CenterPoint Energy Houston Electric
Distribution Plan Projects Greater than $100,000
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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	13094762	Premise Equipment Replacement CEHE IT Admin cycle replacement of computer hardware, testing equipment and premise equipment including copiers and printers.	1,986,041.25	-	1,986,041.25
	13094763	Capital Mobile Data Computer Replacement -Replacement of computer equipment for Distribution related mobile data.	731,082.83	-	731,082.83
	13094765	Equipment and Hardware - LFS: Replacement of computer hardware, testing equipment and premise equipment including copiers and printers for Land and Field Services Dept.	179,331.93	-	179,331.93
	13094766	Equipment and Hardware - GIS; Replacement of computer hardware, testing equipment and premise equipment including copiers and printers for GIS.	593,034.28	-	593,034.28
	13095422	Incident Management mobile application	110,224.19	-	110,224.19
	13095662	Record IBM ELA Software expenses	499,151.87	-	499,151.87
	13096367	HEB016 - CEHE IBM ELA Software	4,921,431.08	-	4,921,431.08
	AA20	General Equipment - Purchase of distribution computer hardware, premise equipment, tools, test equipment, etc.	173,156.11	-	173,156.11
	AA80	Facilities modifications including fencing, shelving, furniture, etc.	4,846,878.96	-	4,846,878.96
	AA81	Security equipment for distribution facilities.	173,910.70	-	173,910.70
	CA1E	Purchase of capital tools such as water pumps to pump out manholes, generators, hydraulic cable presses, cable cutters, confined space air monitors, etc. Also includes capital premise equipment such as printers, multifunction devices, projectors, monitors, etc.	155,749.04	-	155,749.04
	FLEET	Purchase of Vehicles and Power Operated Equipment.	337,453.36	-	337,453.36
	HED070	SPLUNK: project includes a software license, infrastructure hardware and implementation services. Splunk is a tool that can consume, retain and search application logs and other raw, unstructured data generated by AMS applications for performance monitoring and application troubleshooting purposes.	868,402.27	-	868,402.27

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	HXIM	Capital Instrument Purchases - Metering: Capital instrument purchases to support field and shop testing of meters and meter related equipment	116,827.93	-	116,827.93
	HXSF	Field Metering - Purchase of in-service meter equipment.	8,650,408.49	-	8,650,408.49
	HXSH	High Voltage Metering - Purchase of in-service meters.	179,748.78	-	179,748.78
	S/101382/CE/XA71	Purchase capital tools and equipment used by Shop Services	107,264.89	-	107,264.89
	S/101392/CE/OPSKY	New V&D Radio System: Non production Test System for the OpenSky Voice and Mobile Data Radio System (VMDRS). This allows version upgrades and code changes to be tested before putting into production. Also includes equipment for repair of VMDRS.	266,040.42	-	266,040.42
	S/101392/CE/OTHER	Material and other services for items such as test equipment for general support of various radio systems.	430,999.71	-	430,999.71
	S/101710/CE/CELLRELAY	Deploy (Post DOE) existing cell relay-INS	13,218,029.89	(117,233.13)	13,100,796.76
	S/101710/CN/CELLRELAY	Capital replacement of AMS communication equipment.	485,195.00	-	485,195.00
	S/101784/CE/FIBER	Optical Fiber Reactive Restoration. Planned rehabilitation/replacement of fiber system (approx. 25 miles per year).	314,125.89	-	314,125.89
	S/101784/CE/TOWER	Replace Generators where repair is no longer a viable option.	502,929.18	-	502,929.18
	S/101785/CE/AMSCOMM	AMS Communications-services and materials needed to install, replace or upgrade communications equipment at existing SmartGrid/ AMS sites (post AMS project).	789,024.41	7,835.93	796,860.34
	S/101785/CE/FIBER	Replace aged/degraded fiber on CNP's Core Fiber Backbone	1,514,712.60	-	1,514,712.60
	S/101785/CE/SCADA	Design and construct transport telecom infrastructure including towers, shelter, DC Plants, racks, generators and fuel tanks. The infrastructure will support substation SCADA backhaul to Distribution Control Operations and Real Time Operations. Infrastructure will also support metering, AMS/Smart Grid, Security, telephone and other.	122,398.64	-	122,398.64
	S/101785/CE/TMWSY	Capture costs of upgrading (replacing) microwave (MW) radios at several existing locations. Removal of microwave equipment at abandoned site(s).	411,913.32	-	411,913.32

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	S/101785/CN/FIBER	Purchase and labor to install fiber optic cable. Expand network infrastructure requires increase in network to geographically support expanding backhaul infrastructure, establish fiber footprint in locations microwave communications may limit capacity.	2,923,417.08	-	2,923,417.08
	S/101785/CN/MPLS	Replacement of Routers, Battery Plants, Switches, Network Clocks, Terminal Servers, etc. as they approach End of Life/Support.	1,306,954.92	-	1,306,954.92
	S/101785/CN/OPENSKY	Voice and Mobile Data - Major upgrades, hardening and system enhancements/improvements to Voice and Mobile Data Radio System (VMDRS), which is a critical part of the CNP's Telecommunications infrastructure that must remain a reliable, up-to-date system.	265,269.94	-	265,269.94
	S/101785/CN/SCADA	Provide SCADA communication to new electrical substations controlled, managed, monitored by CNP. Services provided by internal telecommunications infrastructure or leased carrier services to fulfill new operational, business, compliance requirements.	1,288,388.02	-	1,288,388.02
	S/101785/CN/TELECOMNTWK	Design and deploy Point to Multipoint (PTMP) radio systems to support Distribution Access and Control and to support Automated Meter systems (AMS) in areas of high interference.	250,476.10	-	250,476.10
	S/101785/CN/TMSY	This WBS/Cost Object is used to purchase and install new Microwave radio and related equipment/systems for the Transport Network.	466,916.94	-	466,916.94
	S/101890/CN/BUCC-FM	Replacement of six 10 ton Wall Mount AC units that serve the AOC PH2 Transformer Vaults.	220,549.01	-	220,549.01
Load Growth					
	AF1A	Planned additions/improvements to the 12kV and 35kV overhead distribution system feeder mains as called for in Planning Issued Distribution Development Plans.	26,939,274.87	4,503,318.06	31,442,592.93
	AF1H	Overhead services to new customers or adding facilities to accommodate additional load to an existing customer.	35,040,922.99	1,409,811.45	36,450,734.44
	AF1U	Underground residential distribution services to new customers.	40,601,136.43	264,447.32	40,865,583.75

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	AF1Z	Only for the installation of overhead service drops and meters to a new customer or service drop replacement to an existing customer adding load where no other facilities are involved.	8,977,077.69	-	8,977,077.69
	AF2A	Unplanned additions/improvements to the 12kV and 35kV overhead distribution system feeder mains relating to area load growth, in conjunction with providing service to customers.	23,433,254.77	2,714,912.16	26,148,166.93
	AF2H	Overhead line extensions to new underground residential distribution subdivisions.	3,033,938.85	75,479.48	3,109,418.33
	CE1A	Planned additions/improvements to the 12kV and 35kV distribution system that requires underground feeder mains and underground dips as called for in Planning Issued Distribution Development Plans.	1,799,745.71	(8,523.39)	1,791,222.32
	CF1R	New major underground services to customers that require three-phase underground facilities to serve their electrical load.	13,102,250.25	(252,584.06)	12,849,666.19
	DF1U	Streetlight New Installations	14,054,940.11	-	14,054,940.11
	HLP/00/0522	CARDIF-Instll 3rd Trf & 8th 12kV Fdr: Work to install transformer and feeder at Cardiff substation to support load growth.	186,301.59	-	186,301.59
	HLP/00/0602	College Substation: Add 7th 12KV Feeder - Substation work to add a feeder to College substation to support load growth.	470,637.54	-	470,637.54
	HLP/00/0822	WOODCREEK-Inst 3rd Trf & (2)35kV Fdr's : Work to install transformer and feeder at Woodcreek substation to support load growth.	3,115,119.66	-	3,115,119.66
	HLP/00/0926	Distribution work to support Freeport area projects.	(0.00)	259,864.06	259,864.06
	HLP/00/0927/TR/0002	Upgrade transmission ckts 80 and 05 Imperial Taps.	675,958.05	210,539.80	886,497.85
	HLP/00/0954	Sandy Point_-Build New 138/12KV Sub;: Work to build new Sandy Point substation to support load growth.	1,186,927.06	-	1,186,927.06
	HLP/00/0997	Conversion of transmission and substation facilites from 69kv to 138kv from Fort Bend to West Columbia	2,871,990.35	378,977.49	3,250,967.84
	HLP/00/1011	Major Underground Rehab - VLT Relay Panels: Replacement of electro-mechanical relay panels with microprocessor relay panels to support system reliability.	254,675.33	58,089.88	312,765.21

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	HLP/00/1012	Major Underground Rehab - VLT Tie Breakers: Replacement of 480V tie breakers to support system reliability.	238,131.81	28,599.00	266,730.81
	HLP/00/1040	Fairmont Substation- Add feeders at Fairmont substation to support load growth.	2,308,044.72	3,818.63	2,311,863.35
	HLP/00/1084	New VILLAGE CREEK substation: Purchase of property for new Village Creek distribution substation to support load growth.	211,540.61	-	211,540.61
	HLP/00/1091	Sienna Substation-Add Transformer and Feeders: Substation work to add transformer and feeders at Sienna substation to support load growth.	195,481.12	-	195,481.12
	HLP/00/1112	Convert HOC substation from 69kv to 138kv	211,601.07	48,845.82	260,446.89
	HLP/00/1150	Rebuild transmission ckt 08G PSARCO to CROSBY	202,672.46	64,320.48	266,992.94
	HLP/00/1152	Red Bluff Substation - Build new Red Bluff substation to support load growth.	16,498,939.84	-	16,498,939.84
	HLP/00/1157	Bringhurst-Replace transformer and add feeder: Work to replace transformer and add feeder at Bringhurst substation to support load growth.	140,637.02	12,645.20	153,282.22
	HLP/00/1185	Hidden Valley Substation -Add transformer and feeders to Hidden Valley substation to support load growth	10,607,222.30	-	10,607,222.30
	HLP/00/1197	Jacintoport -Add Feeder: Substation work to add feeder at Jacintoport substation to support load growth.	310,778.75	20,089.68	330,868.43
	HLP/00/1202	Stafford -Add Feeder: Substation work to add feeder at Stafford substation to support load growth.	994,967.14	-	994,967.14
	HLP/00/1226	READING - INSTALL 35KV TRFS & FDRS - Add transformer and feeders to Reading substation to support load growth	9,413,279.02	(1,311.49)	9,411,967.53
	HLP/00/1249	SPRINGWOODS-INSTALL 2 XFRS AND 6 FEEDERS- Add transformers and feeders to Springwoods substation to support load growth.	9,839,549.79	173,641.80	10,013,191.59
	HLP/00/1253	Blodgett Substation: Add 3rd transformer and 1 feeder at Blodgett substation to support load growth	452,414.65	-	452,414.65
	HLP/00/1259	Parkway -Add Feeders: Substation work to add feeder at Parkway substation to support load growth.	355,659.76	-	355,659.76
	HLP/00/1264	Pasadena -Add Feeder: Substation work to add feeder at Pasadena substation to support load growth.	219,081.37	-	219,081.37

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	HLP/00/1266	Garth: Build new 12kv distribution substation	208,625.31	63,276.78	271,902.09
	HLP/00/1278	NASH - CONVERT TO 138KV- Distribution work to support conversion of Nash substation to 138Kv	296,714.76	5,074.27	301,789.03
	HLP/00/1340	Hall -Add Feeder: Substation work to add feeder at Hall substation to support load growth.	223,871.90	-	223,871.90
	HLP/00/1341	Highlands Substation: Add 8th and 9th 12kv feeders at Highlands substation to support load growth	104,061.97	-	104,061.97
	HLP/00/1349	Upgrade 69kV West Columbia Transformers to 138 kV	125,947.55	-	125,947.55
	HLP/00/1357	Needville -Add Feeders: Substation work to add feeders at Needville substation to support load growth.	252,732.92	-	252,732.92
	HLP/00/1359	Upgrade 69kV West Columbia Power Transformer to 138 kV	206,898.50	38,064.11	244,962.61
Public Improvements					
	AD2D	The relocation of CEHE overhead distribution facilities that are generally less than five poles, due to customer request, including city, state, and federal government infrastructure improvement projects, such as road widening or roadway improvements.	2,960,400.42	274,644.28	3,235,044.70
	AD3D	The relocation of CEHE overhead distribution facilities generally five poles or more, due to customer request, including city, state, and/or federal government infrastructure improvement projects such as road widening or roadway improvements.	6,154,173.60	1,434,432.23	7,588,605.83
	CG1R	Relocation of major underground facilities for road widening, light rail, etc. Includes relocation of overhead to underground at customer's request.	5,273,251.09	414,232.00	5,687,483.09
Restoration					
	AD06	Reactive capitalized replacements that are made to the underground residential distribution system requiring facility replacement. Includes cable replacement, transformers, and other retirement units and their related components.	11,944,833.10	2,540,020.60	14,484,853.70
	AD07	Reactive capitalized replacements made to the overhead distribution system requiring facility replacement.	16,985,568.41	4,401,104.74	21,386,673.15

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	AD86	Reactive capitalized replacements made to the overhead distribution system requiring facility replacement resulting from the effects of adverse weather conditions.	10,173,102.27	3,027,512.87	13,200,615.14
	CD1T	Reactive capitalized replacements made to the major underground system requiring replacement of equipment, cable or structures in response to "lights out." Also includes replacement of system neutral associated with copper theft.	8,204,473.58	1,282,768.65	9,487,242.23
System Improvements					
	AB1C	Planned capital replacement or rehabilitation of overhead distribution system associated with reliability improvement. Includes target top 10% of SAIDI circuits, outage-driven overhead rehab, recurring fuse outages, recurring transformer outages, etc.	10,644,238.25	2,262,238.84	12,906,477.09
	AB1G	Replacement of CEHE-owned poles found defective that are not part of the Groundline Inspection Program or trouble related.	2,963,392.97	838,487.05	3,801,880.02
	AB1S	Planned underground residential distribution cable replacement on a one-span basis. Includes: spans referred from trouble	5,644,859.76	1,779,997.76	7,424,857.52
	AB1V	Planned underground residential distribution cable replacement of 12kV and 35kV partial and total loops. Includes: cable relocations, transformer relocation/replacements, raising transformers, and pedestals.	3,652,374.24	883,186.03	4,535,560.27
	AB1X	Capacitor banks that include the replacement of capital material such as capacitor, vacuum switches, disconnects, controller, etc.	3,936,112.08	421,577.95	4,357,690.03
	AB1Y	Replacement of existing CNP owned area lighting fixtures as a result of failure or damage. (Does not include streetlights).	447,746.94	99,611.07	547,358.01
	AB1Z	Proactive routine capital replacements to the overhead distribution system.	10,223,061.98	3,564,896.67	13,787,958.65
	AB2C	Distribution overhead reliabilty improvement projects	222,148.16	10,638.26	232,786.42
	AB2G	Replacement of CEHE-owned poles based on inspections for ground rotting-- the Groundline Inspection Program.	11,684,857.40	3,466,067.84	15,150,925.24

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	AB2S	Underground residential distribution proactive span replacement.	4,059,811.46	1,112,831.88	5,172,643.34
	AB2V	Proactive URD loop replacement	372,492.61	3,142.03	375,634.64
	AB2Z	Capital grid hardening work that does not involve replacement of a rotten pole.	165,132.15	42,217.34	207,349.49
	AB48	Install C-truss or other approved brace on CEHE poles identified by the Groundline Inspection Program.	5,257,636.51	-	5,257,636.51
	ABCA	Cable Life Extension Program - Testing the condition of underground cable and mitigating components of good cable with a high probability of failure.	17,316,636.08	-	17,316,636.08
	ABP1	Replacement of CEHE retirement units when associated with the replacement of a non-CEHE owned pole.	422,229.82	123,627.84	545,857.66
	ABVM	Vessel moves that require modifications to distribution facilities such as increase in line height requiring addition of retirement units or total relocation of poles/structures	653,418.82	99,444.35	752,863.17
	AFNC	New Capacitor Installations	1,670,977.47	-	1,670,977.47
	CE1B	Proactive replacement of major underground equipment, cable or structures.	10,206,245.24	1,252,993.13	11,459,238.37
	DB16	Streetlight Rehabilitation/Relocations	956,424.92	242,241.93	1,198,666.85
	DB17	Replacement of streetlight standards and/or luminaires as a result of failure or damage. Does not include area lighting.	3,951,527.64	578,937.48	4,530,465.12
	DB18	Streetlight LED Replacement- Program replacement of high pressure sodium, metal halide, and mercury vapor streetlight luminaires with LED streetlight luminaires.	8,783,611.38	443.30	8,784,054.68
	DB2H	Replacement of streetlight standards due to cable cuts.	7,590,581.70	3,241,034.20	10,831,615.90
	HLP/00/0011	Unscheduled Substation Corrective Projects- unscheduled corrective type projects and unforeseen equipment failures. These projects involve replacement of equipment and or structures.	784,309.56	276,665.93	1,060,975.49
	HLP/00/0012	Scheduled Substation Corrective Projects- scheduled corrective projects. These projects involve replacement of equipment and or structures.	1,909,406.53	67,729.61	1,977,136.14
	HLP/00/0014	Replace the logic cages in aging and/or unreliable SCADA Remote Terminal Units (RTU's).	1,494,125.20	140,877.34	1,635,002.54

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	HLP/00/0072	Substation Transformer Firewall Program - Install firewalls between power transformers in a manner that reduces the risk of fire spreading from a failed transformer to adjacent units.	737,136.09	-	737,136.09
	HLP/00/0075	This project provides funding for replacement and repair of failed distribution and transmission transformers as well as replacement of failed transmission circuit breakers. (Transformers may be rewound and the rewind would be capitalized).	10,179,900.88	286.42	10,180,187.30
	HLP/00/0484	Substation Security Upgrades - Installation of security equipment to control physical and cyber access to CNP substations. This includes: Plant separation fencing, security cameras, & cyber security equipment at various substations. These substations are selected based on risk, vulnerability, and impact as determined by CNP security policies and/or future regulatory requirements.	565,386.70	171.29	565,557.98
	HLP/00/0491/0006	WALLISVILLE: Elevate the control house at Wallisville substation for storm hardening	221,514.37	-	221,514.37
	HLP/00/0491/SB/0007	Wharton Substation Flood Mitigation: Elevate the control house at Wharton substation for storm hardening	1,275,219.58	-	1,275,219.58
	HLP/00/0672	This program provides for various protection improvements on the substation system. Work covered with these amounts was associated with replacement of transformer panels at Grant Substation.	233,621.27	0.00	233,621.27
	HLP/00/0909	Replace 35KV//12KV Breakers-This project includes replacement of older troublesome distribution breakers (mostly oil filled) at various substations with newer technology vacuum breakers.	1,027,238.18	235,138.83	1,262,377.01
	HLP/00/0922/TR/0005	Distribution work to support Galveston - W.Galv Rebuild 138kV ckt 63A for hardening of system	450,414.57	-	450,414.57
	HLP/00/0936	Substation improvements include conversion at Fannin substation and new feeder panel at Needville substation.	1,383,263.23	12,586.47	1,395,849.70

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Project Category	Project Number	Description	Additions	Salvage / Removal	Total
General Equipment					
	HLP/00/1004	Major Underground Rehab - VLT Replace 15KV BKRS: Replacement of 15KV Vacuum breakers with G&W Trident 15KV Solid Dielectric Interrupters. Replacement reasons include but not limited to obsolescence and operational issues.	285,743.22	49,719.15	335,462.37
	HLP/00/1013	MUG Rehab - VLT CI Interrupters	694,956.10	77,612.57	772,568.67
	HLP/00/1017	PLAZA DUCT & CABLE- Provide alternate route for underground circuits from Plaza substation to the Texas Medical Center to mitigate congestion and single point of failure from existing single main ductbank system.	101,215.30	-	101,215.30
	HLP/00/1055	Distribution line clearance corrections between transmission and distribution facilities to meet National Electrical Safety Code (NESC) requirements.	38,885.99	85,516.32	124,402.31
	HLP/00/1099	Substation Physical Security Enhancement: Replacement of substation facility fencing with more protective fencing to ensure our critical assets receive a greater level of protection.	735,165.48	-	735,165.48
	HLP/00/1229	MUG Rehab - VLT Network Breakers: Replacement of vault network breakers to support system reliability	839,098.85	104,334.28	943,433.13
	HLP/00/1230	MUG Rehab- VLT Ventilation: Rehab of the ventilation system used to regulate transformer temperatures in electrical vaults.	224,680.43	33,381.69	258,062.12
	HLP/00/1232	Replace underground vault switches	215,223.95	20,396.73	235,620.68
	HLP/00/1247	Rebuild Memorial substation due to extensive damage due to Hurricane Harvey. Rebuild included upgrade of transformers and storm hardening measures to mitigte future flooding iisues.	2,138,660.41	-	2,138,660.41
	HLP/00/1356	Replace existing panels and cabinets containing obsolete Allen Bradley and Omron PLC's with CNP current standard PLC's	320,785.02	-	320,785.02
Intelligent Grid					
	13092982	Security work to support IG initiatives, as well as meet DOE grant requirements	153,186.06	-	153,186.06
	13094602	Design and build an interval data aggregation layer for smart meter data in SAP HANA.	755,613.33	-	755,613.33
	AMSCOMM	Communications to support intelligent grid.	9,872,526.04	-	9,872,526.04
	CG1A	Installation of Telecom boxes for new intelligent grid devices	248,306.70	-	248,306.70

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General Equipment					
	CG1E	Planned Upgrades or Replacements of Communication Equipment supporting Distribution Automation. (IGSD, DACs, Monitoring Systems, etc)	341,443.04	521.10	341,964.14
	IDR	Project to replace standard IDR meters with AMS IDR meters	1,219,777.87	-	1,219,777.87
	IGSD	Planned/proactive IGSD device installations/replacements.	6,534,532.34	562,765.66	7,097,298.00
	S/101220/CN/HED070	Demand Response Management System (DRMS) - E-curtailment product was purchased for AMS with the goal of reducing customer demand at the meter level.	546,220.74	-	546,220.74
	SCIG	Installation of Telecom boxes for intelligent grid devices to support reliability.	962,023.54	-	962,023.54

Total Projects Greater than $100,000	**598,284,058**	**45,028,033**	**643,312,091**
Total of Projects Less than $100,000	**1,244,962**	**218,040**	**1,463,003**
Total of All Projects	**599,529,020**	**45,246,073**	**644,775,093**

EXHIBIT BAT-5 IS VOLUMINOUS AND IS BEING PROVIDED IN ELECTRONIC FORMAT ONLY

Descriptions of Capital System Improvement Reliability Programs

Program	Description
Pole Maintenance Program	The Pole Maintenance Program ensures that a portion of the Company's distribution system poles are assessed annually by contract ground-line crews. Pole assessments include a visual and/or manual assessment. Visual pole assessments are comprised of a field observation for evidence of exterior decay or damage above the ground line. Poles that are seven years old or older are manually excavated and assessed for decay below the ground line, as well as sounded and bored to locate internal voids. Poles of sufficient strength to remain in service until the next scheduled assessment are treated and tagged. Poles that are identified for reinforcement during these assessments are either treated (with a fumigant or preservative, as necessary) and braced, or replaced. The Pole Maintenance Program also includes visual assessment of guy wires, including checking for guy wires that are damaged, broken, frayed or slack, and assessment of guy strains and anchors. As part of the Company's grid hardening initiative, pole assessment and treatment have been accelerated, so approximately 10% of the Company's poles are assessed annually, on average, on a rolling 10-year cycle. As such, pole bracings and replacements should increase accordingly. Additional foreign poles (for example AT&T poles) containing Company facilities that may merit replacement by third parties are also identified.
URD Cable Life Extension Program	The URD Cable Life Extension Program takes an innovative, proactive approach to identify potential failures in aged underground cable and other URD components that do not meet specification before they can occur. By identifying the risk of potential failures, CenterPoint Houston can make wise and prudent investments in its URD infrastructure and ultimately better serve our customers by preventing future outages where they are most likely.
Feeder Inspection Program	The Feeder Inspection Program is a proactive program to inspect distribution feeders and laterals, on a periodic basis to identify and correct issues found with the condition of the feeder that could impact the reliable operation of the feeder. This periodic inspection and maintenance is intended to improve the performance of the feeders under adverse weather conditions. Damaged or broken facilities are identified, reports are made, and work orders to repair are issued accordingly.
Power Factor Program	The Power Factor Program was designed to maintain good power factor on the electric grid. Power factor ("PF") is the ratio of real power (kW or kilowatts) to total power (KVA or kilovolt-amperes) or PF = KW / KVA. While distribution facilities, including conductors and transformers, must transmit KVA, it is only the kW component that does the real work. Therefore, power factor is a relative measure of the amount of real power delivered. A good power factor reduces the amount of current flowing on a distribution circuit and will, as a result, reduce line losses, reduce voltage drop, and enable the circuit to carry more power. CenterPoint Houston installs capacitors and appropriate controls on distribution lines for power factor control in accordance with the planning design criteria for power factor.
Infra-red Program	The Infra-red Program utilizes infra-red technology which allows the Company to see the heat generated by deteriorating components on the distribution system. These "Hot Spots" eventually result in equipment failure and a loss of service. Infra-red technology is a unique tool to find potential equipment outages before they occur, so that proactive repairs can be made prior to an outage. The Infra-red Program reduces the number of equipment failures and improves reliability by decreasing System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). All circuits are inspected on an eight-year cycle. . Seventy benchmark circuits, that are representative of the overall CenterPoint Houston system, are inspected every two years to ensure that the eight-year cycle is adequate to achieve the desired reliability results. If a circuit is identified as a repeating 10% circuit, meaning it's in the top 10% for SAIDI and SAIFI minutes, or a 300% circuit, meaning its SAIDI and SAIFI minutes are three times higher than the average circuit, then it is advanced on the infra-red schedule to the current year. This additional focus on the circuits with the highest SAIDI and SAIFI measurements are done to address performance issues. Also, circuits that are heavily loaded (greater than 500 amps) are inspected, as data has proven a higher failure rate of equipment when subjected to higher load.

Descriptions of Capital System Improvement Reliability Programs

Program	Description
Root Cause Analysis Program	The Root Cause Analysis Program analyzes circuits that the Company projects will not perform as well as desired under the SAIDI and SAIFI metrics. A detailed evaluation of a circuit's outages for the current year is conducted. From this analysis, a recommendation and action plan is generated to address circuit issues. CenterPoint Houston uses outage causes, outage location, outage frequency, customer outage minutes, and the results of a field inspection to develop an action plan that can include a number of possible recommendations to address the root cause of the outages. The recommendations might include a protective coordination study, an infra-red inspection, enhanced lightning protection, reconfiguration to avoid vehicle collisions, reconfiguration of line fuses, tree trimming, and installation or relocation of automated devices. After corrective action is taken, the circuit performance is watched throughout the year to determine if the analysis was correct or if additional measures are necessary. An essential element of the program is to create a proactive response to 10% circuit outages. It is designed to identify and initiate corrective actions on circuits with issues before they become a repeating 10% circuit. In order to accomplish this, a circuit's indices are analyzed against predictive data that indicates operational issues.
Hot Fuse Program	The Hot Fuse Program identifies line and transformer fuses that have experienced recurring outages. On a daily basis, fuses are identified and within approximately four weeks, corrective action is identified. There are two hot fuse criteria: (1) recurring hot fuse – a fuse that has had a minimum of three outages within a 90 day period, and (2) ultra hot fuse – a fuse that has had a minimum of three outages within a 30-day period. Hot fuses are less likely than an ultra hot fuse to have a high impact to the Company's indices if left unaddressed after the 90-day timeframe. These fuse outages are more closely associated with wind-related events that are caused by vegetation or slack span contacts. The ultra hot fuse is more likely to have a high impact to the Company's indices if left unaddressed after the 30-day timeframe. These fuse outages are more closely associated with ongoing issues, such as overloaded devices.In addition, a third criterion applies for fuses that have large customer counts that affect the circuit's overall reliability. For those circuits with greater than four outages in 12 months, these fuses are also reviewed during the Root Cause Analysis process to verify a successful solution to the outages. CenterPoint Houston field personnel inspects all the hot fuses meeting one of these criteria and research outage records to determine the cause of the outages causing the hot fuse. The Company then issues work orders to correct the problem. Typical remedies include tree trimming, the installation of wildlife protection devices, slack span adjustment, the installation of additional fuses to limit the impact of a fault, or the installation of smart fuses that only operate on permanent faults.

STATE OF TEXAS §
§
COUNTY OF HARRIS §

AFFIDAVIT OF BRAD A. TUTUNJIAN

BEFORE ME, the undersigned authority, on this day personally appeared Brad A. Tutunjian, who being by me first duly sworn, on oath, deposed and said the following:

1. "My name is Brad A. Tutunjian. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Distribution Operations and Service Delivery for CenterPoint Energy Houston Electric, LLC.

2. The foregoing direct testimony and the attached exhibits have been prepared by me or under my direct supervision and are true and correct to the best of my knowledge."

Further affiant sayeth not.

Brad A. Tutunjian

Brad A. Tutunjian

SUBSCRIBED AND SWORN TO BEFORE ME on this 21st day of March, 2022.

Kristi Keel

Notary Public in and for the State of Texas

KRISTI KEEL
Notary Public, State of Texas
Comm. Expires 03-14-2024
Notary ID 1190550-2

DOCKET NO. ____________

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL TO AMEND ITS DISTRIBUTION COST RECOVERY FACTOR	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY OF

MARTIN W. NARENDORF JR.

FOR

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

April 5, 2022

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DIRECT TESTIMONY OF MARTIN W. NARENDORF JR.

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Martin W. Narendorf Jr. I am employed by CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company") as Vice President of Electric Engineering and Asset Optimization.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Houston in 1982. I have been employed by CenterPoint Energy, Inc. ("CNP") or one of its affiliates since 1983. My positions with CNP have included engineer and senior engineer in Electrical System protection, Engineering Projects, Supervising Engineer in Zone Technical engineering and Meter Shop Operations, Regional Operations Manager of North and Northwest Regions at Electropaulo, the utility serving one-fourth of the population of Sao Paulo, Brazil, Director of Operations at the Spring Branch Service center, Senior Director of Substation Operations and Asset Management, Vice President of Power Delivery Solutions, and Vice President of High Voltage Operations. I was named to my present position in 2020, at which time I assumed responsibility for the Electric Engineering and Asset Optimization division of CenterPoint Houston.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. As Vice President of Electric Engineering and Asset Optimization, my responsibilities include the planning and designing of the Company's distribution and transmission system, designing, and implementing schemes for protective devices, procuring and assessing low-voltage and high-voltage assets, and ensuring compliance with applicable reliability standards and protocols. I have responsibility for asset management, planning and compliance activities for CNP's electric utility subsidiary in Evansville, Indiana as well.

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

A. I am testifying on behalf of CenterPoint Houston.

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

A. My testimony addresses the reasonableness and necessity of costs CenterPoint Houston incurred for temporary emergency electric energy ("TEEE") facilities under Texas Utilities Code § 39.918, which is a new statute that allows a transmission and distribution utility ("TDU") such as CenterPoint Houston to lease and operate TEEE facilities under certain circumstances and to request recovery of the reasonable and necessary costs of leasing and operating TEEE facilities in a Distribution Cost Recovery Factor ("DCRF") filing. Throughout my testimony, I will refer to TEEE facilities as "mobile generation" facilities.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION")?

A. Yes. I have previously filed testimony at the Commission in Docket No. 49421.

Q. WHAT EXHIBITS HAVE YOU INCLUDED WITH YOUR TESTIMONY?

A. I have prepared or supervised the preparation of the exhibits listed in the table of contents.

II. PURA § 39.918

Q. ARE YOU FAMILIAR WITH PURA § 39.918?

A. Yes. Texas Utilities Code § 39.918, Utility Facilities for Power Restoration After Widespread Power Outage, is a new statute that was added during the last legislative session as a result of the passage of and Governor Abbott signing House Bill ("HB") 2438.

Q. PLEASE DESCRIBE SECTION 39.918.

A. The new statute relates to situations in which there is a widespread power outage that results in a risk to public safety and a loss of electric power for a significant number of distribution customers that has lasted or is expected to last for at least 8 hours.[1] The law allows a TDU to lease and operate facilities that provide temporary emergency electric energy to help restore electric service to its distribution customers during a widespread power outage, under specific circumstances.[2] The statute requires the TDU to use a competitive bidding process, when reasonably practicable, to lease the facilities.[3] A TDU is also required to include in its emergency operations plan ("EOP") filed with the Commission a detailed plan on the utility's use of those facilities.[4] A TDU that leases and operates these types of facilities is authorized to recover the reasonable and necessary costs of leasing and operating the facilities.[5] A TDU can also defer for recovery in a future rate proceeding the incremental O&M expense and return associated with leasing, ownership or operation of the facilities.[6] Cost recovery may

[1] Tex. Util. Code § 39.918(a).
[2] For CenterPoint Houston, the law applies when there is a widespread power outage and ERCOT has ordered CenterPoint Houston to shed load or when CenterPoint Houston's distribution facilities are not being fully served by the grid under normal operations. Tex. Util. Code § 39.918(b)(1).
[3] Tex. Util. Code § 39.918(f).
[4] Tex. Util. Code § 39.918(g).
[5] Tex. Util. Code § 39.918(h).
[6] Tex. Util. Code § 39.918(i).

occur in a base rate proceeding or in an annual rate mechanism proceeding such as this DCRF proceeding.[7]

Q. DID THE COMPANY LEASE AND OPERATE MOBILE GENERATION FACILITIES DURING THE CALENDAR YEAR ENDED DECEMBER 31, 2021?

A. Yes, and the Company is requesting to recover the costs of leasing and operating those facilities in this proceeding. Specifically, the Company seeks recovery of the lease costs for the mobile generation facilities and the operational costs for transportation, mobilization and demobilization, labor and materials for interconnections, fuel for commissioning, testing and operation, purchase and lease of auxiliary equipment, and labor and materials for operations.

Q. DID CENTERPOINT HOUSTON UPDATE ITS EOP FILED WITH THE COMMISSION ON THE USE OF THE MOBILE GENERATION FACILITIES?

A. Yes. On September 30, 2021, and January 28, 2022, the Company filed with the Commission updates to its EOP, which included information pertaining to the use of these facilities.

III. CENTERPOINT HOUSTON MOBILE GENERATION ACTIVITIES

Q. WHAT PROMPTED CENTERPOINT HOUSTON TO LEASE AND OPERATE MOBILE GENERATION FACILITIES?

A. As Company witness Mr. Tutunjian explains, extreme winter weather in February 2021, including Winter Storm Uri, severely impacted the Company's ability to provide

[7] Tex. Util. Code § 39.918(j).

electric service to customers because the Electric Reliability Council of Texas, Inc. ("ERCOT") declared a statewide emergency and ordered utilities in ERCOT to shed load. At the peak of the severe weather, approximately 48.6% of generation capacity in Texas was not available, and approximately 1.4 million CenterPoint Houston customers were without power at some point during the severe weather. Because the generation shortfall and the resulting load shed were so great, the Company was not able to rotate customer outages in periods less than an hour.

Following Winter Storm Uri, CenterPoint Houston was actively involved in identifying, refining, and developing novel solutions to reduce customer impacts during ERCOT load shed events. In this context, Texas Utilities Code § 39.918 authorized new tools that could be used during widespread outages, including after storm events, to help lessen outage duration for customers during load shed events and to aid in restoration of electric service. At the same time, the California Public Utilities Commission approved the use of portable diesel generators to provide reliable electricity supply during planned public safety power shutoffs in areas with wildfires. CenterPoint Houston learned that a few utilities on the West Coast, including Pacific Gas and Electric Company ("PG&E"), had been utilizing these generators to restore power in response to outages caused by wildfires. The Company contacted PG&E and had discussions to understand the applications and the benefits of these mobile generators. Based on these conversations and from additional research related to these applications, CenterPoint Houston concluded that mobile generation facilities would provide substantial value in improving system resiliency for our customers during restoration and load shed events. This is what prompted us to lease and operate mobile generation facilities.

Q. ARE THERE OTHER AVAILABLE TECHNOLOGIES THAT WOULD IMPROVE SYSTEM RESILIENCY FOR CUSTOMERS IN THE SAME WAY THAT MOBILE GENERATION FACILITIES WILL?

A. No. While there are several technologies available that would improve system resiliency for customers and CenterPoint Houston, none of these operate in the same way or are as effective as mobile generation facilities in restoring power during outages that are expected to last 8 hours or longer. Historically, the Company experienced such power outages during hurricanes and during ERCOT-directed load shed events. Mobile generation facilities offer flexible and proven solutions to help restore power in those situations.

Q. DID CENTERPOINT HOUSTON CONSIDER BATTERY TECHNOLOGY IN THE CONTEXT OF ITS SEARCH FOR SOLUTIONS ON SYSTEM RESILIENCY DURING OUTAGES?

A. Yes. However, technologies such as batteries and other storage solutions can currently only be used for a limited operational duration and batteries cannot generate electricity—they can only store it when power is generated from another source. For these reasons, batteries are not yet ideal or cost-effective in situations where the Company is dealing with widespread power outages due to lack of generation that will last for an unknown length of time. It is possible that battery technology will improve in the coming years and that it will become more cost effective. It simply is not there yet.

Finally, the statute requires that TEEE facilities be operated in isolation from the bulk power system. It is not practical to recharge batteries without access to the bulk power system, which may also not be available during an outage of unknown duration.

Q. IF BATTERY TECHNOLOGY IMPROVES AND BECOMES MORE COST EFFECTIVE, IS IT POSSIBLE THAT THOSE RESOURCES MIGHT ONE DAY PROVIDE THE SERVICE THAT MOBILE GENERATION IS CURRENTLY PROVIDING FOR CENTERPOINT HOUSTON CUSTOMERS?

A. It is possible that battery technology could be part of the solution. One of the benefits of the Company's lease agreement for the mobile generation facilities is that the initial long-term lease term is for seven and a half years. That term allows the Company to continue to evaluate other technologies that may provide emergency response service. Until that time, however, through mobile generation, CenterPoint Houston's customers have a reliability solution that is extremely effective and advantageous in the context of extended outage events.

Q. WHAT DOES CENTERPOINT HOUSTON HOPE TO ACCOMPLISH BY LEASING AND OPERATING MOBILE GENERATION FACILITIES?

A. By leasing and operating mobile generation facilities, CenterPoint Houston hopes to provide a faster response to restore electric power in areas affected by widespread outages and to lessen customer outage duration during ERCOT load shed events. CenterPoint Houston has transmission and distribution facilities that serve major load centers near the Texas Gulf Coast, which frequently experiences storms and hurricanes. The intensity and duration of these storms have often resulted in widespread damage to the Company's distribution facilities, preventing them from delivering power from the bulk power system and taking a considerable amount of time to rebuild facilities and restore power from the bulk power system to our customers. Mobile generation facilities can help restore power sooner to customers while the Company's rebuilding efforts are underway.

The Company also plans to use mobile generation facilities to support multi-feeder load rotation during ERCOT-initiated load shed events. CenterPoint Houston serves approximately 25% of ERCOT load based on summer peak loading conditions, which means that CenterPoint Houston's share of the total load shed in ERCOT is 25%.

Q. ARE THERE ANY UNIQUE CHARACTERISTICS TO CENTERPOINT HOUSTON'S SYSTEM THAT MAKE MOBILE GENERATION PARTICULARLY BENEFICIAL?

A. Yes. A utility's share of the load to be shed during an ERCOT-initiated load shed event is based on the utility's total load percentage during ERCOT's peak load, which also includes load from transmission voltage level customers. Over 20% of CenterPoint Houston's load is from customers served directly from the Company's transmission system, which is higher than other utilities in ERCOT. For environmental and safety reasons, these transmission-connected loads cannot be part of the load shed program. Utilities perform load shedding using loads that can be controlled through load shed programs, which are primarily distribution voltage retail customers. Therefore, to meet its load shed obligation, CenterPoint Houston must shed a larger portion of its distribution voltage retail customers compared to other utilities.

Additionally, during winter events, proximity to the coast drives CenterPoint Houston's total load share in ERCOT to be lower than the summer load share of 25%. Despite this disparity during winter months, CenterPoint Houston is still required to meet the load shed obligation based on the summer load share. For instance, during the Winter Storm Uri load shed event, the load share of CenterPoint Houston reached as low as 16% of the ERCOT system load. Because the Company was required to meet the 25% load shed obligation, this disparity in loads between winter load and summer peak load resulted in an additional burden of 1,800 MW of load that had to be shed.

As the percentage of distribution voltage retail customers remaining connected during a load shed event is reduced, it becomes more challenging to keep customers rotated within the 12-hour time frame set by the Commission at the end of Winter Storm Uri. By utilizing mobile generation facilities, CenterPoint Houston can at least partially meet its load shed obligations during an ERCOT-initiated load shed event by disconnecting some distribution voltage customers from the electric grid and maintain service to these customers from mobile generation facilities, thereby reducing the outage impact and duration on distribution customers that would otherwise be caused by the load shed event.

Q. WHAT ACTIONS HAS THE COMPANY TAKEN WITH REGARD TO MOBILE GENERATION FACILITIES?

A. Soon after HB 2483 was passed by the Legislature in response to Winter Storm Uri, CenterPoint Houston began exploring and developing strategies for the potential use of mobile generation facilities to aid in storm restoration and to enhance load rotation capabilities during ERCOT load shed events. After thorough research, the Company made the decision to secure mobile generation facilities through a competitive bid process. Two requests for proposals ("RFP") were issued, one for a short-term lease and one for a long-term lease. The Company received proposals from multiple vendors, and after review, CenterPoint Houston executed contracts with Life Cycle Power for both short-term and long-term leases, in September and December of 2021, respectively.

Q. WHY DID CENTERPOINT HOUSTON CONTRACT WITH LIFE CYCLE POWER?

A. CenterPoint Houston issued RFPs for both short-term and long-term leases and received multiple proposals for each. In both short-term and long-term leases that the Company pursued, contract decisions were based on the bidders' ability to meet the minimum qualification criteria outlined in the Company's RFPs and the financial impact on its customers.

Life Cycle Power was able to offer the entire generation capacity included in both RFPs and within the required timeframes. In the short-term lease proposals that the Company received, Life Cycle Power was the only bidder that offered to meet the delivery timeline requirements to make the mobile generation facilities available for the 2021 hurricane season. In its long-term lease proposal, Life Cycle Power also offered a larger fleet of 30-35 MW and 5 MW mobile generation units and offered to make the entire leased capacity dual-fuel capable. Life Cycle Power proposed these options at competitive pricing and the prepayment option it included made it financially favorable to our customers compared to other proposals the Company received. Other proposals did not meet the requirements of the RFP terms including total capacity or dual-fuel capability.

Q. WHY DID CENTERPOINT HOUSTON EXECUTE BOTH A SHORT-TERM AND A LONG-TERM LEASE?

A. The main purpose of the short-term lease was to have the mobile generation facilities available during the 2021 hurricane season, which turned out to be necessary. CenterPoint Houston successfully deployed one of the leased generators to aid restoration efforts following Hurricane Nicholas. The short-term lease was amended to include extension of the lease term into the 2022 winter months to ensure the generators were available for the winter season when there is a higher probability of lower generation reserves in ERCOT. The amendment is also included in the highly sensitive short-term lease contract attached to my testimony as Exhibit MWN-1.

The long-term lease was aimed at procuring multiple mobile generation facilities with gross nameplate capacity of approximately 500 MW to be available to use year-round during widespread outages. The Company plans to use these mobile generation facilities to aid in storm restorations and to enhance load rotation during load-shed events.

Q. ARE THERE ANY OTHER REASONS AS TO WHY THE COMPANY ENTERED INTO A LEASE AGREEMENT IN SEPTEMBER 2021?

A. Yes, in addition to wanting to have mobile generation facilities available during the 2021 hurricane season, in the event of a natural disaster in the Company's service area causing widespread outages on the distribution system, between the time the Legislature passed HB 2483 and the statute going into effect on September 1, 2021, the

Company had been monitoring industry trends around the nation on the availability and use of temporary generating facilities. Trends were showing less availability of mobile generation facilities following wildfire incidents along the upper west coast, and California Governor Newsom's emergency proclamation. Additionally, Hurricane Ida struck the Louisiana coast in August 2021, and as the restoration took longer than anticipated, other utilities and industries were starting to secure temporary generators to provide power to their customers while their restoration efforts were underway. CenterPoint Houston was concerned with the increasingly limited supply of available mobile generation resources and began the process of securing these facilities without further delay.

Q. PLEASE GENERALLY DESCRIBE THE RFP PROCESS AND DECISION TO ENTER INTO A SHORT-TERM CONTRACT WITH LIFE CYCLE POWER.

A. CenterPoint Houston began the process of requesting proposals for the short-term contract in August 2021. An RFP for eight mobile generation facilities, five with approximately 5 MW nameplate capacity and three with approximately 32 MW nameplate capacity, was issued on August 3, 2021. CenterPoint Houston received proposals from three bidders. As I noted above, after reviewing the proposals, Life Cycle Power was selected based on the material offerings, operational support and lease cost included in the proposal. A two-month contract was signed with Life Cycle Power on September 1, 2021, with the option to extend the contract monthly. The contract term included five SMT60 turbines and three GE TM2500 turbines. A copy of the Highly Sensitive short-term lease contract is attached to my testimony as Exhibit MWN-1.

Q. HOW DID THE COMPANY DETERMINE THE NUMBER OF MEGAWATTS AND FACILITIES IT NEEDED TO PROCURE THROUGH THE SHORT-TERM LEASE?

A. Following Winter Storm Uri, CenterPoint Houston was engaged in identifying solutions to improve system resiliency. In its assessments, the Company identified that having approximately 500 MW of mobile generation facilities, which along with other options the Company is pursuing, would have been sufficient to meet the load shed demands caused by Winter Storm Uri. Based on our research on market availability, procuring a total of 125-130 MW of mobile generation capacity seemed feasible and would meet the immediate need to prepare for 2021 hurricane season. Hence, the decisions on total amount of Megawatts and number of facilities the Company needed to procure through the short-term lease were primarily driven by the amount of capacity the Company determined it needed and the market availability of mobile generation facilities at the time.

Q. PLEASE DESCRIBE THE RFP PROCESS AND LONG-TERM CONTRACT WITH LIFE CYCLE POWER.

A. CenterPoint Houston also began the process of requesting proposals for the long-term contract in September 2021. An RFP for mobile generation facilities with a gross nameplate capacity of approximately 500 MW was issued on October 4, 2021. The Company received proposals from three bidders. As I explained previously, after reviewing the proposals, Life Cycle Power was selected based on the material offerings, operational support and lease cost included in the proposal. The Company signed a contract with Life Cycle Power on December 31, 2021, to lease mobile generation facilities until June 30, 2029. A copy of the highly sensitive long-term lease contract is attached to my testimony as Exhibit MWN-2.

Q. WHY DOES THE LONG-TERM LEASE EXPIRE ON JUNE 30, 2029?

A. The long-term lease expiration date on June 30, 2029, is based on a seven and half year lease agreement. This lease option offered additional financial discounts compared to the five-year option that was offered. There is also a provision to extend the lease term until September 1, 2029, if needed. This lease term conforms with the validity of Texas Utilities Code § 39.918, which is set to expire on September 1, 2029.

Q. DOES THE LONG-TERM LEASE CONTAIN ANY PRICING PROVISIONS THAT AFFECT THE COSTS THE COMPANY MUST PAY?

A. Yes. In the proposal for the long-term lease, Life Cycle Power offered a seven-and-a-half-year option as an alternative to the minimum five-year option that was included in the RFP. Life Cycle Power also included discounted rates for prepayment in the long-term lease, which further reduced the annualized lease cost. The prepayment option will result in a total savings of over 24% to the customers.

Q. WHERE ARE CENTERPOINT HOUSTON'S MOBILE GENERATION FACILITIES LOCATED?

A. CenterPoint Houston's mobile generation facilities are located inside certain Company distribution substations across its service territory. Current locations of mobile generating facilities are shown in the document attached to my testimony as Exhibit MWN-3.

Q. WHY ARE THE FACILITIES IN THOSE LOCATIONS?

A. The mobile generation facilities are located inside distribution substations to allow a faster response to load shed events. The larger, approximately 32 MW facilities require assembly, which can take up to 48 hours. These facilities also require permits to be transported from one location to another. If these facilities are needed during adverse weather conditions like Winter Storm Uri, transportation will be challenging as well. Having these facilities strategically pre-positioned, already assembled, and connected to our distribution substation in a ready state will reduce the time it takes to have the generators warmed up and ready to serve customer load. Locations were chosen based on available space, accessibility, available load, and ease of interconnection to have the mobile generation facilities connected and available for 2021-2022 emergency preparedness. However, should the need arise, the mobile generation facilities are mobile units and can be relocated as operating conditions, road conditions, and other safety considerations permit.

Q. PLEASE DESCRIBE THE APPROXIMATELY 32 MW MOBILE GENERATION FACILITY.

A. CenterPoint Houston reviewed multiple varieties of generators and selected the GE TM2500 and the Mitsubishi FT8 MobilePAC aeroderivative gas turbine generators as the preferred generators to secure for emergency use. These packages were selected due to the reliability of the engine, versatility, and ability to operate on a wide variety of fuels including both gaseous and liquid. The generators also offer enhancements such as trailer mounted design that aid in faster installations during an emergency and ease of transportation. The generators offer higher amounts of power per footprint area needed to operate compared to other generators of its class. The generator occupies approximately 75 feet by 25 feet with a height of 13 feet. In addition, these generators operate at the frequency of the ERCOT grid and CenterPoint Houston's 12.47 kilovolt ("kV") distribution system. Pictures of this facility are included in the document attached to my testimony as Exhibit MWN-3.

Q. PLEASE DESCRIBE THE SOLARTURBINE SMT60 FACILITY.

A. CenterPoint Houston reviewed several options from vendors offering generators in the 5 MW class and selected the SolarTurbine SMT60 generator as an additional resource for emergency use. The SMT60 generator is a single trailer design that can operate on gaseous and liquid fuels. The unit has a footprint of 56 feet by 8 feet 6 inches. This unit was selected due to its small footprint and rapid deployment time. In addition, this generator operates at the frequency of the ERCOT grid and CenterPoint Houston's 12.47 kV distribution system. Pictures of this facility are included in the document attached to my testimony as Exhibit MWN-3.

Q. OPERATIONALLY, HOW DO THE MOBILE GENERATION FACILITIES WORK WITH CENTERPOINT HOUSTON'S EXISTING TRANSMISSION AND DISTRIBUTION SYSTEM?

A. Texas Utilities Code § 39.918 requires mobile generation facilities to be operated in isolation from the bulk power system. When connected to the mobile generation facilities, CenterPoint Houston's distribution feeders and substation buses will be isolated from CenterPoint Houston's transmission system. Currently, all leased CenterPoint Houston facilities have a terminal voltage of 12.47 kV. The mobile generation facilities will be connected to the Company's 12.47 kV distribution system, either inside or outside a substation depending on the type of application. The Company is also working on procuring step-up transformers that allow connection of mobile generation facilities to its 34.5 kV distribution system.

Q. HAS CENTERPOINT HOUSTON PROVIDED SERVICE TO CUSTOMERS USING THE LEASED FACILITIES?

A. Yes. As Company witness Mr. Tutunjian explains, Hurricane Nicholas made landfall along the Texas Gulf Coast on the night of September 13, 2021 and caused damage to several of CenterPoint Houston's distribution facilities near the City of Lake Jackson and the surrounding Matagorda County areas resulting in widespread power outages. The Lake Jackson Civic Center, which served as a center for cooling, electronic recharging, and water distribution for residents, was also without power. While assessing damage, CenterPoint Houston became aware that it might take longer than 48 hours to restore power to the civic center. After discussions with the City of Lake Jackson, the Company deployed a mobile generation facility to this location on September 15th to restore power. Power to the civic center was restored on the same day using the mobile generation facility, and the mobile generation facility remained in operation for approximately 70 hours.[8]

Q. HAS THE COMPANY EXPERIENCED PRIOR POWER OUTAGES OR LOAD SHED EVENTS DURING WHICH IT WOULD HAVE BEEN HELPFUL TO HAVE ACCESS TO MOBILE GENERATION?

A. Yes. There have been four ERCOT load-shed events since 1989 and the most recent one was on February 15, 2021, during Winter Storm Uri. This load-shed event was

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[8] A local Houston news outlet documented the deployment. Video from the event and documentation can be found at: https://www.khou.com/article/news/local/after-hurricane-nicholas-thousands-still-without-power-houston-area/285-edfeb51f-f64e-47ad-ad31-106a3225c2b3.

triggered due to generation shortages that occurred following Winter Storm Uri and is the largest load-shed event in ERCOT's history. CenterPoint Houston was required to shed close to 5,000 MW of load, which exceeded the Company's automated load rotation capabilities. CenterPoint Houston had to resort to manual switching to meet this load-shed obligation and to keep distribution customers adequately rotated. If CenterPoint Houston had mobile generation facilities during this event, it would have allowed additional load to be rotated thereby reducing the outage duration for affected customers.

Q. DESCRIBE THE STRATEGY THE COMPANY DEVELOPED TO DEPLOY THESE RESOURCES DURING LOAD-SHED EVENTS.

A. Load shed events can have significant impacts, as evidenced by Winter Storm Uri, and these events can be unpredictable. CenterPoint Houston has developed strategies to have mobile generation facilities available and ready to be deployed rapidly. All leased mobile generation facilities are located inside certain CenterPoint Houston's distribution substations and will be connected to distribution buses or feeders. Diesel or compressed natural gas tankers are also located on-site and connected to mobile generation facilities, which allows for a continuous operation of six hours or longer before refueling is needed. All the feeders that are planned to be connected to the mobile generation facilities during load shed events have been identified. Procedures required to perform switching to start up the mobile generation facilities, to connect feeders, and for refueling have also been developed. We have also identified all internal stakeholders who need to be engaged during the deployment of mobile generation facilities. When lower generation reserves are anticipated in the ERCOT region, and there is a potential for load shedding, CenterPoint Houston will notify the mobile generation facility operator to begin the warm-up process and perform necessary pre-deployment checks. Internal stakeholders will also be engaged to make necessary preparations including dispatching crews, performing pre-deployment switching, sourcing fuel, and other necessary pre-operational activities. Once load shed is imminent, CenterPoint Houston will confirm that conditions are appropriate for use of the mobile generation facilities. When directed by ERCOT to perform load shedding, the Company will notify operators to start up mobile generation facilities and begin serving load from the facilities. If the total amount of load that CenterPoint Houston is directed to shed is more than the gross capacity of the mobile generation facilities, load rotation will be performed in conjunction with CenterPoint Houston's automated load shed program. This will allow the Company to meet its load shed obligations while minimizing customer outage duration.

Q. HOW MANY OF THESE MOBILE GENERATION FACILITIES WERE IN PLACE AS OF DECEMBER 31, 2021?

A. CenterPoint Houston had nineteen mobile generation facilities in place as of December 31, 2021. These include ten SMT60 turbines with a nameplate capacity of approximately 5 MW, seven GE TM2500 turbines with a nameplate capacity of approximately 32 MW and two FT8 turbines with a nameplate capacity of approximately 32 MW. The total gross capacity of mobile generation facilities in place was approximately 345 MW.

Q. ARE THERE ANY SPECIAL CONSIDERATIONS TO IMPLEMENT THESE RESOURCES TO HELP LOCAL MUNICIPALITIES AND OTHER AGENCIES?

A. CenterPoint Houston's Regulatory and Government Relations team works with cities and counties in CenterPoint Houston's service territory to identity areas and communities that are impacted during storm events, including key locations such as cooling and warming centers and distribution facilities. The deployment of temporary emergency generation at the Lake Jackson Civic Center on September 15, 2021, was a coordinated effort between CenterPoint Houston and the City of Lake Jackson. This facility is a designated cooling and warming center for the City of Lake Jackson residents and the city had planned to use the facility as a distribution center following Hurricane Nicholas. Deployment of the mobile generation facilities at the Lake Jackson Civic Center restored power to allow use of the facility by the residents and for distribution of water and other necessities.

In addition, the City of Houston has launched several initiatives following Winter Storm Uri to prepare for future disasters. CNP has created a "Resilient Now" team to partner with the City of Houston in supporting these initiatives. One such initiative, Complete Communities, which is focused on bridging the gap between equity and opportunity, has identified 10 historically under-resourced neighborhoods. My team, which is leading the deployment of temporary emergency generation facilities, has been working with the Resilient Now team to identify and target these locations as part of our future deployment strategies to limit outage duration in the future.

Q. WHAT TYPES OF COSTS DID CENTERPOINT HOUSTON INCUR FOR THE MOBILE GENERATION FACILITIES?

A. The costs incurred for mobile generation facilities include costs of leasing the facilities, transporting, mobilizing, and demobilizing the facilities, fuel needed for commissioning, operating and readying the mobile generation generators, labor and materials needed for interconnecting the facilities, making prepayments under the leases and related costs. CenterPoint Houston also incurred costs for providing security for the sites during mobilization, demobilization, and operation of the turbines.

Q. ARE THE COSTS REASONABLE AND NECESSARY?

A. Yes. The costs associated with the lease and operation of mobile generation facilities are reasonable and necessary to assist in mitigating outage impacts to CenterPoint Houston customers. The mobile generation assets authorized by the new law provide the Company with additional flexibility to serve our customers in the event of a widespread outage. After going through the competitive bid process, the Company was in possession of all the pertinent information to make an informed decision to have secured mobile generation facilities for emergency preparedness. CenterPoint Houston customers benefit from the investment in these assets and CenterPoint Houston was able to demonstrate the benefit during the aftermath of Hurricane Nicholas by providing temporary power to the Lack Jackson Civic Center.

Electric power is an indispensable resource to customers for meeting basic human needs, such as preparing and maintaining food supplies, heating, cooling, and powering lifesaving medical devices, especially during extreme weather events like Winter Storm Uri. The use of mobile generation facilities will reduce the duration of power outages experienced during ERCOT load shed events by having the facilities connected and ready to be deployed when widespread power outages are anticipated.

Public safety is also CenterPoint Houston's top priority. Our customers' safety and well-being during adverse weather events and generation shortages factored predominately in CenterPoint Houston's decision to secure mobile generation facilities.

Q. ARE THE COSTS ASSOCIATED WITH THE LEASES INCLUDED IN THE COMPANY'S CALCULATION OF ITS REQUESTED DCRF RATE REQUEST?

A. Yes. Company witness Mary A. Kirk addresses the accounting for the costs and related cost recovery schedules in her direct testimony. Company witness John R. Durland addresses the calculation of the DCRF rate in his direct testimony.

Q. DID CENTERPOINT HOUSTON EXCLUDE RETAIL CUSTOMER USAGE DURING THE OPERATION OF THE MOBILE GENERATION FACILITIES (IF APPLICABLE)?

A. Yes. Mr. Durland addresses this issue in his Direct Testimony.

IV. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. CenterPoint Houston's strategy to lease and operate mobile generation facilities in 2021 and for future years is reasonable and necessary to improve resiliency of its distribution system, to aid restoration efforts following widespread outages and to enhance load rotation capabilities during ERCOT directed load shed events. The Legislature wanted TDUs like CenterPoint Houston to have this "tool in its toolbox" when it considered and passed Texas Utilities Code § 39.918. CenterPoint Houston spent a considerable amount of time researching and understanding the benefits temporary generation offers to its customers and engaged in a competitive bid process to select cost-effective options for leasing mobile generation facilities. CenterPoint Houston executed both short-term and long-term contracts to procure these facilities in 2021 and beyond and has successfully demonstrated the use and value these units provide in restoring power to customers. My testimony demonstrates that CenterPoint Houston has made a well-informed decision in procuring mobile generation facilities and developed strategies to utilize these effectively in multiple ways, as permitted by the statute, to improve the quality of service for our customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT MWN-1 (HSPM)

HIGHLY SENSITIVE PROTECTED MATERIALS WILL BE PROVIDED UPON EXECUTION OF A PROTECTIVE ORDER CERTIFICATION

EXHIBIT MWN-2 (HSPM)

HIGHLY SENSITIVE PROTECTED MATERIALS WILL BE PROVIDED UPON EXECUTION OF A PROTECTIVE ORDER CERTIFICATION

Focusing on our core utility businesses

Mobile Generation Facilities

CenterPoint Energy

Deployed Generators

Natural Gas
12.47kV

GE TM2500 Gen 6 ~32MW
Liquid Fuel or Natural Gas
12.47kV

Deployed Generators

Mitsubishi FT8 MobilePac ~32 MW
Liquid Fuel or Natural Gas
12.47KV

GE TM2500 Gen 4 ~32MW
Liquid Fuel or Natural Gas
12.47kV

Deployed Generators

GE TM2500 Gen 8 ~32MW
Liquid Fuel or Natural Gas
12.47kV

CenterPoint Energy

SMT60 and Auxiliary Equipment – Lake Jackson Civic Center

SMT60 Connections – Lake Jackson Civic Center

Dead front bushing on generator
Used Standard MUG 15kV 600A connectors

Connection on High-side of Customer's transformer
Used Standard Terminators to connect to the Fuse cutouts.

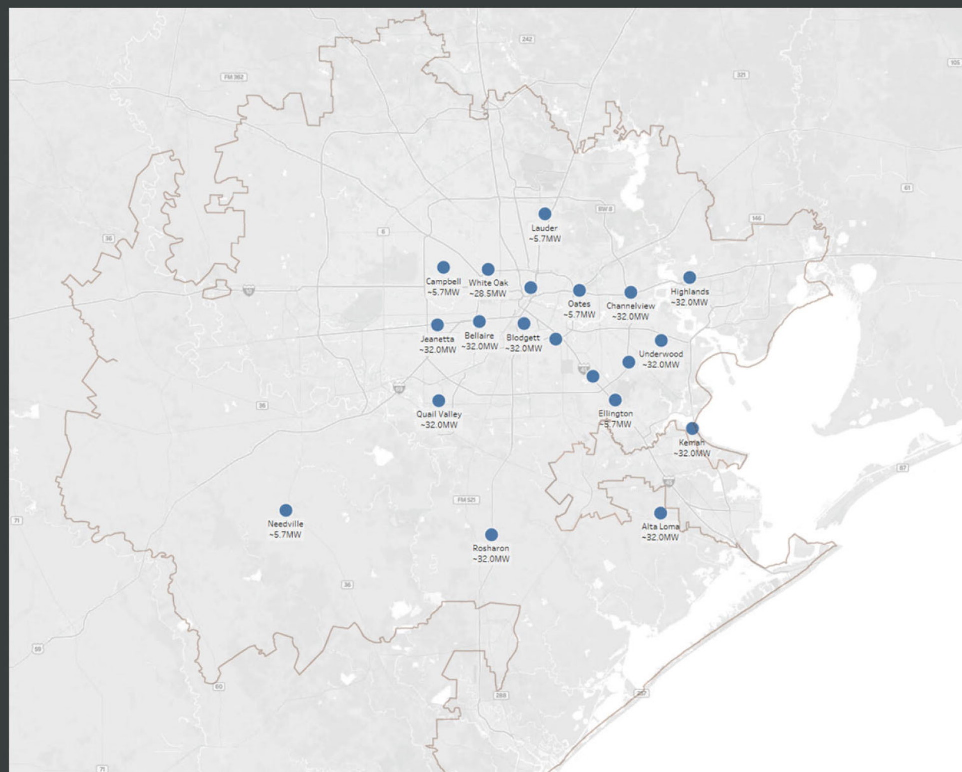
~32 MW Units and Auxiliary Equipment

Substation Connections

Conventional Substation
Install 2000 Amp Switch in open bay position

Low Profile Substation
Use existing 1200 Amp switches
Or
Install new 1200 Amp switches

CNP Generator Deployment Locations



STATE OF TEXAS §
§
COUNTY OF HARRIS §

AFFIDAVIT OF MARTIN W. NARENDORF JR.

BEFORE ME, the undersigned authority, on this day personally appeared Martin W. Narendorf Jr., who being by me first duly sworn, on oath, deposed and said the following:

1. "My name is Martin W. Narendorf Jr. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Electric Engineering and Asset Optimization for CenterPoint Energy Houston Electric, LLC.

2. The foregoing direct testimony and the attached exhibits have been prepared by me or under my direct supervision and are true and correct to the best of my knowledge."

Further affiant sayeth not.

Martin W. Narendorf Jr.
Martin W. Narendorf Jr.

SUBSCRIBED AND SWORN TO BEFORE ME on this 16th day of March, 2022.

Sonia Vela
Notary Public in and for the State of Texas

SONIA VELA
NOTARY ID #1172328-1
My Commission Expires
August 30, 2023

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DOCKET NO. ________

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL TO AMEND ITS DISTRIBUTION COST RECOVERY FACTOR	§ § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY OF

MARY A. KIRK

FOR

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

April 5, 2022

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Exhibits	Descriptions
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Exhibit MAK-04	Construction Overhead Policy
Exhibit MAK-05	Mobile Generation Accounting
Exhibit MAK-06	Carrying Cost Recognition Comparison

Workpapers	Descriptions
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WP Cloud Computing	Calculation of Cloud Computing Costs
WP Wood Pole Treatment	Calculation of Capitalized Wood Pole Treatment
WP Administrative and General Overhead	Calculation of Change in Administrative and General Overhead

GLOSSARY OF ACRONYMS

ADFIT	Accumulated Deferred Federal Income Taxes
A&G OH	Administrative and General Overhead
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CERC	CenterPoint Energy Resources Corp.
CFR	Code of Federal Regulations
CNP	CenterPoint Energy, Inc.
COGS	Cost of Goods Sold
DCRF	Distribution Cost Recovery Factor

EDIT	Excess Deferred Income Taxes
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
MW	Megawatt
PUCT	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
RFP	Rate Filing Package
SMI	Substantially Minor Item
SOX	Sarbanes-Oxley
TAC	Texas Admin Code
TCOS	Transmission Cost of Service
TDU	Transmission and Distribution Utility
TMT	Texas Margin Tax
USOA	Uniform System of Accounts

DIRECT TESTIMONY OF MARY A. KIRK

I. POSITION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME, POSITION, AND BUSINESS ADDRESS?

A. My name is Mary A. Kirk. I am Director Accounting for CenterPoint Energy Service Company, LLC ("CenterPoint Energy"). My business address is 1111 Louisiana Street, Houston, Texas 77002.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND, AS WELL AS YOUR BUSINESS AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Houston-Clear Lake with a Bachelor of Science degree in Accounting. I began my career at CenterPoint Energy, Inc. ("CNP") and its predecessors in 1991. I began my role as Manager of Business Services in October 2006 and was promoted to Division Director in 2007. In April 2009, I became Finance Director of Gas Reporting and Performance for CNP, and in July 2012 I became Director of Financial Accounting for CenterPoint Energy. On January 1, 2022, I became Director Accounting and began to transition the responsibilities of Director of Financial Accounting to my replacement. I am a Certified Public Accountant in the State of Texas.

Q. WHAT WERE YOUR PRIOR RESPONSIBILITIES AS DIRECTOR OF FINANCIAL ACCOUNTING FOR CENTERPOINT ENERGY?

A. As Director of Financial Accounting for CenterPoint Energy until December 31, 2021, I was responsible for the accounting books and records of CNP's regulated gas and electric businesses in the States of Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas, including financial accounting for gas and electric, regulatory reporting, and gas cost accounting for these business units. As such, I was responsible for ensuring that CNP has adequate staff, processes and systems in place to meet its financial and regulatory accounting and reporting requirements for the jurisdictions within the aforementioned states. In addition, I was responsible for the adequacy of certain internal controls including compliance with §404 of the Sarbanes-Oxley Act of 2002 ("SOX") as it relates to CNP's regulated operations. These issues were my responsibility during the years (2019, 2020 and 2021) that are the subject of this filing.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company"), which is an electric distribution service provider in the Electric Reliability Council of Texas, Inc. region.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS OR OTHER REGULATORY AUTHORITIES?

A. Yes. I have presented testimony before the Public Utility Commission of Texas ("PUCT" or "Commission") on behalf of CenterPoint Houston, including in prior DCRF filings. I have also presented testimony on behalf of CenterPoint Energy Resources Corp. ("CERC") in various gas distribution jurisdictions in numerous proceedings before the Arkansas Public Service Commission, the Railroad Commission of Texas, and the Minnesota Public Utilities Commission. In addition, I have supervised the compilation of accounting information used for periodic reporting requirements and various rate and regulatory proceedings before public utility commissions in the states of Arkansas, Louisiana, Oklahoma, Minnesota, Mississippi and Texas.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to support the Company's application for approval of the Distribution Cost Recovery Factor ("DCRF") Rider[1] pursuant to Public Utility Regulatory Act ("PURA") §36.210 and 16 Texas Administrative Code ("TAC") §25.243 I. Specifically, my testimony presents the Company's revenue requirement and all supporting schedules and calculations, with the exception of Schedules H and J, required by the Commission's Distribution Cost Recovery Factor Filing Package ("DCRF-RFP") instructions. In addition, my testimony and the direct testimony of Company witnesses Martin W. Narendorf Jr. and John R. Durland will address the inclusion of amounts for the temporary emergency electric energy facilities, which I refer to as "mobile generation" facilities. Cost recovery for mobile generation facilities in the Company's DCRF request is authorized under Texas House Bill 2483 ("H.B. 2483"), which when enacted became PURA §39.918. Please see Exhibit MAK-01 for a copy of H.B. 2483. My testimony also discusses the internal controls and procedures the Company uses to ensure only eligible costs are included in this filing. My testimony, in conjunction with the direct testimony provided by Company witnesses Brad A. Tutunjian and Mr. Durland, establishes that this filing complies

[1] Tariff for Retail Delivery Service 6.1.16.13 Rider DCRF – Distribution Cost Recovery Factor (April 23, 2020).

with PURA §§36.210 and 39.918, 16 TAC §25.243 and the Commission's DCRF-RFP instructions. My testimony also addresses rate case expenses the Company has incurred in this case, as well as a proposal for the recovery of those expenses and any municipal rate case expenses.

Q. HAS THE COMPANY FILED A DCRF APPLICATION SINCE ITS LAST BASE RATE PROCEEDING?

A. No. As part of the settlement agreement approved by the Commission in Docket No. 49421 (the "49421 Settlement Agreement"),[2] the Company's last base rate proceeding, the Company agreed not to file a DCRF application during the 2020 calendar year.[3] The Company also did not file a DCRF application in 2021. Please refer to the direct testimony of Mr. Durland for a list of previous DCRF cases filed prior to Docket No. 49421.

Q. PLEASE GIVE A BRIEF DESCRIPTION OF THE SCOPE OF THE CURRENT DCRF APPLICATION.

A. The Company's DCRF application reflects the impact of the additions and retirements of distribution facilities on the Company's distribution rate base amount since December 31, 2018, which is the end of the test year in Docket No. 49421, the Company's most recent base rate case.[4] The final order in Docket No. 49421 set the Company's DCRF baseline distribution rate base balance at the value set forth in Exhibit I to the 49421 Settlement Agreement, which is $3,849,401,115.[5] In

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[2] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,* Docket No. 49421, Order (March 9, 2020). The 49421 Settlement Agreement can be found on the Commission's Interchange Filing Search for Docket No. 49421 at item no. 785.
[3] Docket No. 49421, Order at Findings of Fact 126.
[4] Docket No. 49421 Order at Findings of Fact 7.
[5] See Docket No. 49421, Order at Ordering Paragraph 9, and 49421 Settlement Agreement Exhibit I.

addition, the DCRF application includes the Company's request for recovery of amounts incurred under PURA §39.918 related to the Company's incurred costs and investments in mobile generation facilities.

Q. WHAT IS THE INVESTMENT PERIOD IN THE CURRENT DCRF APPLICATION?

A. The current DCRF application investment period is January 1, 2019 through December 31, 2021.

Q. WHAT DCRF-RFP SCHEDULES ARE YOU SPONSORING IN THE CURRENT DCRF APPLICATION?

A. I am sponsoring the following DCRF-RFP schedules and the associated supporting workpapers and a new schedule and associated workpapers the Company created for Excess Deferred Income Taxes ("EDIT") and the mobile generation program:

Schedule A	Summary of Distribution Cost of Service (DCOS)
Schedule B	Summary of Distribution Rate Base
Schedule B-1	Distribution Plant-Gross
Schedule B-5	Distribution Accumulated Depreciation
Schedule B-7	Distribution Accumulated Deferred Federal Income Taxes (ADFIT)
Schedule E-1	Distribution Depreciation Expense
Schedule E-2	Distribution Taxes Other than Income Taxes
Schedule E-3	Distribution Federal Income Taxes
Schedule E-3.7	Plant-Related Accumulated Deferred Federal Income Tax (ADFIT) Balances
Schedule E-3.10	Distribution Plant Accumulated Deferred Federal Income Tax (ADFIT) Change
Schedule E-3.11	Distribution Plant Excess Deferred Income Tax (EDIT) Reg Asset/Liability Change
Schedule K	Annual Earnings Report for the Twelve Months Ended December 31, 2021
Schedule Mobile Generation	Mobile Generation Program

Company witness Mr. John Durland sponsors Schedules H and J of the Company's DCRF-RFP along with associated workpapers.

III. REQUIREMENTS OF DCRF APPLICATION

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 1 OF THE DCRF-RFP, IS THE INFORMATION PROVIDED TAKEN FROM THE COMPANY'S ACCOUNTS AND RECORDS PRESCRIBED IN THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") CHART OF ACCOUNTS?

A. Yes. The information submitted in this filing is taken from the Company's books and records that are maintained according to the FERC Electric Uniform System of Accounts ("FERC USOA").

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 2, DOES YOUR TESTIMONY SUPPORT THE REQUIRED SCHEDULES AND WORKPAPERS?

A. Yes. My testimony supports and adopts the required schedules and workpapers of the DCRF-RFP that I sponsor. I also sponsor additional schedules and workpapers for EDIT and costs incurred for mobile generation facilities under PURA §39.918.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 2, ARE YOUR SCHEDULES AND WORKPAPERS PROVIDED IN NATIVE ELECTRONIC FORMAT INCLUDING ACTIVE EXCEL WORKBOOKS AND ALL LINKED WORKBOOKS, WITH ALL FORMULAS, CELL REFERENCES, LINKS, AND RELATED ITEMS INTACT, FUNCTIONING, AND COMPLETE?

A. Yes those items are intact, functioning and complete, except where Excel data was derived from a non-Excel source and was directly entered into the Excel spreadsheet. These values have been highlighted and sourced in the Excel workpapers. Otherwise, all workbooks are "active" as described in General Instruction No. 2.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 3, ARE THE COSTS AND RETURN CALCULATED IN COMPLIANCE WITH 16 TAC §25.243 AND PURA §39.918?

A. Yes, only the costs and return that are eligible for recovery under 16 TAC §25.243 and PURA §39.918 have been included in the calculation of the Company's proposed DCRF rates.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, HAVE THE SCHEDULES BEEN PREPARED AS NOTED IN THE DCRF-RFP SAMPLE FORMS?

A. Yes, the schedules have been prepared consistent with the DCRF-RFP sample forms, with the exception that some schedules have been modified for Company specifics consistent with modifications the Company has made in prior DCRF filings and for the addition of the mobile generation revenue requirement amount to Schedule A. As previously stated, all schedules and workpapers are provided in native electronic format including active Excel workbooks and all linked workbooks, with all formulas, cell references, links and related information intact, functioning, and complete.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, NOTES 1 AND 2, HAVE WORKPAPERS BEEN PROVIDED FOR THE ADDITIONS, RETIREMENTS, AND OTHER ADJUSTMENTS FOR EACH YEAR BY FERC ACCOUNT?

A. Yes. Additions, retirements, and other adjustments by year and by FERC account are shown in WP/Schedule B-1.1 and WP/Schedule B-5.1.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, NOTE 1, HAVE INDIRECT CORPORATE COSTS AND CAPITALIZED O&M COSTS BEEN EXCLUDED FROM THE DCRF APPLICATION?

A. Yes. In accordance with 16 TAC §25.243(b)(3), the Company has excluded indirect corporate costs and capitalized O&M costs from this DCRF Application. The Company does not assign indirect corporate costs to capital projects. Rather, the Company only capitalizes corporate costs directly associated with capital projects. Because there are no indirect corporate costs assigned to capital projects, no specific adjustments to exclude such costs was needed to the capital investment included in the DCRF application. The Company has also excluded any generation-related costs (except those for mobile generation costs authorized under H.B. 2483), transmission-related costs, and any distribution invested capital recovered through a separate surcharge, tracker, rider, or other mechanism.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, NOTE 2, HAVE ANY AMOUNTS RECORDED TO NON-DISTRIBUTION ACCOUNTS (FERC 303, 352, 353, 391, AND 397) BEEN INCLUDED IN THE DCRF APPLICATION?

A. Yes. The Company has included only distribution-related amounts that have been recorded in these non-distribution FERC accounts in accordance with 16 TAC §25.243(b)(3).

Q. HOW WERE AMOUNTS IN THE NON-DISTRIBUTION FERC ACCOUNTS DETERMINED TO BE DISTRIBUTION-RELATED?

A. Mr. Tutunjian in his direct testimony addresses the determination of distribution-related projects and costs included in the Company's DCRF application.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, NOTE 3, HAVE WORKPAPERS BEEN PROVIDED TO SUPPORT THE ALLOCATION METHODS USED TO DERIVE THE AMOUNTS INCLUDED IN THE REVENUE REQUIREMENT?

A. Yes. Where applicable, the schedule workpapers support allocations used within the calculation of the revenue requirement.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 5, NOTE 4, HAS THE COMPANY'S MOST RECENT ANNUAL EARNINGS REPORT, PURSUANT TO 16 TAC §25.73(b), BEEN PROVIDED?

A. Yes. The Company has prepared the most recent annual earnings report for the calendar year ended December 31, 2021, in accordance with 16 TAC §25.73(b) and attached as Schedule K. The annual earnings report, any proposed adjustments, updates, and workpapers have been provided in Excel format with all workbooks and all linked workbooks having all formulas, cell references, links and related information intact, functioning, and complete.

Q. WITH RESPECT TO THE ANNUAL EARNINGS REPORT FOR THE CALENDAR YEAR ENDED DECEMBER 31, 2021, IS THE COMPANY EARNING MORE THAN ITS AUTHORIZED RATE OF RETURN USING WEATHER-NORMALIZED DATA, PURSUANT TO 16 TAC §25.243(e)(4)?

A. No. As shown on the attached Schedule K (at Schedule III, Column (3), Line 35) the Company has calculated a rate of return using weather-normalized data of 5.53%, which is below the authorized rate of return of 6.51% established in the Company's last rate case.[6]

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 6, DO THE AMOUNTS APPROVED IN THE COMPANY'S LAST COMPREHENSIVE BASE-RATE PROCEEDING CORRESPOND TO THE AMOUNTS IN THE FIRST COLUMN IN YOUR SPONSORED SCHEDULES OF THE DCRF-RFP?

A. Yes. The amounts in column (1) of my sponsored schedules begin with the amounts set forth in Exhibit I to the 49421 Settlement Agreement (DCRF Baseline Rate Case Values) and approved in Docket No. 49421.[7] Consistent with the DCRF-RFP general instructions, Schedule E-3.7, which is the Company total year-end book balance for Accumulated Deferred Federal Income Tax ("ADFIT"), has been updated.

Q. PLEASE DESCRIBE ANY DIFFERENCES BETWEEN COLUMN (1) OF THE PRESCRIBED SCHEDULES AND THE APPROVED AMOUNTS FROM DOCKET NO. 49421, EXHIBIT I.

[6] Docket No. 49421, Order Finding of Fact 60.
[7] Docket No. 49421, Order at Ordering Paragraph 9.

A. Intangible plant assets in FERC 303.02 asset class utilize the four different depreciation rates for intangible plant assets set forth in Exhibit F to the 49421 Settlement Agreement.[8] The different depreciation rates are the result of different asset lives within the asset class. This breakout was not represented on Exhibit I to the 49421 Settlement Agreement. The breakout of FERC asset class 303.02 by its asset lives does not alter the 49421 Settlement Agreement Exhibit I baseline results that were approved in Docket No. 49421. FERC 303.02 has been separated by these four different depreciation rates on Schedule B-1, B-5 and E-1.

Q. IN REFERENCE TO GENERAL INSTRUCTION NO. 7, HAS THE COMPANY PROVIDED A HISTORY OF THE DCRF RATES APPROVED IN PREVIOUS DCRF APPLICATIONS?

A. Yes. In Exhibit JRD-4, Mr. Durland provides the proposed rates within this DCRF application and a history of the DCRF rates previously approved by the Commission. This is the first DCRF application since the Company's last comprehensive base-rate proceeding in Docket No. 49421.

IV. ELIGIBILITY AND RECORDING OF COSTS

Q. DOES THE COMPANY HAVE ADEQUATE POLICIES AND REVIEW PROCEDURES IN PLACE FOR INVESTMENT THAT IS RECOVERED THROUGH THE DCRF?

A. Yes. As detailed below and in the testimony of Mr. Tutunjian, the Company's processes, controls, and training related to work orders ensure the proper classification of distribution and transmission capital investment.

[8] Docket No. 49421, Order at Ordering Paragraph 6.

Q. HOW DOES THE COMPANY ENSURE THAT TRANSACTIONS ARE PROPERLY RECORDED?

A. The Company maintains a system of internal controls. An internal control is simply a process that is effectuated through written policies and procedures that are followed by management and other personnel. The Company's internal controls with respect to the classification of projects between distribution and transmission investments has two major objectives:

- To ensure that financial statements are fairly presented in conformity with generally accepted accounting principles ("GAAP") and contain no material misstatements, and
- To ensure compliance with applicable laws and regulations, including adherence to SOX.

Q. HOW DO THE COMPANY'S POLICIES DETERMINE WHETHER AN EXPENDITURE SHOULD BE TREATED AS A CAPITAL ASSET OR AS AN EXPENSE?

A. The Company's Capitalization Policy and Capitalization of Computer Software Policy, provided in Exhibit MAK-02, govern whether an expenditure should be treated as a capital addition or an expense. The Capitalization Policies were developed in accordance with FERC instructions on Additions and Retirements of Electric Plant, as seen in Exhibit MAK-03, and GAAP. As noted in the policy itself, the purpose of the Capitalization Policy "is to provide the criteria for expenditure capitalization and addition to the capital base." To this end, the Capitalization Policy addresses the timing of work order completion (Page 1), and defines and explains the policies relevant to retirement units (Page 2), substantial minor items (Page 2), and less than substantial minor items (Page 3). Similarly, the Capitalization Policy explicitly lists the types of investment that may be capitalized, to guide employees when they are making a determination on coding an expenditure as capital or expense (Page 4). In short, the document provides employees with rules governing the accounting treatment of capital assets.

Q. WHICH DEPARTMENT WITHIN THE COMPANY IS CHARGED WITH IMPLEMENTING THE CAPITALIZATION POLICY?

A. Property Accounting is charged with implementing the Capitalization Policy.

Q. HOW DOES THE PROPERTY ACCOUNTING DEPARTMENT ENSURE THE AMOUNTS CODED TO CAPITAL ARE ACCURATELY RECORDED?

A. When field work (memorialized through a work order) is complete, an analysis of the materials charged to the work order takes place. This analysis may be conducted systematically or manually depending on the type of asset being constructed. If a work order is found to lack proper items for capitalization, such as materials, that work order is rejected and must be corrected to move forward through the review process. Pursuant to the Capitalization Policy, retirement units are assigned based on the activity and materials used. Consistent with the FERC USOA, the FERC account assigned to the capital corresponds to the retirement unit.

Q. PLEASE EXPLAIN FURTHER HOW THE ANALYSIS MAY BE SYSTEMATIC OR MANUAL DEPENDING ON THE ASSET CONSTRUCTED.

A. With respect to routine construction activities using stock material, the process is typically automated. Manual processing is required for orders that are associated with large, non-routine projects that utilize special order or non-stock materials. The majority of substation orders are processed manually.

Q. DOES THE COMPANY FOLLOW THE FERC USOA IN RECORDING ITS ELIGIBLE DCRF COSTS?

A. Yes. The DCRF Rule, like all Commission rules related to ratemaking, requires the Company to follow the FERC USOA. The Company maintains its books according to the FERC USOA, its enterprise management software system (SAP) tracks all costs by FERC Account, and only those FERC distribution accounts eligible for recovery through the DCRF are included in the Company's application. These are the same books that are audited by the Company's independent auditor every year, auditing not only the Company's actual costs for the year, but the Company's processes and internal controls as well. These are also the same processes and controls that were in place prior to the Company's last base rate proceeding and have been in place for all investment recovered through Interim Transmission Cost of Service ("Interim TCOS") proceedings since Docket No. 49421.

Q. DOES THE COMPANY ALSO HAVE POLICIES AND PROCEDURES IN PLACE TO ENSURE THAT AMOUNTS ARE PROPERLY ASSIGNED TO TRANSMISSION OR DISTRIBUTION FUNCTIONS?

A. Yes. Mr. Tutunjian's testimony addresses the steps that are taken to ensure that the Company's Transmission and Distribution cost assignment is accurate. In short, internal controls are in place to ensure amounts are properly assigned to transmission or distribution. During the preparation of the DCRF and Interim TCOS applications, the Company analyzes the information for consistency between filings.

Q. DO ANY PROCESSES AND CONTROLS ENSURE THAT WORK ORDERS ARE PROPERLY AND ACCURATELY COMPLETED?

A. Yes. On a monthly basis, testing is performed in accordance with the CEHE Sarbanes Oxley control, "Manage Fixed Assets." The Company's Property Accounting Department randomly selects a sample of capital orders that have been completed, processed, and closed. An accounting analyst then tests each order selected and provides evidence from SAP that the order meets the specifications of being a capital order including the appropriate retirement units.

Q. ARE THE INTERNAL CONTROLS OVER CAPITALIZATION SUBJECT TO REVIEW FOR COMPLIANCE WITH SOX REQUIREMENTS?

A. Yes. Pursuant to those controls, on a quarterly basis, the Company's Property Accounting staff samples the automated capital additions and reviews the sample to ensure that the dollars are capitalized to the appropriate retirement unit.

Q. ARE THE COMPANY'S CAPITAL ADDITIONS AUDITED?

A. Yes. During the Company's annual audit, the external auditors sample and review capital additions and compliance with the Capitalization Policy.

Q. DO THE COMPANY'S EXTERNAL AUDITORS SAMPLE AND REVIEW BOTH DISTRIBUTION AND TRANSMISSION CAPITAL WORK ORDERS?

A. Yes.

V. CALCULATION OF REVENUE REQUIREMENT

Q. PLEASE DESCRIBE THE INCREASE IN DISTRIBUTION RATE BASE ON SCHEDULE B OF THE DCRF-RFP.

A. 16 TAC §25.243(b)(3) describes distribution invested capital as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in FERC accounts 303, 352, 353, 360-374, 391, and 397. Net distribution invested capital is then derived by subtracting associated accumulated reserves and adjusting for distribution-related ADFIT and the protected Excess Deferred Income Tax ("EDIT") Reg Liability. Schedule B shows an incremental increase in net distribution invested capital Total Rate Base of $1,035,567,943, which was calculated by taking the difference between the calculated distribution rate base for the current investment period ending December 31, 2021 as required in the schedules, and the approved distribution rate base in 49421 Settlement Agreement Exhibit I approved in Docket. No. 49421.

Q. PLEASE DISCUSS ANY DIFFERENCES BETWEEN THE DCRF SCHEDULES PRESENTED IN THIS FILING AND THE DCRF-RFP OR 16 TAC § 25.243.

A. As stipulated in the final order of Docket No. 49421, the Company's DCRF application must update its distribution rate base to account for the effects of changes to ADFIT and protected EDIT regulatory liability balances.[9] These changes are shown on Schedule B at lines 13 and 14. There are no differences

[9] Docket No. 49421, Order at Finding of Fact 127.

between the Company's DCRF schedules and the DCRF-RFP or 16 TAC § 25.243 with the exception of the addition of a schedule and amounts related to mobile generation program cost recovery.

Q. WHAT RATE OF RETURN WAS APPLIED TO THE INCREASE IN THE COMPANY'S DISTRIBUTION RATE BASE ON SCHEDULE B?

A. As discussed in the direct testimony of Mr. Durland, the Company is required to use the after-tax rate of return from its last rate case per 16 TAC §25.243(d)(2). Per Docket No. 49421, the after-tax rate of return is 6.51%.[10]

Q. HOW WAS THE RETURN ON INCREMENTAL RATE BASE CALCULATED ON SCHEDULE B?

A. The $1,035,567,943 total incremental increase in distribution rate base compared to the approved distribution rate base in Docket No. 49421 was multiplied by the after-tax rate of return of 6.51% to determine the total incremental return on distribution rate base shown on Schedule B of $67,415,473.

Q. PLEASE DESCRIBE THE INCREMENTAL INCREASE IN DISTRIBUTION COST OF SERVICE SHOWN ON SCHEDULE A.

A. The Company followed the DCRF formula outlined in 16 TAC §25.243(d)(1) in calculating the distribution cost of service on Schedule A. Therefore, per 16 TAC §25.243(d)(1), the following expenses are included in the Company's incremental distribution cost of service on Schedule A:

- Depreciation and amortization, as related to gross distribution invested capital;

[10] *Id.* at Finding of Fact 60.

- Taxes other than income taxes, as related to net distribution invested capital and exclusive of municipal franchise fees, and
- Federal income tax, as related to net distribution invested capital.

The incremental values of these allowable expenses are then combined with the incremental return on distribution rate base, from Schedule B, resulting in the Company's total incremental distribution revenue requirement of $138,518,172 for the investment period covered by this DCRF application prior to the inclusion of the Company's request for recovery of costs related to the mobile generation program.

Q. PLEASE DISCUSS THE INCREMENTAL DEPRECIATION EXPENSE INCLUDED IN THE COMPANY'S DCRF-RFP.

A. The incremental depreciation expense is calculated on Schedule E-1. The depreciation rates approved in Docket No. 49421[11] are shown in column (5). These rates are applied to the incremental increase in gross plant in service attributable to the additions in distribution capital investment.

Q. WERE THERE ANY CAPITAL ADJUSTMENTS FROM THE LAST BASE RATE CASE THAT IMPACT DEPRECIATION EXPENSE?

A. Yes. There have been three types of costs incurred by the Company for which capitalization had been adjusted: costs affected by the accounting policy changes, short-term incentive costs associated with capital projects, and non-qualified pension costs. In order to negate the change in depreciation expense in the sub-FCA

[11] *Id.* at Finding of Fact 113.

accounts, the depreciation expense of this adjustment during the filing period is shown on Schedule E-1, line 35.

Q. PLEASE DISCUSS THE CALCULATION OF PROPERTY TAXES IN THE COMPANY'S DCRF-RFP.

A. The property tax attributable to distribution investment was determined by taking the amount of property tax functionalized to distribution in Docket No. 49421[12] and adding to it the increase in property tax attributable to the net distribution plant additions from January 1, 2019 to December 31, 2021. This increase, calculated by applying a net plant factor to the net plant additions multiplied by the ratio of property tax to net plant from Docket No. 49421, is shown on WP/Schedule E-2.1. The total distribution property tax is presented on Schedule E-2.

Q. WHAT METHOD DOES THE COMPANY UTILIZE FOR CALCULATING THE TEXAS MARGIN TAX ("TMT")?

A. Under the TMT statute (Texas Tax Code § 171.101), an entity may calculate margin in one of the following ways: (1) 70% of total revenue; (2) revenue less $1 million; (3) revenue less Cost of Goods Sold ("COGS"); or (4) revenue less certain employee compensation. The Company utilizes the COGS method.

Q. WHY DID THE COMPANY CHOOSE THE COGS METHODOLOGY IN THE CALCULATION OF ITS MARGIN TAX?

A. Under the TMT statute, the Company is required to be included in the consolidated TMT return with its parent and other member companies of the affiliated group. Each member company included in the consolidated group is required to use the

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[12] *Id.* at Finding of Fact 122.

same method of reducing its taxable revenues. CNP, the parent, elected to reduce its consolidated taxable revenues by COGS. This annual election was applied to all companies in the affiliated group, as required by statute. Because the TMT statute has specifically excluded transportation of electricity as an allowable COGS deduction, these costs are not included in the overall COGS reduction to gross revenue in determining the taxable margin. Therefore, the TMT for the Company is based on total revenues without a reduction for COGS.

Q. IS IT APPROPRIATE TO USE TOTAL REVENUES IN THE CALCULATION OF MARGIN TAX FOR THE DCRF CALCULATION?

A. Yes. Using total revenues in the calculation of the DCRF TMT is consistent with the methodology approved in the Docket No. 49421 baseline amount[13] and outlined in 16 TAC §25.243(d).

Q. DOES THE TREATMENT OF THE TMT IN DOCKET NO. 49421 DICTATE HOW THE TMT IS CALCULATED IN THIS FILING?

A. Yes. Per the final order in Docket No. 49421, the Company is permitted to reflect TMT expense based on the rate applicable in the period that rates are recovered.[14] The current rate is 0.75%.[15]

Q. IS THE COMPANY REQUESTING RECOVERY OF ADDITIONAL COSTS OTHER THAN DISTRIBUTION-RELATED COSTS ON SCHEDULE A?

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[13] Docket No. 49421, Order at Finding of Fact 122.
[14] Docket No. 49421, Order at Finding of Fact 96.
[15] Texas Tax Code, Title 2, Subtitle F, Chapter 171, Section 171.002 Rates; Computation of Tax (a).

A. Yes. Consistent with PURA §39.918, the Company is requesting recovery of mobile generation costs as described below in Section VIII.

VI. <u>CHANGES IN ACCOUNTING RULES OR PRACTICES</u>

Q. WHAT ARE THE REQUIREMENTS IN SUBSECTION (d)(3) OF THE DCRF RULE RELATED TO CHANGES IN ACCOUNTING RULES OR PRACTICES?

A. The electric utility is required to clearly identify any costs included as distribution invested capital resulting from a change in accounting rules or practices since the test year in the electric utility's most recent comprehensive base-rate proceeding.

Q. HAS THE COMPANY MET THESE REQUIREMENTS?

A. Yes. The Company has complied with the requirements in subsection (d)(3) of the DCRF Rule by identifying those accounting changes and calculating the impact in the respective workpaper for each of those changes. I also discuss each of these changes in my testimony.

Q. DID ANY COSTS INCLUDED AS DISTRIBUTION INVESTED CAPITAL RESULT FROM A CHANGE IN ACCOUNTING RULES OR PRACTICES SINCE DOCKET NO. 49421?

A. Yes. The Company performed its annual review of the factors outlined in its capitalization policy to determine if they warrant a change in the accounting for certain costs. The following are accounting changes that are addressed in detail further below:

- 2020 changes
  - Park/In-Town Travel and EZ Tag, and
  - Cloud computing implementation.

- 2021 changes
    - Wood pole treatment to restore the poles to original condition, and
    - Administrative and General Overhead ("A&G OH").

These changes resulted in the inclusion of related costs in distribution invested capital.

Q. PLEASE DISCUSS THE 2020 ACCOUNTING PRACTICE CHANGE RELATED TO PARK/IN-TOWN TRAVEL AND EZ TAG COSTS.

A. Beginning in January 2020, the Company began to capitalize parking, tolls, and mileage for employees who allocate their time to capital work through construction overhead. In addition, EZ tag fees for fleet vehicles are being allocated between expense and capital. Costs will be allocated to construction overhead utilizing the same percentage estimate as employee labor costs. A workpaper filed with my direct testimony, WP Park/In-Town Travel and EZ Tag, identifies approximately $646,953 costs assigned to distribution and included in this DCRF application because of this change.

Q. WHY IS IT REASONABLE TO INCLUDE COSTS FOR PARKING/IN-TOWN TRAVEL AND EZ TAG FEES IN CONSTRUCTION OVERHEAD?

A. Under FERC 18 CFR Part 101, Electric Plant Instructions 4, *Overhead Construction Costs*, a utility is authorized to include overhead costs, such as expenses, applicable to construction as a part of its assets. These accounting changes ensures costs, which are directly related to capital activities, are accounted for in a manner that properly follows that function. This includes the capitalization of construction overhead costs related to employee expenses for parking, tolls, mileage and EZ tag fees, which are costs directly related to managing the day-to-day activities of capital work.

Q. PLEASE DISCUSS THE 2020 ACCOUNTING PRACTICE CHANGE RELATED TO IMPLEMENTATION COSTS FOR CLOUD COMPUTING.

A. In August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-15,[16] Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract effective January 1, 2020. Under ASU 2018-15, companies will apply the guidance for internal use software to determine implementation costs that are recognized as an asset presented in the same line in the GAAP where a prepayment of hosting fees would be presented. Specifically, ASU 2018-15 supports the capitalization of the "implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license)."[17]

Q. PLEASE DISCUSS THE FERC GUIDANCE WITH RESPECT TO ASU 2018-15.

A. The FERC issued Docket No. AI-20-1-000 to provide clarification on how to apply ASU No. 2018-15 within the framework and regulatory intent of FERC's existing accounting requirements. FERC determined that implementation costs related to cloud computing arrangements are similar to costs that are incurred to develop internal-use software and therefore should have similar accounting treatment.

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[16] Accounting Standards Update (ASU) No. 2018-15, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement.*
[17] *Id.* at page 1.

Internal-use software costs have traditionally been capitalized consistent with the requirements of Accounting Standards Codification ("ASC") 350-40 and recorded as a utility plant asset in FERC Account 303 (Miscellaneous Intangible Plant). Furthermore, amortization and depreciation of cloud computing costs should be consistent with the requirements of the utility plant accounts in which they are recorded.[18]

Q. WHAT IS THE IMPACT IN THIS FILING RELATED TO CAPITALIZING CLOUD COMPUTING COSTS?

A. The Company incurred $1,616 of cloud computing costs in 2021 as shown on the workpaper WP Cloud Computing Costs filed with my direct testimony. The Company did not incur any costs related to Cloud Computing Arrangements in 2020. When amounts are incurred that qualify for capitalization, the Company applies the FERC approved treatment for GAAP purposes and capitalizes its cloud computing implementation costs as an intangible asset. Each intangible asset is amortized over the life of the license agreement with consideration of potential license extensions or service elements(s).

Q. PLEASE DISCUSS THE 2021 ACCOUNTING PRACTICE CHANGE RELATED TO WOOD POLE TREATMENT COSTS.

A. In 2020, the Company determined its cyclical pole inspection and treatment program, which involves the application of remedial treatment products designed to effectively restore the pole to its original condition, should be capitalized because it differs from traditional maintenance programs that are a temporary fix and do not

[18] *Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract,* Federal Energy Regulatory Commission, Docket No. AI20-1-000 (Dec. 20, 2019).

substantially extend the useful life of the pole. This change was made effective January 2021.

Q. WHY IS IT REASONABLE TO INCLUDE COSTS FOR WOOD POLE TREATMENT AS CAPITAL?

A. The FERC USOA allows for betterment accounting,[19] which is the capitalization of minor items of property if a "substantial" addition results from the activity. The Company classifies this activity as a Substantial Minor Item ("SMI") in the Capitalization Policy. The FERC USOA specifies that the replacement of an SMI can only be capitalized if the conditions of betterment are met and "the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of greater capacity…."[20] In such circumstances, only the excess cost of the replacement SMI over the current installed cost of the existing SMI can be charged to capital. A workpaper filed with my direct testimony, WP Wood Pole Treatment, identifies approximate $584,297 costs included in this filing because of this accounting change.

Q. PLEASE DISCUSS THE 2021 ACCOUNTING PRACTICE CHANGE RELATED TO A&G OH CONSTRUCTION COSTS.

A. During 2020, the Company began an analysis of whether an accounting change was warranted for A&G OH. Pursuant to this analysis, it was determined that certain Administrative and General functions within the organization were supporting capital work and consequently, the cost of that time should be included as capital overhead.

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[19] FERC CFR Part 101 Electric Plant Instructions 10.C.3
[20] *Id.*

Q. WHAT STEPS DID THE COMPANY TAKE TO IDENTIFY THE NEW A&G OH?

A. The Company first determined that it is appropriate to include A&G as a component of construction overhead under FERC accounting guidelines. The Company reviewed FERC 18 CFR Part 101 - Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Electric Plant Instructions No. 4. (Overhead Construction Costs). This section authorizes a utility to include overhead costs, such as general office salaries and expenses, applicable to construction as a part of its assets. After the Company determined that A&G costs are appropriate to capitalize, the Company defined the A&G activities that are included in the capital construction lifecycle as defined by the Company. The capital construction lifecycle commences with executive formulation of alternatives that guide the preparation of a comprehensive capital plan. This capital plan is translated into operational budgets which provide spending guidelines for each of the various business functions throughout the company. In order to facilitate construction activity, ancillary activities such as treasury, human resources, legal, sourcing, and training must be completed to ensure that adequate resources are devoted to the capital plan. The capital lifecycle continues after assets have been constructed and includes back-office activities such as capital budget tracking, unitization of assets to the financial records, and the cost recovery of capital activity through regulatory proceedings. These activities are performed by various departments within the Finance and Regulatory functions.

Based on the capital construction lifecycle definition, the Company reviewed the activities performed by the A&G functions to determine how much time was dedicated to the support of the capital lifecycle. The cost centers associated with each of the A&G support functions were identified. Once this population of cost objects was determined, the Manager of each cost center was surveyed and/or interviewed to determine the time spent in support of capital work. The results of the surveys and interviews were then used to establish the mechanism in SAP to identify these costs as A&G OH. This mechanism allows for the A&G costs to be systematically allocated to construction overhead.

Q. WHAT FACTORS SUPPORT THE PRACTICE CHANGE FOR A&G OH?

A. The Company has incrementally increased its capital spend over the past several years and projects continued future increases. This increase has raised an awareness of the amount of effort support areas are required to provide related to the capital lifecycle. In addition, cost flow changes in 2020 have given the Company the ability to assign the amounts specifically to A&G OH. Previously, costs were combined prior to billing to the Business Units so it was not possible to assign amounts specifically. This greater visibility into cost flows allows for costs to be identified as A&G OH and appropriately assigned to capital. A workpaper filed with my direct testimony, WP Administrative & General Overhead, identifies approximate $2,789,819 costs included in this DCRF application due to this change.

Q. DOES THE COMPANY CLASSIFY THE INCREMENTAL A&G OH AS DIRECT OR INDIRECT CAPITAL CHARGES?

A. The underlying activities identified as A&G OH comprise activities within the asset lifecycle. Accordingly, the Company classifies them as direct.

Q. WHAT IS THE AMOUNT OF DISTRIBUTION CAPITAL INVESTMENT INCLUDED IN THIS FILING AS A RESULT OF THESE ACCOUNTING PRACTICE CHANGES?

A. The distribution capital investment associated with changes in accounting practice or rules totals $4,022,685 and is summarized by category in Table MAK-1 below.

Table MAK-1
Distribution Capital Impact from Changes in Accounting Rules or Practice

Accounting Rules or Practices Changes	
Item	DCRF Amount Invested Capital
Parking/In Town Travel and EZ Tag	$ 646,953
Cloud Computing	1,616
Wood Pole Treatment	584,297
A&G OH	2,789,819
Total	**$ 4,022,685**

Q. HAVE ANY INDIRECT CORPORATE COSTS BEEN INCLUDED IN CAPITAL PROJECTS?

A. No. In order to ensure indirect corporate costs are not included, controls and processes are in place to review charges made to capital projects. For example, the Company follows CNP's Construction Overhead Policy for the inclusion of costs in construction overhead, as seen in Exhibit MAK-04. Business unit owners within the Company are also responsible for reviewing source documents charged to projects for completeness, appropriateness, and compliance with CNP's Capitalization Policy.

Q. HAVE ANY DIRECT CORPORATE COSTS OTHER THAN THE A&G NOTED ABOVE BEEN INCLUDED IN CAPITAL PROJECTS?

A. Yes. Each work order may include some or all of the following overheads, where applicable: stores overhead, transportation overhead, or construction overhead. As included in Docket No. 49421, these costs originate from purchasing and logistics, property accounting, and call center and are allocated to each of the work orders.

VII. MOBILE GENERATION PROGRAM

Q. PLEASE DESCRIBE THE MOBILE GENERATION PROGRAM AUTHORIZED UNDER PURA §39.918.

A. During the 87th Regular Session, the Texas Legislature passed and on June 15, 2021, the Governor of Texas signed, H.B. 2483, which created a new statute, PURA §39.918. The new statute authorizes a transmission and distribution utility in Texas to do the following:

- "lease and operate facilities that provide temporary emergency electric energy to aid in restoring power to the utility's distribution customers during a widespread power outage"; and
- "procure, own, and operate, or enter into a cooperative agreement with other transmission and distribution utilities to procure, own, and operate jointly, transmission and distribution facilities that have a lead time of at least six months and would aid in restoring power to the utility's distribution customers following a widespread power outage."[21]

In addition, the statute requires the PUCT to authorize a transmission and distribution utility to do the following with respect to cost recovery:

- recover the reasonable and necessary costs of leasing and operating the facilities, including the present value of future payments required under the lease, using the rate of return on investment established in the commission's final order in the utility's most recent base rate proceeding; and
- defer for recovery in a future ratemaking proceeding the incremental operations and maintenance expenses and the return, not otherwise

[21] HB 2483 § 39.918 Section 1 (b)(1) and (2).

> recovered in a rate proceeding, associated with the leasing or procurement, ownership, and operation of the facilities.[22]

The statute permits a utility to request cost recovery as follows:

> A transmission and distribution utility may request recovery of the reasonable and necessary costs of leasing or procuring, owning, and operating facilities under this section, including any deferred expenses, through a proceeding under Section 36.210 or in another ratemaking proceeding. A lease under Subsection (b) (1) must be treated as a capital lease or financing lease for ratemaking purposes.[23]

The new statute became effective on September 1, 2021.

Q. ARE THERE BENEFITS TO CUSTOMERS FOR ALLOWING THE COMPANY TO BEGIN RECOVERY OF MOBILE GENERATION COSTS THROUGH THE DCRF?

A. Yes. Costs to customers should ultimately be lower if the Company is able to begin cost recovery as part of this DCRF proceeding, rather than waiting until after the Company's next base rate case, because the amount of carrying costs will be less. In addition, from an inter-generational equity standpoint, recovery through the DCRF allows for gradual cost recovery from the customers who are currently benefitting from the Company's leasing of the facilities.

Q. PLEASE GENERALLY DESCRIBE THE MOBILE GENERATION PROGRAM THE COMPANY IMPLEMENTED IN 2021.

A. On September 1, 2021, the Company entered into a short-term equipment lease agreement initially for 125 MW of temporary emergency electric energy generation capability. The equipment was installed and became operational beginning in September 2021. As of December 31, 2021, the short-term equipment lease was

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[22] HB 2483 § 39.918 Section 1 (h) and (i).

[23] HB 2483 § 39.918 Section 1 (j).

expanded to include additional assets for a total of approximately 220 MW. This equipment held under the short-term lease will be rolled into the long-term lease described below as units meet specific criteria. The short-term lease will terminate either once all units have been converted to the long-term lease or on September 30, 2022.

In December 2021, the Company entered into a 7.5-year long-term equipment lease agreement for a total generation capability up to approximately 500 MW of temporary emergency electric energy generation. In December 2021, under the long-term lease, the Company prepaid for total generation capability of 125 MW of temporary emergency electric generation to be delivered, installed and operational in 2021. The total gross capacity of mobile generation under the two leases in place at December 31, 2021 was approximately 345 MW. Mr. Narendorf discusses the program details in his direct testimony.

Q. HOW HAS THE COMPANY ACCOUNTED FOR THE SHORT-TERM LEASE ON ITS BOOKS AND RECORDS?

A. The September 2021 short-term equipment lease does not meet the FERC criteria for capital lease treatment and is therefore classified as an operating lease for FERC accounting purposes.[24] For ratemaking purposes, the Company is deferring actual costs incurred for recovery as authorized under PURA § 39.918(i). The incremental lease and operating costs associated with this lease are being recorded to a regulatory asset as the costs are incurred. A return is calculated on the short-term lease regulatory asset balance each month using the Company's authorized rate of

[24] FERC CFR Part 101 General Instructions 19.

return of 6.51% from its last comprehensive rate case proceeding, Docket No. 49421. Currently, the equity portion of the return is then offset and will be recognized when the regulatory asset is recovered through rates. The regulatory asset balance on December 31, 2021, associated with the short-term equipment lease is $20,269,958 as shown on Schedule Mobile Generation.

Q. HOW HAS THE COMPANY ACCOUNTED FOR THE LONG-TERM LEASE ON ITS BOOKS AND RECORDS?

A. The long-term equipment lease entered into during December 2021 has been recorded following FERC guidance, which resulted in treating the lease agreement as a capital lease. The criteria for capital lease accounting treatment is such that the present value of the minimum lease payments exceeded the fair value of the leased equipment.[25] When the equipment lease agreement was entered into, the Company recorded the equipment portion of the lease cost as a capital lease asset with an offsetting current liability for the lease obligation. The Company then prepaid the lease for the equipment received, which represents approximately 125 MW of approximately 500 MW of generating capacity under the contract. Because the lease was prepaid, the Company no longer has the lease obligation, which resulted in an immediate expense recognition of $149,703,583. The capital lease asset was derecognized because capital lease accounting required the Company to reduce the asset by an amount equal to the portion of each lease payment that would have been allocated to the reduction of the liability similar to an installment liability. The equipment lease expense was then moved to a regulatory asset. The portion of the

[25] FERC CFR Part 101 General Instructions 19 and 20.

lease prepayment representing service and insurance cost was recorded as short and long-term prepayments in the amounts of $3,830,395 and $24,897,566, respectively. The Company also recorded a decommissioning obligation of $342,544 and associated offsetting regulatory asset that is not being requested in this DCRF application but will be requested after the costs are incurred. The regulatory assets are recorded in FERC account 182.3 Other Regulatory Assets, and the Short- and Long-Term Prepayments are recorded to FERC accounts 165.0 Prepayments and 186.0 Miscellaneous Deferred Debits, respectively. Additionally, operational costs incurred in December 2021 of $829,795 were deferred to the regulatory asset.

PURA § 39.918 allows for deferral of a return on the present value of the capital lease.[26] With the prepayment of the lease, the Company recorded a return of $35,132 on the full balance of the prepayment in the regulatory asset on December 31, 2021. The requested regulatory asset balance for the long-term lease is $150,568,510 on December 31, 2021. Please see WP Mobile Generation for details.

Q. WHAT ARE THE TOTAL COSTS OF THE REGULATORY ASSETS AND PREPAYMENTS FOR MOBILE GENERATION?

A. The details for the Regulatory Assets and Prepayments are shown in Table MAK-2 below.

[26] § 39.918 Section 1 (h) and (i).

Table MAK-2
Mobile Generation Regulatory Assets and Prepayments

	Total Rate Base Mobile Generation			
Category	Lease Payments	Operational Costs	Return	Total Deferral
Short-term Lease	$ 19,882,307	$ 278,353	$ 109,298	$ 20,269,958
Short-term Prepaid O&M	-	3,830,395	-	3,830,395
Long-term Prepaid O&M	-	24,897,566	-	24,897,566
Long-term Prepaid Lease	150,533,378	-	35,132	150,568,510
Total	**$ 170,415,685**	**$ 29,006,314**	**$ 144,431**	**$ 199,566,430**

Q. WHAT ARE THE TAX IMPACTS RELATED TO THE REGULATORY ASSETS AND PREPAID LEASES?

A. For tax filing purposes, the expense deferred for ratemaking purposes is deducted for federal tax purposes resulting in an ADFIT liability on the lease regulatory assets of $35,678,402 on December 31, 2021 shown on Schedule Mobile Generation.

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST IN THIS DCRF APPLICATION RELATED TO MOBILE GENERATION PROGRAM.

A. Pursuant to PURA §39.918, the Company is authorized to request mobile generation amounts for recovery in the DCRF application filed under PURA § 36.210. As such, the Company has included in this DCRF application a separate schedule for Mobile Generation that identifies the regulatory asset and prepaid balances net of ADFIT balances and calculates the Company's requested return and proposed amortization, all adjusted for applicable tax impacts. The Company is requesting an amortization period corresponding to the life of the leases of 12 months for the short-term lease balance and 7.5 years for the long-term lease balances as shown on Schedule Mobile Generation Lines 2-5. The total amount of mobile generation costs requested in this DCRF application is $59,903,845. This amount is shown in Table MAK-3 below and on Schedule Mobile Generation, Line 24 and Schedule A, Line 9.

Table MAK-3
Total Mobile Generation Amounts Requested in the DCRF Application

Mobile Generation Revenue Request				
Category	Amortization Expense	Tax Expense	Rate of Return	Total Revenue Requirement
Short-term Lease	$ 20,269,958	$ -	$ -	$ 20,269,958
Long-term Lease	20,075,801	-	-	20,075,801
Short-term Prepaid	3,830,395	-	-	3,830,395
Long-term Prepaid	3,319,676	-	-	3,319,676
Other	-	1,738,904	10,669,111	12,408,015
Total	**$ 47,495,830**	**$ 1,738,904**	**$10,669,111**	**$ 59,903,845**

Q. **HOW DOES THE COMPANY PLAN TO ACCOUNT FOR THE COSTS OF FUTURE MOBILE GENERATION TRANSACTIONS?**

A. Costs for future mobile generation transactions will be deferred in a similar manner as described above and as shown on Exhibit MAK-05 Mobile Generation Accounting.

Q. **HOW IS THE EQUITY COMPONENT OF CARRYING COST INCLUDED IN THE REVENUE REQUIREMENT TYPICALLY RECOGNIZED FOR ACCOUNTING PURPOSES?**

A. For regulatory accounting purposes, carrying costs – arising from both debt and equity – are deferred to the regulatory asset at the time they are initially recorded. Upon initial recording of equity costs to the regulatory asset, another entry is recorded simultaneously to a contra-regulatory asset in an amount equal and offsetting to the equity costs with the effect of immediately removing the amounts from the income statement. This ensures the equity return is included in the requested regulatory asset as authorized by PURA § 39.918. The contra-regulatory asset continues to offset the amount of equity in the regulatory asset until those amounts are realized as related revenues are recognized over the period authorized by the Commission.

Q. HOW IS THE COMPANY PROPOSING TO RECOGNIZE THE CARRYING COST COMPONENT FOR MOBILE GENERATION INCLUDED IN THE REVENUE REQUIREMENT FOR ACCOUNTING PURPOSES?

A. The Company is requesting the Commission to authorize the Company to record the revenue collected that is attributable to the regulatory asset cost recovery, such that the first dollars collected will represent the full carrying costs of the regulatory asset, with later collections representing recovery of other costs. Under this prioritization proposal, entries similar to those under the typical accounting treatment described above take place, but the timing of those entries changes as it relates to recognition of deferred debt and equity costs because the realization of those amounts occurs earlier. A comparison of the Company's proposal with typical recognition methods is shown in Exhibit MAK-06 Carrying Cost Recognition Comparison.

Q. WHY IS THE COMPANY'S PROPOSED ACCOUNTING TREATMENT APPROPRIATE WITH RESPECT TO MOBILE GENERATION?

A. As addressed in Mr. Narendorf's direct testimony, by prepaying the lease, the Company incurred substantial upfront costs. However, that prepayment also benefitted customers by lowering the overall cost of the lease by approximately

24%. The Company's proposed accounting treatment recognizes the benefit associated with the Company incurring the substantial upfront costs.

Q. WHAT IMPACT DOES THIS PROPOSAL HAVE ON CUSTOMERS?

A. As shown in Exhibit MAK-06, Tab Long-Term, Lines 24 and 54, and Tab Short-Term, Line 24, the Company's proposal has no impact on the total amount recovered from customers.

Q. THE CARRYING COST COMPONENT OF THE REGULATORY ASSETS on DECEMBER 31, 2021, IS SMALL. WHY IS THE COMPANY REQUESTING THIS TREATMENT FOR SUCH A SMALL AMOUNT?

A. The Company will not begin recovery of carrying costs on the December 31, 2021 balances until new rates are implemented from this filing, which are expected to be effective September 1, 2022. During this time, the Company will continue to accrue carrying costs on the short- and long-term lease regulatory assets. This amount is expected to be approximately $476,708 and $4,356,407 for the short- and long-term leases, respectively, as shown in WP Mobile Generation.

Q. DOES THE COMPANY EXPECT TO INCUR ADDITIONAL SHORT-TERM LEASE COSTS IN 2022?

A. Yes. The short-term lease will continue as discussed above through September 2022. The Company expects to spend approximately $29,763,000 of additional lease and operating costs under the short-term lease. During this time, the Company estimates carrying costs of $923,089 will be recorded in 2022. Similar to the way recovery for costs incurred in 2021 is not expected to begin until September 2022, recovery for costs incurred in 2022 is not expected to begin until September 2023.

Likewise, carrying costs will continue to accrue beyond December 31, 2022, until new DCRF rates are implemented, and the Company expects to record approximately $726,664 of carrying costs during that time. These calculations are shown in WP Mobile Generation.

Q. DOES THE COMPANY EXPECT TO INCUR ADDITIONAL LONG-TERM LEASE COSTS IN 2022?

A. Yes. Under the long-term lease, the Company expects to make payments totaling approximately $521,823,000 during 2022. Based on the Company's currently expected payment schedule, estimated carrying costs of $14,336,772 will be recorded in 2022. Similar to the costs incurred under the short-term lease, the Company will not begin recovery of the costs incurred in 2022 under the long-term lease until approximately September 1, 2023. Carrying costs will continue to accrue beyond December 31, 2022, until new DCRF rates are implemented, and the Company expects to record approximately $12,740,311 of carrying costs during that time. These calculations are shown in WP Mobile Generation.

Q. WHAT IS THE TOTAL AMOUNT OF CARRYING COSTS THE COMPANY IS ESTIMATING ON THE MOBILE GENERATION LEASES PRIOR TO RECOVERY OF THE INVESTMENT THROUGH DCRF RATES?

A. Table MAK-4 below details the total estimated carrying costs of $33,704,382 related to mobile generation leases estimated to be recorded prior to recovery of the investments in rates.

Table MAK-4
Mobile Generation Carrying Cost

Carrying Costs (includes estimates)	2021	2022	2023	Total
Short-term Lease 2021 Carrying Costs	$ 109,298	$ 476,708	$ -	$ 586,006
Short-term Lease 2022 Carrying Costs	-	923,089	726,664	1,649,752
Subtotal Short-term	***109,298***	***1,399,797***	***726,664***	***2,235,759***
Long-term Lease 2021 Prepayment Carrying Costs	35,132	4,356,407	-	4,391,539
Long-term Lease 2022 Prepayment Carrying Costs	-	14,336,772	12,740,311	27,077,084
Subtotal Long-term	***35,132***	***18,693,179***	***12,740,311***	***31,468,623***
Total Carrying Costs	**$ 144,431**	**$ 20,092,976**	**$ 13,466,975**	**$ 33,704,382**

Due to the magnitude of this investment and the associated carrying costs, the Company is requesting the prioritization treatment for carrying costs as described above, such that the carrying costs will be recovered first rather than over the full recovery period for the regulatory asset. As discussed above, this has no impact on the total amount recovered from customers.

VIII. RATE CASE EXPENSES

Q. HOW DOES THE COMPANY PROPOSE TO HANDLE RATE CASE EXPENSES INCURRED IN THIS PROCEEDING?

A. Rate case expenses include fees and expenses for outside attorneys and consultants, as well as other reasonable out-of-pocket expenses incurred in connection with this proceeding. The Company proposes to defer the issue of rate case expense recovery to a future DCRF application, general rate case, or other docket created for the purpose of recovering rate case expenses as referenced in 16 TAC §25.245. As mentioned in 16 TAC §25.245(c), deferral of this issue will enable the Commission to review the full costs of this proceeding in the context of the issues raised in this case, as well as the resulting decision.

Q. IN THE EVENT THAT THE COMMISSION DETERMINES THAT RATE CASE EXPENSES SHOULD BE HANDLED IN THIS CASE, WHAT ARE THE COMPANY'S RATE CASE EXPENSES?

A. Through March 31, 2022, the Company has incurred approximately $21,000 in rate case expenses in relation to the current DCRF application. The Company will provide support for any rate case expenses in its rebuttal testimony, if such testimony is necessary, as well as in a future DCRF application, general rate case, other docket created for the purpose of recovering these expenses, or other method ultimately determined by the Commission.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER RATE CASE EXPENSES?

A. The Company proposes to recover its reasonable rate case expenses, as well as the rate case expenses approved by the Commission for reimbursement to municipal intervenors, through a surcharge. To the extent that the rate case expenses to be recovered are less than that required to support a surcharge for expenses associated only with this proceeding, the Company proposes to defer and accumulate these expenses for recovery in a future DCRF application, general rate case, or other docket created for the purpose of recovering rate case expenses once a higher threshold is reached.

IX. <u>REVENUE REQUIREMENT REQUEST</u>

Q. WHAT IS THE TOTAL AMOUNT REQUESTED IN THIS DCRF APPLICATION?

A. The Company is requesting an increase of $138,518,172 for the DCRF and $59,903,845 for the mobile generation program, for a total of $198,422,017 which is prior to the growth adjustment discussed by Mr. Durland.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony supports the DCRF-RFP schedules and corresponding workpapers that I sponsor. Amounts in the DCRF-RFP schedules I sponsor have been calculated according to 16 TAC §25.243 and the DCRF RFP Instructions, with the addition of costs of the mobile generation program according to PURA §39.918. In addition, my testimony demonstrates that the distribution invested capital included in the Company's filing due to a change in accounting practice and methods is properly recovered in the DCRF. For these reasons, I recommend that the Commission approve the Company's combined revenue requirement of $198,422,017 as shown on Schedule A: Summary of Distribution Cost of Service.

In terms of recovery, the Company proposes to recover rate case expenses for the Company and the municipal intervenors through a separate surcharge. To the extent that the level of rate case expenses associated only with this case is determined to not justify a separate surcharge at this time, the Company proposes to defer and accumulate these expenses for recovery in a future DCRF application, general rate case, or docket created for the purpose of recovering rate case expenses once a higher threshold is reached.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

H.B. No. 2483

AN ACT

relating to utility facilities for restoring electric service after a widespread power outage.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF TEXAS:

SECTION 1. Subchapter Z, Chapter 39, Utilities Code, is amended by adding Section 39.918 to read as follows:

Sec. 39.918. UTILITY FACILITIES FOR POWER RESTORATION AFTER WIDESPREAD POWER OUTAGE. (a) In this section, "widespread power outage" means an event that results in:

(1) a loss of electric power that:

(A) affects a significant number of distribution customers of a transmission and distribution utility; and

(B) has lasted or is expected to last for at least eight hours; and

(2) a risk to public safety.

(b) Notwithstanding any other provision of this subtitle, a transmission and distribution utility may:

(1) lease and operate facilities that provide temporary emergency electric energy to aid in restoring power to the utility's distribution customers during a widespread power outage in which:

(A) the independent system operator has ordered the utility to shed load; or

(B) the utility's distribution facilities are not being fully served by the bulk power system under normal operations; and

(2) procure, own, and operate, or enter into a cooperative agreement with other transmission and distribution utilities to procure, own, and operate jointly, transmission and distribution facilities that have a lead time of at least six months and would aid in restoring power to the utility's distribution customers following a widespread power outage. In this section, long lead time facilities may not be electric energy storage equipment or facilities under Chapter 35, Utilities Code.

(c) A transmission and distribution utility that leases and operates facilities under Subsection (b)(1) may not sell electric energy or ancillary services from those facilities.

(d) Facilities described by Subsection (b)(1):

(1) must be operated in isolation from the bulk power system; and

(2) may not be included in independent system operator:

(A) locational marginal pricing calculations;

(B) pricing; or

(C) reliability models.

(e) A transmission and distribution utility that leases and operates facilities under Subsection (b)(1) shall ensure, to the extent reasonably practicable, that retail customer usage during operation of those facilities is adjusted out of the usage reported for billing purposes by the retail customer's retail electric provider.