the utility, computed as though the energy furnished by the qualifying facility had been furnished by the utility, and the actual cost of energy furnished by the utility.

(C) The economic dispatch model should take into consideration the following factors:
(i) fuel costs;
(ii) variable operating and maintenance costs;
(iii) line losses;
(iv) heat rates;
(v) purchased power opportunity;
(vi) system stability; and
(vii) operating characteristics.

(D) Time periods should be hourly if the utility has an automated economic dispatch model available; otherwise the shortest reasonable time period for which costs can be determined should be used.

(E) Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(4) Rates for purchases of nonfirm power shall be based on the market price of energy at the time of sale from the QF unless other arrangements have been made in accordance with paragraph (2) of this subsection. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility. Such agreements may include provisions to prevent the potential for arbitrage.

(j) **Periods during which purchases not required.**

(1) Any PTB REP or electric utility which gives notice to each affected qualifying facility in time for the qualifying facility to cease delivery of energy or capacity to the PTB REP, or electric utility will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, including resource ramp rate limitations that could cause imbalances or the amount of energy put by the QF exceeds the PTB REP's load, purchases from qualifying facilities will result in costs greater than those which the electric utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, provided, however, that this subsection does not override contractual obligations of the PTB REP or electric utility to purchase from a qualifying facility.

(2) Any PTB REP or electric utility which fails to give notice to each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the PTB REP or electric utility will be required to pay the same rate for such purchase of energy or capacity as would be required had the period of greater costs not occurred.

(3) A claim by PTB REP or an electric utility that such a period has occurred or will occur is subject to such verification by the commission either before or after the occurrence.

<u>§25.242 continued</u>

(k) **Rates for sales to qualifying facilities.**

(1) General rules.

(A) Rates for sales to qualifying facilities shall be just and reasonable and in the public interest, and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for standby or other supplementary service shall be based on the amount of capacity contracted for between the qualifying facility and the electric utility, and shall not penalize electric utilities that also purchase power from qualifying facilities. The need for and cost responsibility for special equipment or system modifications shall be determined by application of Subchapter I of this chapter.

(B) Rates for sales that are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the electric utility's other customers with similar load or other cost-related characteristics.

(2) Additional services to be provided to qualifying facilities.

(A) Upon request of a qualifying facility within its service area, each electric utility shall provide:

(i) supplementary power;

(ii) back-up power;

(iii) maintenance power; and

(iv) interruptible power.

(B) An electric utility shall not be required to provide supplementary power, back-up power, or maintenance power to a qualifying facility if the commission finds that provision of such power will:

(i) impair the electric utility's ability to render adequate service to its customers; or

(ii) place an undue burden on the electric utility.

(3) Rates for sales of back-up power and maintenance power. The rate for sales of back-up power or maintenance power:

(A) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(B) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(l) **System emergencies.**

(1) **Qualifying facility obligation to provide power during system emergencies.** A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(A) provided by agreement between such qualifying facility and electric utility; or

(B) ordered under the Federal Power Act, §202(c).

(2) **Discontinuance of purchases and sales during system emergencies.** During any system emergency, an electric utility may discontinue:

(A) purchases from a qualifying facility if such purchases would contribute to such emergency; and

(B) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

<u>§25.242 continued</u>

(m) **Enforcement.** A proceeding to resolve a dispute between an electric utility, PTB REP and a qualifying facility arising under this section may be instituted by filing of a petition with the commission. Electric utilities, PTB REPs, and qualifying facilities are encouraged to engage in alternative dispute resolution prior to the filing of a complaint.

DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

CRYSTAL K. ELBE

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

EVCI utilization and high demand charges. The TECDA Rider would only be applicable to customers taking service under ETI's existing Rate Schedule GS and would only be available to qualifying, separately metered TE charging equipment, regardless of whether the equipment is owned by ETI or the customer. The TECDA Rider would limit the amount of demand billed under Rate Schedule GS to a qualifying customer during any billing period in which the actual calculated load factor is less than 15%. In her direct testimony, Ms. Hill provides additional details on the TECDA policy, supports the calculations underlying the demand adjustment mechanism and provides the proposed new tariff as Exhibit SFH-2.

B. Proposed Schedule Modifications

Q121. WHAT SCHEDULES DOES ETI PROPOSE MODIFYING?

A. The table below sets out the rate schedules and riders, agreements, Rules and Regulations, and Terms and Conditions that ETI proposes to modify along with a description of those non-rate related changes. Rate schedules and rate riders that only have rate changes are not included:

Table 3: 2022 Modified Schedules

Schedule/ Rate Rider	Description	Description of Changes
	Index to Rate Schedules	Updated the order of some rate schedules and included the proposed new schedules.
RLU	Residential Street Lighting Service	Updated the lumens descriptions for the relevant lighting options.
GS	General Service	Updated Delivery Voltage Adjustment section to include "230KV" with 69KV and 138KV as transmission voltage.

Schedule/ Rate Rider	Description	Description of Changes
GS-TOD	General Service – Time of Day	Updated Delivery Voltage Adjustment section to include "230KV" with 69KV and 138KV as transmission voltage.
LGS	Large General Service	Updated Delivery Voltage Adjustment section to include "230KV" with 69KV and 138KV as transmission voltage.
LGS-TOD	Large General Service – Time of Day	Updated Delivery Voltage Adjustment section to include "230KV" with 69KV and 138KV as transmission voltage.
SMC	Special Minimum Charge Rider to Schedules SGS, GS, and LGS	Updated Section III, B reconnection language reference to the MES Schedule.
IS	Rider to Schedule LIPS for Interruptible Service	Updated language to sections discussing: the right to decline service on the IS schedule; reflect practice for the MISO registration process; reflect practice for the MISO Planning Period; and, added clarifying language to interruptions.
PM	Rider to LIPS for Planned Maintenance	Closed to new business. Updated language in the Section II Availability to close schedule after five years from the effective date of the schedule unless an extension is requested by the Company and approved by the appropriate regulatory authority.
EAPS	Economic As-Available Power Service	Updated language in the Section II Availability to replace the language on closing the schedule five years after the effective date (from last case) to the date of October 17, 2023, which is five years from last effective date.
SMS	Standby and Maintenance Service	Updated language allowing Company to require firm service contract and provisions when there is not a firm service contract; incorporate changes to amount of standby service ETI will provide; increase to the notice for request for maintenance service; define limits to maintenance service; and, added provision for customers without a contract for firm service to bill on the GS rate and sign a contract for firm service.
CGS	Competitive Generation Service	Updated language to reflect: MISO name edits and edited references that erroneously stated ETI is not part of an RTO (Section I and

Schedule/ Rate Rider	Description	Description of Changes
		Appendix A); removed Rider RCL reference; and updated the list of applicable riders.
ALS	Area Lighting Service	Closed certain lighting and pole offerings to new business and moved to rate schedule LS-E and updated language in General Provisions on replacements and additional facilities.
ALS-LED	Area Lighting Service – Light Emitting Diode (LED)	Closed one lighting fixture to new business and moved to rate schedule LS-E; added three new light fixtures and three new poles; updated lumens descriptions for the relevant lighting options; and updated language in General Provisions regarding additional facilities.
SHL	Street and Highway Lighting Service	Updated language in Service Conditions regarding replacements.
SHL-LED	Street and Highway Lighting Service – Light Emitting Diode (LED)	Added two new Off-Road light fixtures; updated lumens descriptions for the relevant lighting options; and updated language in Service Conditions regarding replacements.
LS-E	Lighting Service to Existing Installations Only	Withdrew lighting rates that had previously been closed to new business and no longer have customers taking service; addition of lights rates from other rate schedules that are now closed to new business; added new ALS-LED section to Net Monthly Rates, Rate Group C; and updated language in General Provisions regarding replacements.
TSS	Traffic Signal Service	Added a minimum charge provision in the Net Monthly Bill section.
MES	Miscellaneous Electric Service Charges	Updated language on Standard Metering Service for existing meters and new installations and Non-Standard Metering; removed Remote Meter Installation language; and updated language for clarification on Non-Sufficient Funds and Temporary Service sections.
DTK	DataLink Web Based Access to Interval Load Data Rider	Removed the reference to the withdrawn Schedule RCL in the General Provisions section.
AMS	Advanced Metering System Surcharge Rider	Updated list of applicable schedules to account for new or withdrawn rate schedules or rate riders.

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Ryan Magee Sponsoring Witness: N/A Beginning Sequence No. LR900 Ending Sequence No. LR901

Question No.: TIEC 3-6 Part No.: Addendum:

Question:

Referring to the proposed SMS rate schedule:

a. Explain the reasons for the proposed new language in III. A. (1). In particular, why would Schedule GS be the default firm power rate schedule if the customer would otherwise qualify for different rate schedule based on the customer' s size and delivery voltage?

b. Explain the reasons for the proposal to increase the prior notification requirement for Maintenance Service from 24 hours to five days.

c. Explain the reasons for the proposal to limit the availability of Maintenance Service to not more than six times per calendar year or 90 calendar days per Contract Year, whichever is reached first.

d. Define the circumstances in III. B. when Maintenance Service would be no longer available to the Customer.

Response:

a. The proposed change is to prevent potential gaming of the Standby and Maintenance Service (“SMS”). Prior to the new language, large customers could contract for only 1MW of SMS thereby having the SMS rate available to them, but actually need 100 MW of SMS power in the event their co-generating units go off-line. The new proposed language encourages customers to sign-up for the amount of SMS they know they will need and pay monthly reservation fees associated with that need. The firm power rate schedules typically applicable to customers on SMS would be the General Service (“GS”), Large General Service (“LGS”), or Large Industrial Power Service (“LIPS”) rate schedules. The minimum billing demand for these rate schedules is 5 kW, 300 kW, and 2500 kW, respectively. Entergy Texas, Inc. (“ETI”) elected to have the default be the rate schedule with the least restrictive minimum billing demand. This default would apply until the customer executes a contract for service under the applicable rate schedule that meets the customer's needs. This change allows ETI to study the outage and provide timely customer feedback.

b. The proposed change to the prior notification requirement in Schedule SMS is consistent with a customer's planning for a co-generation unit outage because a customer will need to know the schedule for any planned work in advance and be required to schedule crews and material for the co-generation unit's maintenance outage.

c. The intention of the maintenance service under Schedule SMS was for limited planned co-generation maintenance. Prior to the proposed new language for Schedule SMS, an SMS customer could rely on maintenance service throughout the year instead of paying for firm service. A customer's cogeneration should be available for greater than 75% of the calendar year, otherwise the customer requires firm service.

d. For an illustration of when the Maintenance Service would no longer be available to the customer, please see below:

<u>Illustrative</u>

Customer 1:

- 1 schedule maintenance – lasts 45 days (schedule = 1: days = 45)
- 2 schedule maintenance – lasts 30 days (schedule = 2: days = 75)
- 3 schedule maintenance – lasts 20 days (schedule = 3: days = 95); 5 days of this schedule would be disapproved because the days exceed 90.

Customer 2:

- 1 schedule maintenance – lasts 5 days (schedule = 1: days = 5)
- 2 schedule maintenance – lasts 5 days (schedule = 2: days = 10)
- 3 schedule maintenance – lasts 20 days (schedule = 3: days = 30)
- 4 schedule maintenance – lasts 10 days (schedule = 4: days = 40)
- 5 schedule maintenance – lasts 7 days (schedule = 5: days = 47)
- 6 schedule maintenance – lasts 4 days (schedule = 6: days = 51)
- 7 schedule maintenance–lasts 3 days (schedule =7: days = 54); After the 6th scheduled maintenance of the calendar year, the 7th scheduled maintenance would be denied.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR902 Ending Sequence No. LR902

Question No.: TIEC 3-7 Part No.: Addendum:

Question:

Does MISO limit maintenance outages of ETI generating resources to six outages per year or 90 calendar days, whichever is reached first? If so, please provide supporting documents.

Response:

No, Midcontinent Independent System Operator ("MISO") does not limit maintenance outages of generating resources to six outages per year or 90 calendar days. However, MISO has rules and limitations for generation outages included in the MISO Tariff and applicable Business Practice Manuals ("BPM"). For example, BPM-011 states that resources with pending full or partial outages that are planned and/or scheduled and reasonably expected to encompass ninety or more of the first 120 calendar days in the Planning Year shall be precluded and/or prohibited from participation in that Planning Year's Planning Resource Auction ("PRA").

ENTERGY TEXAS, INC.
DERIVATION OF SCHEDULE SMS CHARGES
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2017

Line No.	Description	Amount	Units	Source
(a)	(b)	(c)	(d)	(e)
	Billing Load Charge:			
1	Schedule LIPS Production/Transmission Demand Charge	$6.42	/kW	Q-7 Detail Rev
2	SMS/LIPS Coincidence Ratio	11.379%		CLI
3	Schedule SMS: Standby Transmission Delivery	$0.73	/kW	L1 x L2
4	Schedule LIPS Distribution Demand Charges	$1.32	/kW	Q-7 Detail Rev
5	Schedule SMS: Standby Distribution Delivery	$2.05	/kW	L3 + L4
6	Schedule SMS: Maintenance Transmission Delivery	$0.55	/kW	L3 * .75
7	Schedule SMS: Maintenance Distribution Delivery	$1.86	/kW	L4 + L6
	Energy Charges:			
8	Schedule LIPS Non-Fuel Energy Charges	$0.00406	/kWh	Q-7 Detail Rev
9	Relative Loss Factor: Transmission	99.7%		Note
10	Off-Peak Energy Charge: Transmission	$0.00405	/kWh	L8 x L9
11	Relative Loss Factor: Distribution	103.0%		Note
12	Off-Peak Energy Charge: Distribution	$0.00418	/kWh	L8 x L11
13	On-Peak Energy Charge	$0.03681		WP Q-7 RD-6 SMS Page 2
14	On-Peak Energy Charge: Transmission	$0.03672	/kWh	L13 x L9
15	On-Peak Energy Charge: Distribution	$0.03790	/kWh	L13 x L11

Note:	Energy Losses	Percent	Relative Losses
	Schedule LIPS	1.7847%	
	Transmission	1.5292%	99.7490%
	Distribution	4.8031%	102.9655%
	Source: P-7.2 Energy & Demand at Plant		

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ENTERGY TEXAS, INC.
SCHEDULE SMS COINCIDENCE RATIO
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2017

Line	Period	Average 4CP Demand	Average Monthly Billing Demand	Coincidence Factor
(a)	(b)	(c)	(d)	(e)
1	2007	47,600	441,154	10.7899%
2	2008	31,133	502,301	6.1981%
3	2009	25,017	516,532	4.8433%
4	2010	14,115	531,439	2.6560%
5	2011	57,468	497,199	11.5583%
6	Average 2007-2011			7.2091%
7	Test Year 06/2011	43,205	500,763	8.6278%
8	Test Year 03/2013	41,721	545,859	7.6432%
9	Test Year 12/2017	66,070	478,271	13.8143%
10	SMS Average 2007-2014			8.2664%
11	LIPS 12/2017	805,307	1,108,563	72.6442%
12	Ratio of SMS to LIPS Coincidence Factor			11.379%

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NATIVE FILES UPLOADED TO THE PUC INTERCHANGE

- Exhibit JP-4.xlsx
- Exhibits JP-1 and JP-3.xlsx
- Winter Storm Uri Impact.xlsx

The following files are not convertible:

Winter Storm Uri Impact.xlsx
Exhibit JP-4.xlsx
Exhibits JP-1 and JP-3.xlsx

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.