2022 RATE CASE
ONCOR TOTAL
COMPARISON OF DEPRECIATION RATES
FOR THE TEST PERIOD ENEDED DECEMCEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
398	Miscellaneous Equipment	12,767,814		614,879	4.55%	580,355.17	(34,523)
	General Amortized	416,199,054	5.81%	24,187,073	9.56%	39,769,045	15,581,973
	General Plant Reserve Imbalance					12,475,110	12,475,110
	Total General Plant	859,675,800	3.89%	33,453,919	7.08%	60,839,924	27,386,005
	Total	30,413,869,031		862,983,819	0	897,077,121	34,093,303
	Other Assets:						
		0					
390	General Plant Leasehold Improvements	6,588,405	(3)	439,227	6.67%	439,227	0
303	Intangible	146,167,816	(1)	1,083,338		1,083,338	0
362	Mobile Generators (7 Year Life)	3,146,147					
370	AMS Meters	211,112,886	(1)	0		0	0
370	AMR Meters	82,679	(1)			0	0
387	AMS Communication Equipment	41,548,504	(1)	0		0	0
391	Office Furniture and Equipment	16,170,086	(1)	2,310,705		2,310,705	0
349	Fee Land	115,906,329	(2)	0		0	0
374	Fee Land	96,116,029	(2)	0		0	0
388	Fee Land	33,672,086	(2)	0		0	0
	Total Other Assets	670,510,969		3,833,271		3,833,271	0
	Total Company	31,084,380,001		866,817,090		900,910,392	34,093,303

(1) Asset Fully Accrued
(2) Non Depreciable
(3) Leased assets amortized over lease term. Asset in service December 2020.

2022 RATE CASE
ONCOR LEGACY
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
303	Intangible 3 year	408,078	14.06%	57,376	31.65%	129,157	71,781
303	Intangible 5 year	32,215,865	14.06%	4,529,551	19.18%	6,178,313	1,648,762
303	Intangible 8 year	328,240,028	8.46%	27,769,106	11.26%	36,973,871	9,204,764
303	Intangible 15 year	194,391,584	5.61%	10,905,368	6.46%	12,560,093	1,654,726
303	CC&B & Aegis Systems - Settlement life	364926909.9	4.00%	14,597,076	6.46%	23,578,778	8,981,702
	Total Intangible	920,182,465	6.29%	57,858,477	8.63%	79,420,212	21,561,735
350	Land and Land Rights	521,566,383	1.00%	5,215,664	0.98%	5,100,260	(115,404)
352	Structures and Improvements	312,392,692	2.84%	8,871,952	2.65%	8,290,827	(581,125)
353	Station Equipment	3,275,784,329	2.49%	81,567,030	2.25%	73,732,438	(7,834,592)
354	Towers and Fixtures	1,433,247,199	2.24%	32,104,737	1.96%	28,031,957	(4,072,780)
355	Poles and Fixtures	2,646,547,291	3.99%	105,597,237	3.13%	82,845,413	(22,751,824)
356	Overhead Conductor	2,597,173,723	3.39%	88,044,189	2.72%	70,542,836	(17,501,353)
357	Underground Conduit	60,197,135	2.19%	1,318,317	1.76%	1,056,605	(261,712)
358	Underground Conductor and Devices	84,097,343	2.73%	2,295,857	2.28%	1,915,431	(380,426)
352	DC Tie	1,686,569	2.84%	47,899	2.55%	42,946	(4,952)
353	DC Tie	30,852,549	2.49%	768,228	2.81%	865,433	97,204
352	SVC	12,728,829	2.84%	361,499	5.38%	685,149	323,650
353	SVC	273,676,085	2.49%	6,814,535	3.71%	10,160,778	3,346,243
	Total Transmission	11,249,950,125	2.96%	333,007,144	2.52%	283,270,073	(49,737,071)
360	Land and Land Rights	5,858,702	1.21%	70,890	1.38%	81,047	10,156
361	Structures and Improvements	190,221,732	2.07%	3,937,590	2.08%	3,965,068	27,478
362	Station Equipment	2,328,129,108	1.69%	39,345,382	2.09%	48,606,825	9,261,443
	Total Distribution Substation	2,524,209,542		43,353,862	2.09%	52,652,940	9,299,078
360	Land and Land Rights	18,508,221	1.21%	223,949	1.24%	229,982	6,032
364	Poles, Towers, and Fixtures	2,678,358,261	2.89%	77,404,554	3.55%	95,063,646	17,659,092
365	Overhead Conductor and Devices	1,675,410,858	2.83%	47,414,127	3.18%	53,354,377	5,940,250
366	Underground Conduit	1,082,118,478	1.91%	20,668,463	2.18%	23,578,854	2,910,391
367	Underground Conductor and Devices	2,553,927,528	2.58%	65,891,330	2.22%	56,736,034	(9,155,296)

2022 RATE CASE
ONCOR LEGACY
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
368	Line Transformers	2,493,077,762	2.37%	59,085,943	2.27%	56,703,640	(2,382,303)
369	Services	1,652,238,990	2.79%	46,097,468	3.04%	50,246,720	4,149,252
370	Meters (Post AMS)	199,955,073	3.91%	7,818,243	5.23%	10,466,010	2,647,766
370	IDR Meters	162,996,844	3.91%	6,373,177	4.13%	6,729,285	356,109
371	Installation on Customer Premises	54,631,097	2.98%	1,628,007	4.38%	2,390,143	762,137
373	Street Lighting	437,403,826	3.75%	16,402,643	4.80%	21,013,687	4,611,043
	Total Distribution	13,008,626,939	2.68%	349,007,905	2.89%	376,512,378	27,504,473
389	Land and Land Rights	142,598	1.78%	2,538	2.05%	2,916	378
390	Structures and Improvements	252,408,829	1.78%	4,492,877	1.96%	4,951,041	458,164
397	Communication Equipment	77,314,645	6.13%	4,739,388	4.67%	3,613,499	(1,125,889)
	General Depreciated	329,866,072	2.80%	9,234,803	2.60%	8,567,457	(667,346)
Retired Fully Accrued Assets							
391	Computer Equipment	92,232,608		0	0.00%	-	0
392	Auto/Light Trucks	1,883,342		0	0.00%	-	0
392	Heavy Trucks	84,180					
394	Small Tools	11,312,221		0	0.00%	-	0
396	Power Operated Equipment	3,228,020		0	0.00%	-	0
397	Communication Equipment	3,017,141		0	0.00%	-	0
	General Amortized Retired Plant	111,757,512		0	0.00%	-	0
Amortized Accounts (Retire Assets > ASL)							
391	Office Furniture and Equipment	20,722,829	6.87%	1,423,658	5.00%	1,036,141	(387,517)
391	Computer Equipment	192,918,986	6.87%	13,253,534	14.29%	27,559,855	14,306,321
392	Auto/Light Trucks	2,073,325	7.38%	153,011	11.43%	236,951	83,940
392	Heavy Trucks	956,129	7.38%	70,562	8.00%	76,490	5,928
392	Trailers	16,478,534	7.38%	1,216,116	5.33%	878,855	(337,261)
393	Stores Equipment	4,996,537	3.02%	150,895	2.50%	124,913	(25,982)
394	Large Tools	18,277,262	3.10%	566,595	2.86%	522,207	(44,388)
394	Small Tools	13,755,751	3.10%	426,428	10.00%	1,375,575	949,147
395	Laboratory Equipment	51,910,324	4.43%	2,299,627	4.00%	2,076,413	(223,214)
396	Power Operated Equipment	9,311,426	3.19%	297,034	5.33%	496,609	199,575
397	Communication Equipment	68,445,540	5.26%	3,600,235	6.67%	4,563,036	962,801

2022 RATE CASE
ONCOR LEGACY
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
398	Miscellaneous Equipment	12,736,447	4.82%	613,897	4.55%	578,929	(34,967)
	General Amortized	412,583,090		24,071,595	9.58%	39,525,977	15,454,382
	General Plant Reserve Imbalance					12,475,110	12,475,110
	Total General Plant	854,206,675	3.90%	33,306,398	7.09%	60,568,544	27,262,146
	Total	28,557,175,746		816,533,786		852,424,147	35,890,360
	Other Assets:						
390	General Plant Leasehold Improvements	6,588,405	(3)	439,227	6.67%	438,318.49	(909)
303	Intangible	146,167,816	(1)	1,083,338		1,083,338.40	0
362	Mobile Generators (7 Year Life)	3,146,147					
370	AMS Meters	211,112,886	(1)	0		-	0
370	AMR Meters	82,679	(1)			-	0
387	AMS Communication Equipment	41,548,504	(1)	0		-	0
391	Office Furniture and Equipment	16,170,086	(1)	2,310,705		2,310,705.33	0
349	Fee Land	93,368,707	(2)	0		-	0
374	Fee Land	95,936,060	(2)	0		-	0
388	Fee Land	33,301,137	(2)	0		-	0
	Total Other Assets	647,422,429		3,833,271		3,832,362	(909)
	Total	29,204,598,176		820,367,057		856,256,509	35,889,452
	Difference						

(1) Asset Fully Accrued
(2) Non Depreciable
(3) Leased assets amortized over lease term. Asset in service December 2020.

2022 RATE CASE
NTUSU
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
303	Intangible 3 year	0	14.06%	0	31.65%	0	0
303	Intangible 5 year	0	14.06%	0	19.18%	0	0
303	Intangible 8 year	0	8.46%	0	11.26%	0	0
303	Intangible 15 year	0	5.61%	0	6.46%	0	0
		0				0	0
350	Land and Land Rights	94,360,022	0.00%	0	0.98%	922,722	922,722
352	Structures and Improvements	85,541,924	2.16%	1,847,706	2.65%	2,270,262	422,557
353	Station Equipment	283,344,612	2.55%	7,225,288	2.25%	6,377,614	(847,673)
354	Towers and Fixtures	496,405,556	2.04%	10,126,673	1.96%	9,708,876	(417,797)
355	Poles and Fixtures	224,223,020	2.89%	6,480,045	3.13%	7,018,899	538,854
356	Overhead Conductor	447,407,596	3.14%	14,048,599	2.72%	12,152,210	(1,896,388)
357	Underground Conduit	0	0.00%	0	1.76%	0	0
358	Underground Conductor and Devices	0	0.00%	0	2.28%	0	0
352	DC Tie	0	2.16%	0	2.55%	0	0
353	DC Tie	0	2.55%	0	2.81%	0	0
352	SVC	7,695,877	2.16%	166,231	5.38%	414,242	248,011
353	SVC	65,358,112	2.55%	1,666,632	3.71%	2,426,552	759,920
	Total Transmission	1,704,336,720		41,561,173		41,291,378	(269,795)
360	Land and Land Rights	0	0.00%	0	1.38%	0	0
361	Structures and Improvements	37,729,106	2.68%	1,011,140	2.08%	786,443	(224,697)
362	Station Equipment	105,008,785	3.42%	3,591,300	2.09%	2,192,380	(1,398,920)
	Total Distribution Substation	142,737,890	3.22%	4,602,440	2.09%	2,978,823	(1,623,618)
360	Land and Land Rights	0	0.00%	0	1.24%	0	0
364	Poles, Towers, and Fixtures	648,929	4.48%	29,072	3.55%	23,033	(6,039)
365	Overhead Conductor and Devices	1,104,394	3.87%	42,740	3.18%	35,170	(7,570)
366	Underground Conduit	543,818	1.74%	9,462	2.18%	11,850	2,387
367	Underground Conductor and Devices	1,840,112	3.11%	57,227	2.22%	40,878	(16,349)

2022 RATE CASE
NTUSU
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
368	Line Transformers	5,044	2.37%	120	2.27%	115	(5)
369	Services	0	0.00%	0	3.04%	0	0
370	Meters (Post AMS)	0	0.00%	0	5.23%	0	0
370	IDR Meters	0	0.00%	0	4.13%	0	0
371	Installation on Customer Premises	0	0.00%	0	4.38%	0	0
373	Street Lighting	7,252	3.81%	276	4.80%	348	72
	Total Distribution	4,149,549	3.35%	138,898	2.68%	111,394	(27,504)
389	Land and Land Rights	0	0.00%	0	2.05%	0	0
390	Structures and Improvements	1,443,397	2.22%	32,043	1.96%	28,312	(3,731)
397	Communication Equipment	0	0.00%	0	4.67%	0	0
	General Depreciated	1,443,397	2.22%	32,043	1.96%	28,312	(3,731)
Retired Fully Accrued Assets							
391	Computer Equipment	0		0	0.00%	-	0
392	Auto/Light Trucks	409,765		0	0.00%	-	0
392	Heavy Trucks						
394	Small Tools	0		0	0.00%	-	0
396	Power Operated Equipment	0		0	0.00%	-	0
397	Communication Equipment	0		0	0.00%	-	0
	General Amortized Retired Plant	409,765		0	0.00%	-	0
Amortized Accounts (Retire Assets > ASL)							
391	Office Furniture and Equipment	2,134,401	2.23%	47,597	5.00%	106,720	59,123
391	Computer Equipment	14,048	2.23%	313	14.29%	2,007	1,694
392	Auto/Light Trucks	856,573	5.12%	43,857	11.43%	97,894	54,038
392	Heavy Trucks	0	5.12%	0	8.00%	0	0
392	Trailers	121,214	5.12%	6,206	5.33%	6,465	259
393	Stores Equipment	0	1.71%	0	2.50%	0	0
394	Large Tools	0	3.29%	0	2.86%	0	0
394	Small Tools	83,351	3.29%	2,742	10.00%	8,335	5,593
395	Laboratory Equipment	0	1.85%	0	4.00%	0	0
396	Power Operated Equipment	358,440	2.92%	10,466	5.33%	19,117	8,650
397	Communication Equipment	16,571	20.00%	3,314	6.67%	1,105	(2,209)

2022 RATE CASE
NTUSU
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Account	Description	Original Cost at 12/31/21	Existing Annual Accrual %	Existing Annual Accrual $	Proposed Annual Accrual %	Proposed Annual Accrual $	Difference $
398	Miscellaneous Equipment	31,367	3.13%	982	4.55%	1,426	444
	General Amortized	3,615,964		115,478	6.72%	243,068	127,590
	General Plant Reserve Imbalance					0	0
	Total General Plant	5,469,126	2.70%	147,521	4.96%	271,380	123,859
	Total	1,856,693,285		46,450,033		44,652,975	(1,797,058)
	Other Assets:						
390	General Plant Leasehold Improvements	0	(3)				
303	Intangible	0	(1)	0		-	0
362	Mobile Generators (7 Year Life)						
370	AMS Meters	0	(1)	0		-	0
370	AMR Meters	0	(1)			-	0
387	AMS Communication Equipment	0	(1)	0		-	0
391	Office Furniture and Equipment	0	(1)	0		-	0
349	Fee Land	22,537,622	(2)	0		-	0
374	Fee Land	179,969	(2)	0		-	0
388	Fee Land	370,949	(2)	0		-	0
	Total Other Assets	23,088,540		0		0	0
	Total	1,879,781,825		46,450,033		44,652,975	(1,797,058)
	Difference						

(1) Asset Fully Accrued
(2) Non Depreciable
(3) Leased assets amortized over lease term. Asset in service December 2020.

APPENDIX C

Summary of Life and Salvage Recommendations

2022 RATE CASE
ONCOR ELECTRIC DELIVERY
COMPARISON OF EXISTING AND PROPOSED
DEPRECIATION PARAMETERS

		NTUSU			ONCOR LEGACY			ONCOR LEGACY			ONCOR TOTAL				
		Approved Docket 45714 & 41474			Proposed Docket 46957			Approved Settlement 46957			Proposed			Change	
Account No.	**Description**	**Curve**	**ASL**	**Net Salvage**	**Curve**	**ASL**	**Net Salvage**	**Curve**	**ASL**	**Net Salvage**	**Curve**	**ASL**	**Net Salvage**	**Life**	**Net Salvage**
Intangible															
303	Intangible Plant	NA	NA	NA	NA	NA	NA	NA	NA	NA	3	R2	0%	NA	NA
303	Intangible Plant	NA	NA	NA	5	SQ	0%	5	SQ	0%	5	R2	0%	0	0%
303	Intangible Plant	NA	NA	NA	8	SQ	0%	8	SQ	0%	8	R2	0%	0	0%
303	Intangible Plant	NA	NA	NA	15	SQ	0%	15	SQ	0%	15	R2	0%	0	0%
Transmission															
350	Land and Land Rights	NA	NA	NA	100	R3	0%	100	R3	0%	100	R4	0%	0	0%
352	Structures and Improvements	50	R4	-5%	52	S6	-50%	48	S6	-37%	55	R4	-50%	7	-13%
353	Station Equipment	45	R5	-10%	45	R2	-10%	46	L0.5	-15%	50	L0.5	-15%	4	0%
354	Towers and Fixtures	60	R3	-20%	65	R3	-34%	60	R3	-35%	72	R2.5	-40%	12	-5%
355	Poles and Fixtures	54	R3	-50%	56	R2.5	-75%	50	R2	-100%	55	R1.5	-75%	5	25%
356	Overhead Conductor	50	R3	-50%	51	R5	-50%	50	R2	-70%	50	S5	-40%	0	30%
357	Underground Conduit	NA	NA	NA	60	R3	-10%	50	R3	-10%	60	R3	-10%	10	0%
358	Underground Conductor and Devices	NA	NA	NA	40	R3	-10%	40	S3	-10%	50	S3	-20%	10	-10%
352	DC Tie	50	R4	-5%	52	S6	-50%				55	R4	-50%	55	-50%
353	DC Tie	45	R5	-10%	45	R2	-10%	46	L0.5	-15%	30	R2	-15%	-16	0%
352	SVC	50	R4	-5%	52	S6	-50%				55	R4	-50%	55	-50%
353	SVC	45	R5	-10%	45	R2	-10%	46	L0.5	-15%	30	R2	-15%	-16	0%
Distribution															
360	Land and Land Rights	NA	NA	NA	70	R3	0%	70	R3	0%	70	R3	0%	0	0%
361	Structures and Improvements	50	R3	-5%	52	S6	-33%	52	S6	-25%	65	R4	-40%	13	-15%
362	Station Equipment	35	R3	-10%	55	R1.5	-18%	55	R1.5	-7%	57	R1.5	-25%	2	-18%
364	Poles, Towers, and Fixtures	42	R5	-50%	44	R1	-100%	44	R1	-40%	54	R0.5	-100%	10	-60%
365	Overhead Conductor and Devices	39	R4	-30%	41	R1.5	-54%	41	R1.5	-40%	52	R0.5	-75%	11	-35%
366	Underground Conduit	60	R3	-10%	50	R3	-30%	50	R3	-20%	60	R2.5	-40%	10	-20%
367	Underground Conductor and Devices	37	R4	-10%	37	R1	-10%	37	R1	-5%	49	R0.5	-20%	12	-15%
368	Line Transformers	41	R5	-5%	44	R1	-25%	44	R1	-15%	50	L0.5	-20%	6	-5%
369	Services	35	R2.5	-30%	34	S6	-30%	34	S6	-15%	37	S6	-30%	3	-15%
370	Meters (Post Deployment)	30	R2.5	-15%	15	R1.5	-5%	20	R0.5	-5%	20	R0.5	-7%	0	-2%
370	Meters (IDR)				15	R1.5	-5%	20	R0.5	-5%	20	R0.5	-10%	0	-5%
371	Installation on Customer Premises	25	R1	-15%	25	S6	-60%	25	S6	-20%	25	S6	-60%	0	-40%
373	Street Lighting	30	R2	-10%	25	S6	-40%	25	S6	-20%	25	S6	-40%	0	-20%
General Depreciated															
389	Land and Land Rights	NA	NA	NA	60	R2	0%	60	R2	0%	65	R2	0%	5	0%
390	Structures and Improvements	45	R2	0%	58	R1	0%	58	R1	0%	60	R1	-5%	2	-5%
397	Communication Equipment	NA	NA	NA	20	R2	0%	20	R2	0%	25	R1	-2%	5	-2%
Amortized Accts															
391	Office Furniture and Equipment	15	L1	0%	15	SQ	0%	15	SQ	0%	20	SQ	0%	5	0%
391	Computer Equipment **				7	SQ	0%	15	SQ	0%	7	SQ	0%	-8	0%
392	Transportation Equipment	8	L1.5	15%	13	SQ	10%	13	SQ	10%	10	SQ	20%	-3	10%
392.1	Automobiles/ Light Trucks	8	L1.5	15%	7	SQ	10%	13	SQ	10%	7	SQ	20%	-6	10%
392.2	Heavy Trucks	8	L1.5	15%	10	SQ	10%	13	SQ	10%	10	SQ	20%	-3	10%
392.3	Trailers	8	L1.5	15%	10	SQ	10%	13	SQ	10%	15	SQ	20%	2	10%
393	Stores Equipment				40	SQ	0%	40	SQ	0%	40	SQ	0%	0	0%
394	Tool, Shop, and Garage Equipment	20	R2	0%	35	SQ	0%	35	SQ	0%	35	SQ	0%	0	0%
394	Tools **	20	R2	0%	10	SQ	0%	35	SQ	0%	10	SQ	0%	-25	0%
395	Laboratory Equipment	20	R2	0%	25	SQ	0%	25	SQ	0%	25	SQ	0%	0	0%
396	Power Operated Equipment	18	L4	5%	30	SQ	10%	30	SQ	10%	15	SQ	20%	-15	10%
397	Communication Equipment	5	SQ	0%	20	SQ	0%	20	SQ	0%	15	SQ	0%	-5	0%
398	Miscellaneous Equipment	20	R2	0%	22	SQ	0%	22	SQ	0%	22	SQ	0%	0	0%

ONCOR Approved Parameters approved in Docket 46957 for accounts 350-398.
Approved Parameter for Account 303 approved in Docket 38929.
** Account 391 Computer and 394 Tools are proposed to be separated going forward.

APPENDIX D

Allocation of Accumulated Provision for Depreciation

2022 RATE CASE
Oncor Electric Delivery LLC
CALCULATION OF INTANGIBLE PLANT BOOK ASSOCIATED WITH TRANSMISSION RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Unit	Func code	Plant Acct	Prop Unit	Vntg Yr	Age	Investment	ASL	RL	Theo Res	Proration	Alloc Res	$ x RL	Composite RL
TRN	I	303	1000	2018	3.50	19,835.68	5.00	2.24	10,954.61	1.509	16,525.42	44,405.34	
TRN	I	303	1000	2017	4.50	805,221.38	5.00	1.66	538,401.61	1.509	805,221.38	1,334,098.83	
TRN	I	303	1000	2016	5.50	810,110.98	5.00	1.20	615,907.13	1.509	810,110.98	971,019.27	
TRN	I	303	1000	2014	7.50	809,733.15	5.00	0.60	712,727.28	1.509	809,733.15	485,029.35	
TRN	I	303	1000	2010	11.50	408,674.69	5.00	0.00	408,674.69	1.509	408,674.69	0.00	
						2,853,575.88	**5 Total**		2,286,665.32		2,850,265.62	2,834,552.80	0.99
TRN	I	303	1000	2021	0.50	10,101,801.94	8.00	7.55	567,456.10	1.509	856,027.67	76,274,766.75	
TRN	I	303	1000	2020	1.50	5,447,301.87	8.00	6.68	900,237.45	1.509	1,358,040.15	36,376,515.37	
TRN	I	303	1000	2019	2.50	2,665,116.14	8.00	5.84	718,153.52	1.509	1,083,360.08	15,575,700.95	
TRN	I	303	1000	2018	3.50	15,514,639.88	8.00	5.06	5,710,541.38	1.509	8,614,554.41	78,432,788.02	
TRN	I	303	1000	2017	4.50	905,993.26	8.00	4.32	417,076.72	1.509	629,175.03	3,911,332.36	
TRN	I	303	1000	2016	5.50	4,296,913.91	8.00	3.64	2,343,832.26	1.509	3,535,754.18	15,624,653.21	
TRN	I	303	1000	2015	6.50	10,084,850.24	8.00	3.02	6,277,864.66	1.509	9,470,381.72	30,455,884.67	
TRN	I	303	1000	2014	7.50	1,208,103.62	8.00	2.48	834,303.07	1.509	1,208,103.62	2,990,404.39	
TRN	I	303	1000	2013	8.50	11,398,744.26	8.00	2.01	8,539,738.30	1.509	11,398,744.26	22,872,047.71	
TRN	I	303	1000	2012	9.50	4,444,998.97	8.00	1.61	3,549,196.66	1.509	4,444,998.97	7,166,418.47	
TRN	I	303	1000	2011	10.50	1,280,510.69	8.00	1.28	1,075,358.31	1.509	1,280,510.69	1,641,219.03	
						67,348,974.78	**8 Total**		30,933,758.42		43,879,650.79	291,321,730.92	4.33
TRN	I	303	1000	2021	0.50	10,118,264.78	15.00	14.55	304,397.20	1.509	459,193.99	147,208,013.65	
TRN	I	303	1000	2020	1.50	30,159,257.68	15.00	13.66	2,695,980.28	1.509	4,066,981.97	411,949,161.04	
TRN	I	303	1000	2019	2.50	8,663,932.05	15.00	12.79	1,277,462.13	1.509	1,927,096.97	110,797,048.87	
TRN	I	303	1000	2018	3.50	10,017,836.39	15.00	11.94	2,045,170.68	1.509	3,085,212.59	119,589,985.58	
TRN	I	303	1000	2017	4.50	524,235.50	15.00	11.11	135,991.48	1.509	205,147.97	5,823,660.35	
TRN	I	303	1000	2009	12.50	23,572.50	15.00	5.47	14,979.31	1.509	22,596.81	128,897.92	
TRN	I	303	1000	2008	13.50	117,463.53	15.00	4.91	78,976.24	1.509	117,463.53	577,309.29	
TRN	I	303	1000	2007	14.50	360,424.87	15.00	4.40	254,672.56	1.509	360,424.87	1,586,284.64	
						59,984,987.30	**15 Total**		6,807,629.88		10,244,118.70	797,660,361.34	13.30
						130,187,537.96	**Grand Total**		40,028,053.61		56,974,035.11		

56,974,035.11	Total Reserve
56,974,035.11	Adjusted Reserve
0.00	Difference
1.509	Proration Factor

2022 Rate Case
Oncor Electric Delivery LLC
CALCULATION OF INTANGIBLE PLANT BOOK ASSOCIATED WITH DISTRIBUTION RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Unit	Account	Func code	Plant Acct	Prop Unit	Vntg Yr	Age	Investment	ASL	RL	Theo Res	Proration	Alloc Res	$ x RL	Composite RL
ESD	1010900	I	303	1000	2020	1.50	408,077.79	3	1.76	168,460.90	1.072	180,561.31	**718,850.66**	
							408,077.79	**3 Total**		168,460.90		180,561.31	718,850.66	1.76
ESD	1010900	I	303	1000	2,021.00	0.50	17,512,778.19	5	4.55	1,565,141.50	1.072	1,677,564.26	79,738,183.43	
ESD	1010900	I	303	1000	2,020.00	1.50	5,513,668.94	5	3.70	1,428,378.79	1.072	1,530,978.01	20,426,450.73	
ESD	1010900	I	303	1000	2,019.00	2.50	5,218,066.65	5	2.93	2,162,622.51	1.072	2,317,961.81	15,277,220.72	
ESD	1010900	I	303	1000	2018	3.50	503,811.68	5	2.24	278,239.07	1.072	298,224.74	1,127,863.06	
ESD	1010900	I	303	1000	2,017.00	4.50	318,770.95	5	1.66	213,142.37	1.072	228,452.20	528,142.90	
ESD	1010900	I	303	1000	2,016.00	5.50	33,359.19	5	1.20	25,362.16	1.072	27,183.90	39,985.16	
ESD	1010900	I	303	1000	2,014.00	7.50	261,833.56	5	0.60	230,465.95	1.072	247,020.12	156,838.04	
							29,362,289.16	**5 Total**		5,903,352.35		6,327,385.04	117,294,684.03	3.99
ESD	1010900	I	303	1000	2021	0.50	54,412,525.66	8	7.55	3,056,555.61	1.072	3,276,105.35	410,847,760.37	
ESD	1010900	I	303	1000	2020	1.50	34,808,270.48	8	6.68	5,752,519.20	1.072	6,165,717.67	232,446,010.21	
ESD	1010900	I	303	1000	2019	2.50	38,778,737.34	8	5.84	10,449,483.37	1.072	11,200,060.71	226,634,031.73	
ESD	1010900	I	303	1000	2018	3.50	16,826,460.60	8	5.06	6,193,388.97	1.072	6,638,254.73	85,064,573.05	
ESD	1010900	I	303	1000	2017	4.50	27,399,092.45	8	4.32	12,613,254.41	1.072	13,519,253.54	118,286,704.35	
ESD	1010900	I	303	1000	2016	5.50	22,682,396.23	8	3.64	12,372,538.32	1.072	13,261,247.03	82,478,863.29	
ESD	1010900	I	303	1000	2015	6.50	10,194,851.78	8	3.02	6,346,341.11	1.072	6,802,193.29	30,788,085.36	
ESD	1010900	I	303	1000	2014	7.50	41,338,300.47	8	2.48	28,547,775.58	1.072	30,598,337.57	102,324,199.09	
ESD	1010900	I	303	1000	2013	8.50	11,654,555.89	8	2.01	8,731,387.86	1.072	9,358,555.89	23,385,344.23	
ESD	1010900	I	303	1000	2012	9.50	2,359,904.07	8	1.61	1,884,311.72	1.072	2,019,660.20	3,804,738.82	
ESD	1010900	I	303	1000	2008	13.50	435,958.35	8	0.51	408,166.01	1.072	435,958.35	222,338.76	
							260,891,053.32	**8 Total**		96,355,722.16		103,275,344.33	1,316,282,649.26	5.05
ESD	1010900	I	303	1000	2021	0.50	24,669,168.87	15	14.55	742,145.63	1.072	795,453.31	358,905,348.57	
ESD	1010900	I	303	1000	2020	1.50	20,614,621.71	15	13.66	1,842,771.27	1.072	1,975,135.93	281,577,756.61	
ESD	1010900	I	303	1000	2019	2.50	90,288,779.74	15	12.79	13,312,719.42	1.072	14,268,960.52	1,154,640,904.84	
ESD	1010900	I	303	1000	2018	3.50	45,221,781.37	15	11.94	9,232,159.32	1.072	9,895,297.32	539,844,330.79	
ESD	1010900	I	303	1000	2017	4.50	229,417,962.70	15	11.11	59,513,114.88	1.072	63,787,890.35	2,548,572,717.37	
ESD	1010900	I	303	1000	2016	5.50	4,195,092.34	15	10.30	1,313,451.81	1.072	1,407,795.91	43,224,607.97	
ESD	1010900	I	303	1000	2015	6.50	5,613,048.49	15	9.52	2,049,396.22	1.072	2,196,602.58	53,454,783.98	
ESD	1010900	I	303	1000	2014	7.50	220,906.18	15	8.77	91,755.77	1.072	98,346.50	1,937,256.19	
ESD	1010900	I	303	1000	2013	8.50	19,263,663.99	15	8.04	8,932,483.94	1.072	9,574,096.52	154,967,700.79	
ESD	1010900	I	303	1000	2012	9.50	8,406,899.34	15	7.35	4,287,621.23	1.072	4,595,597.35	61,789,171.69	
ESD	1010900	I	303	1000	2011	10.50	3,301,556.15	15	6.69	1,829,647.58	1.072	1,961,069.58	22,078,628.50	
ESD	1010900	I	303	1000	2010	11.50	36,508,026.51	15	6.06	21,759,820.63	1.072	23,322,809.69	221,223,088.23	
ESD	1010900	I	303	1000	2009	12.50	9,504,731.66	15	5.47	6,039,846.37	1.072	6,473,683.30	51,973,279.42	
ESD	1010900	I	303	1000	2008	13.50	1,314,674.55	15	4.91	883,917.40	1.072	947,408.42	6,461,357.22	
ESD	1010900	I	303	1000	2007	14.50	792,593.03	15	4.40	560,038.20	1.072	600,265.26	3,488,322.40	
							499,333,506.63	**15 Total**		132,390,889.66		141,900,412.55	5,504,139,254.56	11.02
							789,994,926.90	**Grand Total**		234,818,425.08		251,683,703.23	6,938,435,438.51	
												251,683,703.23		
												0.00		Difference
												1.072	Proration	

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2022 RATE CASE
ONCOR ELECTRIC DELIVERY LLC
CALCULATION OF GENERAL PLANT BOOK RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
350	2021	0.5	15,385,657.13	100	99.50	0.00%	76,864.74	76,864.74	1.121	86,159.99	1,530,879,238.71	
350	2020	1.5	47,317,830.87	100	98.50	0.00%	709,152.80	709,152.80	1.121	794,910.63	4,660,867,806.56	
350	2019	2.5	16,202,920.18	100	97.50	0.00%	404,698.07	404,698.07	1.121	453,638.19	1,579,822,211.11	
350	2018	3.5	11,562,241.86	100	96.50	0.00%	404,276.33	404,276.33	1.121	453,165.45	1,115,796,552.97	
350	2017	4.5	11,571,372.59	100	95.50	0.00%	520,154.95	520,154.95	1.121	583,057.27	1,105,121,763.79	
350	2016	5.5	22,528,324.09	100	94.51	0.00%	1,237,631.11	1,237,631.11	1.121	1,387,297.80	2,129,069,298.38	
350	2015	6.5	1,778,696.76	100	93.51	0.00%	115,471.89	115,471.89	1.121	129,435.90	166,322,486.91	
350	2014	7.5	34,472,331.17	100	92.51	0.00%	2,581,968.99	2,581,968.99	1.121	2,894,206.42	3,189,036,218.34	
350	2013	8.5	210,222,366.11	100	91.51	0.00%	17,843,155.19	17,843,155.19	1.121	20,000,927.39	19,237,921,092.38	
350	2012	9.5	15,664,049.17	100	90.51	0.00%	1,485,772.66	1,485,772.66	1.121	1,665,447.10	1,417,827,651.25	
350	2011	10.5	21,823,184.84	100	89.52	0.00%	2,287,595.49	2,287,595.49	1.121	2,564,234.34	1,953,558,934.82	
350	2010	11.5	16,656,461.81	100	88.52	0.00%	1,912,031.40	1,912,031.40	1.121	2,143,253.29	1,474,443,041.43	
350	2009	12.5	1,750,118.51	100	87.52	0.00%	218,338.29	218,338.29	1.121	244,741.94	153,178,021.76	
350	2008	13.5	4,294,120.92	100	86.53	0.00%	578,487.09	578,487.09	1.121	648,443.52	371,563,382.56	
350	2007	14.5	8,483,991.60	100	85.53	0.00%	1,227,387.72	1,227,387.72	1.121	1,375,815.68	725,660,388.16	
350	2006	15.5	15,377,143.59	100	84.54	0.00%	2,377,624.71	2,377,624.71	1.121	2,665,150.79	1,299,951,888.41	
350	2005	16.5	3,971,893.86	100	83.54	0.00%	653,633.04	653,633.04	1.121	732,676.87	331,826,081.51	
350	2004	17.5	3,791,318.52	100	82.55	0.00%	661,593.01	661,593.01	1.121	741,599.43	312,972,551.44	
350	2003	18.5	460,052.81	100	81.56	0.00%	84,848.77	84,848.77	1.121	95,109.53	37,520,403.73	
350	2002	19.5	6,615,324.69	100	80.56	0.00%	1,285,726.06	1,285,726.06	1.121	1,441,208.87	532,959,862.91	
350	2001	20.5	16,468,175.92	100	79.57	0.00%	3,363,961.38	3,363,961.38	1.121	3,770,765.12	1,310,421,454.35	
350	2000	21.5	200,401.49	100	78.58	0.00%	42,921.22	42,921.22	1.121	48,111.69	15,748,026.64	
350	1999	22.5	510,266.76	100	77.59	0.00%	114,336.58	114,336.58	1.121	128,163.29	39,593,018.49	
350	1998	23.5	7,681,727.42	100	76.60	0.00%	1,797,198.36	1,797,198.36	1.121	2,014,533.50	588,452,906.26	
350	1997	24.5	3,438,350.84	100	75.62	0.00%	838,378.45	838,378.45	1.121	939,763.53	259,997,239.09	
350	1996	25.5	17,782.33	100	74.63	0.00%	4,511.26	4,511.26	1.121	5,056.80	1,327,107.38	
350	1995	26.5	67,590.28	100	73.65	0.00%	17,812.84	17,812.84	1.121	19,966.95	4,977,743.55	
350	1994	27.5	885,323.78	100	72.66	0.00%	242,025.80	242,025.80	1.121	271,293.97	64,329,798.44	
350	1993	28.5	1,096,408.49	100	71.68	0.00%	310,496.29	310,496.29	1.121	348,044.60	78,591,219.50	
350	1992	29.5	480,533.01	100	70.70	0.00%	140,794.26	140,794.26	1.121	157,820.51	33,973,874.58	
350	1991	30.5	387,453.33	100	69.72	0.00%	117,313.25	117,313.25	1.121	131,499.94	27,014,007.51	
350	1990	31.5	4,485,991.98	100	68.75	0.00%	1,402,077.64	1,402,077.64	1.121	1,571,630.84	308,391,434.18	
350	1989	32.5	2,503,138.38	100	67.77	0.00%	806,738.85	806,738.85	1.121	904,297.75	169,639,953.35	
350	1988	33.5	11,982,681.36	100	66.80	0.00%	3,978,425.28	3,978,425.28	1.121	4,459,536.12	800,425,608.15	
350	1987	34.5	4,093,505.85	100	65.83	0.00%	1,398,813.87	1,398,813.87	1.121	1,567,972.38	269,469,198.39	
350	1986	35.5	2,250,923.21	100	64.86	0.00%	790,956.05	790,956.05	1.121	886,606.34	145,996,716.15	
350	1985	36.5	4,917,895.99	100	63.90	0.00%	1,775,569.32	1,775,569.32	1.121	1,990,288.86	314,232,667.46	
350	1984	37.5	3,320,431.44	100	62.93	0.00%	1,230,770.31	1,230,770.31	1.121	1,379,607.32	208,966,113.04	
350	1983	38.5	7,194,850.34	100	61.97	0.00%	2,735,915.52	2,735,915.52	1.121	3,066,769.70	445,893,482.29	
350	1982	39.5	5,130,966.41	100	61.02	0.00%	2,000,174.88	2,000,174.88	1.121	2,242,055.96	313,079,153.40	
350	1981	40.5	3,321,123.63	100	60.06	0.00%	1,326,310.71	1,326,310.71	1.121	1,486,701.43	199,481,291.52	
350	1980	41.5	4,121,650.92	100	59.11	0.00%	1,685,153.63	1,685,153.63	1.121	1,888,939.21	243,649,728.99	
350	1979	42.5	7,192,983.25	100	58.17	0.00%	3,008,943.94	3,008,943.94	1.121	3,372,815.43	418,403,931.27	
350	1978	43.5	1,476,360.18	100	57.23	0.00%	631,501.02	631,501.02	1.121	707,868.42	84,485,916.01	
350	1977	44.5	4,309,711.83	100	56.29	0.00%	1,883,896.23	1,883,896.23	1.121	2,111,715.74	242,581,560.00	
350	1976	45.5	5,411,473.61	100	55.35	0.00%	2,416,080.10	2,416,080.10	1.121	2,708,256.60	299,539,350.60	
350	1975	46.5	1,904,824.72	100	54.42	0.00%	868,174.31	868,174.31	1.121	973,162.60	103,665,041.41	
350	1974	47.5	3,709,619.36	100	53.50	0.00%	1,725,102.73	1,725,102.73	1.121	1,933,719.35	198,451,663.22	
350	1973	48.5	2,464,871.72	100	52.58	0.00%	1,168,958.63	1,168,958.63	1.121	1,310,320.77	129,591,308.52	
350	1972	49.5	1,806,944.17	100	51.66	0.00%	873,497.59	873,497.59	1.121	979,129.63	93,344,657.84	
350	1971	50.5	914,144.76	100	50.75	0.00%	450,240.00	450,240.00	1.121	504,687.51	46,390,476.19	
350	1970	51.5	3,009,194.04	100	49.84	0.00%	1,509,377.70	1,509,377.70	1.121	1,691,906.69	149,981,634.35	
350	1969	52.5	1,104,228.25	100	48.94	0.00%	563,816.76	563,816.76	1.121	631,999.10	54,041,149.19	
350	1968	53.5	2,330,013.04	100	48.04	0.00%	1,210,563.33	1,210,563.33	1.121	1,356,956.72	111,944,970.89	
350	1967	54.5	982,376.88	100	47.16	0.00%	519,136.49	519,136.49	1.121	581,915.65	46,324,038.75	
350	1966	55.5	1,115,488.90	100	46.27	0.00%	599,338.84	599,338.84	1.121	671,816.87	51,615,005.53	
350	1965	56.5	3,708,407.01	100	45.39	0.00%	2,025,036.43	2,025,036.43	1.121	2,269,924.02	168,337,058.14	

2022 RATE CASE
ONCOR ELECTRIC DELIVERY LLC
CALCULATION OF GENERAL PLANT BOOK RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
350	1964	57.5	1,843,126.65	100	44.52	0.00%	1,022,535.06	1,022,535.06	1.121	1,146,190.19	82,059,159.42	
350	1963	58.5	1,047,785.70	100	43.66	0.00%	590,360.03	590,360.03	1.121	661,752.25	45,742,567.35	
350	1962	59.5	932,160.72	100	42.80	0.00%	533,218.23	533,218.23	1.121	597,700.29	39,894,249.09	
350	1961	60.5	888,467.17	100	41.95	0.00%	515,795.72	515,795.72	1.121	578,170.88	37,267,144.59	
350	1960	61.5	180,243.25	100	41.10	0.00%	106,163.20	106,163.20	1.121	119,001.51	7,408,004.78	
350	1959	62.5	1,019,938.07	100	40.26	0.00%	609,295.28	609,295.28	1.121	682,977.33	41,064,279.44	
350	1958	63.5	738,747.85	100	39.43	0.00%	447,459.09	447,459.09	1.121	501,570.30	29,128,876.48	
350	1957	64.5	592,852.67	100	38.61	0.00%	363,977.65	363,977.65	1.121	407,993.45	22,887,502.40	
350	1956	65.5	1,060,311.42	100	37.79	0.00%	659,634.63	659,634.63	1.121	739,404.23	40,067,678.82	
350	1955	66.5	6,367,817.46	100	36.98	0.00%	4,013,075.74	4,013,075.74	1.121	4,498,376.87	235,474,171.88	
350	1954	67.5	214,226.82	100	36.18	0.00%	136,727.32	136,727.32	1.121	153,261.75	7,749,950.20	
350	1953	68.5	629,005.25	100	35.38	0.00%	406,454.24	406,454.24	1.121	455,606.74	22,255,100.82	
350	1952	69.5	338,568.02	100	34.59	0.00%	221,443.87	221,443.87	1.121	248,223.07	11,712,415.31	
350	1951	70.5	184,489.03	100	33.81	0.00%	122,105.75	122,105.75	1.121	136,871.99	6,238,328.48	
350	1950	71.5	143,601.28	100	33.04	0.00%	96,152.87	96,152.87	1.121	107,780.64	4,744,840.61	
350	1949	72.5	29,518.15	100	32.28	0.00%	19,990.56	19,990.56	1.121	22,408.02	952,758.54	
350	1948	73.5	124,481.46	100	31.52	0.00%	85,245.04	85,245.04	1.121	95,553.72	3,923,642.05	
350	1947	74.5	3,691.26	100	30.77	0.00%	2,555.45	2,555.45	1.121	2,864.48	113,581.18	
350	1946	75.5	94,150.92	100	30.03	0.00%	65,879.06	65,879.06	1.121	73,845.82	2,827,185.57	
350	1945	76.5	9,081.33	100	29.29	0.00%	6,421.08	6,421.08	1.121	7,197.58	266,025.10	
350	1944	77.5	9,738.13	100	28.57	0.00%	6,956.30	6,956.30	1.121	7,797.52	278,183.49	
350	1943	78.5	26,130.03	100	27.85	0.00%	18,853.73	18,853.73	1.121	21,133.71	727,630.01	
350	1942	79.5	69,025.91	100	27.13	0.00%	50,296.57	50,296.57	1.121	56,378.94	1,872,933.72	
350	1941	80.5	57,521.73	100	26.43	0.00%	42,319.83	42,319.83	1.121	47,437.57	1,520,190.03	
350	1940	81.5	1,772.56	100	25.73	0.00%	1,316.49	1,316.49	1.121	1,475.70	45,606.76	
350	1939	82.5	57,502.86	100	25.04	0.00%	43,105.72	43,105.72	1.121	48,318.49	1,439,714.17	
350	1938	83.5	1,142.21	100	24.35	0.00%	864.06	864.06	1.121	968.55	27,814.96	
350	1935	86.5	152.31	100	22.34	0.00%	118.29	118.29	1.121	132.59	3,402.45	
350	1934	87.5	31.75	100	21.68	0.00%	24.87	24.87	1.121	27.87	688.49	
350	1933	88.5	260.52	100	21.04	0.00%	205.70	205.70	1.121	230.58	5,481.50	
350	1932	89.5	160,175.05	100	20.41	0.00%	127,487.16	127,487.16	1.121	142,904.18	3,268,788.51	
350	1931	90.5	74.99	100	19.79	0.00%	60.15	60.15	1.121	67.43	1,483.81	
350	1930	91.5	20,708.44	100	19.18	0.00%	16,736.71	16,736.71	1.121	18,760.68	397,172.60	
350	1929	92.5	151,180.66	100	18.59	0.00%	123,082.37	123,082.37	1.121	137,966.72	2,809,828.63	
350	1928	93.5	177,751.48	100	18.01	0.00%	145,742.90	145,742.90	1.121	163,367.58	3,200,858.35	
350	1927	94.5	407,131.59	100	17.44	0.00%	336,108.85	336,108.85	1.121	376,754.48	7,102,274.20	
350	1926	95.5	623,000.88	100	16.90	0.00%	517,726.95	517,726.95	1.121	580,335.66	10,527,392.86	
350	1925	96.5	114,531.13	100	16.37	0.00%	95,785.34	95,785.34	1.121	107,368.65	1,874,579.34	
350	1924	97.5	25,201.17	100	15.85	0.00%	21,205.92	21,205.92	1.121	23,770.35	399,524.93	
350	1923	98.5	5,376.35	100	15.36	0.00%	4,550.76	4,550.76	1.121	5,101.09	82,558.61	
350	1922	99.5	117.16	100	14.87	0.00%	99.73	99.73	1.121	111.79	1,742.71	
350	1921	100.5	2,242.07	100	14.41	0.00%	1,919.00	1,919.00	1.121	2,151.07	32,306.91	
350	1920	101.5	5,410.93	100	13.96	0.00%	4,655.57	4,655.57	1.121	5,218.57	75,535.70	
350	1919	102.5	11,445.84	100	13.53	0.00%	9,897.74	9,897.74	1.121	11,094.67	154,809.98	
350	1918	103.5	39,393.08	100	13.11	0.00%	34,230.35	34,230.35	1.121	38,369.83	516,272.71	
350	1917	104.5	782,964.19	100	12.70	0.00%	683,528.28	683,528.28	1.121	766,187.33	9,943,591.19	
350	1916	105.5	319,821.35	100	12.31	0.00%	280,459.13	280,459.13	1.121	314,375.05	3,936,221.73	
350	1914	107.5	9,503.24	100	11.56	0.00%	8,404.65	8,404.65	1.121	9,421.02	109,858.93	
350	1913	108.5	470,363.72	100	11.20	0.00%	417,665.80	417,665.80	1.121	468,174.11	5,269,792.37	
350	1912	109.5	7,252.72	100	10.86	0.00%	6,465.25	6,465.25	1.121	7,247.09	78,747.34	
350 Total			615,926,404.49				95,265,096.18	95,265,096.18		106,785,501.30	52,066,130,830.93	84.53
352	2021	0.5	33,046,391.70	55	54.50	-50.00%	300,173.59	450,260.39	1.121	504,710.37	1,801,041,995.81	
352	2020	1.5	32,925,620.00	55	53.50	-50.00%	897,128.56	1,345,692.84	1.121	1,508,427.43	1,761,567,029.27	
352	2019	2.5	15,388,522.57	55	52.50	-50.00%	698,727.62	1,048,091.43	1.121	1,174,837.09	807,938,722.33	
352	2018	3.5	22,821,177.61	55	51.50	-50.00%	1,450,473.80	2,175,710.70	1.121	2,438,819.33	1,175,388,709.52	
352	2017	4.5	14,444,419.17	55	50.51	-50.00%	1,180,155.27	1,770,232.90	1.121	1,984,307.11	729,534,514.59	
352	2016	5.5	30,825,011.58	55	49.51	-50.00%	3,077,541.13	4,616,311.70	1.121	5,174,562.13	1,526,110,874.56	

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Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
352	2015	6.5	29,172,589.97	55	48.51	-50.00%	3,441,292.07	5,161,938.10	1.121	5,786,171.11	1,415,221,384.77	
352	2014	7.5	15,040,590.42	55	47.52	-50.00%	2,046,631.11	3,069,946.67	1.121	3,441,195.22	714,667,761.88	
352	2013	8.5	42,387,222.35	55	46.52	-50.00%	6,534,774.10	9,802,161.16	1.121	10,987,536.20	1,971,884,653.56	
352	2012	9.5	13,485,457.25	55	45.53	-50.00%	2,322,792.04	3,484,188.06	1.121	3,905,530.82	613,946,586.50	
352	2011	10.5	11,665,252.01	55	44.53	-50.00%	2,219,872.01	3,329,808.01	1.121	3,732,481.59	519,495,900.22	
352	2010	11.5	14,061,167.95	55	43.54	-50.00%	2,929,287.44	4,393,931.17	1.121	4,925,289.13	612,253,427.81	
352	2009	12.5	16,973,188.64	55	42.55	-50.00%	3,841,371.13	5,762,056.69	1.121	6,458,862.03	722,249,963.20	
352	2008	13.5	11,091,982.20	55	41.56	-50.00%	2,709,547.80	4,064,321.70	1.121	4,555,819.99	461,033,892.09	
352	2007	14.5	10,152,929.07	55	40.58	-50.00%	2,662,089.88	3,993,134.82	1.121	4,476,024.49	411,996,155.46	
352	2006	15.5	9,543,665.46	55	39.60	-50.00%	2,672,915.21	4,009,372.81	1.121	4,494,226.14	377,891,263.86	
352	2005	16.5	7,601,982.70	55	38.62	-50.00%	2,264,575.22	3,396,862.83	1.121	3,807,645.35	293,557,411.35	
352	2004	17.5	7,275,078.83	55	37.64	-50.00%	2,296,374.80	3,444,562.20	1.121	3,861,112.99	273,828,721.83	
352	2003	18.5	9,144,843.89	55	36.67	-50.00%	3,048,328.30	4,572,492.44	1.121	5,125,443.81	335,308,357.69	
352	2002	19.5	9,107,149.16	55	35.70	-50.00%	3,196,170.39	4,794,255.59	1.121	5,374,024.76	325,103,832.32	
352	2001	20.5	7,721,479.91	55	34.73	-50.00%	2,845,218.92	4,267,828.38	1.121	4,783,936.73	268,194,354.48	
352	2000	21.5	4,137,069.57	55	33.77	-50.00%	1,596,567.73	2,394,851.60	1.121	2,684,460.93	139,727,600.99	
352	1999	22.5	3,205,598.25	55	32.82	-50.00%	1,292,651.43	1,938,977.15	1.121	2,173,457.60	105,212,074.95	
352	1998	23.5	1,257,664.79	55	31.87	-50.00%	528,800.02	793,200.04	1.121	889,121.69	40,087,562.12	
352	1997	24.5	1,098,996.43	55	30.93	-50.00%	480,868.31	721,302.46	1.121	808,529.54	33,997,046.83	
352	1996	25.5	493,371.28	55	30.00	-50.00%	224,241.66	336,362.49	1.121	377,038.80	14,802,129.09	
352	1995	26.5	264,983.70	55	29.08	-50.00%	124,892.61	187,338.91	1.121	209,993.80	7,705,010.01	
352	1994	27.5	747,957.06	55	28.16	-50.00%	364,988.55	547,482.82	1.121	613,689.90	21,063,268.13	
352	1993	28.5	2,699,164.80	55	27.25	-50.00%	1,361,625.93	2,042,438.89	1.121	2,289,430.96	73,564,638.06	
352	1991	30.5	978,973.43	55	24.60	-50.00%	541,181.42	811,772.14	1.121	909,939.72	24,078,560.29	
352	1990	31.5	1,726,151.42	55	23.73	-50.00%	981,353.36	1,472,030.04	1.121	1,650,042.59	40,963,893.14	
352	1989	32.5	1,080,272.71	55	22.88	-50.00%	630,895.23	946,342.85	1.121	1,060,784.06	24,715,761.34	
352	1988	33.5	1,783,822.28	55	22.04	-50.00%	1,069,003.70	1,603,505.55	1.121	1,797,417.42	39,315,022.07	
352	1987	34.5	841,805.31	55	21.21	-50.00%	517,128.56	775,692.84	1.121	869,497.36	17,857,221.09	
352	1986	35.5	233,365.72	55	20.40	-50.00%	146,811.58	220,217.37	1.121	246,848.25	4,760,477.73	
352	1985	36.5	830,858.04	55	19.60	-50.00%	534,790.96	802,186.44	1.121	899,194.82	16,283,689.28	
352	1984	37.5	336,475.31	55	18.81	-50.00%	221,391.82	332,087.73	1.121	372,247.09	6,329,591.84	
352	1983	38.5	529,396.21	55	18.04	-50.00%	355,764.41	533,646.61	1.121	598,180.48	9,549,749.12	
352	1982	39.5	592,367.55	55	17.28	-50.00%	406,255.87	609,383.80	1.121	683,076.56	10,236,142.66	
352	1981	40.5	333,036.01	55	16.53	-50.00%	232,915.09	349,372.63	1.121	391,622.25	5,506,650.85	
352	1980	41.5	933,334.11	55	15.80	-50.00%	665,166.62	997,749.93	1.121	1,118,407.80	14,749,212.01	
352	1979	42.5	472,339.11	55	15.08	-50.00%	342,799.59	514,199.39	1.121	576,381.51	7,124,673.39	
352	1978	43.5	342,440.12	55	14.38	-50.00%	252,918.88	379,378.31	1.121	425,256.52	4,923,668.42	
352	1977	44.5	1,328,893.76	55	13.69	-50.00%	998,232.25	1,497,348.38	1.121	1,678,422.67	18,186,382.86	
352	1976	45.5	785,329.21	55	13.00	-50.00%	599,640.33	899,460.50	1.121	1,008,232.23	10,212,888.32	
352	1975	46.5	882,828.44	55	12.34	-50.00%	684,800.37	1,027,200.56	1.121	1,151,419.89	10,891,543.63	
352	1974	47.5	1,468,776.07	55	11.69	-50.00%	1,156,716.41	1,735,074.61	1.121	1,944,897.13	17,163,281.42	
352	1973	48.5	544,956.30	55	11.05	-50.00%	435,440.53	653,160.80	1.121	732,147.52	6,023,367.11	
352	1972	49.5	208,366.16	55	10.45	-50.00%	168,795.28	253,192.92	1.121	283,811.53	2,176,398.50	
352	1971	50.5	552,736.04	55	9.86	-50.00%	453,612.96	680,419.44	1.121	762,702.54	5,451,769.32	
352	1970	51.5	348,146.77	55	9.31	-50.00%	289,217.93	433,826.90	1.121	486,289.58	3,241,085.93	
352	1969	52.5	240,345.56	55	8.79	-50.00%	201,955.16	302,932.74	1.121	339,566.39	2,111,472.04	
352	1968	53.5	132,750.60	55	8.29	-50.00%	112,740.42	169,110.63	1.121	189,561.18	1,100,559.82	
352	1967	54.5	295,181.69	55	7.83	-50.00%	253,181.97	379,772.96	1.121	425,698.89	2,309,984.46	
352	1966	55.5	247,529.46	55	7.39	-50.00%	214,273.92	321,410.88	1.121	360,279.09	1,829,054.59	
352	1965	56.5	128,742.96	55	6.98	-50.00%	112,406.89	168,610.34	1.121	189,000.39	898,483.60	
352	1964	57.5	187,338.19	55	6.59	-50.00%	164,882.51	247,323.76	1.121	277,232.61	1,235,062.61	
352	1963	58.5	123,456.42	55	6.23	-50.00%	109,475.36	164,213.04	1.121	184,071.32	768,958.31	
352	1962	59.5	71,697.06	55	5.88	-50.00%	64,026.16	96,039.24	1.121	107,545.59	421,899.34	
352	1961	60.5	95,621.62	55	5.56	-50.00%	85,961.23	128,941.85	1.121	143,432.43	531,321.34	
352	1960	61.5	114,076.85	55	5.24	-50.00%	103,202.28	154,803.42	1.121	171,115.28	598,101.27	
352	1959	62.5	81,462.11	55	4.94	-50.00%	74,142.57	111,213.86	1.121	122,193.17	402,574.59	
352	1958	63.5	152,713.51	55	4.65	-50.00%	139,798.41	209,697.61	1.121	229,070.27	710,330.55	

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352	1957	64.5	29,340.01	55	4.37	-50.00%	27,008.77	40,513.16	1.121	44,010.02	128,217.93	
352	1956	65.5	111,024.39	55	4.09	-50.00%	102,759.16	154,138.74	1.121	166,536.59	454,587.59	
352	1955	66.5	48,263.51	55	3.82	-50.00%	44,909.12	67,363.68	1.121	72,395.27	184,491.32	
352	1954	67.5	92,109.45	55	3.56	-50.00%	86,155.18	129,232.77	1.121	138,164.18	327,485.02	
352	1953	68.5	61,990.18	55	3.29	-50.00%	58,278.88	87,418.31	1.121	92,985.27	204,121.76	
352	1952	69.5	73,039.57	55	3.04	-50.00%	69,008.68	103,513.02	1.121	109,559.36	221,699.05	
352	1951	70.5	30,205.84	55	2.78	-50.00%	28,676.75	43,015.13	1.121	45,308.76	84,099.82	
352	1950	71.5	66,159.95	55	2.53	-50.00%	63,113.89	94,670.83	1.121	99,239.93	167,533.47	
352	1949	72.5	67,347.35	55	2.29	-50.00%	64,548.45	96,822.68	1.121	101,021.03	153,939.34	
352	1948	73.5	77,555.38	55	2.05	-50.00%	74,670.14	112,005.21	1.121	116,333.07	158,688.08	
352	1947	74.5	337.47	55	1.82	-50.00%	326.33	489.50	1.121	506.21	612.64	
352	1946	75.5	6,121.29	55	1.60	-50.00%	5,943.55	8,915.32	1.121	9,181.94	9,775.70	
352	1945	76.5	2,360.73	55	1.39	-50.00%	2,301.25	3,451.87	1.121	3,541.10	3,271.46	
352	1944	77.5	1,409.68	55	1.18	-50.00%	1,379.50	2,069.25	1.121	2,114.52	1,659.73	
352	1943	78.5	3,176.02	55	0.98	-50.00%	3,119.54	4,679.31	1.121	4,764.03	3,106.53	
352	1942	79.5	871.00	55	0.79	-50.00%	858.47	1,287.71	1.121	1,306.50	688.95	
352	1941	80.5	298,693.76	55	0.53	-50.00%	295,819.60	443,729.40	1.121	448,040.64	158,078.89	
352	1939	82.5	7,588.93	55	0.32	-50.00%	7,544.14	11,316.22	1.121	11,383.40	2,463.23	
352	1938	83.5	66.88	55	0.00	-50.00%	66.88	100.32	1.121	100.32	0.00	
352	1931	90.5	278.83	55	0.00	-50.00%	278.83	418.25	1.121	418.25	0.00	
352	1930	91.5	3,344.87	55	0.00	-50.00%	3,344.87	5,017.31	1.121	5,017.31	0.00	
352	1929	92.5	18,579.57	55	0.00	-50.00%	18,579.57	27,869.36	1.121	27,869.36	0.00	
352	1928	93.5	119,806.22	55	0.00	-50.00%	119,806.22	179,709.33	1.121	179,709.33	0.00	
352	1927	94.5	4,727.08	55	0.00	-50.00%	4,727.08	7,090.62	1.121	7,090.62	0.00	
352	1925	96.5	14,949.27	55	0.00	-50.00%	14,949.27	22,423.91	1.121	22,423.91	0.00	
352	1924	97.5	3,131.45	55	0.00	-50.00%	3,131.45	4,697.18	1.121	4,697.18	0.00	
352	1921	100.5	4,222.50	55	0.00	-50.00%	4,222.50	6,333.75	1.121	6,333.75	0.00	
352	1920	101.5	1,510.09	55	0.00	-50.00%	1,510.09	2,265.14	1.121	2,265.14	0.00	
352	1917	104.5	289.70	55	0.00	-50.00%	289.70	434.55	1.121	434.55	0.00	
352 Total			397,934,615.40				73,038,284.55	109,557,426.83		122,655,024.60	17,869,298,196.62	44.91
353	2021	0.5	297,244,349.35	50	49.55	-15.00%	2,695,090.74	3,099,354.35	1.121	3,474,159.17	14,727,462,930.70	
353	2020	1.5	285,736,090.81	50	48.68	-15.00%	7,519,042.36	8,646,898.72	1.121	9,692,567.91	13,910,852,422.27	
353	2019	2.5	219,123,606.94	50	47.86	-15.00%	9,375,470.85	10,781,791.48	1.121	12,085,633.19	10,487,406,804.31	
353	2018	3.5	226,759,798.49	50	47.07	-15.00%	13,301,602.79	15,296,843.21	1.121	17,146,689.99	10,672,909,784.80	
353	2017	4.5	162,858,714.34	50	46.30	-15.00%	12,054,753.18	13,862,966.15	1.121	15,539,414.22	7,540,198,058.11	
353	2016	5.5	221,992,810.70	50	45.55	-15.00%	19,738,885.91	22,699,718.80	1.121	25,444,795.08	10,112,696,239.47	
353	2015	6.5	186,956,901.40	50	44.83	-15.00%	19,327,944.73	22,227,136.44	1.121	24,915,063.35	8,381,447,833.59	
353	2014	7.5	135,592,505.08	50	44.13	-15.00%	15,923,454.99	18,311,973.23	1.121	20,526,439.59	5,983,452,504.71	
353	2013	8.5	218,647,489.74	50	43.45	-15.00%	28,663,325.92	32,962,824.81	1.121	36,949,018.18	9,499,208,191.12	
353	2012	9.5	110,694,141.44	50	42.78	-15.00%	15,980,410.65	18,377,472.25	1.121	20,599,859.39	4,735,686,539.59	
353	2011	10.5	197,503,591.73	50	42.14	-15.00%	31,059,205.48	35,718,086.30	1.121	40,037,473.37	8,322,219,312.42	
353	2010	11.5	108,663,954.85	50	41.51	-15.00%	18,449,016.24	21,216,368.68	1.121	23,782,063.48	4,510,746,930.51	
353	2009	12.5	102,351,725.17	50	40.90	-15.00%	18,621,414.34	21,414,626.49	1.121	24,004,296.61	4,186,515,541.41	
353	2008	13.5	93,008,055.76	50	40.31	-15.00%	18,018,413.44	20,721,175.46	1.121	23,226,986.56	3,749,482,116.04	
353	2007	14.5	103,009,904.90	50	39.74	-15.00%	21,134,352.65	24,304,505.55	1.121	27,243,648.65	4,093,777,612.49	
353	2006	15.5	71,206,560.03	50	39.19	-15.00%	15,398,934.14	17,708,774.26	1.121	19,850,295.78	2,790,381,294.40	
353	2005	16.5	83,085,173.27	50	38.65	-15.00%	18,860,674.98	21,689,776.23	1.121	24,312,720.19	3,211,224,914.42	
353	2004	17.5	60,439,208.95	50	38.13	-15.00%	14,349,275.12	16,501,666.39	1.121	18,497,212.39	2,304,496,691.40	
353	2003	18.5	68,350,005.32	50	37.62	-15.00%	16,916,920.22	19,454,458.25	1.121	21,807,085.29	2,571,654,254.91	
353	2002	19.5	66,672,700.65	50	37.14	-15.00%	17,153,408.41	19,726,419.67	1.121	22,111,934.99	2,475,964,611.99	
353	2001	20.5	54,194,836.98	50	36.66	-15.00%	14,456,456.51	16,624,924.98	1.121	18,635,376.64	1,986,919,023.70	
353	2000	21.5	33,174,572.86	50	36.20	-15.00%	9,153,995.91	10,527,095.29	1.121	11,800,136.60	1,201,028,847.75	
353	1999	22.5	28,491,199.60	50	35.76	-15.00%	8,115,628.74	9,332,973.06	1.121	10,461,609.20	1,018,778,542.82	
353	1998	23.5	14,164,969.87	50	35.32	-15.00%	4,157,505.63	4,781,131.47	1.121	5,359,313.55	500,373,212.01	
353	1997	24.5	10,084,110.25	50	34.90	-15.00%	3,044,714.57	3,501,421.75	1.121	3,924,848.58	351,969,784.12	
353	1996	25.5	7,396,045.87	50	34.49	-15.00%	2,293,852.86	2,637,930.79	1.121	2,956,935.68	255,109,650.55	
353	1995	26.5	10,480,728.20	50	34.09	-15.00%	3,334,634.22	3,834,829.35	1.121	4,298,575.14	357,304,699.18	

2022 RATE CASE
ONCOR ELECTRIC DELIVERY LLC
CALCULATION OF GENERAL PLANT BOOK RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
353	1994	27.5	15,603,810.52	50	33.70	-15.00%	5,087,147.44	5,850,219.56	1.121	6,557,686.42	525,833,154.00	
353	1993	28.5	26,944,152.41	50	33.31	-15.00%	8,991,867.21	10,340,647.29	1.121	11,591,141.44	897,614,260.09	
353	1992	29.5	14,510,169.70	50	32.93	-15.00%	4,952,336.88	5,695,187.41	1.121	6,383,906.25	477,891,641.01	
353	1991	30.5	23,404,620.14	50	32.56	-15.00%	8,163,096.65	9,387,561.14	1.121	10,522,798.62	762,076,174.65	
353	1990	31.5	30,068,317.35	50	32.19	-15.00%	10,709,659.31	12,316,108.20	1.121	13,805,494.78	967,932,902.22	
353	1989	32.5	12,766,078.20	50	31.83	-15.00%	4,640,350.70	5,336,403.31	1.121	5,981,734.39	406,286,374.94	
353	1988	33.5	24,969,979.55	50	31.46	-15.00%	9,256,924.75	10,645,463.47	1.121	11,932,819.03	785,652,739.80	
353	1987	34.5	16,563,952.86	50	31.11	-15.00%	6,259,067.25	7,197,927.33	1.121	8,068,372.46	515,244,280.69	
353	1986	35.5	10,328,957.88	50	30.75	-15.00%	3,976,067.26	4,572,477.35	1.121	5,125,426.90	317,644,530.83	
353	1985	36.5	13,809,423.20	50	30.40	-15.00%	5,412,406.50	6,224,267.48	1.121	6,976,967.95	419,850,834.96	
353	1984	37.5	13,319,157.80	50	30.06	-15.00%	5,312,345.56	6,109,197.39	1.121	6,847,982.44	400,340,612.21	
353	1983	38.5	16,772,386.17	50	29.72	-15.00%	6,804,347.75	7,824,999.91	1.121	8,771,276.91	498,401,921.01	
353	1982	39.5	10,952,530.81	50	29.38	-15.00%	4,517,360.38	5,194,964.44	1.121	5,823,191.32	321,758,521.50	
353	1981	40.5	11,413,782.57	50	29.04	-15.00%	4,783,921.69	5,501,509.95	1.121	6,166,807.37	331,493,043.87	
353	1980	41.5	16,913,207.95	50	28.71	-15.00%	7,200,765.81	8,280,880.68	1.121	9,282,287.33	485,622,106.93	
353	1979	42.5	13,323,028.32	50	28.39	-15.00%	5,759,378.07	6,623,284.78	1.121	7,424,238.41	378,182,512.40	
353	1978	43.5	7,711,275.04	50	28.06	-15.00%	3,383,356.62	3,890,860.12	1.121	4,361,381.71	216,395,920.77	
353	1977	44.5	12,498,656.50	50	27.74	-15.00%	5,563,779.94	6,398,346.93	1.121	7,172,098.83	346,743,827.97	
353	1976	45.5	9,955,503.55	50	27.43	-15.00%	4,494,665.35	5,168,865.15	1.121	5,793,935.85	273,041,910.22	
353	1975	46.5	7,523,091.82	50	27.11	-15.00%	3,443,551.74	3,960,084.50	1.121	4,438,977.40	203,977,004.00	
353	1974	47.5	7,962,578.79	50	26.80	-15.00%	3,693,979.81	4,248,076.78	1.121	4,761,796.57	213,429,949.25	
353	1973	48.5	6,366,335.61	50	26.50	-15.00%	2,992,407.56	3,441,268.70	1.121	3,857,421.21	168,696,402.43	
353	1972	49.5	4,233,409.19	50	26.20	-15.00%	2,015,472.61	2,317,793.50	1.121	2,598,084.19	110,896,829.25	
353	1971	50.5	6,018,844.19	50	25.90	-15.00%	2,901,516.38	3,336,743.83	1.121	3,740,256.16	155,866,390.66	
353	1970	51.5	5,279,307.74	50	25.60	-15.00%	2,576,254.14	2,962,692.26	1.121	3,320,970.54	135,152,680.23	
353	1969	52.5	3,682,050.17	50	25.31	-15.00%	1,818,361.26	2,091,115.44	1.121	2,343,993.97	93,184,445.69	
353	1968	53.5	3,128,284.54	50	25.02	-15.00%	1,562,998.26	1,797,447.99	1.121	2,014,813.32	78,264,314.18	
353	1967	54.5	2,778,382.97	50	24.73	-15.00%	1,404,084.45	1,614,697.12	1.121	1,809,962.39	68,714,925.94	
353	1966	55.5	6,402,361.58	50	24.45	-15.00%	3,271,754.79	3,762,518.01	1.121	4,217,519.19	156,530,339.50	
353	1965	56.5	2,039,500.56	50	24.17	-15.00%	1,053,654.37	1,211,702.52	1.121	1,358,233.67	49,292,309.69	
353	1964	57.5	2,578,857.04	50	23.89	-15.00%	1,346,583.06	1,548,570.52	1.121	1,735,839.10	61,613,699.10	
353	1963	58.5	2,420,957.32	50	23.62	-15.00%	1,277,395.47	1,469,004.79	1.121	1,646,651.49	57,178,092.51	
353	1962	59.5	1,005,228.16	50	23.35	-15.00%	535,844.99	616,221.74	1.121	690,741.42	23,469,158.35	
353	1961	60.5	995,065.22	50	23.08	-15.00%	535,758.60	616,122.39	1.121	690,630.05	22,965,331.12	
353	1960	61.5	1,007,852.86	50	22.81	-15.00%	547,983.67	630,181.22	1.121	706,389.02	22,993,459.52	
353	1959	62.5	1,420,805.16	50	22.55	-15.00%	779,955.85	896,949.23	1.121	1,005,417.27	32,042,465.41	
353	1958	63.5	2,443,138.47	50	22.29	-15.00%	1,353,827.61	1,556,901.75	1.121	1,745,177.83	54,465,543.12	
353	1957	64.5	1,115,924.15	50	22.04	-15.00%	624,089.71	717,703.17	1.121	804,494.99	24,591,722.04	
353	1956	65.5	1,881,355.05	50	21.78	-15.00%	1,061,694.60	1,220,948.79	1.121	1,368,598.09	40,983,022.63	
353	1955	66.5	978,866.27	50	21.53	-15.00%	557,301.63	640,896.88	1.121	718,400.52	21,078,231.82	
353	1954	67.5	1,478,536.00	50	21.29	-15.00%	849,103.74	976,469.30	1.121	1,094,553.70	31,471,613.12	
353	1953	68.5	1,032,212.09	50	21.04	-15.00%	597,840.67	687,516.76	1.121	770,658.15	21,718,571.24	
353	1952	69.5	833,173.11	50	20.80	-15.00%	486,594.19	559,583.32	1.121	627,253.71	17,328,945.89	
353	1951	70.5	612,665.75	50	20.56	-15.00%	360,744.73	414,856.43	1.121	465,025.01	12,596,051.25	
353	1950	71.5	809,640.75	50	20.32	-15.00%	480,556.75	552,640.26	1.121	619,471.03	16,454,200.23	
353	1949	72.5	793,686.73	50	20.09	-15.00%	474,799.32	546,019.22	1.121	612,049.31	15,944,370.34	
353	1948	73.5	316,550.29	50	19.86	-15.00%	190,830.03	219,454.53	1.121	245,993.16	6,286,013.24	
353	1947	74.5	8,204.89	50	19.63	-15.00%	4,983.74	5,731.31	1.121	6,424.39	161,057.29	
353	1946	75.5	59,814.29	50	19.40	-15.00%	36,601.97	42,092.26	1.121	47,182.48	1,160,616.21	
353	1945	76.5	24,935.63	50	19.18	-15.00%	15,370.03	17,675.54	1.121	19,813.04	478,279.92	
353	1944	77.5	12,426.35	50	18.96	-15.00%	7,714.24	8,871.38	1.121	9,944.19	235,605.53	
353	1943	78.5	70,962.40	50	18.74	-15.00%	44,362.30	51,016.64	1.121	57,186.09	1,330,005.05	
353	1942	79.5	27,428.18	50	18.53	-15.00%	17,264.80	19,854.52	1.121	22,255.52	508,169.21	
353	1941	80.5	1,337,125.14	50	18.31	-15.00%	847,342.14	974,443.46	1.121	1,092,282.88	24,489,150.10	
353	1940	81.5	412.15	50	18.10	-15.00%	262.91	302.35	1.121	338.91	7,461.94	
353	1939	82.5	41,144.29	50	17.90	-15.00%	26,416.54	30,379.02	1.121	34,052.76	736,387.50	
353	1938	83.5	659.88	50	17.69	-15.00%	426.37	490.33	1.121	549.63	11,675.31	

2022 RATE CASE
ONCOR ELECTRIC DELIVERY LLC
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FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
353	1936	85.5	249.82	50	17.29	-15.00%	163.42	187.94	1.121	210.66	4,319.82	
353	1935	86.5	27.28	50	17.09	-15.00%	17.95	20.65	1.121	23.14	466.35	
353	1933	88.5	1,550.00	50	16.71	-15.00%	1,032.01	1,186.81	1.121	1,330.33	25,899.51	
353	1932	89.5	104.61	50	16.52	-15.00%	70.05	80.55	1.121	90.29	1,728.21	
353	1931	90.5	353.78	50	16.33	-15.00%	238.21	273.94	1.121	307.06	5,778.73	
353	1930	91.5	23,576.38	50	16.15	-15.00%	15,960.89	18,355.03	1.121	20,574.70	380,774.29	
353	1929	92.5	53,637.16	50	15.97	-15.00%	36,505.73	41,981.59	1.121	47,058.42	856,571.45	
353	1928	93.5	385,354.18	50	15.79	-15.00%	263,648.22	303,195.46	1.121	339,860.87	6,085,297.80	
353	1927	94.5	16,912.95	50	15.62	-15.00%	11,630.75	13,375.37	1.121	14,992.85	264,109.84	
353	1926	95.5	2,317.87	50	15.44	-15.00%	1,601.98	1,842.27	1.121	2,065.06	35,794.66	
353	1925	96.5	55,090.85	50	15.27	-15.00%	38,263.16	44,002.64	1.121	49,323.88	841,384.32	
353	1924	97.5	7,819.43	50	15.11	-15.00%	5,457.16	6,275.73	1.121	7,034.66	118,113.57	
353	1923	98.5	113,892.41	50	14.94	-15.00%	79,860.67	91,839.78	1.121	102,945.96	1,701,586.77	
353	1921	100.5	14,608.44	50	14.62	-15.00%	10,337.26	11,887.85	1.121	13,325.44	213,559.16	
353	1920	101.5	6,098.66	50	14.46	-15.00%	4,334.65	4,984.84	1.121	5,587.66	88,200.70	
353	1915	106.5	670.88	50	13.72	-15.00%	486.77	559.79	1.121	627.48	9,205.47	
353	1912	109.5	4,822.42	50	13.31	-15.00%	3,538.58	4,069.36	1.121	4,561.47	64,192.13	
353	1900	121.5	7,335.90	50	11.93	-15.00%	5,585.19	6,422.97	1.121	7,199.70	87,535.28	
353 Total			3,559,128,940.87				534,641,648.34	614,837,895.59		689,190,223.15	151,224,364,626.70	42.49
354	2021	0.5	71,337,648.73	70	69.53	-40.00%	481,541.36	674,157.90	1.121	755,683.80	4,959,927,516.02	
354	2020	1.5	133,419,225.30	70	68.58	-40.00%	2,698,866.99	3,778,413.78	1.121	4,235,337.24	9,150,425,081.91	
354	2019	2.5	59,577,164.05	70	67.64	-40.00%	2,005,754.59	2,808,056.43	1.121	3,147,634.61	4,029,998,661.96	
354	2018	3.5	53,698,639.86	70	66.71	-40.00%	2,527,581.94	3,538,614.71	1.121	3,966,539.28	3,581,974,054.60	
354	2017	4.5	58,542,456.29	70	65.77	-40.00%	3,537,485.63	4,952,479.88	1.121	5,551,383.12	3,850,347,946.38	
354	2016	5.5	55,602,327.20	70	64.84	-40.00%	4,100,376.94	5,740,527.71	1.121	6,434,729.55	3,605,136,518.29	
354	2015	6.5	27,458,000.37	70	63.91	-40.00%	2,389,296.74	3,345,015.43	1.121	3,749,528.04	1,754,809,254.40	
354	2014	7.5	187,072,140.94	70	62.98	-40.00%	18,752,808.92	26,253,932.49	1.121	29,428,819.73	11,782,353,241.42	
354	2013	8.5	576,728,813.83	70	62.06	-40.00%	65,415,424.51	91,581,594.32	1.121	102,656,553.67	35,791,937,252.14	
354	2012	9.5	71,386,965.67	70	61.14	-40.00%	9,034,304.01	12,648,025.62	1.121	14,177,550.96	4,364,686,315.94	
354	2011	10.5	126,801,946.27	70	60.23	-40.00%	17,706,411.84	24,788,976.57	1.121	27,786,706.74	7,636,687,410.33	
354	2010	11.5	84,230,644.28	70	59.31	-40.00%	12,858,817.41	18,002,344.38	1.121	20,179,367.32	4,996,027,880.64	
354	2009	12.5	22,946,259.05	70	58.41	-40.00%	3,800,767.21	5,321,074.10	1.121	5,964,551.42	1,340,184,428.68	
354	2008	13.5	7,987,856.87	70	57.50	-40.00%	1,426,262.77	1,996,767.88	1.121	2,238,236.95	459,311,587.10	
354	2007	14.5	21,978,354.48	70	56.60	-40.00%	4,206,960.35	5,889,744.49	1.121	6,601,991.11	1,243,997,589.19	
354	2006	15.5	40,144,352.46	70	55.70	-40.00%	8,198,111.63	11,477,356.28	1.121	12,865,312.61	2,236,236,858.34	
354	2005	16.5	17,962,600.52	70	54.81	-40.00%	3,897,029.81	5,455,841.73	1.121	6,115,616.50	984,589,949.96	
354	2004	17.5	10,626,513.12	70	53.93	-40.00%	2,440,205.22	3,416,287.31	1.121	3,829,418.83	573,041,552.84	
354	2003	18.5	10,752,263.45	70	53.04	-40.00%	2,604,622.77	3,646,471.88	1.121	4,087,439.61	570,334,847.71	
354	2002	19.5	41,818,468.10	70	52.16	-40.00%	10,654,794.86	14,916,712.81	1.121	16,720,590.42	2,181,457,126.60	
354	2001	20.5	33,294,202.02	70	51.29	-40.00%	8,898,243.63	12,457,541.08	1.121	13,964,031.13	1,707,717,087.40	
354	2000	21.5	2,280,195.17	70	50.42	-40.00%	637,695.54	892,773.75	1.121	1,000,736.86	114,974,974.24	
354	1999	22.5	2,381,265.29	70	49.56	-40.00%	695,337.15	973,472.01	1.121	1,091,193.95	118,014,969.61	
354	1998	23.5	1,915,860.36	70	48.70	-40.00%	582,920.96	816,089.34	1.121	914,779.00	93,305,758.04	
354	1997	24.5	5,305,552.81	70	47.85	-40.00%	1,678,955.37	2,350,537.52	1.121	2,634,787.95	253,861,820.46	
354	1996	25.5	1,646,463.09	70	47.00	-40.00%	540,952.65	757,333.70	1.121	848,918.05	77,385,731.11	
354	1995	26.5	1,018,072.79	70	46.16	-40.00%	346,743.01	485,440.22	1.121	544,144.49	46,993,084.47	
354	1994	27.5	1,266,997.89	70	45.32	-40.00%	446,661.16	625,325.62	1.121	700,946.23	57,423,571.42	
354	1993	28.5	1,859,688.57	70	44.49	-40.00%	677,676.25	948,746.75	1.121	1,063,478.67	82,740,862.16	
354	1992	29.5	1,212,023.68	70	43.67	-40.00%	455,951.43	638,332.00	1.121	715,525.47	52,925,057.46	
354	1991	30.5	1,422,233.79	70	42.85	-40.00%	551,665.19	772,331.26	1.121	865,729.25	60,939,802.32	
354	1990	31.5	1,114,647.62	70	42.03	-40.00%	445,310.24	623,434.34	1.121	698,826.24	46,853,616.37	
354	1989	32.5	1,624,604.28	70	41.23	-40.00%	667,754.18	934,855.85	1.121	1,047,907.94	66,979,506.93	
354	1988	33.5	6,726,411.74	70	40.43	-40.00%	2,841,681.61	3,978,354.25	1.121	4,459,456.51	271,931,109.28	
354	1987	34.5	3,178,243.06	70	39.63	-40.00%	1,378,751.03	1,930,251.45	1.121	2,163,676.69	125,964,441.83	
354	1986	35.5	6,086,918.56	70	38.85	-40.00%	2,709,060.15	3,792,684.21	1.121	4,251,333.39	236,450,088.83	
354	1985	36.5	7,825,840.04	70	38.06	-40.00%	3,570,345.33	4,998,483.46	1.121	5,602,949.90	297,884,630.01	

2022 RATE CASE
ONCOR ELECTRIC DELIVERY LLC
CALCULATION OF GENERAL PLANT BOOK RESERVE AND REMAINING LIFE
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Acct	Vintage Yr	Age	Plant	ASL	Remaining Life	Net Salvage	Theo Res 0% Salv	Theo Res w Salv	Proration	Allocated Res	$ x RL	RL
354	1984	37.5	41,706,934.64	70	37.29	-40.00%	19,489,041.04	27,284,657.46	1.121	30,584,190.23	1,555,252,551.99	
354	1983	38.5	9,123,582.56	70	36.52	-40.00%	4,363,462.06	6,108,846.88	1.121	6,847,589.55	333,208,434.98	
354	1982	39.5	11,432,807.59	70	35.76	-40.00%	5,592,042.78	7,828,859.89	1.121	8,775,603.67	408,853,536.90	
354	1981	40.5	13,367,122.93	70	35.01	-40.00%	6,682,176.44	9,355,047.02	1.121	10,486,352.56	467,946,254.29	
354	1980	41.5	7,721,170.49	70	34.26	-40.00%	3,942,128.31	5,518,979.63	1.121	6,186,389.66	264,532,952.88	
354	1979	42.5	2,131,714.56	70	33.52	-40.00%	1,110,890.21	1,555,246.29	1.121	1,743,322.18	71,457,704.72	
354	1978	43.5	2,541,367.68	70	32.79	-40.00%	1,350,958.78	1,891,342.30	1.121	2,120,062.26	83,328,622.77	
354	1977	44.5	4,164,712.69	70	32.06	-40.00%	2,256,999.53	3,159,799.34	1.121	3,541,913.77	133,539,921.48	
354	1976	45.5	12,551,313.77	70	31.35	-40.00%	6,930,663.51	9,702,928.92	1.121	10,876,303.81	393,445,518.14	
354	1975	46.5	8,088,064.74	70	30.64	-40.00%	4,547,975.07	6,367,165.10	1.121	7,137,146.18	247,806,276.68	
354	1974	47.5	4,384,822.19	70	29.94	-40.00%	2,509,560.21	3,513,384.29	1.121	3,938,257.75	131,268,338.59	
354	1973	48.5	2,322,496.52	70	29.24	-40.00%	1,352,216.93	1,893,103.70	1.121	2,122,036.67	67,919,571.31	
354	1972	49.5	7,130,824.56	70	28.56	-40.00%	4,221,496.63	5,910,095.28	1.121	6,624,802.92	203,652,955.16	
354	1971	50.5	6,706,147.96	70	27.88	-40.00%	4,034,886.61	5,648,841.25	1.121	6,331,955.44	186,988,294.78	
354	1970	51.5	5,370,578.80	70	27.22	-40.00%	3,282,491.93	4,595,488.70	1.121	5,151,221.01	146,166,080.78	
354	1969	52.5	6,087,949.41	70	26.56	-40.00%	3,778,285.16	5,289,599.22	1.121	5,929,270.29	161,676,497.51	
354	1968	53.5	2,310,062.00	70	25.91	-40.00%	1,455,065.48	2,037,091.68	1.121	2,283,437.11	59,849,756.21	
354	1967	54.5	1,825,187.96	70	25.27	-40.00%	1,166,347.62	1,632,886.67	1.121	1,830,351.60	46,118,823.82	
354	1966	55.5	2,571,066.33	70	24.64	-40.00%	1,666,124.37	2,332,574.11	1.121	2,614,652.23	63,345,937.38	
354	1965	56.5	889,072.94	70	24.02	-40.00%	584,023.94	817,633.51	1.121	916,509.91	21,353,430.25	
354	1964	57.5	3,211,121.81	70	23.41	-40.00%	2,137,362.91	2,992,308.07	1.121	3,354,167.79	75,163,123.17	
354	1963	58.5	2,552,635.73	70	22.81	-40.00%	1,720,925.20	2,409,295.28	1.121	2,700,651.28	58,219,737.18	
354	1962	59.5	4,931,104.51	70	22.22	-40.00%	3,365,997.93	4,712,397.11	1.121	5,282,267.14	109,557,460.43	
354	1961	60.5	2,411,192.85	70	21.64	-40.00%	1,665,785.50	2,332,099.70	1.121	2,614,120.44	52,178,514.67	
354	1960	61.5	451,290.63	70	21.07	-40.00%	315,436.10	441,610.55	1.121	495,014.49	9,509,816.84	
354	1959	62.5	104,242.74	70	20.52	-40.00%	73,689.35	103,165.09	1.121	115,640.84	2,138,737.14	
354	1958	63.5	227,071.53	70	19.97	-40.00%	162,282.86	227,196.01	1.121	254,670.81	4,535,206.80	
354	1957	64.5	550,661.56	70	19.44	-40.00%	397,736.67	556,831.34	1.121	624,168.93	10,704,742.33	
354	1956	65.5	441,323.96	70	18.92	-40.00%	322,042.96	450,860.15	1.121	505,382.65	8,349,669.70	
354	1955	66.5	347,022.22	70	18.41	-40.00%	255,753.56	358,054.99	1.121	401,354.56	6,388,806.08	
354	1954	67.5	772,151.72	70	17.91	-40.00%	574,537.40	804,352.36	1.121	901,622.67	13,833,002.32	
354	1953	68.5	101,003.57	70	17.43	-40.00%	75,852.68	106,193.75	1.121	119,035.76	1,760,562.22	
354	1952	69.5	337,204.34	70	16.96	-40.00%	255,506.96	357,709.74	1.121	400,967.57	5,718,816.67	
354	1951	70.5	9,663.84	70	16.50	-40.00%	7,385.85	10,340.19	1.121	11,590.63	159,459.21	
354	1950	71.5	56,679.46	70	16.05	-40.00%	43,680.41	61,152.57	1.121	68,547.75	909,933.47	
354	1949	72.5	43,733.30	70	15.62	-40.00%	33,974.31	47,564.03	1.121	53,315.94	683,129.63	
354	1948	73.5	3,486.18	70	15.20	-40.00%	2,729.26	3,820.96	1.121	4,283.03	52,984.66	
354	1947	74.5	2,842.58	70	14.79	-40.00%	2,242.00	3,138.80	1.121	3,518.37	42,040.70	
354	1942	79.5	30,655.90	70	12.92	-40.00%	24,996.98	34,995.77	1.121	39,227.81	396,124.50	
354	1941	80.5	317,636.98	70	12.58	-40.00%	260,543.50	364,760.90	1.121	408,871.43	3,996,543.42	
354	1940	81.5	1,511.46	70	12.25	-40.00%	1,246.91	1,745.67	1.121	1,956.78	18,518.52	
354	1939	82.5	85,966.71	70	11.93	-40.00%	71,312.16	99,837.03	1.121	111,910.31	1,025,818.40	
354	1932	89.5	2,161.68	70	9.93	-40.00%	1,855.09	2,597.12	1.121	2,911.19	21,461.57	
354	1931	90.5	1,528.13	70	9.67	-40.00%	1,317.08	1,843.92	1.121	2,066.90	14,773.29	
354 Total			1,929,652,755.31				297,954,160.60	417,135,824.84		467,580,047.14	114,218,901,629.94	59.19
355	2021	0.5	349,533,921.54	55	54.59	-75.00%	2,618,549.26	4,582,461.21	1.121	5,136,618.10	19,080,345,475.34	
355	2020	1.5	248,738,585.96	55	53.77	-75.00%	5,576,379.91	9,758,664.84	1.121	10,938,779.87	13,373,921,332.85	
355	2019	2.5	290,790,938.27	55	52.95	-75.00%	10,838,084.92	18,966,648.61	1.121	21,260,284.84	15,397,406,934.16	
355	2018	3.5	271,830,322.04	55	52.14	-75.00%	14,148,417.35	24,759,730.37	1.121	27,753,923.79	14,172,504,757.73	
355	2017	4.5	210,909,620.95	55	51.33	-75.00%	14,078,504.80	24,637,383.40	1.121	27,616,781.41	10,825,711,388.12	
355	2016	5.5	257,652,006.56	55	50.52	-75.00%	20,967,392.37	36,692,936.65	1.121	41,130,212.34	13,017,653,780.28	
355	2015	6.5	99,870,160.57	55	49.72	-75.00%	9,579,943.47	16,764,901.07	1.121	18,792,280.03	4,965,961,940.68	
355	2014	7.5	140,782,395.54	55	48.92837	-75.00%	15,541,429.39	27,197,501.43	1.121	30,486,494.43	6,888,253,138.47	
355	2013	8.5	177,283,959.06	55	48.136744	-75.00%	22,122,639.92	38,714,619.86	1.121	43,396,377.64	8,533,872,552.58	
355	2012	9.5	52,234,063.50	55	47.349317	-75.00%	7,265,932.03	12,715,381.05	1.121	14,253,051.69	2,473,247,230.86	
355	2011	10.5	39,157,922.51	55	46.566093	-75.00%	6,004,623.21	10,508,090.62	1.121	11,778,833.70	1,823,431,461.29	

INDEX TO THE DIRECT TESTIMONY

OF DANE A. WATSON, WITNESS FOR

ONCOR ELECTRIC DELIVERY COMPANY LLC

DIRECT TESTIMONY OF DANE A. WATSON

I. POSITION AND QUALIFICATIONS

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

A. My name is Dane A. Watson. My business address is 101 E. Park Blvd, Suite 220, Plano Texas 75074. I am a Partner of Alliance Consulting Group ("Alliance"). Alliance provides consulting and expert services to the utility industry.

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

A. I am testifying on behalf of Oncor Electric Delivery Company LLC ("Oncor" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a master's degree in Business Administration from Amberton University.

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

A. Yes. I have conducted depreciation studies and filed testimony on depreciation and valuation issues before the Commission in Docket Nos. 11735, 12160, 15195, 16650, 18490, 20285, 22350, 23640, 24040, 32766, 34040, 35763, 35717, 36633, 38147, 38339, 38480, 38929, 40020, 40604, 40606, 40824, 41474, 42004, 42469, 43695, 43950, 44746, 44704, 45414, 46957, 47527, 48371, 48231, 48401, 49421, 49831, 50288, 50557, 50944, 51536. 51611, and 51802 among others. In addition, I have testified on behalf of various entities in more than 290 proceedings before more than 35 different regulatory bodies in my 37-year career of performing depreciation studies. My Exhibit DAW-1 lists instances in which I have conducted depreciation studies, filed written testimony, and/or testified live before various regulatory commissions.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("SDP") has established international standards for depreciation professionals. The SDP administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and am a Certified Depreciation Professional ("CDP").

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Since graduating from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance in 2004 and am responsible for conducting depreciation, valuation, and certain accounting-related studies for utilities in various industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with TXU Corp. and its predecessors ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I also served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer ("PE") in the State of Texas and a CDP. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and have held numerous offices on the Executive Board of the

Dallas Section of IEEE as well as national and worldwide offices. I have twice served as President of the SDP, most recently in 2015. I also teach depreciation seminars on an annual basis for EEI and the American Gas Association (both basic and advanced levels), and I develop and teach the advanced training for the SDP and other venues.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

- discuss the recent depreciation study completed for Oncor assets; and
- support and justify the recommended depreciation rate changes for Oncor assets based on the results of the depreciation study.

The depreciation study is provided as Exhibit DAW-2 to my direct testimony.

Q. HAS THE COMPOSITION OF ONCOR'S ASSETS CHANGED SINCE THE LAST DEPRECIATION STUDY?

A. Yes. In Oncor's last base-rate case, Docket No. 46957, the Commission's Order was predicated on Oncor and the company known at that time as Sharyland Distribution & Transmission Services, L.L.C. ("Sharyland") reaching closing on a transaction to exchange assets (Oncor was to acquire primarily distribution assets, while Sharyland was to receive certain Oncor transmission assets). The Sharyland transaction did close, and the asset exchange took place in 2017. This transaction is discussed in greater detail in Company witness Mr. James A. Greer's direct testimony. Also, Oncor's distribution facilities in the McAllen and Mission, Texas area that were acquired in the asset exchange were sold to AEP Texas Inc. for net book value with no gain or loss arising from the sale. As a result, there was no impact on my depreciation analysis related to this transaction.

Additionally, as described in greater detail in the direct testimony of Oncor witness Mr. Wesley R. Speed, in 2019, the Commission approved a transaction in Docket No. 48929 that resulted in Oncor's acquisition of the electric transmission assets previously held by Sharyland and/or Sharyland Utilities, L.P. Following the close of that transaction, Sharyland became a wholly-owned subsidiary of Oncor, Oncor Electric Delivery Company NTU LLC ("Oncor NTU"), and continues to hold those assets. Those assets now held by Oncor NTU include mostly transmission, distribution, and general plant. The Oncor NTU assets are currently being depreciated at the depreciation rates approved for Sharyland in Docket No. 45414, which retained the then-existing depreciation rates from Docket No. 41474.

Q. HOW ARE THE ASSETS HELD BY ONCOR NTU TREATED IN THIS DEPRECIATION STUDY?

A. At Oncor's request, I have prepared one depreciation study that combines Oncor and Oncor NTU assets. I am recommending one set of combined depreciation and amortization rates to be applied to both companies. Since Oncor's acquisition, Oncor NTU's transmission facilities have been operated and maintained, and new assets have been constructed and accounted for, consistent with the same business practices currently utilized by Oncor.

Q. WILL ONCOR AND ONCOR NTU BE SEPARATE BUSINESS ENTITIES FOR FINANCIAL REPORTING AND TAX PURPOSES?

A. Yes. As agreed and ordered by the Commission in Docket No. 48929, each entity will maintain separate books and records for external reporting and tax purposes. The rate filing package will reflect a single consolidated Company (including legacy Oncor and Oncor NTU), with functionalization of electric utility plant in service as specified by Commission rules. Functionalization of the consolidated Company's electric utility plant and the corresponding depreciation reserve accounts are discussed in the direct testimony of Company witness Mr. W. Alan Ledbetter. I functionalized accumulated depreciation and amortization amounts as well as proposed depreciation and amortization amounts for rate making based on functionalization plant amounts provided to me.

Q. WHAT IS THE AMOUNT OF ANNUAL DEPRECIATION EXPENSE THAT YOU ARE RECOMMENDING IN THIS PROCEEDING?

A. Based on the Company's depreciable plant in service at December 31, 2021, I recommend an annual depreciation expense for the combined utility plant assets of Oncor and Oncor NTU of approximately $900.9 million dollars. This is an increase of $34.1 million over the annualized depreciation expense calculated on year-end 2021 investment using the current depreciation rates, which were approved approximately four and a half years ago for Oncor in Docket No. 46957 and six and a half years ago in Sharyland's Docket No. 41474. For purposes of my testimony, I will refer to the combined costs of utility plant assets and the depreciation expense for Oncor and Oncor NTU as those of "Oncor."

Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE INFLUENCED THE PROPOSED CHANGES IN THE COMPANY'S DEPRECIATION RATES?

A. There are two key factors that are driving the change in depreciation rates. First, the lives of assets contained within certain utility plant accounts have changed from the last depreciation study, with many of the asset lives being longer than previously approved. This has, therefore, necessitated a change in the lives and corresponding depreciation rate for the account, resulting in decreased depreciation expense. Second, the underlying cost of removing transmission and distribution assets has changed since the current net salvage rates (*i.e.,* rates reflecting removal costs less salvage proceeds) were established. In certain accounts, this has resulted in the Company incurring removal costs for retiring assets that have not been provided for in depreciation rates. These under-recovered amounts require that additional accruals be provided for in net salvage rates, which results in increased depreciation expense. This is somewhat offset by the experienced net salvage moving less negative in certain other accounts.

Q. DOES THE DEPRECIATION STUDY YOU SPONSOR IN THIS CASE REFLECT THE MOST CURRENT DATA AVAILABLE FOR ONCOR ASSETS?

A. Yes. In preparing this study, I have updated the data, analysis, and the resulting depreciation rates reflected in the depreciation study that I previously performed for Oncor assets through December 31, 2016, to reflect historical data through test-year-end December 31, 2021.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

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

Q. WHAT COST-OF-SERVICE SCHEDULES DO YOU SPONSOR IN ONCOR'S RATE FILING PACKAGE ("RFP")?

A. I sponsor Schedule B-5 and co-sponsor Schedule E-1.

Q. HAVE YOUR TESTIMONY, YOUR EXHIBITS, AND THE RFP SCHEDULES THAT YOU SPONSOR BEEN PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes. My testimony, exhibits, and workpapers and the schedules that I sponsor or co-sponsor were prepared by me or under my direct supervision and are true and correct to the best of my knowledge and belief.

III. DEPRECIATION POLICY

Q. WHAT OBJECTIVE SHOULD THE COMMISSION STRIVE TO ACHIEVE IN SETTING DEPRECIATION RATES?

A. The objective of computing depreciation is to determine and include depreciation expense in customer rates and to ensure that, prospectively, all customers benefiting from the use of the Company's assets pay their pro rata share of the investment, including the future costs to remove and dispose of these assets at the end of their useful life. Customers pay their pro-rata share through the allocation of the cost of the depreciable assets over their useful life. Depreciation is recognized by charging a portion of the consumption of the assets to each accounting period through the application of Commission-approved depreciation rates.

Q. IS THIS OBJECTIVE CONSISTENT WITH COMMISSION RULES AND HISTORICAL PRACTICE?

A. Yes. As required by 16 Tex. Admin. Code ("TAC") § 25.231(b)(1)(B) and the Commission's prior rate decisions, the Commission has a long-standing practice of establishing depreciation rates using the straight-line depreciation method based on the actual historic data of the utility. The straight-line method of depreciation operates by collecting a pro rata share of the cost of the investment, including removal cost, net of salvage, from all customers that use the asset over its useful life.

Q. WHAT IS THE BEST EVIDENCE THAT THE COMMISSION CAN RELY ON IN ORDER TO ENSURE THAT THE COST OF ASSETS ARE RATABLY RECOVERED OVER THE SERVICE LIVES?

A. The best evidence is based on the actual experience of the specific group of assets being analyzed, as taken from the actual books and records of the Company to the fullest extent possible. Adjustments to the Company's asset cost recovery may at times be necessary when the actual historical experience of the Company reflects changing lives or net salvage factors. Changes can be driven by, among other things, changes in the Company's construction, operating or maintenance practices, as conveyed to me through interviews with Company personnel. This evidence is found in my depreciation study, which is based on the Company's plant investment in service at December 31, 2021.

IV. <u>ONCOR DEPRECIATION STUDY</u>

A. SUMMARY OF THE DEPRECIATION STUDY RESULTS

Q. HAVE YOU PREPARED A DEPRECIATION STUDY FOR ONCOR?

A. Yes. In connection with the filing of this case, I undertook a comprehensive analysis of annual depreciation for Oncor that is based on the Company's depreciable plant in service at December 31, 2021. The depreciation study analyzed the property characteristics of the Company's transmission plant, distribution plant, and general plant and proposes depreciation rates for these assets. Additionally, I have calculated the appropriate depreciation rates to be applied to the Company's investments in Federal Energy Regulatory Commission ("FERC") Account 303, Intangible Plant assets, based on an analysis of computer business system service lives that were provided to me by Company witness Ms. Malia A. Hodges and by also taking into consideration those amounts that have previously been recovered for these systems in the Company's rates. The study, along with the calculation of the rates for Intangible Plant assets, is attached to my direct testimony as Exhibit DAW–2.

Q. ARE ALL OF ONCOR'S ASSETS THAT ARE INCLUDED IN ACCOUNT 101, ELECTRIC PLANT IN SERVICE, INCLUDED IN THE DEPRECIATION STUDY?

A. No. Assets included in Account 101 that are classified as non-depreciable land are not included in the depreciation study. I have also excluded any asset that is not included in rate base, such as the Company's investment in aircraft. Additionally, as discussed in more detail in the testimony of Mr. Ledbetter, I have excluded certain transmission assets that are included in the proposed transfer of facilities to Lubbock Power and Light in Docket No. 52726. I have also excluded $3.2 million of plant in Account 362 consisting of mobile generators that are recovered through a capital lease. Finally, as discussed in the direct testimony of Company witness Mr. Ledbetter, there is a balance of approximately $23.5 million in unamortized FERC *A114 Electric Plant Acquisition Adjustments* related to Oncor NTU. I have provided Mr. Ledbetter with the estimated remaining useful life of these assets as of the 2021 test-year-end in order to determine the annual amortization expense associated with this investment in Oncor NTU FERC A114. I have incorporated my recommended depreciation expense for all other investment in the total requested depreciation and amortization expense shown in both RFP Schedule E-1 and the depreciation study, Exhibit DAW-2, Appendix B.

Q. HAVE THE RESULTS OF YOUR DEPRECIATION STUDY BEEN INCLUDED IN THE COMPANY'S TEST-YEAR-END DECEMBER 31, 2021 COST-OF-SERVICE REQUEST?

A. Yes. The results of my depreciation study have been applied to the plant balances as of December 31, 2021, and have been included in the Company's requested cost of service.

Q. WHEN DID THE LAST CHANGE IN THE COMPANY'S DEPRECIATION RATES OCCUR?

A. The last change in the Company's intangible, transmission, distribution, and general plant depreciation rates occurred in November 2017 with the final Order in Docket No. 46957. Those rates were established using (in part) a study I conducted based on plant in service at December 31, 2016, and were the result of a Commission-approved settlement agreement. As I previously mentioned, the depreciation rates utilized by Oncor NTU were approved in Sharyland's Docket No. 41474.

Q. ARE THE DEPRECIATION RATES IN THE SETTLEMENT AGREEMENT FROM DOCKET NO. 46957 INDICATIVE OF YOUR RECOMMENDATIONS IN THIS CASE?

A. No. In Docket No. 46957, Oncor agreed to depreciation rates that resulted in a depreciation expense that was $125 million lower than the amount originally requested in that case. My study in this proceeding is a thorough review of Oncor's assets and does not incorporate positions and negotiations that were necessary to obtain a settlement agreement in Docket No. 46957.

Q. DOES YOUR CURRENT DEPRECIATION STUDY ESTABLISH THAT THE COMPANY'S TRANSMISSION AND DISTRIBUTION ASSETS ARE CONTINUING TO EXPERIENCE LONGER SERVICE LIVES AND CHANGING NEGATIVE NET SALVAGE LEVELS?

A. Yes. A trend in longer service lives and changing net salvage amounts for the Company's transmission and distribution property has continued to occur since the 2016 depreciation study was completed. The Company's proposed depreciation rates in this case reflect this experience.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR TRANSMISSION PLANT BASED ON YOUR RECENT STUDY?

A. Yes. Based on my most recent depreciation study, the annual depreciation expense for Transmission assets, including transmission substations, should be decreased by approximately $50.0 million per year. This reflects the difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for Transmission, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR TRANSMISSION ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for transmission is 2.51 percent compared to the current functional depreciation rate of 2.89 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR DISTRIBUTION SUBSTATIONS BASED ON YOUR CURRENT STUDY?

A. Yes. Based on the current depreciation study, the annual depreciation expense for distribution substations should be increased by approximately $7.7 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for distribution substations, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR DISTRIBUTION SUBSTATIONS ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for distribution substations is 2.09 percent compared to the current functional depreciation rate of 1.80 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR DISTRIBUTION PLANT EXCLUDING SUBSTATIONS BASED ON YOUR CURRENT STUDY?

A. Yes. Based on the current depreciation study, the annual depreciation expense for distribution assets other than substations should be increased by approximately $27.5 million per year. This reflects the difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for distribution, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR DISTRIBUTION EXCLUDING SUBSTATIONS ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for distribution excluding substations is 2.89 percent as compared to the current functional depreciation rate of 2.68 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR GENERAL PLANT BASED ON YOUR MOST RECENT STUDY?

A. Yes. Based on my most recent study, the annual depreciation and vintage group amortization expense for general plant assets should be increased by approximately $39.9 million per year. This amount was determined by comparing the difference in depreciation expense between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for general plant as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR GENERAL PLANT ARE YOU PROPOSING AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. Oncor adopted the vintaged group amortization methodology consistent with FERC Accounting Release Number 15 ("AR-15") as of January 1, 2008. I calculated depreciation expense for a number of General Plant asset groups using this method. The General Plant accounts where Oncor adopted AR-15 amortization included Accounts 391 through 398 (excluding a portion of Account 397). AR-15 provides for the amortization of general plant over the same life as recommended in this study (with a separate amortization to allocate deficit or excess reserve as necessary). At the end of the amortizable life, all property is then retired from the books. Implementation of this approach did not affect the annual depreciation expense accrued by Oncor and provides for the retirement of assets and the simplification of accounting for certain general plant property. The Commission approved this approach in Docket No. 35717, Oncor's 2008 base-rate case, and Oncor has continued the use of AR-15 methodology since that case. Accounts 389 (Land Rights), 390 (Buildings and Structures) and portions of Account 397 (Communication Equipment) use the traditional (*i.e.*, non-AR-15 methodology) depreciation methodology and calculations. The effective proposed functional rate for general plant including AR15 assets is 7.09 percent as compared to the currently approved 3.89 percent. The study's workpapers include the amortization schedules for this approach. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of this rate are found in Exhibit DAW-2, Appendix A.

B. METHODOLOGICAL OVERVIEW OF DEPRECIATION STUDY

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR PURPOSES OF CONDUCTING YOUR DEPRECIATION STUDY AND PREPARING YOUR DIRECT TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conducted the depreciation study in four phases, as shown in my Exhibit DAW-2. The four phases are: Data Collection; Analysis; Evaluation; and Calculation. I began each of the studies by collecting the historical data to be used in the analysis. After the data had been assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, is then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans should be applied. As the former manager of the property accounting organization for the Company, I have personal knowledge of the Company's Continuing Property Records system and the fixed asset accounting procedures used by the Company. I am, therefore, uniquely positioned to gather, analyze, and evaluate the data used in the Company's depreciation studies. Using all of these resources, I then calculate the depreciation rate for each function.

Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?

A. There are four FERC functional classifications of property included in this study: intangible; transmission; distribution; and general property. Intangible property consists of software used for various purposes in the course of business. The transmission plant function includes high-voltage structures, substations, and transmission lines operating at 60 KV or greater that are used in the transmission of energy to the distribution system. The distribution plant function includes easements and Right-of-Ways, substation structures and equipment, transformers, meters, service conductors, conduit, distribution lines, guard lights, and street lighting used in the distribution and end use of energy on the distribution system that operates at less than 60 KV. The general plant function includes facilities associated with the overall operation of the business such as office equipment and computers rather than with a specific transmission or distribution classification. Some asset categories that were previously depreciated in larger asset group accounts have been segregated into different sub-accounts for this study. The asset sub-accounts relate to Direct Current ("DC") Ties, Static VAR Compensators ("SVC"), and Static Synchronous Compensator ("Statcom") equipment, separation of computer equipment from office fixtures and furnishings, and separation of small tools from other large tool, shop, and garage equipment.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE FOR YOUR STUDY?

A. I have used the straight-line, Average Life Group, remaining-life depreciation system to calculate annual and accrued depreciation in the study. The Commission has approved the use of this methodology in prior rate cases because it is reasonable and widely accepted. In addition, the Company wanted the depreciation study for this proceeding to employ the same accepted methodology that has been used in past depreciation studies for purposes of consistency.

C. SERVICE LIVES

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIFE FOR EACH ACCOUNT?

A. The establishment of an appropriate average service life for each account within a functional group was determined by using one of two widely accepted depreciation analyses: Actuarial analysis or Simulated Plant Record ("SPR") methods. Because vintaged data used in actuarial analysis contains more information than unaged data in SPR analysis, actuarial analysis is the preferred analysis tool for accounts when there are both a sufficient number of transaction years available to model an account and sufficient transactions within those years to be predictive in modeling the historical life parameters.

Q. WHAT ACCOUNTS USED ACTUARIAL ANALYSIS FOR LIFE SELECTIONS?

A. The accounts using actuarial analysis as the primary life modeling tool were: Accounts 352-355, 361, and 390 (where there were 32 years of actuarial data – from 1990-2021). I also modeled the depreciation portion of Account

397 with actuarial analysis since transaction data was amiable from 2000 through 2021. I excluded assets that are subject to amortization under AR-15 from life analysis. Accounts 356, 362, and many of the distribution overhead and underground line accounts 364-369 and, 371-373 were modeled with SPR analysis. In the case of distribution accounts (Accounts 364 through 369 and 371-373), which generally had only 23 years of actuarial data, the number of transaction years was not sufficient in many cases to conduct a fully predictive actuarial analysis. For this reason, I placed more weight on the SPR analysis for these accounts. Graphs and tables supporting the actuarial analysis or SPR and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Oncor Depreciation Study (Exhibit DAW-2) and the workpapers filed with Exhibit DAW-2. Judgment was used to factor any differences in the expected future life characteristics of the assets into the selection of lives. I would stress that the objective of life selection is to estimate the future life characteristics of assets and to not simply measure the historical life characteristics and mechanically project them into the future. More information can be found in the life analysis section of the Oncor Depreciation Study contained in Exhibit DAW-2.

1. Service Life Characteristics for Transmission and Distribution Substation Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE TRANSMISSION FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 6 of the12 accounts have longer lives ranging from an additional 7 years for Accounts 352 (Structures and Improvements) and 12 years for Account 354 (Towers and Fixtures) to an additional 4 years for Account 353 (Station Equipment). The lives for one account remained unchanged from the prior study, and the four accounts related to DC Ties and SVC assets have decreases in life.

Q. WHAT IS THE CAUSE OF THE GENERAL INCREASE IN LIVES FOR THE TRANSMISSION FUNCTIONAL GROUP?

A. Generally, transmission infrastructure across the country is experiencing longer service lives. The lengthening of service lives for transmission assets can be attributed to the changing mix of assets within the accounts, practices that extend the life of assets, and more robust maintenance practices. There are other factors that somewhat moderate the life increases such as a higher level of electronics on the system (which have shorter lives than the traditional long-lived assets in the accounts).

2. Service Life Characteristics for Distribution Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE DISTRIBUTION FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 8 out of the 13 distribution accounts have longer lives ranging from an additional two years for Account 362 – (Station Equipment) to an additional 13 years for Account 361 – (Structures and Improvements). No accounts had a decrease in life. Accounts 360 – (Land Rights), 370 – (Meters), 371 – (Installation on Customer Premises), and 373 - (Street Lighting) are proposed to retain the existing life.

Q. WHAT IS THE CAUSE OF THE GENERAL INCREASE IN LIVES FOR THE DISTRIBUTION FUNCTIONAL GROUP?

A. The Company has successfully implemented aggressive preventive maintenance programs that have increased the useful lives of distribution function assets. These preventive maintenance programs include cable cure for underground conductors, pole treatments and reinforcement, and a newer standard for cross-linked polyethylene ("XLP") conductors. These programs have extended the lives of distribution assets.

3. Service Life Characteristics for General Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE GENERAL PLANT FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 4 of the 16 general plant accounts have longer lives ranging from an additional two years for Account 390 – (Structures and Improvements) to an additional five years for Account 389 – (Land and Land Rights) and 397 (Communication Equipment – non-AR-15 methodology). For those general plant accounts that are subject to AR-15 amortization, this study recommends separating the assets in Account 391 (Office Furniture and Equipment) into two sub-accounts: (i) Computer Equipment; and (ii) Other Office Furniture and Equipment. Account 392 (Transportation Equipment) is proposed to be segregated into three separate sub-accounts: Light Trucks; Heavy Trucks; and Trailers. Additionally, Account 394 (Tools, Shop and Garage Equipment) is proposed to be separated into two sub-accounts: small tools and large tools. The separation of accounts 391, 392, and 394 into the proposed sub-accounts allows for these assets to be grouped and amortized using the AR-15 methodology more closely to their expected useful lives. Since these accounts are being recovered through general plant amortization, there is an automatic retirement process and, therefore, it is not possible to perform actuarial analysis to estimate the lives of those assets. As with other new asset groups, I have interviewed Company subject matter experts who work with the assets, and I used my professional judgment and experience to estimate the lives for these categories of plant. As such, Accounts 391, 392, and 394 collectively show an overall reduction in life.

Q. WHAT HAS CAUSED THE CHANGE IN LIVES FOR GENERAL PLANT ASSETS?

A. The largest increase in service life for general plant is in Account 390 – (Structures and Improvements). The increase in Account 390 is based on the expectation that the buildings and structures in this account are lasting longer than projected in 2016. The decreases in lives for Accounts 391 and 394 are based on a review of the assets in these accounts that have resulted in the proposal for new sub-accounts that I previously discussed.

4. Service Life of Intangible Assets

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR INTANGIBLE ASSETS BASED ON THE MOST RECENT STUDY?

A. Yes. Based on the most recent depreciation study, the annual depreciation expense for Intangible assets recorded in Account 303 should be increased by approximately $21.6 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for Intangible assets, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q, WHAT DEPRECIABLE LIVES ARE CURRENTLY USED BY ONCOR FOR DEPRECIATION OF INTANGIBLE ASSET INVESTMENT THAT IS RECORDED IN FERC ACCOUNT 303?

A. Oncor's intangible assets are currently classified into three groups – assets with five-year, eight-year, and 15-year estimated service lives. The Company has developed a set of comprehensive criteria for determining the service life for each of its software systems. While I have not personally made the determination of each system's expected useful life, I have reviewed the Company's criteria for assigning lives to its various computer software assets and find them to be reasonable and consistent with computer business system lives used by other companies within the electric utility industry. A listing of each of Oncor's computer business systems recorded in Account 303 and their estimated service lives are contained in my workpapers.

Q. ARE THESE THE SAME SERVICE LIFE GROUPS THAT WERE APPROVED IN THE COMPANY'S LAST BASE-RATE CASE?

A. Yes, with one exception. The Company has proposed the addition of a three-year service life group, which corresponds to the contractual licensing period for certain software applications. The five-year, eight-year, and 15-year service life groups are the same ones that were previously requested by Oncor and approved in the Company's last base-rate case, Docket No. 46957. In that docket, I calculated the depreciation rates for each of the Company's service life groups and have used the same methodology from Docket No. 46957 to calculate the service life group rates for this case

Q. PLEASE DESCRIBE WHAT IS MEANT BY CALCULATING DEPRECIATION RATES USING THE GROUP CONCEPT FOR INTANGIBLE ASSETS.

A. Calculating depreciation rates for intangible assets using the group concept allows for the accounting and ratemaking treatment to "mirror" the same treatment that is used for tangible assets, such as that used for poles and conductors. Under the group concept, depreciation expense is calculated by considering the remaining lives of the assets and the amount of accumulated depreciation that has been allocated to the group. Depreciation is then calculated and systematically allocated to accounting periods over the life of the properties. The amount allocated to each accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each estimated service life group. Upon retirement of an asset within the group, the original cost of the asset is removed from Electric Plant in Service FERC Account 101 and is charged to the depreciation reserve FERC Account 108 as opposed to recording a gain or loss on the income statement.

Q. IS ONCOR PROPOSING TO MAKE ANY CHANGES TO ITS ESTIMATED SERVICE LIFE GROUPS IN THIS CASE?

A. Yes. As I previously mentioned, Oncor proposes a new three-year life category be approved in addition to approval and continued use of the existing five-year, eight-year, and 15-year service life groups that were established in Docket No. 46957. This new three-year life category is needed for depreciation of Oncor's hosted software applications having three-year fixed-term agreements. Hosted software applications are those systems that are either owned by a third party and licensed by Oncor for a fixed period of time or a software application owned by Oncor that was developed by a third party and is hosted by the third party for a fixed period of time. Presently, third parties only support three- or five-year fixed-term agreements, therefore necessitating the addition of a new three-year service life category. For this filing, the Company requests the amount of approximately $408 thousand be included in the proposed three-year life group.

Q. HAS ONCOR ADDED OR REPLACED ANY SOFTWARE APPLICATIONS OR SYSTEMS SINCE ITS LAST BASE-RATE CASE THAT HAVE BEEN ADDED TO THESE GROUPS?

A. Yes. Oncor has added a number of new software applications or systems. Please refer to Company witnesses Mr. Joel S. Austin and Ms. Hodges' direct testimony for a discussion of these investments that have been added or replaced since the Company's last base-rate case. Each new software application or system placed into service during this time period has been assigned either a three-year, five-year, eight-year, or 15-year estimated service life. None of these software assets were projected to have a life in excess of 15 years.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR INTANGIBLE ASSETS BASED ON THE NEW GROUP DEPRECIATION RATES THAT YOU HAVE CALCULATED?

A. Yes. Based on my calculation of new group depreciation rates, the annual depreciation expense for Intangible assets should be increased by approximately $21.6 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for intangible assets, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. HAVE THERE BEEN ANY SIGNIFICANT CHANGES TO SOFTWARE ASSET SERVICE LIVES FOR SOFTWARE ADDED SINCE THE COMPANY'S LAST BASE-RATE CASE?

A. No. The systems that have been placed into service have incorporated the same life groups previously adopted in the Company's last base-rate case. I would note, however, that for the limited purpose of settling prior distribution cost recovery factor ("DCRF") cases, the Company agreed to temporarily recognize longer lives for two major intangible systems placed in service since Oncor's last base-rate case. Specifically, the Company's Customer Care and Billing ("CC&B") (placed in service in November 2017) and Advanced Enterprise Geographic Information System ("AEGIS") (placed in service in 2020) projects associated with these systems are included in the 15-year service life intangible asset group in this filing, In order to reflect the actual expected lives of CC&B and AEGIS. In my opinion, the 15-year lives recommended by the Company is more in line with the lives used by other utilities across the nation, regardless of the fact that Oncor agreed to a 25-year amortization period for these assets for settlement purposes in one or more prior DCRF cases.

Q. IN YOUR OPINION, WHAT FACTORS SUPPORT A 15-YEAR LIFE FOR THESE ASSETS?

A. Based on my interviews and discussions with Company management and Information Technology subject matter experts, the CC&B project included the replacement of a mainframe-based customer information and billing system that was more than 30 years old. The life of the prior Oncor system, however, has little relevance to today's technology and systems. In light of today's rapid pace of technological advancement and the evolving needs of customer information systems and graphical management tools, a 25-year life is outside industry norms. Oncor periodically upgrades the software implemented as part of the CC&B project, and these upgrades will eventually rewrite and replace existing computer code. When Oncor ascertains that the original code has been fully replaced through upgrades, the original software asset investment will be retired. Based on the upgrade schedule, even 15 years is possibly longer than the original vintage year 2017 may last. Therefore, it is reasonable to expect that the CC&B investment placed in service in 2017 will have a significantly shorter useful life than the previous investment it replaced, and extending the life of the asset beyond 15 years is simply not rational.

Similarly, a 25-year amortization period for the AEGIS investment does not reasonably align with the actual expected life of the asset. On the contrary, the proposed 15-year life is consistent with the expected useful life for large computer business systems that I have observed across electric and gas utility industries in the state of Texas and across the United States, as well as being consistent with Oncor's own accounting processes.

5. Service Life New Asset Groups

Q. ARE THERE ANY NEW CATEGORIES OF TANGIBLE ASSETS THAT ONCOR OWNS THAT WERE NOT PART OF THE COMPANY'S LAST DEPRECIATION STUDY IN DOCKET NO. 46957?

A. Yes. Since the last depreciation study, Oncor has added new asset types and has requested that I examine the asset mix in various accounts and determine if any sub-groupings would be appropriate for these new-assets. In the Transmission function, I reviewed information for DC Ties, Static Var Compensators (SVC), and StatCom Assets. I recommend these assets be separated into new, distinct subaccounts. Because these assets have only been in service a short time, there is insufficient historical retirement data available to model or predict the retirement patterns for those assets. Thus, I have interviewed Company experts who operate the assets and have used my professional judgment and experience to estimate the lives for those categories of plant.

D. NET SALVAGE RATES

Q. WHAT IS THE SIGNIFICANCE OF NET SALVAGE RATES FOR ONCOR PLANT ASSETS?

A. In general, net salvage values are the amounts received for retired property (salvage) less any costs incurred to sell or remove the property (removal). When salvage exceeds removal (positive net salvage), the net salvage reduces the amount to be depreciated over time. When removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated. For transmission and distribution plant in this depreciation study, the net salvage percentages were calculated for each property account using Company data from 1995 or 1998 through 2021. For general plant accounts, the net salvage percentages were calculated by property account using Company data from 1995 through 2021.

Q. HOW DID YOU DETERMINE THE NET SALVAGE RATES THAT YOU UTILIZED IN YOUR STUDY?

A. I examined the experience realized by the Company by observing the average net salvage for various bands (or combinations) of years. Using averages (such as the five-year and 10-year average bands) allows the smoothing of the timing differences between when retirements, removal cost, and salvage are booked and smooths the natural variations between years. By looking at successive average bands ("rolling bands"), an experienced analyst can see trends in the data that would signal the future net salvage in the account. This examination, in combination with the feedback of Company personnel related to any changes in operations or maintenance that would affect the future net salvage of the Company, allowed the selection of the best estimate of future net salvage for each account.

Q. IS THIS A REASONABLE METHOD FOR DETERMINING NET SALVAGE RATES?

A. Yes, it is. This methodology is commonly employed throughout the industry and is the method recommended in authoritative texts.

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGE IN THE NET SALVAGE VALUES OF THE TRANSMISSION AND DISTRIBUTION PROPERTY FROM THE EXISTING NET SALVAGE RATES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. The net salvage values for both transmission and distribution property have experienced a significant change since the Commission established the current net salvage rates for these assets more than four and a half years ago in Oncor's Docket No. 46957 and six and a half years ago in Sharyland's Docket No. 41474. The net salvage values used in the calculation of the transmission and distribution depreciation rates are listed in Exhibit DAW-2, Appendix E.

1. Net Salvage Rates for Transmission and Distribution Substation Property

Q. WHAT HAS CAUSED THE SIGNIFICANT CHANGE IN NET SALVAGE RATES FOR TRANSMISSION AND DISTRIBUTION SUBSTATION PROPERTY?

A. There are two primary reasons for the significant change in net salvage rates for transmission and distribution substation property. The first reason has to do with the Company's historical removal cost experience having changed from what is reflected in the current depreciation rates. A second reason is a change in capital investment deployed since Docket No. 46957.

Q. HAVE TRANSMISSION AND DISTRIBUTION SUBSTATION REMOVAL COSTS CHANGED SINCE THE SETTLEMENT AGREEMENT WAS ADOPTED IN DOCKET NO. 46957?

A. Yes, as shown in the net salvage analysis in Exhibit DAW-2, removal costs for almost every plant account have changed since the last depreciation study that I performed for Oncor.

Q. WHAT ACTIVITIES WERE TAKING PLACE AT THE TIME OF THE FINAL ORDER IN DOCKET NO. 46957?

A. Between the years 2003 through 2008, the Company began a program to mitigate congestion on transmission lines in the DFW area and replace assets. Congestion mitigation projects required the reconductoring and rebuilding of towers and poles. Those projects have moderated and continued at a reduced level since Docket No. 35717. Since Docket No. 46957, Oncor has focused on replacement of its aging infrastructures, which has increased net salvage costs from 2008-2016 when the Company deployed capital to smart grid projects and competitive renewable energy zone projects. Since 2017, capital spending has resumed a normal balance between new infrastructure (greenfield) and infrastructure replacement (brownfield), more retirements are expected to occur in both the transmission and distribution accounts.

Q. WHAT NET SALVAGE RATES ARE YOU RECOMMENDING FOR THE TRANSMISSION ASSETS?

A. The recommended net salvage rates for Transmission assets are shown in Exhibit DAW-2, Appendix C. Detailed computations by account are shown in Appendix E.

2. Net Salvage Rates for Distribution (Accounts 364-373) Property

Q. WHAT HAS CAUSED THE SIGNIFICANT CHANGE IN NET SALVAGE RATES FOR DISTRIBUTION PLANT?

A. The data related to the Company's actual experience in recent years demonstrates that the Company has continued to experience significant increases in the removal cost incurred to retire assets since the existing depreciation rates were established based on a 2016 Depreciation Study. Increasing costs of construction in metropolitan areas and work required by distribution system upgrades have both contributed to increasing distribution removal costs. Additionally, in order to reach a settlement in Docket No. 46957, the Company agreed to net salvage parameters that were lower than its historic experience at that time. More detail can be found in the Salvage Analysis section of my Depreciation Study found in Exhibit DAW-2.

3. Net Salvage Rates for General Property

Q. WHAT NET SALVAGE VALUE WAS USED IN THE CALCULATION OF THE GENERAL PLANT DEPRECIATION RATES?

A. Net salvage rates for general plant accounts are listed in Exhibit DAW-2, Appendix C.

Q. HAVE THE NET SALVAGE RATES CHANGED FOR GENERAL PLANT PROPERTY?

A. The net salvage rates for general plant have changed very little. General plant net salvage was set at 0 percent for the general plant function in Docket No. 46957 and at a positive 10 percent for Transportation Equipment and Power Operated Equipment. This study recommends moving to a positive 20 percent for both Transportation Equipment, Account 392, and Power Operated Equipment, Account 396, and a negative five percent for general plant Structures and Improvements, Account 390, and a negative two percent for Account 397, Communication Equipment - non-AR-15 property. All other general plant accounts retain the same zero percent net salvage approved in Docket No. 46957.

4. Net Salvage Rates for New Categories of Assets

Q. WHAT NET SALVAGE VALUE WAS USED IN THE CALCULATION OF THE NEW CATEGORIES OF ASSETS

A. Net salvage rates for new asset groups are listed in Exhibit DAW-2, Appendix C.

Q. HOW DID YOU DETERMINE NET SALVAGE RATES FOR NEW ASSET TYPES?

A. Where possible, I used my recommendations for similar assets with historical experience within the same function to estimate net salvage for these new asset groups (e.g., transmission station equipment as a surrogate for DC Tie and SVC equipment).

V. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The depreciation rates I propose in this case are an accurate estimate of Oncor's future life and salvage expectations and should be accepted. The proposed plant depreciation rate reflects the significant changes that have occurred in Oncor's depreciable and amortizable property since Docket No. 46957. As such, the depreciation expense that I recommend should be adopted. Finally, Oncor will continue to periodically review the depreciation rates for its property in an effort to ensure that all customers are charged for their appropriate share of the capital expended for their benefit.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF TEXAS §
§
COUNTY OF DALLAS §

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

My name is Dane A. Watson. I am of legal age and a resident of the State of Texas. The foregoing direct testimony and attached exhibits offered by me is true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true, and correct.

____
Dane A. Watson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Dane A. Watson this ______ day of May, 2022.

____
Notary Public, State of Texas

INDEX TO THE DIRECT TESTIMONY
OF W. ALAN LEDBETTER, WITNESS FOR
ONCOR ELECTRIC DELIVERY COMPANY LLC

Q. PLEASE DESCRIBE ANY EXCEPTIONS TO THE NORMAL REGULATORY TREATMENT OF ROU ASSETS.

A. As described in the direct testimony of Oncor witness Mr. Keith Hull, in late 2021, Oncor leased multiple mobile generation assets to aid the Company's ability to restore power after a widespread power outage event, as authorized by PURA § 39.918(b)(1). Pursuant to US GAAP, the lease associated with these mobile generation assets is classified as an operating lease and follows the Topic 842 accounting treatment described above. However, pursuant to the provisions in PURA § 39.918(j), these assets have been reclassified as financial leases in this rate proceeding to reflect the present value of future payments required under the lease in the Company's balance of invested capital (*i.e.*, rate base) and the long-term debt component of Oncor's capitalization and weighted average cost of capital calculation.

4. Retirement Benefits

Q. PLEASE DESCRIBE US GAAP CHANGES REGARDING DISCLOSURE OF CERTAIN RETIREMENT BENEFITS FOR EXTERNAL FINANCIAL REPORTING.

A. As reported in Oncor's 2018 SEC Form 10-K, which is available in the "Investor Relations" section of the www.oncor.com web-site or on the Commission's filing interchange (Project No. 18688, Item No. 275), Oncor adopted the FASB amendment to Topic 715, "Compensation – Retirement Benefits" arising from ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." For US GAAP purposes, Topic 715 requires the non-service cost components of net retirement benefit plan costs to be presented as non-operating in the income statement and prescribes that only the service cost component of net retirement benefit plan cost is eligible for capitalization as part of inventory or property, plant, and equipment. Oncor adopted this amendment to US GAAP at the beginning of 2018 and applied the income implementation of rates in November 2017. At the 2021 test-year-end, a balance of approximately $721,000 related to this transaction remains in FERC A114. The calculation of the annual amortization expense of about $67,600 annually is shown in my workpaper WP/II-B-11/01.

In addition, as approved in Docket No. 46957, Oncor acquired the negative plant acquisition of about $2.7 million recorded in FERC A114 from SDTS as a result of the November 2017 asset exchange transaction between Oncor and SDTS arising from the Docket No. 46957 settlement ("2017 Asset Exchange"). At the 2021 test-year-end, the remaining unamortized balance of this negative plant acquisition adjustment reflected a credit total of $2,266,261. This plant acquisition adjustment is being amortized over the estimated life of the related assets and serves to reduce recognized amortization expense by $98,236 annually.

In Docket No. 41430, the Commission approved in 2013 an acquisition by SDTS of transmission assets held by SPS. Consistent with the guidance in the USOA for FERC A114, SDTS recognized a PP&E acquisition adjustment of approximately $29.3 million. As reflected in the final Order in Docket No. 41430, the Commission found that the acquisition was in the public interest and that the purchase price was reasonable (*e.g.*, see Finding of Fact Nos. 73, 85, and 88), but ruled that the "ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will be determined in Sharyland's next base rate case" (see Ordering Paragraph No. 3 and Conclusion of Law No. 14). Notwithstanding that determination, following completion of the transaction with SPS, SDTS/SU commenced amortization of the acquisition adjustment amount over the expected remaining useful life of the assets. As discussed earlier, the InfraREIT Acquisition resulted in Oncor acquiring the assets purchased pursuant to the Docket No. 41430 Order. As of the 2021 test-year-end, there remains a balance of $23.5 million in unamortized FERC A114 investment related to Oncor NTU.

As discussed in Company witness Mr. Speed's direct testimony, SDTS's purchase of these assets prior to the InfraREIT Acquisition reflects prudent acquisition of used and useful assets at a price below alternative options then available to meet the utility's needs. Accordingly, consistent with instructions contained within the USOA, Oncor requests in this proceeding the recovery of about $851,000 annually over the assets' remaining estimated useful life of approximately 27.56 years and rate base inclusion of the $23.5 million remaining amount related to the acquisition adjustment now on Oncor's books resulting from the InfraREIT Acquisition. Company witness Mr. Watson has provided me the estimated remaining useful life of these assets as of the 2021 test-year-end in order to determine the annual amortization expense associated with the investment in Oncor NTU FERC A114. The calculation of the annual amortization expense is contained in my workpaper WP/II-B-11/03.

d. Lubbock Power & Light Interconnection Assets

Q. PLEASE DESCRIBE THE JOINT PROJECT BETWEEN ONCOR AND THE CITY OF LUBBOCK, ACTING THROUGH LP&L.

A. As described in the direct testimony of Oncor witness Mr. Speed, another aspect of the InfraREIT Acquisition relates to a joint project involving the build out of approximately 175 miles of transmission lines and associated station work to join the City Of Lubbock to the ERCOT market, with final ownership of the resulting assets being equally shared between Oncor and LP&L ("Interconnection Plan"). The joint project was completed in 2021 and involved Oncor constructing the facilities and LP&L reimbursing Oncor for LP&L's respective share of the assets. The LP&L-owned assets and a corresponding liability were removed from Oncor's balance sheet at the end of the project when title to the LP&L portion of the assets was transferred to LP&L. As a unique and nonrecurring construction project, the transfer of title was accounted for as a sale of nonfinancial assets at cost.

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PUC DOCKET NO. 41430
SOAH DOCKET NO. 472-13-4202

FILING CLERK

JOINT REPORT AND APPLICATION OF SHARYLAND UTILITIES, L.P., SHARYLAND DISTRIBUTION & TRANSMISSION SERVICES, L.L.C., AND SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF PURCHASE AND SALE OF FACILITIES, FOR APPROVAL OF REGULATORY ACCOUNTING TREATMENT OF GAIN ON SALE, AND FOR TRANSFER OF CERTIFICATE RIGHTS	§ § § § § § § § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the joint report and application of Sharyland Utilities, L.P. (Sharyland Utilities), Sharyland Distribution & Transmission Services, L.L.C (SDTS) (together, Sharyland), and Southwestern Public Service Company (SPS) for approval of (1) Sharyland's purchase from SPS of the Hobbs-to-Midland and Grassland-to-Borden transmission lines, the Midland County and Borden County substations, and associated land rights (the facilities); (2) the transfer of SPS's certificate-of-convenience-and-necessity (CCN) rights pertaining to the facilities to Sharyland; and (3) SPS's proposed treatment of the gain from its sale of the facilities. The State Office of Administrative Hearings' administrative law judge (SOAH ALJ) filed a proposal for decision (PFD) on October 30, 2013, in which the ALJ found that the transaction is in the public interest and recommended approval of SDTS's purchase of the facilities and the transfer of the associated CCN rights from SPS to Sharyland Utilities. Additionally, the ALJ found that the issue of whether to include in invested capital a greater amount than the net book value of the facilities should be deferred for determination in Sharyland's next base rate case and that $37 million represents the reasonable value of the facilities. The ALJ also recommended that the Commission adopt the unopposed stipulation filed by SPS concerning the accounting treatment of the gain on sale of the facilities and related issues. On December 5, 2013, the

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SOAH ALJ filed a letter recommending several modifications to the PFD based on exceptions filed by parties.

The Commission agrees with the SOAH ALJ that the transaction is in the public interest and should be approved, but clarifies that the determination that the value of the facilities is reasonable under PURA § 14.101(b) is not dispositive of any issue in subsequent rate proceedings before the Commission, including the applicability of PURA § 36.053. The Commission believes that PURA § 14.101(b) requires that the Commission evaluate the reasonableness of the purchase price in order to determine whether the transaction is in the public interest. In this case, the Commission finds that $37 million represents a reasonable purchase price for the facilities, because SPS will receive value in excess of the book value of the facilities, and Sharyland will obtain increased transmission capabilities at a cost less than its other alternatives. Accordingly, the Commission adds new conclusion of law 8A, deletes finding of fact 61, modifies conclusions of law 8 and 10, and findings of fact 88 and 92.

In all other respects, the Commission adopts the PFD, as modified by the ALJ's letter dated December 5, 2013, including all findings of fact and conclusions of law not specified above.

The Public Utility Commission of Texas (Commission) adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Procedural History

1. On April 29, 2013, Sharyland Utilities, L.P. (Sharyland Utilities), Sharyland Distribution & Transmission Services, L.L.C. (SDTS) (together, Sharyland), and Southwestern Public Service Company (SPS) filed their joint report and application (application) for sale, transfer, or merger of facilities pursuant to PURA § 14.101(b).

2. The application sought approval of (a) the purchase by Sharyland and sale by SPS of approximately 66 miles of two SPS transmission lines (the Hobbs-to-Midland line and the Grassland-to-Borden line), two substations, and associated land rights and facilities

(facilities) located in West Texas; (b) the regulatory accounting treatment of the gain on sale of the facilities proposed by SPS; and (c) the transfer of the associated certificate-of-convenience-and-necessity (CCN) rights for the facilities from SPS to Sharyland pursuant to PURA § 37.154. Sharyland's and SPS's service area boundaries would be unaffected.

3. The following parties were granted intervention in this docket: Office of Public Utility Counsel (OPUC), Alliance of Xcel Municipalities (AXM), Oncor Electric Delivery Company LLC (Oncor), Southwest Power Pool, Inc. (SPP), Golden Spread Electric Cooperative, Inc. (Golden Spread), Texas Industrial Energy Consumers (TIEC) and Pioneer Natural Resources USA, Inc. (Pioneer).

4. On May 9, 2013, the Commission referred this matter to the State Office of Administrative Hearings (SOAH).

5. On June 11, 2013, a prehearing conference was held. On June 17, 2013, the ALJ issued SOAH Order No. 2 adopting a procedural schedule.

6. The Commission issued a preliminary order on June 19, 2013.

7. The hearing on the merits was convened on September 3, 2013, and concluded on the same day. The record closed on October 3, 2013, when the ALJ granted Sharyland's unopposed motion to admit as late-filed evidence Sharyland's Exhibit No. 10, the Electric Reliability Council of Texas's (ERCOT) 2012 *West Texas Sensitivity Study Report* (WTS Study) issued on September 17, 2013.

Notice

8. Notice of the application in this docket was provided by first-class mail to: (a) all counties in which the facilities are located; (b) all entities listed in the Commission's transmission matrix in Docket No. 40946, *Commission Staff's Application to Set 2013 Wholesale Transmission Service Rates for ERCOT*; (c) all neighboring utilities and electric cooperatives; and (d) counsel for all parties in (i) Docket No. 40824, *Application of Southwestern Public Service Company for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for the Period January 1, 2010 through June 30, 2012;* (ii) Docket No. 37990, *Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., Hunt Transmission Services,*

L.L.C., Cap Rock Energy Corporation, and NewCorp Resources Electric Cooperative, Inc. for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262, and 39.915; (iii) Docket No. 39070, *Application of Sharyland Utilities, L.P. to Approve Study and Plan Pursuant to the Commission's Order in Docket No. 37990 Concerning the Movement of Sharyland's Stanton and Colorado City Divisions from the Southwest Power Pool to ERCOT*; and (iv) Docket No. 39592, *Application of Sharyland Utilities, L.P. to Approve Retail Plan Pursuant to the Commission's Order in Docket No. 37990 and for Other Relief.* Further notice of this docket was provided by publication in newspapers having general circulation in the counties in which the facilities are located once a week for two consecutive weeks in accordance with P.U.C. PROC. R. 22.55.

9. Notice was approved by the ALJ in SOAH Order No. 2 on June 14, 2013.

10. Proof of notice by mail and proof of publication was filed on July 25, 2013.

Description of the Applicants and the Proposed Transaction

11. SPS is a fully integrated generation, transmission, and distribution utility serving the Panhandle and South Plains areas of Texas, as well as the eastern and southwestern portions of New Mexico.

12. Sharyland Utilities is a transmission and distribution utility serving five geographically distinct divisions in Texas.

13. SDTS was formed by the owners of Sharyland Utilities for the purpose of permitting Sharyland Utilities to transfer its ownership interest in its transmission and distribution assets to SDTS to allow the company broader alternatives for obtaining equity for significant capital expenditures, consistent with the Commission's order in Docket No. 35287.

14. SPS and Sharyland have entered into an asset purchase agreement (APA) dated March 29, 2013, under which SPS has agreed to sell the facilities to Sharyland subject to meeting the conditions for closing, including obtaining regulatory approvals (the transaction).

15. The Hobbs-to-Midland and Grassland-to-Borden transmission lines are currently operated at 230-kV but are capable of operation at 345-kV.

16. The purchase price for the facilities would be $37,000,000 (subject to adjustments for expenditures and proceeds resulting from any force majeure or casualty/condemnation loss between the execution date and the closing date).

17. Regulatory approvals by the Federal Energy Regulatory Commission (FERC) and the New Mexico Public Regulation Commission (NMPRC) are also required.

18. FERC approved SPS's application for approval on August 14, 2013. SPS's application for approval by the NMPRC is still pending.

Background

19. In July 2010, the Commission approved a transaction in Docket No. 37990 whereby Sharyland acquired control of Cap Rock Energy Corporation (Cap Rock) and all of Cap Rock's transmission and distribution assets were transferred to SDTS. Prior to the order in Docket No. 37990, Cap Rock operated four separate divisions located in West Texas, the Hill Country, and Northeast Texas (now the Stanton, Colorado City, Brady, and Celeste divisions).

20. The Stanton and Colorado City divisions are currently interconnected primarily to the SPP and receive wholesale power from SPS; the Brady and Celeste divisions are interconnected to ERCOT and receive wholesale power from the Lower Colorado River Authority and the city of Garland.

21. In approving Sharyland's acquisition of Cap Rock in Docket No. 37990, the Commission required Sharyland to submit (a) a third-party study analyzing and evaluating issues relating to moving the Stanton and Colorado City divisions from SPP to ERCOT and (b) a proposal whether Sharyland's customers ultimately located in ERCOT should be moved to retail competition.

22. The Commission subsequently approved a plan in Docket No. 39070 in July 2011 to move the Stanton and Colorado City divisions from SPP to ERCOT by the end of December 2013.

23. Sharyland's proposal to implement retail competition in the former Cap Rock divisions was approved by the Commission in Docket No. 39592 in August 2012. Pursuant to the Commission's order, Sharyland filed an application to establish unbundled retail delivery rates for the Brady, Celeste, Colorado City, and Stanton divisions on May 31, 2013. Retail competition will be implemented for the former Cap Rock divisions by May 1, 2014, or 90 days after Sharyland files tariffs for retail delivery rates, whichever is later.

24. The Stanton and Colorado City divisions are currently served by an approximately 305-mile 138-kV transmission line owned by Sharyland (the Sharyland Loop) interconnected to SPP. The northernmost portion of the Sharyland Loop consists of an approximately 97-mile 138-kV transmission line that connects to two SPS substations—the Borden County and Midland County substations—at the terminal points of SPS's Hobbs-to-Midland transmission line and the Grassland-to-Borden transmission line.

25. SPS utilizes the Hobbs-to-Midland transmission line and the Grassland-to-Borden transmission line to provide wholesale electric service to Sharyland's Stanton and Colorado City divisions. Sharyland's wholesale power contract with SPS will terminate on December 31, 2013, and, pursuant to the Commission's order in Docket No. 39070, Sharyland will move the Stanton and Colorado City divisions to ERCOT by December 31, 2013.

26. The Commission's order approving Sharyland's acquisition of Cap Rock in Docket No. 37990 obligates Sharyland, if requested by SPS, to leave Sharyland's 138-kV transmission line between the Borden County and Midland County substations (the Borden-to-Midland line) connected to SPS after the Stanton and Colorado City divisions are disconnected from SPP and moved to ERCOT to maintain the connection between SPS's Hobbs-to-Midland and Grassland-to-Borden transmission lines in SPP.

27. By letters dated April 19 and June 9, 2011, SPS notified Sharyland that it was electing its option under the settlement in Docket No. 37990 to require Sharyland to leave the Borden-to-Midland transmission line interconnected to SPP and provide transmission service to SPS at cost. Those letters, however, acknowledged that SPS's decision to utilize the Borden-to-Midland transmission line was subject to various contingencies and

that SPS did not intend to use the Borden-to-Midland transmission line any longer than necessary.

The Agreed Transfer Option

28. The Commission approved an agreed transfer option (ATO) in Docket No. 39070 that prescribed the transmission and distribution facilities that would be needed to be constructed in order to transfer Sharyland's Stanton and Colorado City divisions from SPP to ERCOT by December 31, 2013.

29. Several options for transferring the Stanton and Colorado City divisions were considered in Docket No. 39070, including options that would require the construction of transmission facilities to replace the Borden-to-Midland transmission line.

30. Because of the possibility that SPS would relinquish its right under the settlement in Docket No. 37990 to require the Borden-to-Midland transmission line to remain in SPP, the ATO provided for the construction of temporary distribution solutions that would allow Sharyland to serve its customers in the northern portion of its system after the transfer of the Stanton and Colorado City divisions to ERCOT.

31. The ATO was designed to allow Sharyland to reliably serve customers in the Stanton and Colorado City divisions after the transfer to ERCOT while avoiding the construction of facilities that would be unnecessary if SPS subsequently relinquished its option to use the Borden-to-Midland transmission line.

32. The ATO provided Sharyland the flexibility to adjust to SPS's potential relinquishment of the Borden-to-Midland transmission line and to accomplish a full transfer of the Stanton and Colorado City divisions at a lower cost than would be possible under other transfer options considered in Docket No. 39070.

33. In approving the ATO in Docket No. 39070, the Commission stated that the ATO "may allow Sharyland to avoid the construction of unnecessary transmission facilities that would replicate the Borden-to-Midland facilities in the event that SPS releases the Borden-to-Midland facilities by 2015."

34. Since the ATO was approved in 2011, growth in electrical demand has significantly exceeded Sharyland's projections primarily because of increases in demand from oil and gas customers.

35. In Docket No. 39070, Sharyland projected that total load for the divisions at the end of 2013 would be approximately 200 MW. Sharyland is now projecting that its load in 2014 will be approximately 300 MW, an increase of 50% over the projected load in mid-2011 when the order in Docket No. 39070 was issued.

36. Unexpected load growth in oil and gas loads in West Texas is being experienced by all transmission service providers in the area. According to the 2012 ERCOT report entitled *Report on Existing and Potential Electric System Constraints and Needs*, "the revitalization of the Permian Basin oil play has increased electric demand at unprecedented rates in some areas which have caused a substantial amount of congestion on some transmission elements."

37. Because of the rapid growth on its system, Sharyland will not be able to maintain reliable service to customers in the Stanton and Colorado City divisions under the ATO without constructing additional transmission facilities unless the Borden-to-Midland transmission line is moved to ERCOT.

38. The ATO approved in Docket No. 39070 will not allow Sharyland to provide reliable service to its customers after the move of the Stanton and Colorado City divisions to ERCOT in light of the unexpected growth in demand that has occurred since the ATO was adopted.

39. If the Borden-to-Midland transmission line remains in SPP, service to loads at Sharyland's Brown, Koch, Grady, Vealmoor, and Fairview substations will be through radial distribution feeds under the ATO. Distribution solutions will not provide reliable service to these loads due to the growth that is occurring and additional transmission will need to be constructed.

40. The ATO also required Sharyland to construct a 10-mile 138-kV transmission line to maintain the transmission path between SPS's Borden County and Midland County substations after the move of the Stanton and Colorado City divisions to ERCOT

(Gardendale-to-Grady line). The estimated cost of the Gardendale-to-Grady transmission line is $8 million.

41. Sharyland obtained Commission approval to construct the Gardendale-to-Grady line in Docket No. 40537. This line will not be needed if the proposed transaction is approved.

42. Upon closing of the transaction, SPS will relinquish its option to require Sharyland to leave the Borden-to-Midland transmission line connected to SPP, and Sharyland can move that transmission line to ERCOT with the rest of the Stanton and Colorado City divisions.

Sharyland's Northern Loop Study

43. On June 14, 2013, Sharyland filed its *Northern Loop Project Study* with ERCOT's regional planning group (RPG) setting forth its proposed long-term options for maintaining reliability in the Stanton and Colorado City divisions. That study stated that, if the proposed transaction is not approved and Sharyland is unable to move the Borden-to-Midland transmission line to ERCOT at the end of 2013, Sharyland will need to construct additional transmission facilities in order to assure reliable service to customers in the northernmost portion of its system.

44. Estimated costs of the alternative transmission facilities that would be necessary if the proposed transaction was not approved ranged from approximately $40 million to $76 million. On July 17, 2013, ERCOT Staff notified RPG that review of Sharyland's *Northern Loop Project Study* was complete. Sharyland now has all of the ERCOT approvals needed to move forward with constructing new transmission facilities if the transaction proposed in this proceeding is not approved and the Borden-to-Midland transmission line does not move to ERCOT at the end of 2013.

45. The estimated cost of the new transmission facilities that will be constructed if the proposed transaction is not approved is $51.5 million. The transmission lines will not be available for approximately four years and new right-of-way will need to be acquired to build the facilities.

46. If the proposed transaction is not approved, Sharyland will also need to construct the new 10-mile Gardendale-to-Grady transmission line required by the ATO at a cost of

approximately $8 million in order to maintain SPS's transmission path between SPS's Borden County and Midland County substations.

47. Total estimated avoided transmission cost savings to ERCOT ratepayers attributable to SPS's relinquishment of its option to require Sharyland to leave the Borden-to-Midland transmission line in SPP if the proposed transaction is approved are $59.5 million. In addition, the Borden-to-Midland transmission line will be available for use immediately upon its transfer to ERCOT and no new right-of-way will be required.

The West Texas Sensitivity Study

48. ERCOT initiated the *West Texas Sensitivity Study* earlier this year to address reliability and economic transmission needs to meet the rapid growth in oil and gas loads in the ERCOT West and Far West Zones.

49. ERCOT presented updates on the WTS Study at RPG meetings in May, June, July, and August 2013.

50. The final ERCOT WTS Study issued on September 17, 2013, recommended the use of the Hobbs-to-Midland and Grassland-to-Borden transmission lines as reliability projects in the West Zone if the proposed transaction is approved. If the proposed transaction is not approved and new 345-kV transmission lines have to be constructed, the estimated cost is $75 million. In addition, the Hobbs-to-Midland and Grassland-to-Borden transmission lines will be available for use by ERCOT within 18 months after approval of the proposed transaction as compared with four years required to construct new transmission lines in the West Zone.

51. Use of the existing Hobbs-to-Midland and Grassland-to-Borden transmission lines will also eliminate the need to require new right-of-way to construct additional transmission lines to replace the SPS facilities.

Sharyland's Proposed Journal Entries for the Proposed Transaction

52. The original cost of the facilities as of December 31, 2013, is $14,147,517. Accumulated depreciation as of that date is estimated to be $5,702,742. Therefore, net book value of the facilities as of closing is estimated to be $8,444,775.

53. Upon closing, SDTS will record the net book value of the facilities to the utility-plant-in-service account on its books.

54. The acquisition adjustment will not be recorded to the utility-plant-in-service account. Instead, it will be recorded as an acquisition adjustment in FERC Account No. 114 on SDTS's books.

55. Sharyland's proposed journal entries for the facilities are reasonable.

56. Sharyland will request recovery of the acquisition adjustment in Sharyland's next rate case.

Reasonable Value of the Facilities to be Transferred

57. The purchase price of $37 million was reached in arm's length negotiations between two unaffiliated parties, either of which could have declined to enter into the proposed transaction.

58. SPS advised Sharyland that it was unwilling to sell the facilities at net book value.

59. In reaching a negotiated price, SPS and Sharyland took into account several factors, including the original cost of construction of the facilities, the net book value, the cost to construct replacement facilities, the cost savings to ERCOT ratepayers if the Borden-to-Midland transmission line was moved to ERCOT and Sharyland was able to avoid the construction of alternative transmission facilities in order to maintain reliability on its system, the timing benefits to Sharyland if it was able to avoid the construction of new transmission facilities, and the potential benefits of the facilities to reduce congestion and improve reliability in the West Zone of ERCOT.

60. Sharyland concluded that the purchase price of $37 million was reasonable in view of estimated avoided transmission cost savings to ERCOT ratepayers of approximately $135 million in addition to the reliability, congestion mitigation, and timing benefits of the transaction.

61. DELETED.

Effects of the Proposed Transaction on Health or Safety, Jobs in Texas, and Quality of Service

62. The proposed transaction will not adversely affect the health or safety of either customers or employees.

63. The proposed transaction will not result in the transfer of any jobs from citizens in this state to workers domiciled elsewhere.

64. The proposed transaction will improve reliability for Sharyland's customers and in the ERCOT West Zone and will not materially affect reliability for SPS.

Consistency of the Proposed Transaction with the Public Interest

65. The proposed transaction will provide significant net benefits to ERCOT and Sharyland ratepayers that will offset the purchase price of $37 million. Avoided transmission cost savings if the proposed transaction is approved are estimated to be $135 million as compared with a purchase price of $37 million.

66. SPS ratepayers will benefit because they will receive a refund of a portion of the $29 million gain on sale. The SPS lines will be removed from SPS's rate base at an estimated cost savings to SPS ratepayers of approximately $535,000 per year (Texas retail), and SPS will be relieved of paying lease payments to Sharyland for use of the Borden-to-Midland transmission line in the amount of an estimated $750,000 per year (Texas retail), for total annual savings of approximately $1.35 million for SPS's Texas retail customers.

67. Reliability of service to Sharyland's customers will improve significantly if the proposed transaction is approved.

68. Reliability of service will also improve in the West Zone if the Hobbs-to-Midland and Grassland-to-Borden transmission lines are available to ERCOT.

69. Approval of the proposed transaction will eliminate the need to obtain new right-of-way in order to construct new transmission facilities to replace the Borden-to-Midland transmission line and to replace the SPS transmission lines in the West Zone. Moving the Borden-to-Midland transmission line and the SPS facilities to ERCOT will assure that the reliability benefits are available significantly earlier than if new transmission needs to be built.

70. ERCOT's most recent update on its WTS Study indicates that the Hobbs-to-Midland and Grassland-to-Borden transmission lines are needed as reliability projects in the West Zone.

71. If the proposed transaction is approved, the SPS lines will be available to interconnect new wind generators to ERCOT and will assist in reducing congestion in the West Zone.

72. Approval of the proposed transaction will allow the transition of Sharyland's Stanton and Colorado City divisions from SPP to ERCOT to be accomplished in a manner that will minimize costs to ERCOT ratepayers.

73. Transfer of the facilities to Sharyland is consistent with the public interest.

Stipulation Regarding SPS Issues

74. On September 20, 2013, the following parties filed an unopposed stipulation regarding issues specific to SPS: Staff, SPS, OPUC, AXM, TIEC, and Pioneer. The other parties in the case do not oppose the stipulation.

75. The signatories agree that the proposed transaction is in the public interest under PURA § 14.101 in regards to SPS.

76. The signatories agree that the Commission should approve the transfer of SPS's CCN rights associated with the facilities to Sharyland.

77. The signatories agree that the Commission should amend SPS's CCN to allow SPS to cease providing service over the portions of its transmission facilities that will be dismantled, specifically, the Hobbs-to-Midland line from structure 350 to structure 197 and the Grassland-to-Borden line from structure 62 to structure 64.

78. The signatories agree that SPS's net pre-tax gain on sale resulting from the proposed transaction will be allocated to the Texas retail jurisdiction and then divided between SPS and its Texas retail customers using the formula set out in Exhibit A to this Order. Under the stipulation, 45% of the total company net pre-tax gain on sale will be allocated to the Texas retail jurisdiction and 60% of the Texas retail portion of the net pre-tax gain on sale will be provided to SPS's Texas retail customers. The dollar amounts in Exhibit A

are current estimates and are subject to true up. The 45% and 60% values are fixed and not subject to true up.

79. Under the stipulation, the estimated dollar amount of the net pre-tax gain to be provided to SPS's Texas retail customers is $5,678,752. SPS will provide 90% of that estimated amount, or $5,110,877, to its Texas retail customers through bill credits during its February 2014 billing month. The bill credits will be allocated and implemented through the rate design reflected in Exhibit B to this Order.

80. Under the stipulation, after actual dollar amounts are available to replace the estimated dollars on Exhibit A, SPS will file a true-up to refund the difference between $5,110,877 and the final, actual dollar amount owed to SPS's Texas retail customers using the formula set out in Exhibit A. In calculating the final, actual dollar amount owed to SPS's Texas retail customers: (i) the dollar amount for "Outside Legal and Transaction Costs" (line 12) may not exceed $350,000 (total company); and (ii) the dollar amount for "Indemnifications under the APA" (line 14) may not exceed $370,000 (total company). The true-up filing will present an updated Exhibit A to show the actual dollar amounts used in the calculation. The signatories do not waive their right to contest, in the true-up proceeding, the reasonableness of the estimated dollar amounts subject to true up, which are (1) the amount of legal and transactional costs, (2) the amount of indemnification payments made to third parties, and (3) the amount incurred by SPS to disengage from the Sharyland system and to dismantle the portion of the Hobbs-to-Midland line from structure 350 to structure 197. The true-up filing also will present a true-up tariff, which will reflect the same inter-class allocation, rate design, and refund methods shown on Attachment B. After the true-up occurs, any difference between the balance owed to each rate class as shown in the true-up filing and the amount actually refunded to that rate class will be reflected in SPS's cumulative monthly deferred fuel-cost balances by rate class. For rate classes billed on a per-kW or per-kWh rate premised upon the original refund month (February 2014), the incremental rate ($/kW or $/kWh) to be refunded or surcharged to that rate class will be based upon the refund or surcharge month of the true up.

81. Under the stipulation, the preliminary refund of the pre-tax gain is contingent upon the proposed transaction closing. If the proposed transaction does not close, no refunds are due.

82. The signatories agreed that they will support the stipulation before the Commission.

83. The signatories further agreed that:

a. There are no third-party beneficiaries of the stipulation.

b. The stipulation resolves issues only with respect to the Texas retail jurisdiction and shall not be binding on or have any effect on proceedings in other jurisdictions.

c. Signatories are not agreeing to any methodology or theory that may support or underlie any of the dollar amounts, rates in tariffs, depreciation rates, dollar balances, or other monetary or numerical values set out in, or attached to, the stipulation.

d. The stipulation was drafted by all the signatories and is the result of negotiation, compromise, settlement, and accommodation.

e. The settlement is in the public interest.

f. The terms and conditions of the stipulation are interdependent, and the various provisions of the stipulation are not severable. None of the provisions of the stipulation will become fully operative unless the Commission has entered a final order approving the stipulation. If the Commission issues a final order inconsistent with the terms of the stipulation, each signatory has the right to withdraw from the stipulation and to obtain a hearing and advocate any position it deems appropriate with respect to any issue in the stipulation.

g. The stipulation is binding on each of the signatories only for the purpose of settling the issues as set forth herein in this jurisdiction only and for no other purposes.

h. The matters resolved in this docket are resolved on the basis of a compromise and settlement.

i. Except to the extent that the stipulation expressly governs a signatory's rights and obligations for future periods, the stipulation shall not be binding or precedential on a signatory outside of this proceeding or a proceeding to enforce the terms of the stipulation.

j. Section IV(c) of the stipulation includes forward-looking provisions and corresponding obligations.

k. A signatory's support of the matters contained in the stipulation may differ from the position taken or testimony presented by it in other dockets or other jurisdictions. To the extent that there is a difference, a signatory does not waive its position in any of those other dockets or jurisdictions. Because this is a stipulated resolution, no signatory is under any obligation to take the same positions as set out in the stipulation in other dockets or jurisdictions, regardless of whether other dockets present the same or a different set of circumstances, except as otherwise may be explicitly provided by the stipulation. Agreement by the signatories to any provision in the stipulation will not be used against any signatory in any future proceeding with respect to different positions that may be taken by that signatory.

l. The provisions of the stipulation are intended to relate to only the specific matters referred to in the stipulation. By agreeing to the stipulation, no signatory waives any claim it may otherwise have with respect to issues not expressly provided for in the stipulation.

84. The stipulation is reasonable and should be approved.

Findings in Accordance with the Preliminary Order

85. **Issue No. 1**: The sale of the facilities to SDTS is in the public interest under PURA § 14.101(b).

a. The proposed transaction will increase the reliability of the ERCOT transmission system and will not lead to any material deterioration of reliability for SPS's customers due to facilities that have been constructed since the Hobbs-to-Midland and Grassland-to-Borden transmission lines were placed in service. The costs for ERCOT to operate its system will be significantly reduced due to the reduction of congestion in the West Zone. Costs of operating the SPP system will not be materially affected.

b. The impact of the proposed transaction will be to reduce costs for both Sharyland and SPS. Costs for ERCOT will also be reduced because the need to build new transmission estimated to cost $135 million will be avoided. The proposed transaction will not have an adverse impact on any other utility in SPP or ERCOT.

c. The proposed transaction will improve the reliability of Sharyland's service by allowing Sharyland to move the Borden-to-Midland transmission line to ERCOT. This will provide an additional transmission source to customers in the northern portion of the Sharyland system. The proposed transaction is the most cost-effective alternative for Sharyland to achieve this improvement in reliability because it will utilize existing facilities and will avoid the construction of new transmission facilities. All ERCOT ratepayers, including Sharyland customers, will experience cost savings because the proposed transaction will eliminate the need to construct new transmission facilities at an estimated cost of $135 million. SPS customers will also benefit because they will receive a refund of a portion of the $29 million acquisition adjustment associated with the proposed transaction as well as total annual savings of approximately $1.35 million for SPS's Texas retail customers. The proposed transaction will not have an adverse impact on customers of any other utility in SPP or ERCOT.

86. **Issue No. 2**: The total estimated cost of this proposed project is approximately $8.0 million, including approximately $6.5 million to dismantle portions of the lines, install dead-end structures where SPS's lines will terminate, reduce the net book value of those portions being dismantled to zero, and reduce to zero net book value the stranded costs representing the portion of the Grassland-to-Borden transmission line between the Grassland substation and structure 62, approximately $700,000 to remove two autotransformers, $350,000 for SPS to obtain the necessary transaction and regulatory approvals, and $370,000 for one percent of the sale proceeds for indemnification. This proposed estimate is reasonable, and reflects an effort by SPS to minimize costs associated with the transaction.

87. **Issue No. 3**: Whether it is reasonable and in the public interest to allow SDTS the ability to include in invested capital a greater amount than the net book value of the facilities should be deferred for determination in Sharyland's next base rate case.

88. **Issue No. 4**: The purchase price of $37 million represents a reasonable purchase price for the facilities, taking into account the arm's length nature of the negotiations, the replacement value of the facilities of $99 million, the reliability, congestion mitigation, and timing benefits associated with the purchase of the facilities and the move of the Borden-to-Midland transmission line from SPP to ERCOT, and the estimated $135 million in avoided transmission cost savings to ERCOT ratepayers if the transaction is approved.

89. **Issue No. 5**: The transfer will not adversely affect health or safety of customers or employees of either Sharyland or SPS because the transmission assets are being

transferred from one Commission-certificated utility to another. Sharyland has the resources to operate the facilities in a safe and reliable manner, to respond to outages, and to provide maintenance and repair services as required.

90. **Issue No. 6**: The proposed transaction will not result in a transfer of jobs from citizens of this state to workers domiciled elsewhere because Sharyland operates exclusively within Texas. Current employees of Sharyland will perform all necessary tasks for the transferred facilities. For the same reason, SPS will not eliminate or transfer any jobs as a result of the proposed transaction.

91. **Issue No. 7**: The proposed transaction will not result in a decline of service. Sharyland has the ability to adequately operate transmission facilities and provide transmission service pursuant to PURA § 37.154(a). Sharyland currently holds CCN Nos. 30026, 30114, 30191, and 30192, and has provided reliable and safe transmission and distribution service within ERCOT since it began serving its first customer in the McAllen division in February 2000. Sharyland is fully capable of providing adequate service to its customers if the proposed transaction is approved.

92. **Issue No. 8**: SPS will receive $37 million in consideration.

93. **Issue No. 9**: In light of the avoided transmission cost savings of $135 million, the increase in reliability for Sharyland customers and ERCOT, the reduction of congestion in the West Zone of ERCOT, the annual cost savings to SPS ratepayers, and no adverse effect on health, safety, or employment, the proposed transaction is consistent with the public interest.

94. **Issue No. 10**: The Commission should approve SPS's transfer of the CCN rights for the facilities to Sharyland under PURA § 37.154. Sharyland is fully capable of providing adequate service to its customers if the proposed transaction is approved.

95. **Issue No. 11**: The stipulation's proposed regulatory accounting treatment of the net pre-tax gain on sale is reasonable and should be approved.

96. **Issue No. 12**: The stipulation's proposed treatment regarding indemnification obligations is reasonable.

II. Conclusions of Law

1. Sharyland, SDTS, and SPS are electric utilities as defined in PURA § 31.002.

2. The Commission has jurisdiction and authority over this matter pursuant to PURA §§ 14.101 and 37.154.

3. Pursuant to PURA § 14.053 and Texas Government Code § 2003.049(b), SOAH has jurisdiction over all matters relating to the conduct of the hearing in this case, including the preparation of a proposal for decision.

4. Sharyland and SPS have the burden of proving that the proposed sale and purchase of facilities and the proposed transfer of SPS's CCN rights with respect to the transmission lines is consistent with the public interest pursuant to PURA §§ 14.101 and 37.154.

5. This docket was processed in accordance with the requirements of PURA and the Administrative Procedure Act, Texas Government Code ch. 2001.

6. Notice of this proceeding was provided in compliance with P.U.C. PROC. R. 22.52.

7. PURA § 14.101(b)(1) requires the Commission to consider the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, or consolidated.

8. Taking into consideration the cost savings associated with the proposed transaction, the improvements to reliability and mitigation of congestion, and the timing benefits of utilizing existing transmission facilities rather than constructing new facilities, the purchase price of $37 million represents a reasonable purchase price for the facilities within the meaning of PURA § 14.101(b)(1).

8A. The determination that the value of the facilities is reasonable under PURA § 14.101(b) is not dispositive of any issue in subsequent rate proceedings before the Commission, including without limitation the applicability of PURA § 36.053.

9. The proposed transaction will not adversely affect the health or safety of customers or employees, result in the transfer of jobs out of Texas, or cause a decline in service within the meaning of PURA § 14.101(b)(2).

10. SPS will receive consideration equal to the reasonable purchase price of the facilities to be transferred within the meaning of PURA § 14.101(b)(3).

11. The proposed transaction will provide significant net benefits to both ERCOT and SPP ratepayers and is consistent with the public interest pursuant to PURA § 14.101(b)(4).

12. Sharyland and SPS have sustained their burden of proof with respect to the public interest determination mandated by PURA § 14.101(b).

13. Sharyland has shown that it has the ability to provide adequate service if the facilities are transferred to Sharyland pursuant to PURA § 37.154.

14. The ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will not be determined in this proceeding but will be addressed in Sharyland's next rate proceeding.

15. The stipulation, taken as a whole, is a just and reasonable resolution of all the issues it addresses, results in just and reasonable rates, is supported by a preponderance of the credible evidence in the record, is consistent with the relevant provisions of PURA, is consistent with the public interest and, thus, should be approved.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following Order:

1. The proposal for decision prepared by the SOAH ALJ is adopted to the extent consistent with this Order.

2. The application is granted to the extent consistent with this Order.

3. The ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will be determined in Sharyland's next base rate case.

4. Upon the closing of the proposed transaction, SPS's CCN rights associated with the facilities are transferred to Sharyland.

5. Upon the closing of the proposed transaction, SPS's CCN is amended to reflect that SPS is no longer providing service over the portions of its transmission facilities that will be dismantled, specifically, the Hobbs-to-Midland line from structure 350 to structure 197 and the Grassland-to-Borden line from structure 62 to structure 64.

6. Entry of this Order is consistent with the stipulation and does not indicate the Commission's endorsement of any principle or methodology that may underlie the stipulation. Further, the entry of this Order should not be regarded as precedent as to the appropriateness of any principle or methodology underlying the stipulation.

7. All other motions, requests for specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 20th day of December 2013.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, CHAIRMAN

KENNETH W. ANDERSON, JR., COMMISSIONER

BRANDY D. MARTY, COMMISSIONER

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ATTACHMENT A

Exhibit A to Stipulation

Southwestern Public Service Company
Estimated Net Gain on Sale and Regulatory Sharing
PUCT Case No. 41430

Line No.	(A)	(B) Financial Estimate	(C) Texas Estimate
1	**Cash Proceeds Received from Sharyland:**		
2	Sales Price per the APA Section 3.1	$ 37,000,000	$ 37,000,000
3	Capital Expenditures due to Force Majeure or other loss per APA Section 3.1	-	-
4	Total	37,000,000	37,000,000
5	**Less: Book Value of Assets Sold/Transferred:**		
6	Estimated Net Book Value as of 12/31/2013	8,444,775	8,002,904
7	**Less: Removal Costs (Hobbs - Midland Line Segment) - Not Sold**	3,535,164	3,535,164
8	**Less: Book Value of Assets Written Down to Zero NBV:**		
9	Estimated Net Book Value as of 12/31/2013	3,186,040	3,014,019
10	**Less: Estimated Costs to Move Autotransformers**	695,500	695,500
11	**Less: Estimated Costs Related to the Sale Transaction:**		
12	Outside Legal and Transaction Costs	350,000	350,000
13	Potential Upgrade Adjustments	-	-
14	Indemnifications under the APA (1% of purchase price, 12 month period) (Section 10 of APA)	370,000	370,000
15	Subtotal	720,000	720,000
16	Total Assets Sold/Transferred/Written Off and Costs of the Sale	16,581,479	15,967,587
17	**Estimated Pre-tax Net Gain on the Sale Before Regulatory Sharing**	$ 20,418,521	$ 21,032,413
18	**Tax Expense / (Benefit) Calculation on Gain:**		
19	Estimated Pre-tax Gain on the Sale	$ 20,418,521	
20	add: Difference between Book and Tax Basis of Assets Sold / Retired	9,748,790	
21	Estimated Tax Gain on the Sale	30,167,311	
22	x Current Federal and State Composite Income Tax Rate	36.4744%	
23	Estimated Current Federal and State Income Tax Expense on the Sale	$ 11,003,346	
24	Estimated Deferred Federal and State Income Tax Expense on the Sale	(3,397,989)	
25	Estimated Current and Deferred Federal and State Income Tax Expense on the Sale	7,605,357	
26	**Estimated After Tax Net Gain on the Sale**	$ 12,813,164	
27	**Book Gain by Jurisdiction:**		
28	Jurisdictional Percent	100.00%	45.00%
29	Jurisdictional Net Gain	$ 20,418,521	$ 9,464,586
30	**Calculation of Regulatory Sharing of Net Gain with Customers:**		
31	Jurisdictional Net Gain (Total Jurisdiction)		$ 9,464,586
32	Percent of Net Pre-tax Gain Provided to Customers		60.00%
33	Total Regulatory Sharing of Pre-tax Net Gain with Customers	$ 7,089,404	$ 5,678,752
34	**Deferred Tax Calculation on Shared Net Gain:**		
35	Pre-tax Net Gain Shared	$ 7,089,404	
36	x Composite Tax Rate (State and Federal)	36.4744%	
37	Deferred Tax Expense	$ 2,585,818	

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Xcel Energy
SOUTHWESTERN PUBLIC SERVICE

Section No. IV
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Exhibit B

ELECTRIC TARIFF

REFUND TO IMPLEMENT DOCKET NO. 41430 (TRANSMISSION ASSET SALE REFUND)

APPLICABILITY: To all customers receiving service between February 1, 2014 and February 28, 2014 in order to return refunds associated with the stipulation regarding SPS-related issues approved in PUCT Docket No. 41430 ("Stipulation").

RATE: For each of the customer classes the following amounts will be returned to the classes based on the specific refund parameters described below.

Rate Class	February 2014 Refund Amount
Residential	$1,443,516
Small General Service	$88,980
Secondary General Service	$1,186,337
Primary General Service	$699,788
SAS-4 CRMWA	$43,130
SAS-8 Orion (formerly Degussa)	$14,820
LGS-T 69kV	$243,380
LGS-T 115 kV+	$1,175,808
Small Municipal and School Service	$11,039
Large Municipal Service	$82,950
Large School Service	$95,880
Street and Area Lighting	$25,248
Total Refund	**$5,110,876**

Basis for Refund

Residential Customers: $0.007540 per kWh consumed from February 1, 2014 through February 28, 2014.

Small General Service: $0.005211 per kWh consumed from February 1, 2014 through February 28, 2014.

REGIONAL VICE PRESIDENT, RATES & REGULATORY AFFAIRS

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Xcel Energy
SOUTHWESTERN PUBLIC SERVICE

Section No. IV
Sheet No. IV-200
Original

ELECTRIC TARIFF

REFUND TO IMPLEMENT DOCKET NO. 41430
(TRANSMISSION ASSET SALE REFUND)

Secondary General Service: $0.175 per average kW billed from July 1, 2012 through June 30, 2013.

Primary General Service: $2.314 per kW billed from February 1, 2014 through February 28, 2014.

SAS-4 CRMWA: $0.004206 per kWh billed from February 1, 2014 through February 28, 2014.

SAS-8 Orion (formerly Degussa): $0.004206 per kWh billed from February 1, 2014 through February 28, 2014.

LGS-T 69kV and LGS-T 115 kV+: Refunds to customers will be calculated on a customer by customer basis. The refund amount will be based on the average of demand usage billed in November and December 2013 and returned to customers on their bill rendered in February 2014.

Small Municipal and School Service: $0.006430 per kWh consumed from February 1, 2014 through February 28, 2014.

Large Municipal Service: $1.940 per kW billed from February 1, 2014 through February 28, 2014.

Large School Service: $2.042 per kW billed from February 1, 2014 through February 28, 2014.

Street and Area Lighting: $0.005163 per kWh consumed from February 1, 2014 through February 28, 2014.

REGIONAL VICE PRESIDENT, RATES & REGULATORY AFFAIRS 15

Request

Please identify all changes in Oncor's accounting policy since Oncor's last base-rate case in Texas in which Oncor has changed from expensing a cost in a non-operating expense account, i.e., below the line, to an operating expense account. For each change, provide a detailed description of revised accounting policy, regulatory accounting support for the change in accounting policy, the FERC accounts affected, and the impact of the change in 2021.

Response

The following response was prepared by or under the direct supervision of W. Alan Ledbetter, the sponsoring witness for this response.

Since Oncor's last base-rate case (Docket No. 46957), the Company has not implemented any changes to its accounting policy regarding expensing a cost in a non-operating expense account.

It should be noted, however, that Oncor is requesting in this proceeding recovery of the annual amortization expense of the investment reflected in Federal Energy Regulatory Commission ("FERC") account 114-*Electric plant acquisition adjustments* related to the acquisition of facilities from Southwestern Public Service Company ("SPS") that are now held by Oncor NTU.

During the 2021 test year, the annual amortization of this balance was recorded in FERC account 425-*Miscellaneous amortization*, which dictates that this account includes "(a)mortization of utility plant acquisition adjustments, or of intangible included in utility plant in service when not authorized to be included in utility operating expenses by the Commission" (see Item 1. of the description for account 425 in the FERC Uniform System of Accounts).

In this proceeding, Oncor proposes that the annual amortization of $850,968 be included in FERC account 406-*Amortization of electric plant acquisition adjustments*. As prescribed in the FERC USOA description for account 406, "(t)his account shall be debited or credited, as the case may be, with amounts includible in operating expenses, pursuant to approval or order of the Commission, for the purpose of providing for the extinguishment of the amount in account 114, Electric Plant Acquisition Adjustments."

Please refer to pages 37-38 (beginning on line 14 of page 37) of Mr. Ledbetter's direct testimony (see Bates pages 601-602) and supporting workpaper WP/II-B-11/03 (Bates pages 4331-4332) for discussion concerning this FERC account 114 acquisition adjustment and requested FERC account 406 annual amortization expense of $850,968. Also reference the direct testimony of Dane A. Watson, page 9 lines 22 through 29 (Bates page 733).

For additional information please refer to the order in Docket No. 41430 (see Interchange Item 146) regarding the Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C. ("SDTS"), and Southwestern Public Service

Company for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain On Sale, and for Transfer of Certificate Rights. In particular, note that the Order reflects the following:

Finding of Fact No. 54. The acquisition adjustment will not be recorded to the utility-plant-in-service account. Instead, it will be recorded as an acquisition adjustment in FERC Account No. 114 on SDTS's books. (See Order page 11 of 21).

Finding of Fact No. 56. Sharyland will request recovery of the acquisition adjustment in Sharyland's next rate case. (See Order page 11 of 21).

Conclusion of Law No. 14. The ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will not be determined in this proceeding but will be addressed in Sharyland's next rate proceeding. (See Order page 20 of 21).

Ordering Paragraph No. 3. The ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will be determined in Sharyland's next base rate case. (See Order page 20 of 21).

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PUBLIC UTILITY COMMISSION
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APPLICATION OF ELECTRA TELEPHONE COMPANY, INC. FOR THE TRANSFER OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FROM ELECTRA TELEPHONE COMPANY	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In open meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that this docket was processed by an examiner in accordance with applicable statutes and Commission rules. The revised Examiner's Report, containing findings of fact and conclusions of law, is **ADOPTED** and **INCORPORATED** by reference into this Order. The Commission further issues the following Order:

1. The application of Electra Telephone Company, Inc. (the Corporation) for a determination that the purchase of 100 percent of the assets of Electra Telephone Company is consistent with the public interest is **GRANTED** to the extent reflected in the findings and conclusions made by the Commission.

2. Certificate of Convenience and Necessity No. 40027 is transferred from Electra Telephone Company to the Corporation.

3. To the extent that the debt service of the Corporation includes, for purposes of ratemaking, an acquisition adjustment above the net original cost of the property transferred, it is not in the public interest to the extent that it unreasonably affects rates or service.

4. The question of the appropriate treatment of the acquisition adjustment is reserved for and shall be considered in the Corporation's next rate case.

5. All motions, applications, proposed Findings of Fact and Conclusions of Law and any other requests or proposals for relief

not granted by the examiner, or ruled upon herein either expressly or by implication, are **DENIED** for want of merit.

SIGNED AT AUSTIN, TEXAS on this 6th day of August 1990.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytak
MARTA GREYTOK, COMMISSIONER

SIGNED: Paul D. Meek
PAUL D. MEEK, CHAIRMAN

DISSENT

I respectfully dissent. PURA Section 41(a), which requires utility rates to be based on the original cost of property used by and useful to the public utility in providing service, clearly obligates the Commission to reject the acquisition adjustment requested in this case. Approval of that acquisition adjustment sends a false signal to investors and other utilities.

Even if an acquisition adjustment were appropriate, the entire amount should not be placed on the books of the regulated utility. As Electra has admitted, the purchase of this company enabled the applicant successfully to bid for a cellular phone franchise. Part of the acquisition adjustment should be attributed to that unregulated company.

SIGNED: Jo Campbell
JO CAMPBELL, COMMISSIONER

ATTEST:

Mary Ross McDonald
MARY ROSS MCDONALD
SECRETARY OF THE COMMISSION

State Office of Administrative Hearings

Cathleen Parsley
Chief Administrative Law Judge

2013 OCT 30 PM 12: 40

October 30, 2013

TO: **Stephen Journeay, Director**
Commission Advising and Docket Management
William B. Travis State Office Building
1701 N. Congress, 7th Floor
Austin, Texas 78701

Courier Pick-up

RE: **SOAH Docket No. 473-13-4202**
PUC Docket No. 41430

Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights

Enclosed is the Proposal for Decision (PFD) in the above-referenced case. By copy of this letter, the parties to this proceeding are being served with the PFD.

Please place this case on an open meeting agenda for the Commissioners' consideration. There is no deadline in this case. Please notify me and the parties of the open meeting date, as well as the deadlines for filing exceptions to the PFD, replies to the exceptions, and requests for oral argument.

Sincerely,

Richard R. Wilfong

Richard R. Wilfong
Administrative Law Judge

RRW/ls
Enclosure
xc: All Parties of Record

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SOAH DOCKET NO. 473-13-4202
PUC DOCKET NO. 41430

JOINT REPORT AND APPLICATION OF SHARYLAND UTILITIES, L.P., SHARYLAND DISTRIBUTION & TRANSMISSION SERVICES, L.L.C., AND SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF PURCHASE AND SALE OF FACILITIES, FOR APPROVAL OF REGULATORY ACCOUNTING TREATMENT OF GAIN ON SALE, AND FOR TRANSFER OF CERTIFICATE RIGHTS	§ § § § § § § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

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> public interest does ***not*** equate to a finding that the acquisition adjustment will automatically be includable in rate base in the future rate proceeding.[43]

As the order in Docket No. 8374 makes clear, acquisition adjustments are properly examined *in rate cases*.[44] It is only in a rate case that a utility may ask the Commission to consider placing all or part of the purchase price, including any portion above original cost, into cost of service.[45] Sale, transfer, merger (STM) proceedings, by contrast, task the Commission with determining whether certain transactions are consistent with the public interest based on its consideration of factors that do not examine the full impact that the transaction will have on rates.

Recognizing the different purposes served by a rate case on the one hand and a proceeding to approve a transaction as being consistent with the public interest on the other, the Commission has provided guidance as to what "alternative approaches" exist under the circumstances presented here:

> Either the transaction can be recognized by the Commission and all questions relating to public interest findings can be reserved for the utility's next rate case, or a public interest finding can be made with regard to all facets of the transaction ***except*** an acquisition adjustment, which can be reserved for the rate case.[46]

The Commission found that the sale of assets in Docket No. 8374 was in the public interest. The Commission went on to conclude, however, that the issue of whether the acquisition adjustment should be included in rate base was an issue that should properly be addressed in the utility's future base rate case.[47] The Commission also clarified that a finding that the transaction is in the public interest does not equate to a finding that the acquisition adjustment will automatically be includable in rate base in the future base rate proceeding.[48]

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[43] Commission Staff's Statement of Position at 3 (Aug. 28, 2013).

[44] *Application of Electra Telephone Company, Inc. for the Transfer of a Certificate of Public Convenience and Necessity from Electra Telephone Company*, Docket No. 8374, 16 P.U.C. BULL. 59, 70-73 (Aug. 1, 1990).

[45] *Id.*

[46] *Id.* (emphasis added).

[47] *Id.* at 70–73.

[48] *Id.* at 72–73.

According to Commission Staff, TIEC, and Pioneer, consistent with prior practice, the Commission should address Issue No. 3 in Sharyland's future base rate case when Sharyland seeks approval of the acquisition adjustment's inclusion in rate base.

TIEC additionally argued that Sharyland did not request a determination of this issue in its Application, the issue was not noticed, and a predetermination of the issue would constitute an impermissible advisory opinion.[49]

Sharyland acknowledged, in apparent agreement with its opponents on this issue, that the general rule that has emerged from the Commission's decisions on acquisition adjustments is that the Commission would utilize a two-step process for addressing recovery of acquisition adjustments. The STM proceeding would determine whether the transaction was in the public interest and whether the acquiring utility could provide adequate service. The ratemaking treatment of the acquisition adjustment would then be decided in the utility's rate case when the utility sought to recover the acquisition adjustment, where the Commission could determine whether recovery of the acquisition adjustment would have an unreasonable effect on the utility's rates.

However, according to Sharyland, although Issue No. 3 overlaps to some extent with the issues that will be addressed in the future rate case when Sharyland seeks recovery of the acquisition adjustment, that does not mean the Commission should not address Issue No. 3 in this proceeding. Sharyland explained that in this case, the cost of the acquisition adjustment will be recovered through Sharyland's wholesale transmission rates and the effect of allowing recovery can only be addressed in a proceeding setting new transmission rates for Sharyland.[50] However, the Commission should determine in the STM proceeding whether Sharyland is entitled to seek recovery of the acquisition adjustment since that will clearly have an effect on a

[49] See *Joint Petition of Southwestern Public Service Company and Golden Spread Electric Cooperative, Inc. for Declaratory Order,* Docket No. 35820, Order on Certified Issue at 3 (June 27, 2008) (ruling that a determination regarding rate treatment of costs resulting from a transaction that had not occurred would constitute an impermissible advisory opinion).

[50] Tr. at 44.

Request

Referring to Direct Testimonies of Wesley Speed and Alan Ledbetter, regarding the InfraREIT Acquisition and related acquisition premium, please:

a) Provide any study or analysis demonstrating quantifiable benefits that will be realized by Texas customers associated with the InfraREIT Acquisition in excess of the proposed acquisition premium of $23.5 million;

b) Provide any study or analysis quantifying the benefits of the InfraREIT Acquisition that have been realized by Texas customers to date.

c) To the extent that a demonstration of quantifiable benefits in excess of the acquisition premium cannot be demonstrated, please provide any additional rationale for recovery of the acquisition premium not already presented on the record.

Response

The following response was prepared by or under the direct supervision of W. Alan Ledbetter and Wesley R. Speed, the sponsoring witnesses for this response.

Please see pages 37-38 of Mr. Ledbetter's direct testimony (Bates pages 601-602) indicating that the Commission has ruled that the acquisition by Sharyland Utilities, L.P. and Sharyland Distribution & Transmission Services, L.L.C. (together "Sharyland") of the transmission assets held by Southwestern Public Service Company ("SPS") is in the public interest, noting that: "The purchase price of $37 million represents a reasonable purchase price for the facilities, taking into account the arm's length nature of the negotiations, the replacement value of the facilities of $99 million, the reliability, congestion mitigation, and timing benefits associated with the purchase of the facilities and the move of the Borden-to-Midland transmission line from SPP to ERCOT, and the estimated $135 million in avoided transmission cost savings to ERCOT ratepayers if the transaction is approved" (see Finding of Fact number 88 of the Docket No. 41430 Order, Commission Interchange Item 146, page 17 of 21).

Thus, the reasonableness of the Sharyland acquisition of the SPS assets that generated the $23.5 million acquisition adjustment has already been ruled upon by the Commission. The issue in Oncor's present request to change rates only involves the mechanism for regulatory recovery of the acquisition adjustment, as reflected in Conclusion of Law number 14 of the Docket No. 41430 Order (page 20 of 21), which provides that "(t)he ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will not be determined in this proceeding but will be addressed in Sharyland's next rate proceeding." Please see Oncor's response to OPUC RFI Set No. 2, Question No. 2-08 filed in this docket, for a description of the proposed regulatory treatment.

ONCOR.

ONCOR PRINCIPLES, POLICIES AND PROCEDURES – ACCOUNTING

Title:	**50-02 Allowance for Funds Used During Construction (AFUDC)**
Responsible Officer:	**Controller**
Contact:	**Mindy Marshall (214-486-3173)**
Last Reviewed/Revised Date:	**June 21, 2021**

Scope / Application

This accounting policy and procedure ("AP&P") applies to all Oncor business organizations constructing capital assets.

Purpose

The purpose of this policy is to establish a uniform policy and procedure for the computation, accrual, and allocation of Allowance for Funds Used During Construction (AFUDC).

Policy

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts lists AFUDC as one of the components of construction cost. AFUDC is a cost accounting procedure whereby amounts based upon interest charges on borrowed funds and a return on equity capital used to finance construction are charged to electric plant. The accrual of AFUDC is in accordance with generally accepted accounting principles for the industry, but does not represent current cash income.

The regulated business organizations and assets of Oncor that fall under SFAS 71 are capitalizing AFUDC as required by FERC, compounded semiannually, on expenditures for ongoing construction work in progress (CWIP) not otherwise allowed in rate base by regulatory authorities. The AFUDC rate is determined on the basis of, but is less than, the cost of capital used to finance the construction program.

Procedure

Computation of AFUDC Rate

AFUDC rates are based on the capital structure of the Company as of the end of the prior fiscal year. The AFUDC rate is calculated using estimates of the short-term debt balances and related cost applicable to CWIP and the average balances of CWIP. The balances for long-term debt, preferred stock, preferred securities, and common equity are the actual book balances as of the end of the prior fiscal year. The cost rates for long-term debt, preferred stock, and preferred securities are the weighted average cost of such capital. The cost rate for common equity is the rate that was granted in the most recent rate proceeding. The AFUDC rate is monitored and calculated monthly until year end using 13 month averages of short-term debt applicable to CWIP and CWIP balances (both calculated using actual balances as they occur plus outstanding estimates); and, the weighted average cost of equity and long term debt. After determining the maximum AFUDC accrual rate, Property Accounting calculates the percentage allocation between borrowed funds (Debt) and other funds (Equity). Monthly, the Oncor Assistant Controller

reviews the maximum allowable AFUDC rate as calculated by Property Accounting, and selects a rate less than or equal to that maximum.
If the actual AFUDC rate projected for the end of the year is higher than the AFUDC rate applied during the year by 25 basis points or more, the rate is changed on a retroactive basis to the beginning of the year to reflect the new rate per the requirements of FERC Order Number 561. This retroactive adjustment usually occurs near the end of the year.

AFUDC Rate Formula

The formula and elements for the computation of the allowance for funds used during construction as prescribed by FERC are:

$A_i = s\,(S/W) + d\,(D/D+P+C)\,(1-S/W)$

$A_e = [1-S/W]\,[p\,(P/D+P+C) + c\,(C/D + P + C)]$

This rate is reduced programmatically within the Financial Information Management (FIM) system to reflect a semi-annual compounding using the following formula:

$A_{is} = (1 + A_i/2)^{1/6} - 1$
$A_{es} = (1 + A_e/2)^{1/6} - 1$

Where:
A_i=Gross allowance for borrowed funds used during construction rate.

A_e=Allowance for other funds used during construction rate.

A_{is} and A_{es} = Semi-annual compounded rate equivalent to A_i and A_e.

Elements:
S=Average short-term debt.

s=Short-term debt interest rate.

D=Long-term debt.

d=Long-term debt interest rate.

P=Preferred stock and securities.

p=Preferred stocks and securities cost rate.

C=Common equity.

c=Common equity cost rate.

W=Average balance in CWIP.

Application of AFUDC

AFUDC is accrued using the process as shown below. The current month AFUDC accrual is calculated at month end using the prior month CWIP balance of each eligible project, plus or minus any adjustments, multiplied times the monthly AFUDC rate.

EXAMPLE

A project is estimated to install facilities on a customer's premises. Construction is to begin 1-1-06 and be completed 5-1-06. The customer is to pay $100,000 in advance, representing Contributions In Aid of Construction (CIAC). Construction costs are as follows:

New Construction (excluding CIAC & AFUDC) = $235,000

The cost subject to AFUDC would be $135,000 ($235,000-$100,000). Since this is a FIM capital project to construct facilities and the construction period is greater than thirty days, this project will receive AFUDC. The estimated AFUDC is as follows:

	JAN	FEB	MAR	APR	MAY	TOTAL
Beginning Balance	-	($25,000)	$15,000	$55,131	$95,613	-
Customer Payment	($100,000)	-	-	-	-	($100,000)
Construction Expenditures	75,000	40,000	40,000	40,000	40,000	235,000
Estimated AFUDC	-	-	131	482	837	1,450
Ending Balance	(25,000)	15,000	55,131	95,613	136,450	136,450
Previous Month's						
Balance Times	-	-	15,000	55,131	95,613	
AFUDC Monthly Rate	0.00875	0.00875	0.00875	0.00875	0.00875	
Estimated AFUDC			$ 131	$ 482	$ 837	

Property Accounting calculates the monthly accrual of AFUDC estimate using the appropriate accrual rate applied against eligible CWIP project balances based on the following criteria:

- Must be a valid capital project in FIM
- Requires at least 30 days to complete
- Cost at least $1

An eligible project will receive AFUDC beginning the month after charges to the job are first recorded and will continue to receive AFUDC until the project is put in service. If it is determined that a project currently receiving AFUDC is delayed for a period of one year or more, written notification should be sent to Property Accounting requesting temporary discontinuance of AFUDC. This notification should include an explanation for the delay, an estimate when construction will continue, and a signature from the level of management which authorized the project or a superior level.

Note: Property Accounting will review each such notification with the Assistant Controller. The projects that qualify will be excluded from the AFUDC and allocation bases. Generally, no adjustment will be made for periods prior to the current month AFUDC accrual. The project will be excluded from the AFUDC process until construction expenditures resume on a continuous basis. In the month following the month that construction expenditures resume, the AFUDC accrual on this project will resume.

ACCOUNTING STRUCTURE:

Accrual and Allocation of AFUDC is recorded by the following entries:

Debit

Each eligible CWIP project

Credit

- Expense account 4321000-AFUDC Debt
- Revenue account 4191000-AFUDC Equity

Revision History

June 11, 2010	Adoption of Oncor policy
November 7, 2011	Updated policy to delete section on, and other references to Capitalized Interest.
August 17, 2015	Deleted reference to accrual period is from the 16th day of the prior month to the 15th day of the current period.
August 15, 2017	Review of Oncor policy on August 15, 2017 – No changes.
August 30, 2019	Updated policy for title change and short term debt ceiling
June 21, 2021	Updated title from Director of Accounting to Assistant Controller

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AC17-262-000
January 30, 2018

Troutman Sanders LLP
Attention: Mr. Christopher R. Jones
Counsel for Ameren Illinois Company and
Ameren Transmission Company of Illinois
401 9th Street, N.W., Suite 1000
Washington, D.C. 20004-2134

Dear Mr. Jones:

This is in response to your letter dated August 18, 2017. You filed the letter on behalf of Ameren Illinois Company and Ameren Transmission Company of Illinois (jointly, Applicants) to request a waiver of certain requirements of Order No. 561 to allow for the monthly calculation of their Allowance for Funds Used During Construction (AFUDC) rate,[1] effective January 1, 2017.

Based on the Applicants' representations that their monthly AFUDC rate computation will not result in AFUDC amounts recorded in excess of that prescribed in Order No. 561, the request for a waiver is granted. Applicants are directed to implement controls and procedures to ensure that the AFUDC rate computation as proposed in this request will not, in fact, result in AFUDC amounts recorded in excess of that prescribed in Order No. 561.

Order No. 561 provides specific instructions for computing AFUDC. Order No. 561 requires that the AFUDC rate computation include certain estimated inputs, i.e., estimates of current year average construction work in progress and short-term debt balances, and short-term debt rates. Order No. 561 requires public utilities to compare the estimates to actual experience and adjust capitalized AFUDC, if a significant deviation between AFUDC rates computed based on estimated and actual realized inputs should occur. It defines "significant" to be more than one quarter of a percentage point

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[1] *Order Adopting Amendment to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies*, Order No. 561, 57 FPC 608 (1977), *order clarified,* Order No. 561-A, 2 FERC ¶ 61,050 (1978).

(25 basis points) of the gross AFUDC rate. Also, Order No. 561 generally requires that compounding of AFUDC occur no more frequently than semiannually.

Applicants represent that because short-term debt balances and rates can fluctuate throughout the year, "significant deviations" from the estimate can frequently occur. Applicants also indicate that calculating AFUDC based on actual debt expense on a monthly basis will more accurately align their ratemaking books with the actual costs of securing debt financing for construction. Applicants explain that performing a true-up at the end of the year is procedurally burdensome. Accordingly, Applicants request waiver of Order No. 561 and the associated Commission accounting regulations pertaining to the AFUDC rate computation requiring average short-term debt balances and rates, and average CWIP balance, to be estimated for the current year, as well as the requirement to adjust only at year-end for "significant deviations."

Instead, Applicants propose to calculate AFUDC monthly, based on appropriate monthly balances. Applicants contend that monthly computation of the AFUDC rate with the proposed actual inputs will not result in a rate in excess of that calculated under the directives of Order No. 561. Accordingly, the proposed AFUDC rate computation is accepted, provided that Applicants implement controls and procedures to ensure that the AFUDC rate computation as proposed in this request will not, in fact, result in AFUDC amounts recorded in excess of that prescribed in Order No. 561.

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2017). The Director has designated this authority to the Acting Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2017).

Sincerely,

Steven D. Hunt
Acting Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

Document Content(s)

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AC12-114-000
November 7, 2012

PNM Resources
Attention: Mr. Thomas G. Sategna
Vice President and Corporate Controller
Alvarado Square
Albuquerque, NM 87138-2701

Dear Mr. Sategna:

This is in response to your June 20, 2012 letter, as amended on August 29, 2012. You filed the letters on behalf of Public Services Company of New Mexico and Texas New Mexico Power (jointly, the PNM Utilities) to request a waiver of certain requirements of Order No. 561 to allow for the monthly calculation of their Allowance for Funds Used During Construction (AFUDC) rate.[1]

Based on the PNM Utilities' representations that their monthly AFUDC rate computation will not result in AFUDC amounts recorded in excess of that prescribed in Order No. 561, the request for a waiver is granted.

Order No. 561 provides specific instructions for computing AFUDC. Order No. 561 requires that the AFUDC rate computation include certain estimated inputs, i.e., estimates of current year average construction work in progress and short-term debt balances, and short-term debt rates. Order No. 561 requires public utilities to compare the estimates to actual experience and adjust capitalized AFUDC, if a significant deviation between AFUDC rates computed based on estimated and actual realized inputs should occur. It defines "significant" to be more than one quarter of a percentage point (25 basis points) of the gross AFUDC rate. Also, Order No. 561 generally requires that compounding of AFUDC occur no more frequently than semiannually.

The PNM Utilities represent that their construction projects vary with regard to consummation timing and duration so that a year-end true-up as prescribed in

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[1] *Order Adopting Amendment to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies*, Order No. 561, 57 FPC 608 (1977), *order clarified,* Order No. 561-A, 2 FERC ¶ 61,050 (1978).

Order No. 561 is procedurally burdensome. Also, the PNM Utilities indicate that their short-term debt balances and rates are volatile and difficult to estimate. In this regard, the PNM Utilities assert that it is highly likely that a significant deviation from the estimate will occur. Moreover, the PNM Utilities contend that using estimates for short-term debt balances and rates and construction work in progress balances in the computation of their AFUDC rates, and only allowing for true-ups at year-end can potentially result in inaccurate and misleading interim financial reporting.

Accordingly, the PNM Utilities request authorization to compute their AFUDC rates monthly using actual inputs to replace the estimate inputs and need for true-ups with the use of actual values from the most recent periods. The PNM Utilities state that monthly computation of the AFUDC rate with the proposed actual inputs will not result in a rate in excess of that calculated under the directives of Order No. 561. Therefore, the Utilities propose that the monthly AFUDC rate computation be based on the following inputs:

Element	Computation Method
Work in progress (W):	Simple average of the current month's beginning and ending balances
Short-term debt (S):	Current month's weighted average balance
Short-term debt rate (s):	Current month's actual expense divided by (S)
Long-term debt (D):	Prior month's ending balance
Long-term debt rate (d):	Prior month's actual expense divided by (D)
Preferred stock (P):	Prior month's ending balance
Preferred stock rate (p):	Prior month's actual cost divided by (P)
Common equity (C):	Prior month's ending balance
Common equity rate (c):	From last rate case in primary jurisdiction

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2012). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2012).

Sincerely,

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement

Document Content(s)

KeyCite Yellow Flag - Negative Treatment

Order Clarified by Amendments to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies (Classes A, B, C and D) To Provide for the Determination of Rate for Computing the Allowance for Funds Used During Construction and Revisions of Certain Schedule Pages of FPC Reports, F.E.R.C., January 20, 1978

57 F.P.C. 608, 1977 WL 16195

AMENDMENTS TO UNIFORM SYSTEM OF ACCOUNTS FOR PUBLIC UTILITIES AND LICENSEES AND FOR NATURAL GAS COMPANIES (CLASSES A, B, C AND D) TO PROVIDE FOR THE DETERMINATION OF RATE FOR COMPUTING THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND REVISIONS OF CERTAIN SCHEDULE PAGES OF FPC REPORTS,

DOCKET NO. RM75–27
ORDER NO. 561
ORDER ADOPTING AMENDMENT TO UNIFORM SYSTEM OF ACCOUNTS FOR PUBLIC UTILITIES AND LICENSEES AND FOR NATURAL GAS COMPANIES
February 2, 1977*

****1 *608** Before Commissioners: Richard L. Dunham, Chairman; Don S. Smith, John H. Holloman III and James G. Watt.

On May 20, 1975, the Commission issued a notice of proposed rulemaking in Docket No. RM75–27 (40 F.R. 23322, May 29, 1975). This rulemaking proposed to establish a uniform formulary method for determining the maximum rates to be used in computing the Allowance for Funds Used During Construction (AFUDC) and to provide accounting and reporting requirements for AFUDC which accord with the elements entering into the determination of AFUDC rates. The stated objective of the proposed rule was to establish a method which would give recognition to the interrelationship between capital utilized for rate case purposes and the capital components of AFUDC in a manner that would permit utility to achieve a rate of return on its total utility operations, including its constructions program, at approximately the rate which would be allowed in a rate case.

Comments were invited from interested parties on or before July 7, 1975. Due to requests, this date was extended to September 5, 1975. In response to the proposed rulemaking, the Commission received comments from 79 respondents (Attachment A). In general, the reaction to the proposed rulemaking was favorable as to its overall objective, but many respondents questioned the ability of the proposal to meet such objective and made suggestions for improvement.

Many respondents objected to the weight given short-term debt in the proposed rule and suggested a number of alternatives. These respondents argued that short-term debt is not necessarily the first source of construction funds, as would be indicated by application of he proposed formula, and should be ignored or given less weight. We are not convinced, however, that we should modify the proposed formula with respect to short-term debt. It is generally impossible to specifically trace the source of funds used for ***609** various corporate purposes and it was not the purpose of our proposed rule to do so. Instead, we proposed a rule that would give a utility an opportunity to be compensated for the total cost of capital devoted to utility operations, including its construction program. In order to accomplish this, it is necessary to look to how the cost of capital is handled in a rate proceeding so that a method for determining AFUDC can be devised that will not result in double counting of the same capital cost or will not omit important categories of capital cost. Typically, short-term debt has not been included in rate of return computations for cost of service purposes on the grounds that such debt is temporary and is used essentially for construction purposes; however, the cost of such debt represents a valid and necessary expenditure for conducting utility operations which ultimately must be recovered through rates. By adopting the approach of permitting the capitalization of short-term debt cost through AFUDC, we provide such a mechanism. It should be understood that this method is for the purpose of establishing a rate for AFUDC and not for establishing a method for allocating short-term interest cost for the purpose of a rate proceeding.

****2** Many respondents also questioned the use of embedded cost rates for long-term debt and preferred stock in the proposed AFUDC formula and suggested incremental cost rates be used instead. For essentially the same reasons that we believe the proposed handling of short-term debt should not be modified, we are rejecting this suggestion. If incremental cost rates were utilized for these categories of capital cost in the AFUDC formula, there would be a double counting for the same costs. Embedded cost rates are normally used for rate of return purposes and such cost rates include the cost of new as well as old issues of long-term debt and preferred stock. Therefore, the composite return on rate base collected through rates provides for the proportionate recovery of new or incremental capital costs in the ratio of rate base to the size of the capital structure used for rate of return purposes. If we assume fo the sake of argument that the sum of a utility's permanent capital structure plus short-term borrowing is equal to the sum of its rate base plus construction work in progress balances, it is obvious that the use of incremental cost for AFUDC purposes and embedded cost for rate of return purposes would result in double counting of the same costs. Although the above illustration somewhat oversimplifies the issue, we believe that the principle is adequately demonstrated.

The other basic component for AFUDC relates to common equity funds. Comments by respondents on this subject primarily related to how the reasonable cost rate for common equity funds should be determined. Unlike debt costs or the cost of preferred stock, which can be objectively determined by analysis of actual contractual obligations and expenditures, the cost of common equity is not ordinarily related to contractual requirements. In the proposed rule we indicated that the cost rate to be used for common equity would be the rate granted common equity in the last rate proceeding before ***610** the body having primary rate jurisdiction or, if such rate is not available, the average rate actually earned during the preceding 3 years should be used. We recognize, based on the comments received, that this approach may require some modification in situations where ratemaking bodies use other than an 'original cost' rate base or where utilities are subject to multiple rate jurisdiction. However, in developing a general rule relating to AFUDC, we find any possible inequities of this nature can best be handled on an individual company basis.

Having considered the broad issues of the various components of the AFUDC, it is now necessary to focus on the many constructive and helpful comments and suggestions received relating to other facets of the proposed rulemaking.

Many comments were received regarding the desirability of segregating AFUDC into two components, borrowed funds and other funds, and the relocation of the allowance for borrowed funds to the Interest Charges Section of the income statement. The main objection to this proposed requirement was that it would have the effect of reducing interest coverages and thereby restrict the issuances of additional debt by some companies. We recognized that this may be a particularly uninviting aspect of the proposed rule for some utilities since 'Other Income' will be reduced upon application of the proposed rule and such income is frequently, in whole or part, used for interest coverage tests.[1] However, we believe this change to be necessary in order to better inform readers of the financial statements of utilities as to the nature and level of the capitalized allowance for borrowed funds. Since there is little conceptual difference between capitalization of the cost of borrowed funds used for construction purposes and other costs of construction such as labor and materials, we believe that the readers of financial statements will be better informed if such construction interest is shown as an allocation of cost by a reduction in the Interest Charges Section of the income statement rather than as an income item.

****3** A number of respondents criticized the proposal to determine the current year's AFUDC rates by the use of average actual book balances and cost rates of the prior year principally because short-term debt cost rates and balances are very volatile and the use of averages for a previous year does not give a proper indication of the cost of short-term debt for prospective computations of AFUDC. We agree that this is a valid point and believe that modifications of the proposed rule in this are are necessary.

We are modifying the proposed rule to provide that the balances of long-term debt, preferred stock, and common equity for use in the formula for the current year will be the balances in such accounts at the end of the prior year; the cost rates for long-term debt and preferred stock will be the effective ***611** weighted average cost of such capital. The average short-term debt balances and related cost and the average construction work in progress balance will be estimated for the current year. We shall require, however, that public utilities and natural gas companies monitor their actual experience and adjust to actual at year-end if a significant deviation from the estimate should occur. For this purpose we shall consider a significant deviation to exist if the gross AFUDC rate exceeds by more than one-quarter of a percentage point (25 basis points) the rate that is derived from the formula by use of actual 13 monthly balances of construction work in progress and the actual weighted average cost and balances for short-term debt outstanding during the year.

Many respondents requested clarification as to whether premiums, discounts and expenses related to long-term debt, and compensating balances and commitment fees related to short-term debt, were to be considered when determining the cost rate for such funds. With respect to long-term debt, the cost of such capital should be the yield to maturity determined in the same manner as set forth in § 35.13(b)(4)(iii), Statement G—Rate of Return, of the Commission's Regulations under the Federal Power Act and § 154.63(f), Statement F(3)—Debt Capital, of the Commission's Regulations under the Natural Gas Act which gives appropriate recognition to premiums, discounts and expenses related to long-term debt. In regard to short-term debt, several respondents have pointed out that compensating balances and commitment fees have cost implications with respect to bank loans and as support for commercial paper and urged that recognition be given for such costs. We agree that in some instances, such items could properly be considered in determining the effective cost rate for short-term debt for use in the formula. However, primarily because of measurement problems, we do not believe that specific recognition should be given in the general rule. Instead, where an individual company has a written agreement and can support the fact that compensating balances and commitment fees are necessary in order to obtain favorable short-term financing and are not considered in its rate proceedings, we will permit an adjustment to the nominal short-term interest rates to reflect this additional cost. We believe that this approach is necessary because of the diversity of rate treatment for these items; the commingling and lack of identification of bank balances kept for normal operating purposes and those used for compensating bank balance purposes; and the frequent lack of formal agreements for required levels of compensating bank balances.

****4** Some respondents commented that the value of noninvestor sources of funds such as accumulated deferred income taxes and contributions in aid of construction should be recognized in the formula. We are not adopting this suggestion since normally the entire balances in the accumulated deferred income taxes accounts are used to reduce rate base for cost of service purposes.[2] To include such balances in determining the AFUDC rate would ***612** result in double counting of the same dollars. The same reasons apply for contributions in aid of construction, since under our Uniform System of Accounts such contributions are credited directly to construction costs.

A number of respondents commented that previously capitalized AFUDC should be included in the cost base to which the AFUDC rate applies since AFUDC is a cost of construction similar to labor, materials and other elements of construction. Thus, it is asserted that the compound method must be recognized if AFUDC is to properly compensate the utility for use of funds while devoted to construction. We agree that compounding of AFUDC is proper in theory and necessary as a matter of sound cost determination; however, we believe that a monthly compounding of AFUDC as suggested by some respondents may result in excessive amounts capitalized since cash outlays for interest and dividends are not normally made on a monthly basis. We shall therefore permit compounding but no more frequently than semiannually.

A number of respondents also indicated that any rules issued with respect to AFUDC should apply to Nuclear Fuel in Process of Refinement, Conversion, Enrichment and Fabrication (Account 120.1) in the same manner as Construction Work in Progress. We agree with these comments and will so provide.

Certain other constructive suggestions received from respondents have been included in the accounting instructions for the purpose of adding clarity to the accounting text.

We have also deleted that portion of the proposed plant instructions pertaining to computations of income taxes. We believe that these proposed instructions are not now necessary in view of our Order Nos. 530 (53 FPC 2123),530–A (55 FPC 162)and 530–B (56 FPC 739) in Docket Nos. R–424, Accounting for Premiums, Discount and Expense of Issue, Gains and Losses Debt, and Interperiod Allocation on Refunding and Reaquisition of Long-Term Debt, and Interperiod Allocation of Income Taxes and R–

446, Amendments to the Uniform System of Accounts for Classes A, B and C Public Utilities and Licensees and Natural Gas Companies: Deferred Income Taxes. As stated in Order No. 530–A:

The accounting for deferred income taxes prescribed in Order No. 530 was structured to accommodate utilities under the rate jurisdiction of the various state regulatory bodies that may or may not authorize deferred tax accounting for rate purposes (See General Instruction 18). If a net of tax allowance for funds rate is prescribed by a regulatory body in setting the rate levels of utilities, we consider that such treatment is consistent with the intent of Order No. 530 and it is not necessary for utilities to set aside deferred income taxes related to the interest component ***613** of the allowance for funds rate. In light of this, we do not believe that it is necessary to make provision in the Uniform System of Accounts to cover this matter.

The Commission finds:

****5** (1) The notice and opportunity to participate in this rulemaking proceeding with respect to the matters presently before this Commission through the submission, in writing, of data, views, comments and suggestions in the manner described above, are consistent and in accordance with the procedural requirements prescribed by 5 U.S.C. 553.

(2) The amendments to Parts 101 and 104 of the Commission's Uniform System of Accounts for Public Utilities and Licensees and to FPC Forms No. 1, No. 1–F, and No. 5 required by § 141.1, 141.2, and 141.25 in Chapter I, Title 18 of the Code of Federal Regulations, herein prescribed, are necessary and appropriate for the administration of the Federal Power Act.

(3) The amendments to Parts 201 and 204 of the Commission's Uniform System of Accounts for Natural Gas Companies, and to FPC Forms No. 2, No. 2–A, and No. 11 required by § 260.1, 260.2, and 260.3 in Chapter I, Title 18 of the Code of Federal Regulations, herein prescribed, are necessary and appropriate for the administration of the Natural Gas Act.

(4) Since the amendments prescribed herein, which were not included in the notice of the proceeding, are consistent with the prime purpose of the Proposed Rulemaking, further notice thereof is unnecessary.

(5) Good cause exists for making the amendments to the Uniform System of Accounts for Public Utilities and Licensees and Natural Gas Companies ordered herein effective on January 1, 1977, and the amendments to FPC Forms No. 1, No. 1–F, No. 2, No. 2–F, No. 5, and No. 11 ordered herein, effective for the reporting year 1977.

The Commission, acting pursuant to the provisions of the Federal Power Act, as amended, particularly Sections 3, 4, 301, 304, 308, 309, and 311 (41 Stat. 1063, 1065; 49 Stat. 838, 839, 854, 855, 858, 859; 16 U.S.C. 796, 797, 825, 825c, 825g, 825h, 825j) and of the Natural Gas Act, as amended, particularly Sections 8, 10, and 16 (52 Stat. 825, 826, 830; 15 U.S.C. 717g, 717i, 717***o***), *orders:*

(A) Effective January 1, 1977, the Commission's Uniform System of Accounts for Class A and Class B Public Utilities and Licensees in Part 101, Chapter I, Title 18 of the Code of Federal Regulations is amended as follows:

(1) The General Instructions are amended by revising paragraph ‘I’ of Instruction ‘17. *Long-Term Debt: Premium, Discount and Expense, and Gain of Loss on Reacquisition*.’ As amended, this portion of General Instruction 17 reads:

***614** GENERAL INSTRUCTIONS

17. *Long-Term Debt: Premium, Discount and Expense, and Gain or Loss on Reacquisition*.