VI. SCHEDULES

Discount factor
0.06

Schedule PKC-1a
OCA Testimony DG 17-198
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Attachment OCA 13-1.a
Levelized and Annualized Supplemental Cases
($ in 000's)

		A	B	C	D	J	J-A+B-C+D	Discounted
	Gas Year	Granite Bridge Pipeline (Levelized)	Granite Bridge Pipeline (Annualized)	2.0 Bcf Granite Bridge LNG (Levelized)	2.0 Bcf Granite Bridge LNG (Annualized)	Scenario 1513 Base Case Supplemental (2.0 Bcf) (Levelized)	Scenario 1513 Base Case Supplemental (2.0 Bcf) (Annualized)	Scenario 1513 Base Case Supplemental (2.0 Bcf) (Annualized)
	2018-2019					$86,663	$86,663	
	2019-2020					$85,042	$85,042	
	2020-2021					$86,157	$86,157	
	2021-2022					$87,661	$87,661	
1	2022-2023	$17,633	$22,833	$16,801	$21,604	$134,216	$144,219	$ 144,219
2	2023-2024	$17,633	$22,253	$28,802	$36,478	$123,103	$135,399	$ 127,735
3	2024-2025	$17,633	$21,697	$28,802	$35,456	$126,984	$137,702	$ 122,554
4	2025-2026	$17,633	$21,161	$28,802	$34,419	$131,412	$140,556	$ 118,014
5	2026-2027	$17,633	$20,644	$28,802	$33,434	$135,261	$142,905	$ 113,194
6	2027-2028	$17,633	$20,146	$28,802	$32,497	$139,144	$145,352	$ 108,615
7	2028-2029	$17,633	$19,664	$28,802	$31,598	$141,344	$146,171	$ 103,045
8	2029-2030	$17,633	$19,198	$28,802	$30,719	$143,651	$147,132	$ 97,851
9	2030-2031	$17,633	$18,734	$28,802	$29,844	$146,009	$148,152	$ 92,952
10	2031-2032	$17,633	$18,270	$28,802	$28,971	$148,736	$149,542	$ 88,514
11	2032-2033	$17,633	$17,807	$28,802	$28,098	$150,685	$150,155	$ 83,846
12	2033-2034	$17,633	$17,343	$28,802	$27,227	$153,101	$151,236	$ 79,669
13	2034-2035	$17,633	$16,880	$28,802	$26,357	$155,413	$152,215	$ 75,646
14	2035-2036	$17,633	$16,417	$28,802	$25,487	$158,173	$153,642	$ 72,034
15	2036-2037	$17,633	$15,954	$28,802	$24,619	$159,968	$154,106	$ 68,161
16	2037-2038	$17,633	$15,491	$28,802	$23,805	$162,479	$155,340	$ 64,818
17	2038-2039	$17,633	$15,028	$28,802	$23,133	$157,573	$149,298	$ 58,771
	Totals	$299,767	$319,517	$477,625	$493,746	$2,812,774	$2,848,645	$ 1,619,638

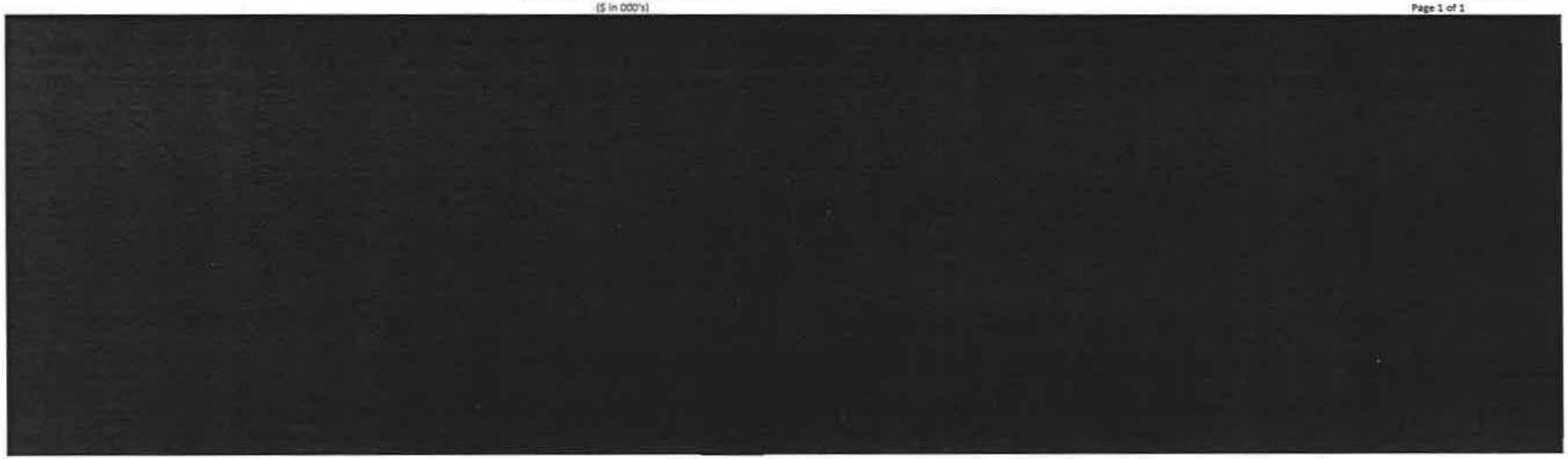
Note: Cell A2 is the discount factor

Discount factor
0.06

Confidential Attachment OCA 12-2.a
Levelized and Annualized Supplemental Cases
($ in 000's)

REDACTED

Schedule PKC-1h
OCA Testimony DG 17-198
Page 1 of 1



Discount factor
0.06

Schedule PKC-2a
OCA Testimony DG 17-198
Page 1 of 1

Attachment OCA 13-1.c
Levelized and Annualized Supplemental Cases
($ in 000's)

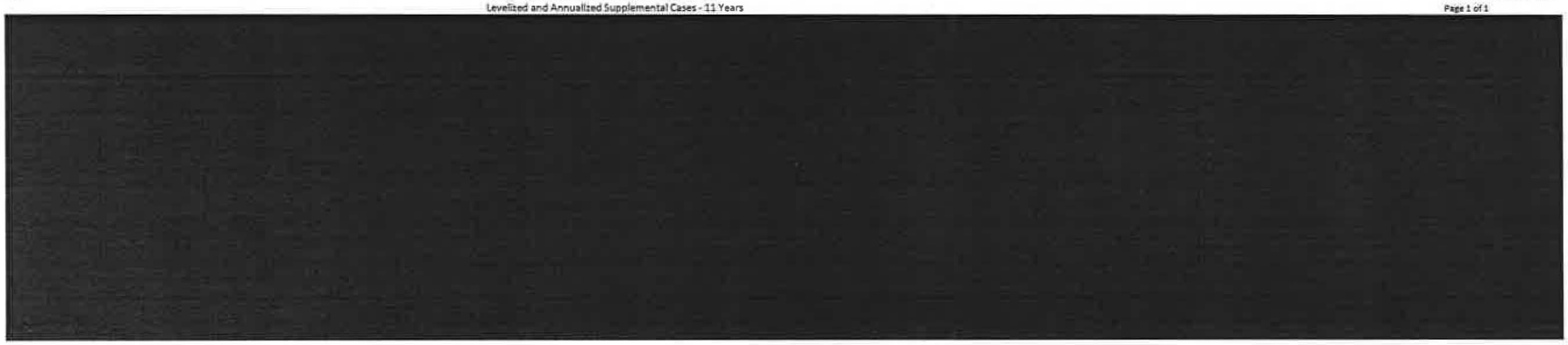
		A	B	C	D	J	J-A+B-C+D	
	Gas Year	Granite Bridge Pipeline (Levelized)	Granite Bridge Pipeline (Annualized)	2.0 Bcf Granite Bridge LNG (Levelized)	2.0 Bcf Granite Bridge LNG (Annualized)	Scenario 1513-11 Base Case Supplemental (2.0 Bcf) (Levelized)	Scenario 1513-11 Base Case Supplemental (2.0 Bcf) (Annualized)	Scenario 1513-11 Discounted
	2018-2019					$86,662	$86,662	
	2019-2020					$85,042	$85,042	
	2020-2021					$86,157	$86,157	
	2021-2022					$87,661	$87,661	
1	2022-2023	$17,633	$22,833	$16,801	$21,604	$134,216	$144,219	$ 144,219
2	2023-2024	$17,633	$22,253	$28,802	$36,478	$123,102	$135,398	$ 127,734
3	2024-2025	$17,633	$21,697	$28,802	$35,456	$126,988	$137,706	$ 122,558
4	2025-2026	$17,633	$21,161	$28,802	$34,419	$131,407	$140,552	$ 118,010
5	2026-2027	$17,633	$20,644	$28,802	$33,434	$135,262	$142,905	$ 113,194
6	2027-2028	$17,633	$20,146	$28,802	$32,497	$139,144	$145,352	$ 108,616
7	2028-2029	$17,633	$19,664	$28,802	$31,598	$134,351	$139,178	$ 98,115
	Totals	$123,434	$148,398	$189,610	$225,486	$1,269,992	$1,330,832	$ 832,446

Note: Cell A2 is the discount factor

Discount factor
0.06

Confidential Attachment OCA 12-5.b
Levelized and Annualized Supplemental Cases - 11 Years

REDACTED



0.06

Confidential Attachment OCA 12-18.e
Levelized and Annualized Supplemental Cases - Low Demand Case
($ in 000's)

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Schedule PKC-3a
OCA Testimony DG 17-198
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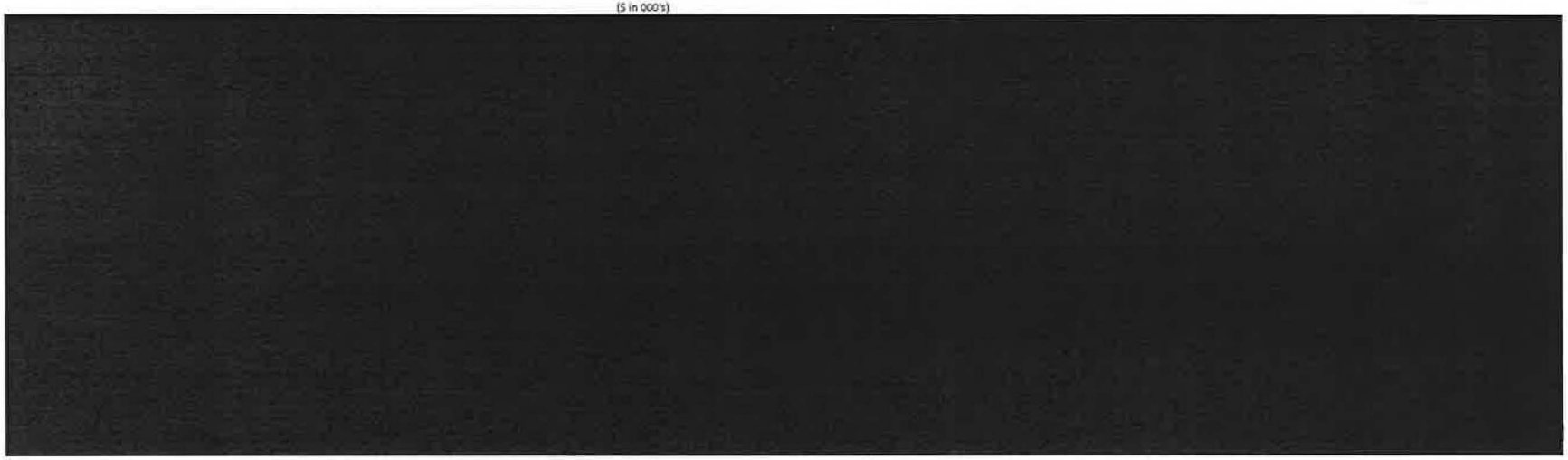

Discount factor
0.06

Schedule PKC-3b
OCA Testimony DG 17-198
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Attachment OCA 14-4.c
Levelized and Annualized Supplemental Cases - Low Demand Case
($ in 000's)

	A	B	C	D	E	F	G	H	I	I-A+B-C+D	J	J-A+B-E+F	K	K-A+B-G+H	Discounted
			2.0 Bcf	2.0 Bcf	1.2 Bcf	1.2 Bcf	1.5 Bcf	1.5 Bcf	Scenario 1559 Base Case Supplemental (2.0 Bcf)	Scenario 1559 Base Case Supplemental (2.0 Bcf)	Scenario 1560 Base Case Supplemental (1.2 Bcf)	Scenario 1560 Base Case Supplemental (1.2 Bcf)	Scenario 1561 Base Case Supplemental (1.5 Bcf)	Scenario 1561 Base Case Supplemental (1.5 Bcf)	Scenario 1559 Base Case Supplemental (2.0 Bcf)
	Gas Year	Granite Bridge Pipeline (Levelized)	Granite Bridge Pipeline (Annualized)	Granite Bridge LNG (Levelized)	Granite Bridge LNG (Annualized)	Granite Bridge LNG (Levelized)	Granite Bridge LNG (Annualized)	Granite Bridge LNG (Levelized)	Granite Bridge LNG (Annualized)	(Levelized)	(Annualized)	(Levelized)	(Annualized)	(Levelized)	(Annualized)	(Annualized)
	2018-2019									$85,106	$85,106	$85,105	$85,105	$85,106	$85,106	
	2019-2020									$82,304	$82,304	$82,304	$82,304	$82,304	$82,304	
	2020-2021									$81,874	$81,874	$81,874	$81,874	$81,874	$81,874	
	2021-2022									$81,512	$81,512	$81,512	$81,512	$81,512	$81,512	
1	2022-2023	$17,633	$22,833	$16,801	$21,604	$15,371	$19,670	$15,850	$20,318	$126,279	$136,282	$122,322	$131,821	$123,792	$133,460	$136,282
2	2023-2024	$17,633	$22,253	$28,802	$36,478	$26,350	$33,219	$27,171	$34,310	$115,880	$128,177	$116,537	$128,026	$115,984	$127,743	$120,921
3	2024-2025	$17,633	$21,697	$28,802	$35,456	$26,350	$32,298	$27,171	$33,355	$118,430	$129,148	$119,306	$129,318	$118,743	$128,991	$114,941
4	2025-2026	$17,633	$21,161	$28,802	$34,419	$26,350	$31,364	$27,171	$32,387	$121,510	$130,654	$122,427	$130,969	$121,846	$130,589	$109,700
5	2026-2027	$17,633	$20,644	$28,802	$33,434	$26,350	$30,478	$27,171	$31,468	$124,143	$131,786	$125,104	$132,242	$124,507	$131,815	$104,337
6	2027-2028	$17,633	$20,146	$28,802	$32,497	$26,350	$29,635	$27,171	$30,593	$126,869	$133,077	$127,853	$133,650	$127,229	$133,164	$99,643
7	2028-2029	$17,633	$19,664	$28,802	$31,598	$26,350	$28,826	$27,171	$29,754	$128,197	$133,024	$129,291	$133,797	$128,628	$133,242	$93,777
8	2029-2030	$17,633	$19,198	$28,802	$30,719	$26,350	$28,035	$27,171	$28,933	$129,681	$133,162	$130,883	$134,132	$130,174	$133,501	$88,561
9	2030-2031	$17,633	$18,734	$28,802	$29,844	$26,350	$27,248	$27,171	$28,117	$131,281	$133,425	$132,594	$134,593	$131,831	$133,878	$83,712
10	2031-2032	$17,633	$18,270	$28,802	$28,971	$26,350	$26,463	$27,171	$27,302	$133,223	$134,029	$134,662	$135,412	$133,824	$134,592	$79,331
11	2032-2033	$17,633	$17,807	$28,802	$28,098	$26,350	$25,678	$27,171	$26,488	$134,613	$134,083	$136,142	$135,644	$135,267	$134,758	$74,871
12	2033-2034	$17,633	$17,343	$28,802	$27,227	$26,350	$24,895	$27,171	$25,676	$136,368	$134,503	$138,013	$136,268	$137,088	$135,303	$70,855
13	2034-2035	$17,633	$16,880	$28,802	$26,357	$26,350	$24,112	$27,171	$24,864	$138,148	$134,950	$139,876	$136,884	$138,879	$135,818	$67,066
14	2035-2036	$17,633	$16,417	$28,802	$25,487	$26,350	$23,331	$27,171	$24,053	$140,130	$135,599	$142,053	$137,817	$140,975	$136,640	$63,574
15	2036-2037	$17,633	$15,954	$28,802	$24,619	$26,350	$22,551	$27,171	$23,243	$141,605	$135,743	$143,634	$138,155	$142,514	$136,906	$60,039
16	2037-2038	$17,633	$15,491	$28,802	$23,805	$26,350	$21,819	$27,171	$22,484	$143,490	$136,350	$145,666	$138,992	$144,476	$137,646	$56,894
17	2038-2039	$17,633	$15,028	$28,802	$23,133	$26,350	$21,217	$27,171	$21,859	$137,897	$129,623	$143,337	$135,599	$140,910	$132,992	$51,026
	Totals	$299,767	$319,517	$477,625	$493,746	$436,971	$450,838	$450,582	$465,203	$2,558,540	$2,594,411	$2,580,496	$2,614,113	$2,567,463	$2,601,834	$1,475,380

$1,453,894

Delta $21,486

Discount factor
0.06 1.25

Attachment OCA 12-19.2
Annualized Supplemental Cases - Low Demand Case

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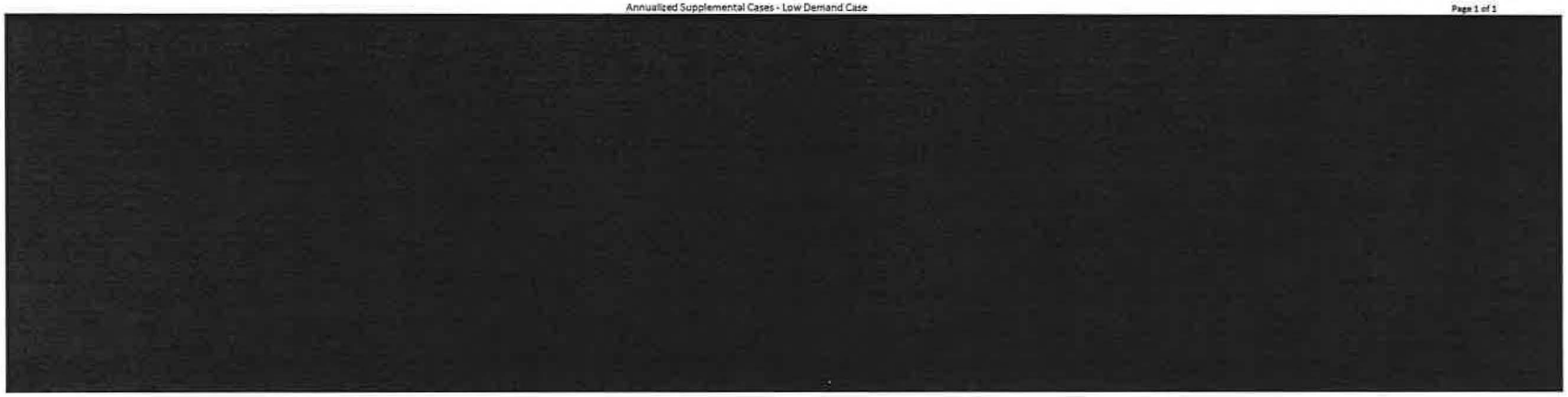
Schedule PKC-3c
OCA Testimony DG 17-198
Page 1 of 1



Discount factor
0.06

Schedule PKC-4a
OCA Testimony DG 17-198
Page 1 of 1

Attachment OCA 14-5.c
Levelized and Annualized Supplemental Cases - Low Demand Case - 11 Years
($ in 000's)

	A	B	C	D	E	F	G	H	I	I-A+B-C+D	J	J-A+B-E+F	K	K-A+B-G+H	Discounted
Gas Year	Granite Bridge Pipeline (Levelized)	Granite Bridge Pipeline (Annualized)	2.0 Bcf Granite Bridge LNG (Levelized)	2.0 Bcf Granite Bridge LNG (Annualized)	1.2 Bcf Granite Bridge LNG (Levelized)	1.2 Bcf Granite Bridge LNG (Annualized)	1.5 Bcf Granite Bridge LNG (Levelized)	1.5 Bcf Granite Bridge LNG (Annualized)	Scenario 1559-11 Base Case Supplemental (2.0 Bcf) (Levelized)	Scenario 1559-11 Base Case Supplemental (2.0 Bcf) (Annualized)	Scenario 1560-11 Base Case Supplemental (1.2 Bcf) (Levelized)	Scenario 1560-11 Base Case Supplemental (1.2 Bcf) (Annualized)	Scenario 1561-11 Base Case Supplemental (1.5 Bcf) (Levelized)	Scenario 1561-11 Base Case Supplemental (1.5 Bcf) (Annualized)	Scenario 1559-11 Base Case Supplemental (2.0 Bcf) (Annualized)
2018-2019									$85,106	$85,106	$85,106	$85,106	$85,106	$85,106	
2019-2020									$82,304	$82,304	$82,304	$82,304	$82,304	$82,304	
2020-2021									$81,874	$81,874	$81,874	$81,874	$81,874	$81,874	
2021-2022									$81,512	$81,512	$81,512	$81,512	$81,512	$81,512	
1 2022-2023	$17,633	$22,833	$16,801	$21,604	$15,371	$19,670	$15,850	$20,318	$126,279	$136,282	$122,322	$131,821	$123,792	$133,460	$136,282
2 2023-2024	$17,633	$22,253	$28,802	$36,478	$26,350	$33,219	$27,171	$34,310	$115,880	$128,176	$116,537	$128,026	$115,984	$127,743	$120,921
3 2024-2025	$17,633	$21,697	$28,802	$35,456	$26,350	$32,298	$27,171	$33,355	$118,446	$129,163	$119,306	$129,318	$118,743	$128,991	$114,955
4 2025-2026	$17,633	$21,161	$28,802	$34,419	$26,350	$31,364	$27,171	$32,387	$121,493	$130,638	$122,427	$130,969	$121,845	$130,589	$109,686
5 2026-2027	$17,633	$20,644	$28,802	$33,434	$26,350	$30,478	$27,171	$31,468	$124,142	$131,786	$125,104	$132,242	$124,507	$131,815	$104,387
6 2027-2028	$17,633	$20,146	$28,802	$32,497	$26,350	$29,635	$27,171	$30,593	$126,908	$133,116	$127,853	$133,650	$127,229	$133,163	$99,472
7 2028-2029	$17,633	$19,664	$28,802	$31,598	$26,350	$28,826	$27,171	$29,754	$121,338	$126,165	$125,199	$129,705	$123,489	$128,103	$88,942
Totals	$123,434	$148,398	$189,610	$225,486	$173,471	$205,490	$178,874	$212,184	$1,185,283	$1,246,123	$1,189,544	$1,246,527	$1,186,386	$1,244,660	$774,644
															$753,207
														Delta	$21,437

Discount factor
0.06
1

Confidential Attachment OCA 12-18.f
Levelized and Annualized Supplemental Cases - Low Demand Case - 11 Years

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Schedule PKC-4b
OCA Testimony DG 17-198
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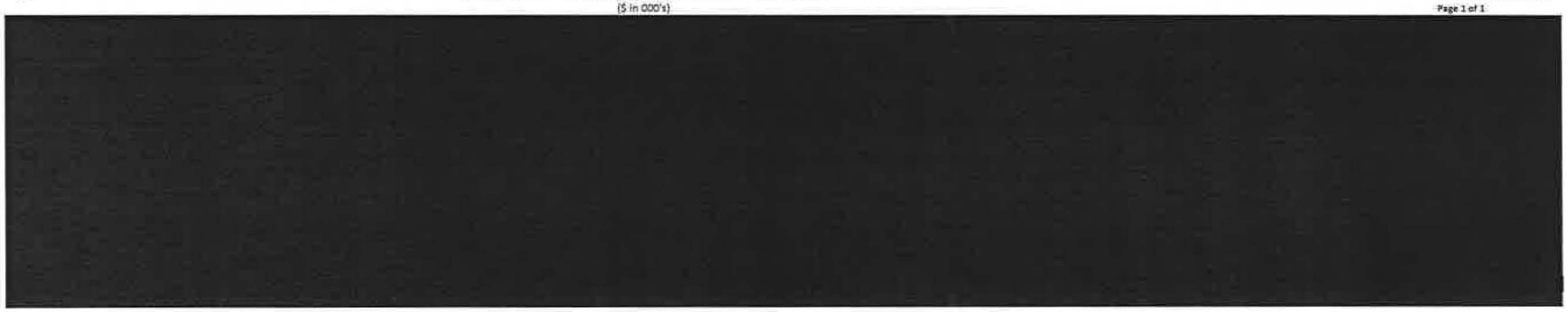
Discount factor
0.06
1.25

REDACTED

Confidential Attachment OCA 12-18.f
Levelized and Annualized Supplemental Cases - Low Demand Case - 11 Years
($ in 000's)



Discount factor
0.06

Schedule PKC-5a
OCA Testimony DG 17-198
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Attachment OCA 14-2.c
Levelized and Annualized Supplemental Cases - 50% Demand Case
($ in 000's)

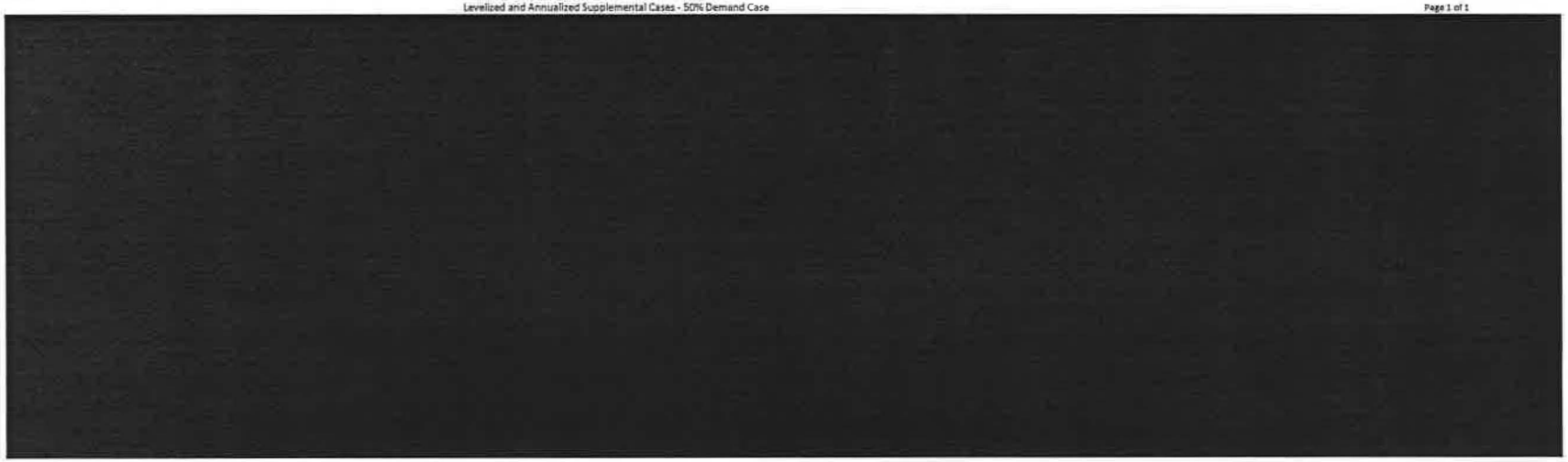
		A	B	C	D	E	F	G	H	I	I-A+B-C+D	J	J-A+B-E+F	K	K-A+B-G+H	Annualized/Discounted
	Gas Year	Granite Bridge Pipeline (Levelized)	Granite Bridge Pipeline (Annualize	2.0 Bcf Granite Bridge LNG (Levelized)	2.0 Bcf Granite Bridge LNG (Annualize	1.2 Bcf Granite Bridge LNG (Levelized)	1.2 Bcf Granite Bridge LNG (Annualize	1.5 Bcf Granite Bridge LNG (Levelized)	1.5 Bcf Granite Bridge LNG (Annualize	Scenario 1556 Base Case Supplemental (2.0 Bcf) (Levelized)	Scenario 1556 Base Case Supplemental (2.0 Bcf) (Annualized	Scenario 1557 Base Case Supplemental (1.2 Bcf) (Levelized)	Scenario 1557 Base Case Supplemental (1.2 Bcf) (Annualized)	Scenario 1558 Base Case Supplemental (1.5 Bcf) (Levelized)	Scenario 1558 Base Case Supplemental (1.5 Bcf) (Annualized)	Scenario 1556 Base Case Supplemental (2.0 Bcf) (Annualized)
	2018-2019									$85,117	$85,117	$85,117	$85,117	$85,117	$85,117	
	2019-2020									$82,379	$82,379	$82,379	$82,379	$82,379	$82,379	
	2020-2021									$82,237	$82,237	$82,246	$82,246	$82,246	$82,246	
	2021-2022									$82,695	$82,695	$82,336	$82,336	$82,336	$82,336	
1	2022-2023	$17,633	$22,833	$16,801	$21,604	$15,371	$19,670	$15,850	$20,318	$127,731	$137,733	$123,395	$132,894	$124,866	$134,533	$137,733
2	2023-2024	$17,633	$22,253	$28,802	$36,478	$26,350	$33,219	$27,171	$34,310	$116,800	$129,097	$117,519	$129,008	$116,944	$128,703	$121,789
3	2024-2025	$17,633	$21,697	$28,802	$35,456	$26,350	$32,298	$27,171	$33,355	$119,593	$130,311	$120,545	$130,556	$119,956	$130,204	$115,976
4	2025-2026	$17,633	$21,161	$28,802	$34,419	$26,350	$31,364	$27,171	$32,387	$122,913	$132,057	$123,919	$132,461	$123,301	$132,044	$110,878
5	2026-2027	$17,633	$20,644	$28,802	$33,434	$26,350	$30,478	$27,171	$31,468	$125,726	$133,370	$126,795	$133,934	$126,147	$133,455	$105,641
6	2027-2028	$17,633	$20,146	$28,802	$32,497	$26,350	$29,635	$27,171	$30,593	$128,595	$134,803	$129,698	$135,495	$129,018	$134,952	$100,733
7	2028-2029	$17,633	$19,664	$28,802	$31,598	$26,350	$28,826	$27,171	$29,754	$129,976	$134,803	$131,189	$135,695	$130,470	$135,084	$95,031
8	2029-2030	$17,633	$19,198	$28,802	$30,719	$26,350	$28,035	$27,171	$28,933	$131,503	$134,985	$132,815	$136,064	$132,044	$135,371	$89,772
9	2030-2031	$17,633	$18,734	$28,802	$29,844	$26,350	$27,248	$27,171	$28,117	$133,140	$135,283	$134,559	$136,558	$133,732	$135,779	$84,878
10	2031-2032	$17,633	$18,270	$28,802	$28,971	$26,350	$26,463	$27,171	$27,302	$135,118	$135,924	$136,665	$137,414	$135,773	$136,542	$80,453
11	2032-2033	$17,633	$17,807	$28,802	$28,098	$26,350	$25,678	$27,171	$26,488	$136,525	$135,995	$138,161	$137,662	$137,236	$136,727	$75,939
12	2033-2034	$17,633	$17,343	$28,802	$27,227	$26,350	$24,895	$27,171	$25,676	$138,311	$136,446	$140,092	$138,346	$139,083	$137,297	$71,878
13	2034-2035	$17,633	$16,880	$28,802	$26,357	$26,350	$24,112	$27,171	$24,864	$140,101	$136,903	$141,975	$138,983	$140,908	$137,847	$68,037
14	2035-2036	$17,633	$16,417	$28,802	$25,487	$26,350	$23,331	$27,171	$24,053	$142,136	$137,605	$144,209	$139,973	$143,060	$138,725	$64,515
15	2036-2037	$17,633	$15,954	$28,802	$24,619	$26,350	$22,551	$27,171	$23,243	$143,635	$137,772	$145,830	$140,351	$144,626	$139,019	$60,937
16	2037-2038	$17,633	$15,491	$28,802	$23,805	$26,350	$21,819	$27,171	$22,484	$145,534	$138,394	$147,907	$141,234	$146,623	$139,793	$57,747
17	2038-2039	$17,633	$15,028	$28,802	$23,133	$26,350	$21,217	$27,171	$21,859	$139,963	$131,689	$145,631	$137,893	$143,095	$135,177	$51,839
	Totals	$299,767	$319,517	$477,625	$493,746	$436,971	$450,838	$450,582	$465,203	$2,589,726	$2,625,597	$2,612,982	$2,646,599	$2,598,959	$2,633,330	$1,493,776

Discount factor
0.06

Confidential Attachment OCA 12-17.e
Levelized and Annualized Supplemental Cases - 50% Demand Case

REDACTED

Schedule PKC-5b
OCA Testimony DG 17-198
Page 1 of 1



Discount factor
0.06

Schedule PKC-6a
OCA Testimony DG 17-198
Page 1 of 1

Attachment OCA 14-3.c
Levelized and Annualized Supplemental Cases - 50% Demand Case - 11 Years
($ in 000's)

		A	B	C	D	E	F	G	H	I	I-A+B-C+D	J	J-A+B-E+F	K	K-A+B-G+H	Annualized/ Discounted
	Gas Year	Granite Bridge Pipeline (Levelized	Granite Bridge Pipeline (Annualize	2.0 Bcf Granite Bridge LNG (Levelized	2.0 Bcf Granite Bridge LNG (Annualize	1.2 Bcf Granite Bridge LNG (Levelized	1.2 Bcf Granite Bridge LNG (Annualize	1.5 Bcf Granite Bridge LNG (Levelized	1.5 Bcf Granite Bridge LNG (Annualize	Scenario 1556-11 Base Case Supplemental (2.0 Bcf) (Levelized)	Scenario 1556-11 Base Case Supplemental (2.0 Bcf) (Annualized)	Scenario 1557-11 Base Case Supplemental (1.2 Bcf) (Levelized)	Scenario 1557-11 Base Case Supplemental (1.2 Bcf) (Annualized	Scenario 1558-11 Base Case Supplemental (1.5 Bcf) (Levelized)	Scenario 1558-11 Base Case Supplemental (1.5 Bcf) (Annualized	Scenario 1556-11 Base Case Supplemental (2.0 Bcf) (Annualized)
	2018-2019									$85,117	$85,117	$85,117	$85,117	$85,117	$85,117	
	2019-2020									$82,379	$82,379	$82,379	$82,379	$82,379	$82,379	
	2020-2021									$82,237	$82,237	$82,246	$82,246	$82,246	$82,246	
	2021-2022									$82,695	$82,695	$82,336	$82,336	$82,336	$82,336	
1	2022-2023	$17,633	$22,833	$16,801	$21,604	$15,371	$19,670	$15,850	$20,318	$127,731	$137,733	$123,395	$132,894	$124,866	$134,533	$137,733
2	2023-2024	$17,633	$22,253	$28,802	$36,478	$26,350	$33,219	$27,171	$34,310	$116,801	$129,097	$117,519	$129,008	$116,944	$128,703	$121,790
3	2024-2025	$17,633	$21,697	$28,802	$35,456	$26,350	$32,298	$27,171	$33,355	$119,610	$130,327	$120,545	$130,556	$119,957	$130,204	$115,991
4	2025-2026	$17,633	$21,161	$28,802	$34,419	$26,350	$31,364	$27,171	$32,387	$122,897	$132,042	$123,919	$132,461	$123,301	$132,044	$110,865
5	2026-2027	$17,633	$20,644	$28,802	$33,434	$26,350	$30,478	$27,171	$31,468	$125,726	$133,370	$126,795	$133,934	$126,147	$133,455	$105,641
6	2027-2028	$17,633	$20,146	$28,802	$32,497	$26,350	$29,635	$27,171	$30,593	$128,634	$134,842	$129,699	$135,496	$129,018	$134,952	$100,762
7	2028-2029	$17,633	$19,664	$28,802	$31,598	$26,350	$28,826	$27,171	$29,754	$123,091	$127,918	$127,087	$131,593	$125,320	$129,934	$90,177
	Totals	$123,434	$148,398	$189,610	$225,486	$173,471	$205,490	$178,874	$212,184	$1,196,918	$1,257,758	$1,201,037	$1,258,020	$1,197,629	$1,255,903	$782,959

Discount factor
0.06

REDACTED

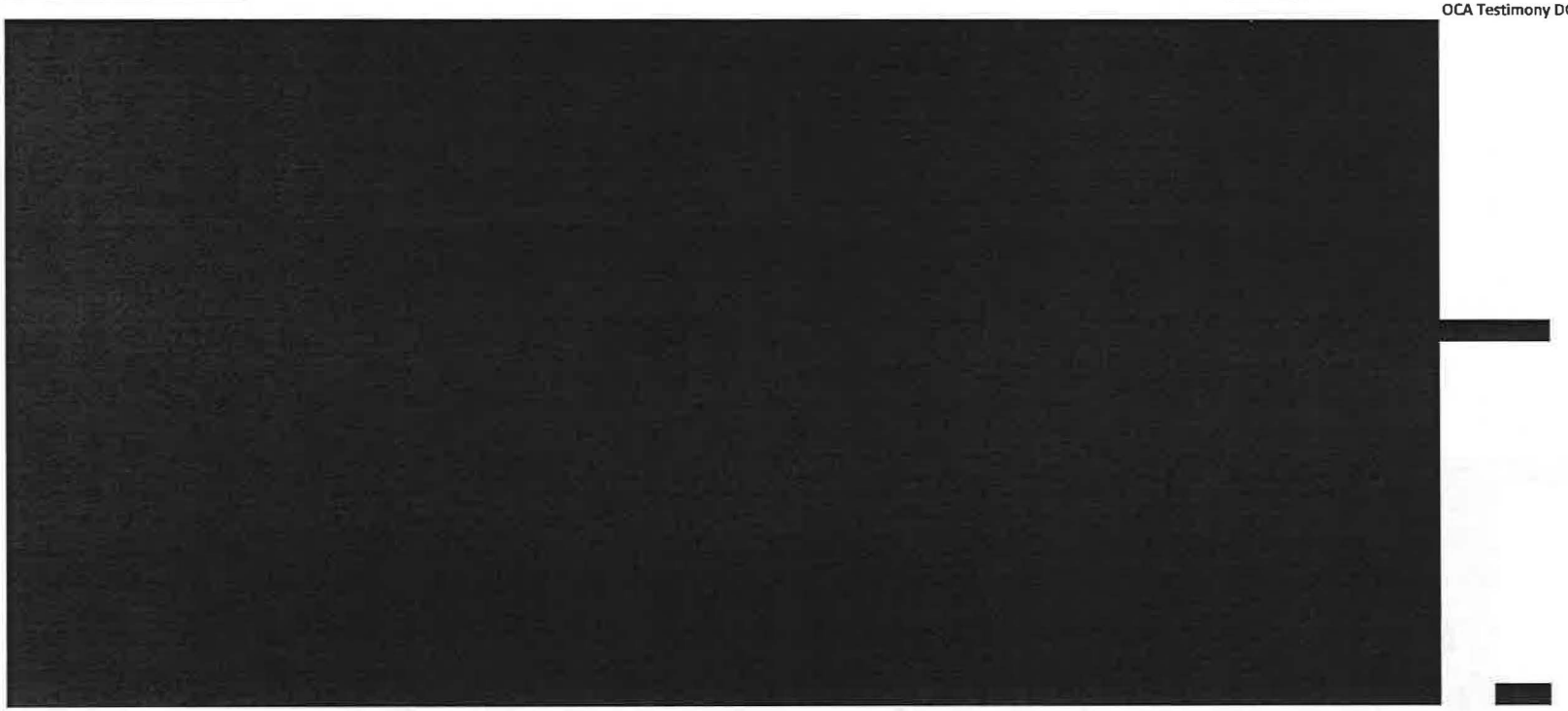
Schedule PKC-6b
OCA Testimony DG 17-198
Page 1 of 1

Levelized and Annualized Supplemental Cases - 50% Demand Case - 11 Years

Company Forecast Bill Impact

REDACTED

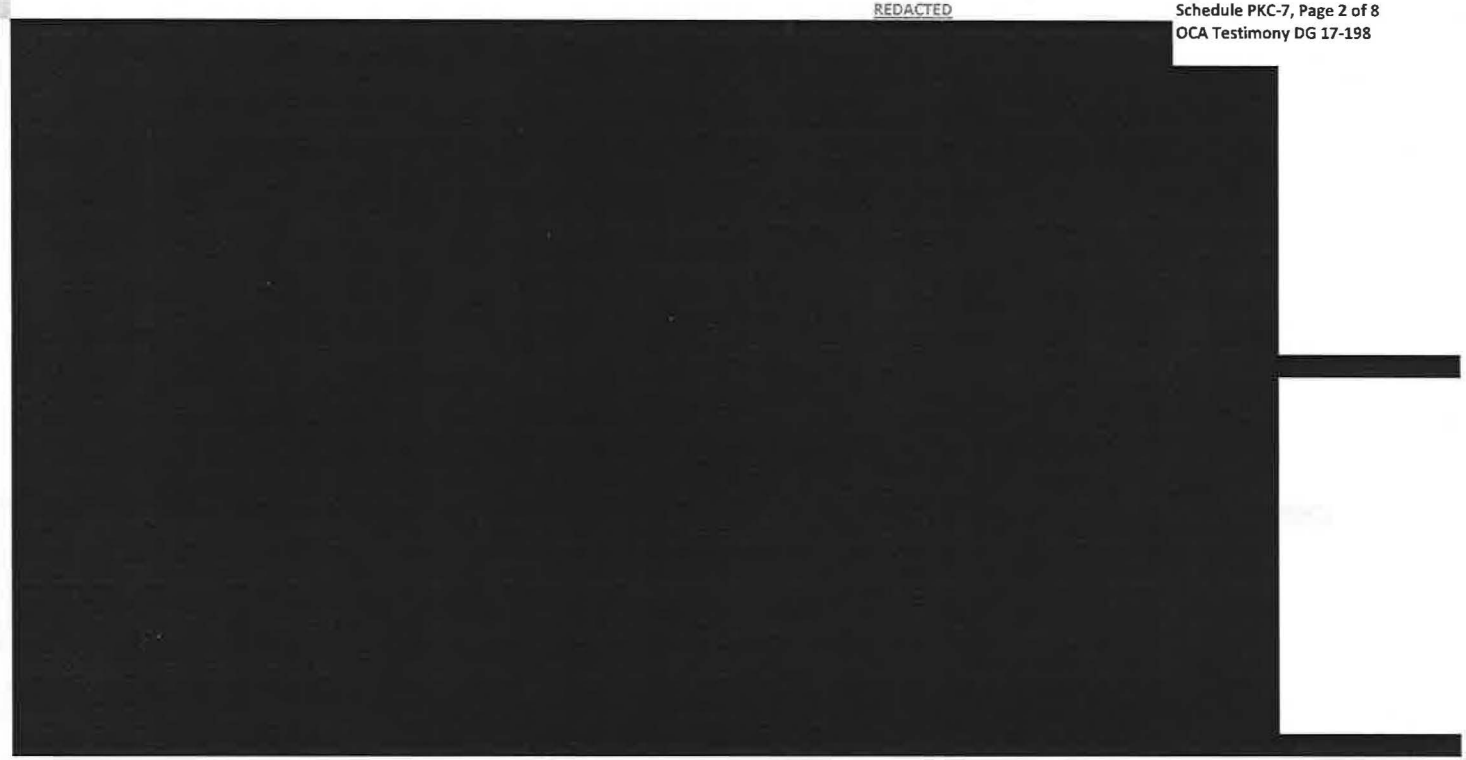
Schedule PKC-7, Page 1 of 8
OCA Testimony DG 17-198



OCA Forecast Bill Impact

REDACTED

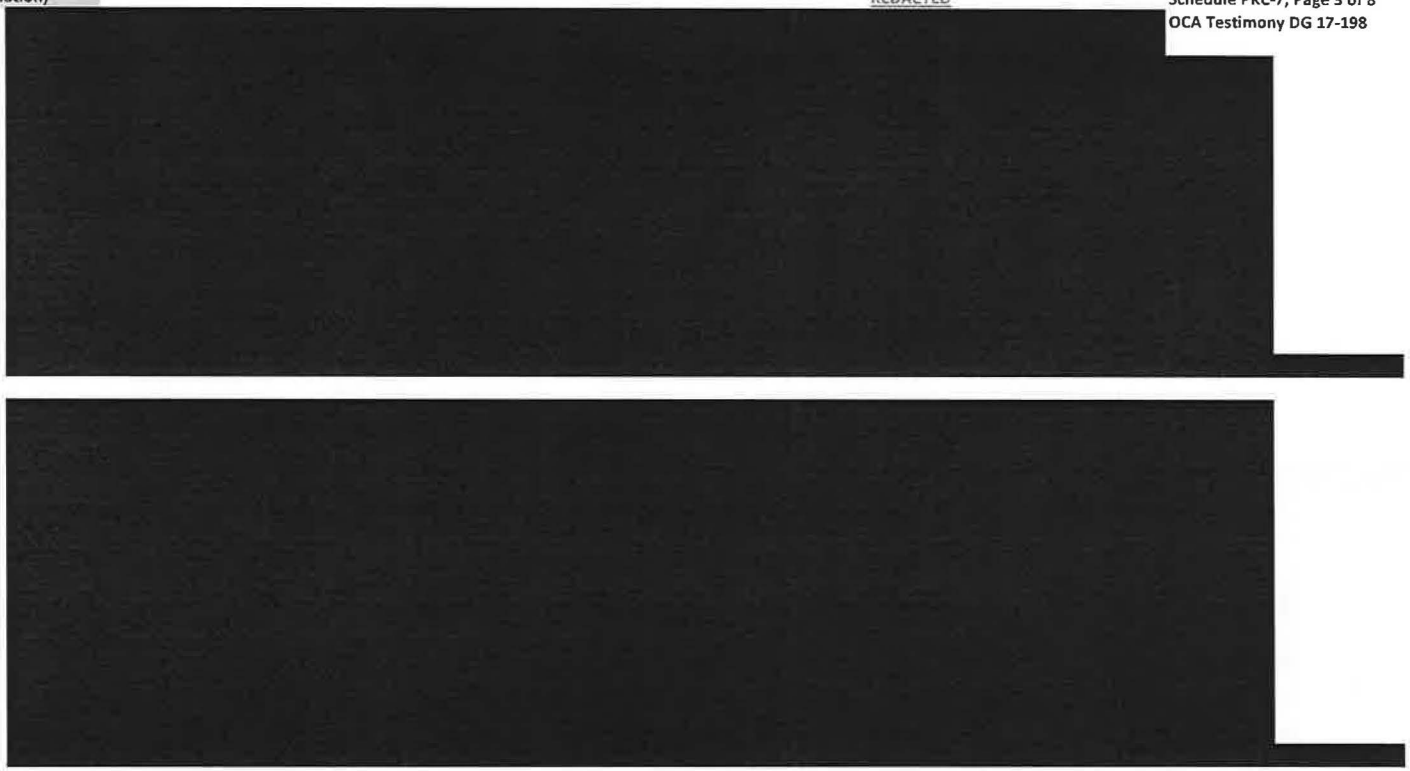
Schedule PKC-7, Page 2 of 8
OCA Testimony DG 17-198



Company Forecast (10% cost escalation)
Bill Impact

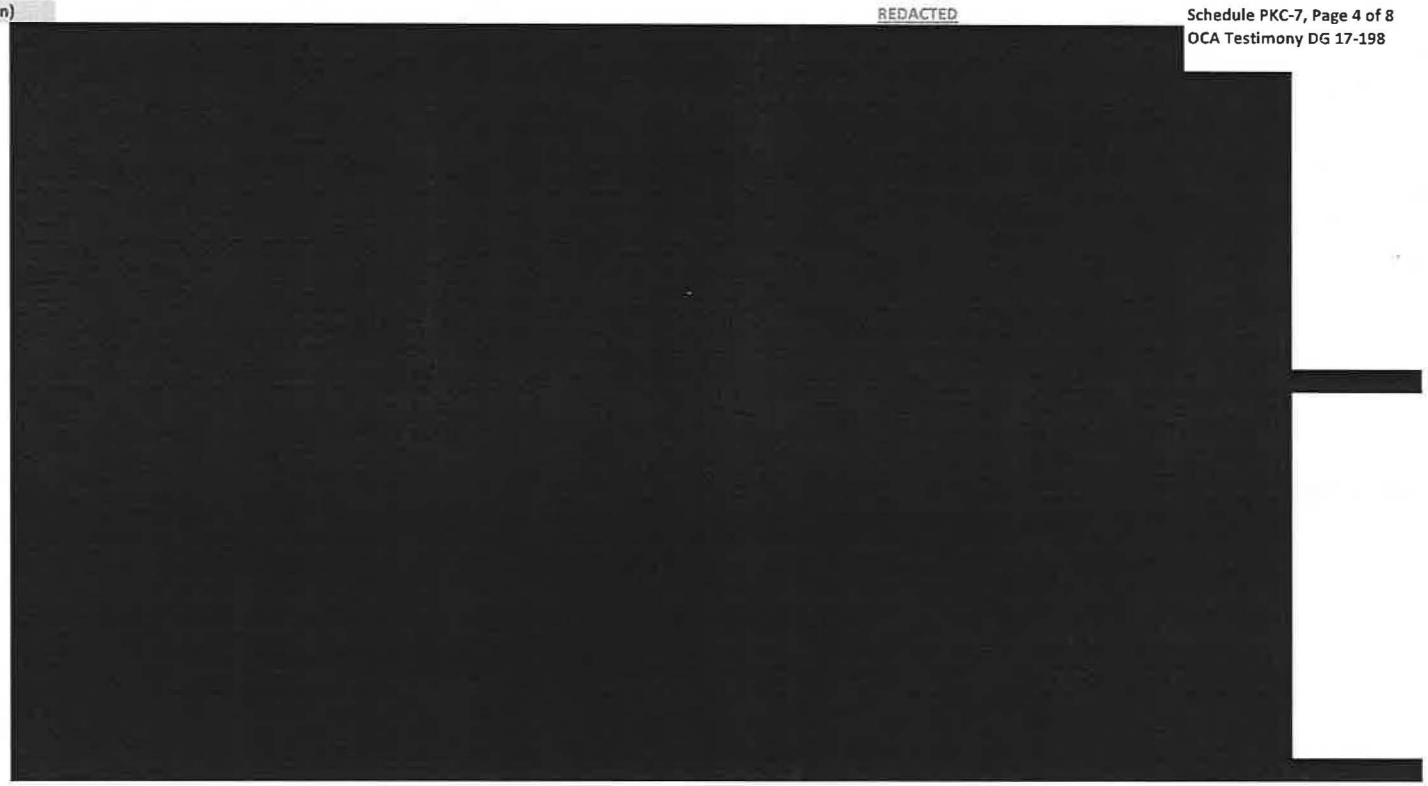
REDACTED

Schedule PKC-7, Page 3 of 8
OCA Testimony DG 17-198



OCA Forecast (10% cost escalation)
Bill Impact

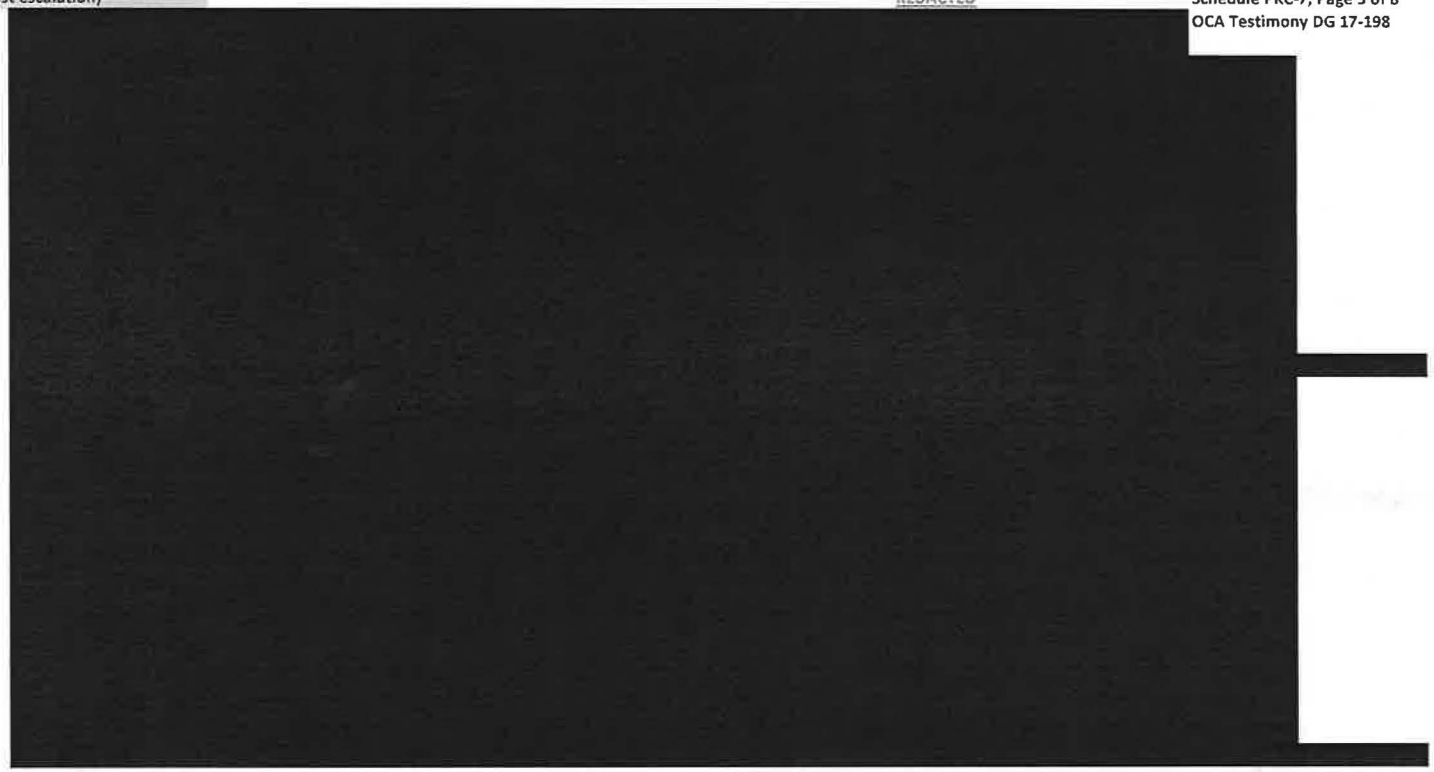
REDACTED



Company's Forecast (with 25% cost escalation)
Bill Impact

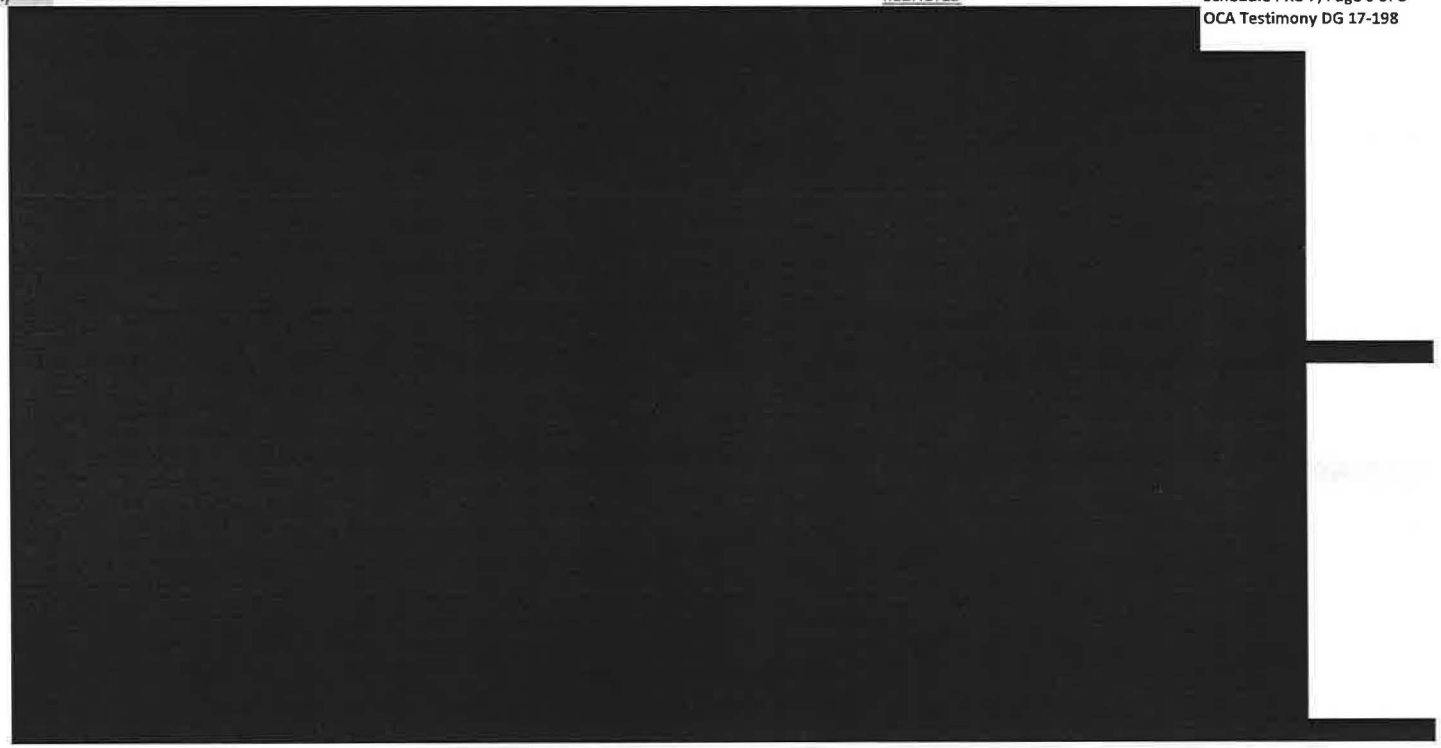
REDACTED

Schedule PKC-7, Page 5 of 8
OCA Testimony DG 17-198



OCA Forecast (25%cost escalation)
Bill Impact

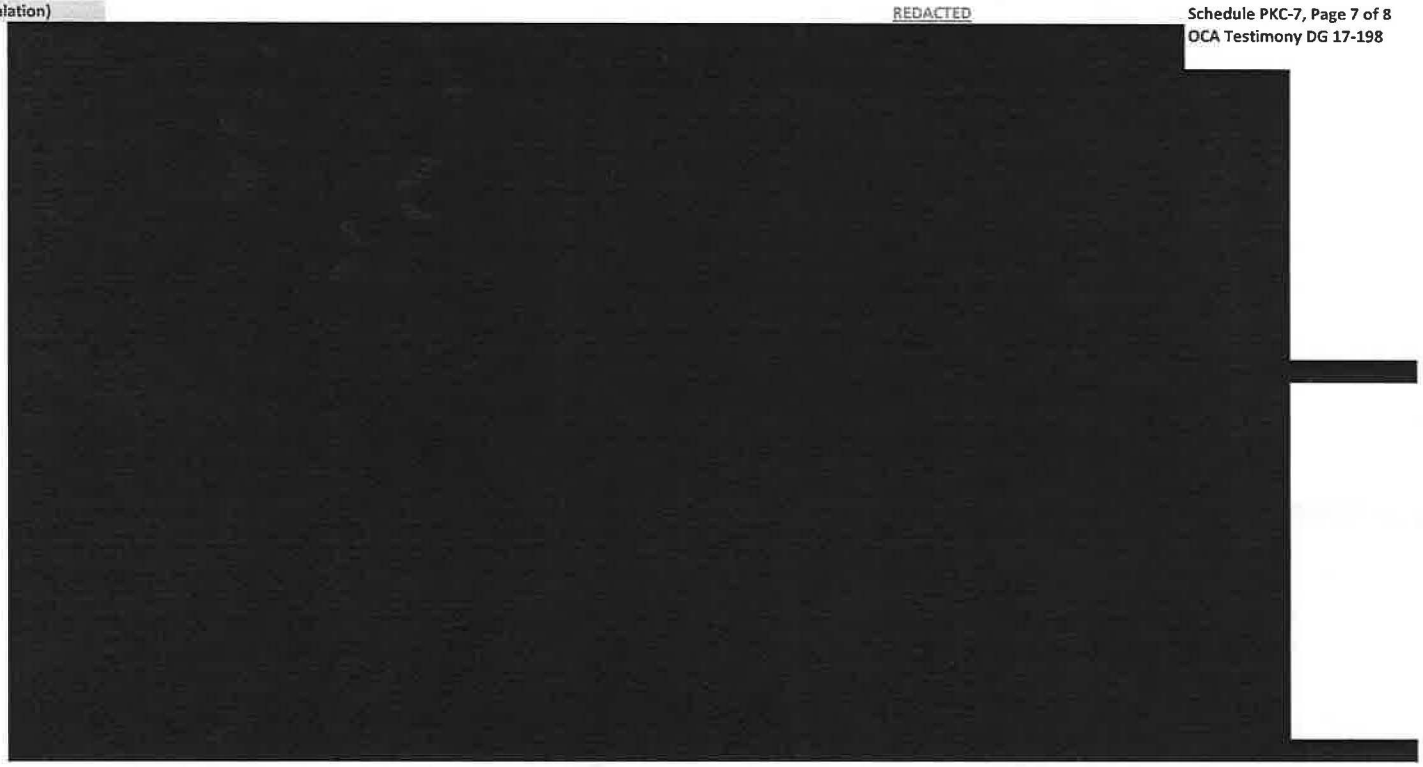
REDACTED



Company Forecast (50% cost escalation)
Bill Impact

REDACTED

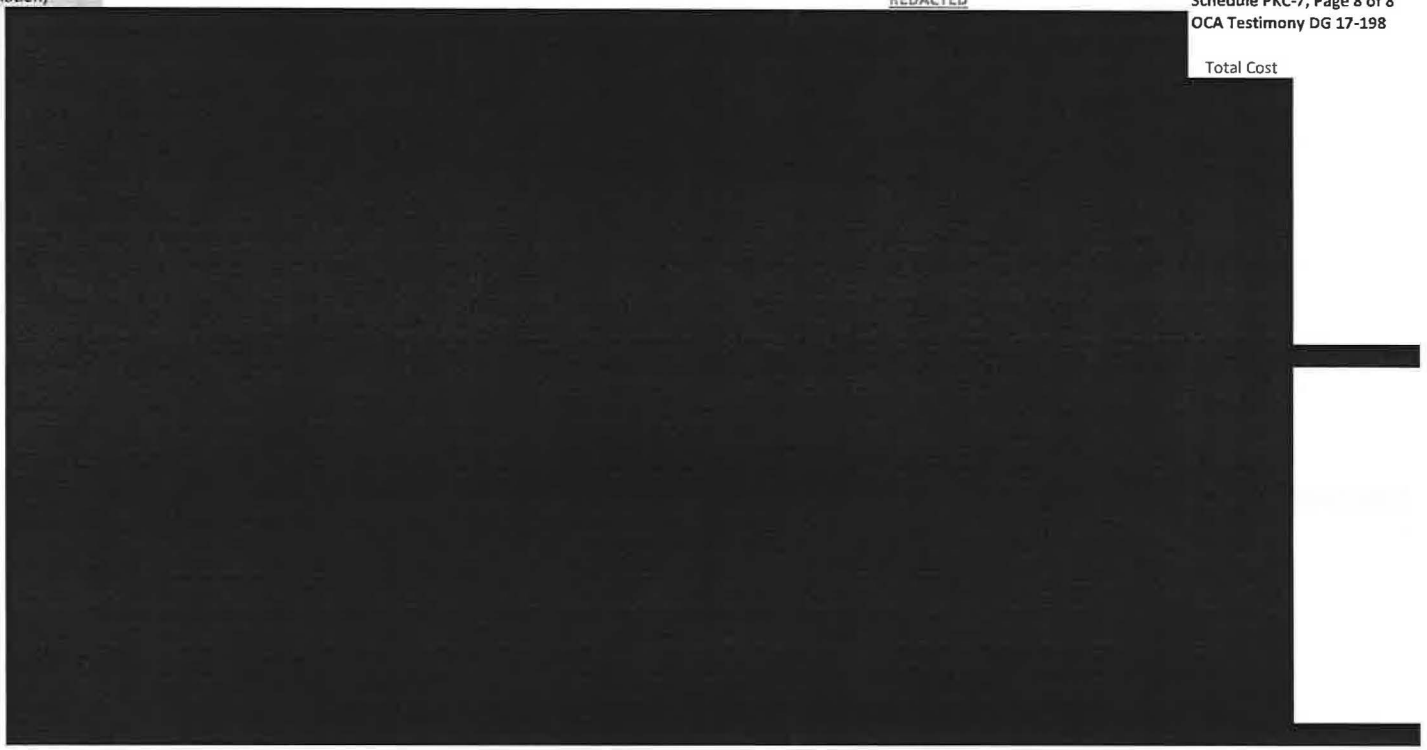
Schedule PKC-7, Page 7 of 8
OCA Testimony DG 17-198



OCA Forecast (with 50% cost escalation)
Bill Impact

REDACTED

Schedule PKC-7, Page 8 of 8
OCA Testimony DG 17-198



VII. ATTACHMENTS

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

Conservation Law Foundation Technical Session Data Requests - Set 1

Date Request Received: 6/1/18
Request No. CLF Tech 1-2

Date of Response: 6/27/18
Respondent: William R. Killeen
James M. Stephens
Adam Perry

REQUEST:

Please see Staff Data Requests - Set 2, Request No. Staff 2-78, a, b, c, d and e.

Please respond the questions about projections of customer and usage growth.

RESPONSE:

Please see Attachment CLF Tech 1-2.1, which contains the "Comprehensive Response" referred to in the responses to several other requests in this docket, and Attachment CLF Tech 1-2.2.

Detailed Review of EnergyNorth's Demand Forecast
Docket Nos. DG 17-152 and DG 17-198

I. Executive Summary

Pursuant to the May 23, 2018, technical session in Docket No. DG 17-152 and the May 24, 2018, technical session in Docket No. DG 17-198, the Company has undertaken a detailed review of its forecasted customer additions and how those estimated customer additions are integrated into the results of the econometric models (together defined herein as the Demand Forecast). The Company's detailed review resulted in the modification of certain assumptions related to the out-of-model adjustments used to produce the Demand Forecast, including:

- The customers of Concord Steam Corporation ("Concord Steam") were included in the estimate of customer additions for the existing service territory and have now been removed from the forecasted additions for the existing service territory. These customer additions are included as an out-of-model adjustment.
- The forecasted customer additions in Windham and Pelham were included in the estimate of customer additions in the existing service territory and have now been removed from the forecasted additions for the existing service territory. These customer additions are included as an out-of-model adjustment.
- The overall number of customer additions has been reduced to reflect more recent information, specifically:
    - In the initial filing, the Company included a 400-unit development in Windham; however, subsequent to the filing, the project has been reduced and is currently indefinitely delayed. As such, the project and the 400 units were removed from the forecasted customer additions for Windham and Pelham.
    - The forecasted customer additions for the potential franchise areas (i.e., Epping, Candia, and Raymond) were determined to be too high and have been lowered. Specifically, the initial filing assumed a total of 244 customers per year from the potential franchise areas, which was reduced to a total of 120 customers per year.
    - The forecasted customer composition for the potential franchise areas (i.e., the allocation between residential and commercial and industrial ("C&I") customers) resulted in a disproportionate number of commercial customer additions; specifically, the C&I customer allocation of 60% was corrected to be consistent with the Company's actual recent experience where 20% of the customer additions are C&I customers (as reflected in the residential and C&I customer additions data for 2016 and 2017 provided in the response to Staff 3-13 in Docket No. DG 17-152).[1] In addition, the 20% is consistent with the assumed C&I customer allocation for customers added in the existing service territory and in Windham and Pelham.
    - The Company also addressed a timing issue with respect to the start date for the initial customers from the potential franchise areas. The start date for these customers was delayed to better reflect the timing of the Granite Bridge Pipeline.

- For modeling purposes, certain formulas and calculations were simplified. For example, the approach to allocate the annual customer additions from the Sales and Marketing forecast to

[1] For ease of reference, all Company responses referred to in this detailed review are provided as Attachment Staff Tech 1-7.2.

monthly customer additions was simplified, which also corrected an error regarding monthly customer additions.

- The assumption regarding natural gas consumption for Innovative Natural Gas, LLC ("iNATGAS") has been updated to reflect the actual usage information from this past winter.

As a result of these modifications to the Demand Forecast, the Company's forecast of natural gas demand has been slightly reduced as illustrated in Table 1 below.

Table 1: Updated Demand Forecast Results (Dth)

	Original Demand Forecast			Updated Demand Forecast		
Split-Year	Normal Year	Design Year	Design Day	Normal Year	Design Year	Design Day
2017/2018	15,634,082	16,901,795	156,822	14,640,845	15,833,870	157,848
2018/2019	16,075,247	17,376,013	160,989	15,235,354	16,449,392	164,571
2019/2020	16,575,525	17,944,792	164,640	15,648,467	16,923,283	167,643
2020/2021	17,000,558	18,367,180	168,934	16,150,273	17,414,989	168,942
2021/2022	17,527,589	18,933,736	173,917	16,585,278	17,881,953	174,618
2022/2023	18,071,614	19,519,884	179,382	17,864,174	19,198,013	184,000
2023/2024	18,638,472	20,168,391	184,432	18,354,074	19,760,680	188,352
2024/2025	19,009,173	20,530,513	188,856	18,660,183	20,055,937	192,033
2025/2026	19,416,449	20,969,502	192,933	19,008,442	20,431,417	195,542
2026/2027	19,788,597	21,371,088	196,785	19,318,284	20,765,901	198,777
2027/2028	20,198,023	21,852,258	199,954	19,659,031	21,169,792	201,364
2028/2029	20,471,958	22,107,358	203,491	19,872,063	21,362,731	204,235
2029/2030	20,798,293	22,459,424	206,790	20,136,752	21,648,299	206,906
2030/2031	21,108,206	22,794,033	210,016	20,392,048	21,924,085	209,593
2031/2032	21,476,694	23,234,556	212,972	20,701,897	22,297,494	212,031
2032/2033	21,678,072	23,409,030	215,843	20,858,981	22,428,427	214,448
2033/2034	21,960,444	23,713,995	218,828	21,075,945	22,663,122	216,822
2034/2035	22,227,307	24,002,078	221,631	21,269,443	22,872,418	218,944
2035/2036	22,564,042	24,410,287	224,148	21,516,836	23,180,235	220,704
2036/2037	22,742,621	24,558,141	226,863	21,618,013	23,249,243	222,599
2037/2038	23,007,564	24,844,142	229,590	21,798,963	23,444,867	224,511
CAGR (17/18 - 21/22)	2.9%	2.9%	2.6%	3.2%	3.1%	2.6%
CAGR (17/18 - 37/38)	2.0%	1.9%	1.9%	2.0%	2.0%	1.8%

As shown in Table 1, based on the changes to the Demand Forecast discussed above, the Company is forecasting Normal Year and Design Year demand to increase at a compound annual growth rate ("CAGR") of approximately 2.0% and Design Day demand to increase at a CAGR of 1.8% over the 2017/18 to 2037/38 time period, which is similar to the growth in the Company's initial filing, the pace of growth in recent years, and well within the estimates of natural gas demand growth of other local distribution companies in the New England region (as provided in the responses to Staff 3-2 in Docket No. DG 17-152 and Staff 2-30 in Docket No. DG 17-198).

The inclusion of changes to the Demand Forecast, although slightly lowering the expected demand, does not alter the primary conclusions documented by the Company in Docket Nos. DG 17-152 and DG 17-198, specifically:

- The customer additions and associated volume from the econometric model do not capture the Company's focus on customer growth in New Hampshire;
- An adjustment to the results of the econometric model is warranted and supported by the recent level of customer additions, access to new and potential franchise areas, and the regulatory programs approved by the Commission, none of which are captured in the historical data; and
- An adjustment based on information developed by the Sales and Marketing team, as well as the experience and judgment of that team, is a reasonable approach to estimate the level of adjustment to the results of the econometric model.

In addition, the Company reviewed the implications of changes to the forecasted customer additions on its SENDOUT® resource portfolio optimization analysis, as initially filed in Docket No. DG 17-198 and in the responses to OCA 2-86 and OCA 2-106R in Docket No. DG 17-198. Specifically, the revised Demand Forecast was uploaded into the SENDOUT® model for an assessment of the Company's gas supply portfolio; and, based on the results of that analysis, coupled with the non-price factors discussed in the various Company submissions in Docket Nos. DG 17-152 and DG 17-198, the Company concludes that the Granite Bridge Project, as outlined in Docket No. DG 17-198, continues to be the best cost option for the customers of EnergyNorth. As shown by Tables 2 and 3 below, the results of the SENDOUT® model continue to support the Granite Bridge Project as the best cost option to meet the demand requirements of EnergyNorth's customers.

Table 2: EnergyNorth SENDOUT® Model Runs - "Prime Revised"[2]

Resource Planning Scenario	Granite Bridge LNG	Propane Facilities	Resource Mix Results Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)	Total System Cost ($000)	Comparison to Base Case Prime
Base Case Prime	2.0 Bcf	No	7,920	0	0	$2,645,295	$ -
Base Case Prime Sensitivity	2.0 Bcf	Yes	7,920	0	0	$2,645,925	$ 630
Alternative Case Prime	No	No	3,080	104,920	360	$2,850,073	$ 204,778
Alternative Case Prime Sensitivity	No	Yes	15,040	50,370	7,000	$2,667,144	$ 21,849

Table 3: EnergyNorth SENDOUT® Model Runs - LNG Tank Size Scenarios - "Prime Revised"

Resource Planning Scenario	Granite Bridge LNG	Propane Facilities	Resource Mix Results Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)	Total System Cost ($000)	Comparison to 2.0 Bcf Tank ($000)
Base Case Prime	2.0 Bcf	No	7,920	0	0	$2,645,295	$ -
Base Case Prime	1.2 Bcf	No	7,920	0	470	$2,651,792	$ 6,497
Base Case Prime	1.5 Bcf	No	7,920	0	0	$2,653,873	$ 8,578
Base Case Prime	2.5 Bcf	No	7,920	0	0	$2,724,443	$ 79,148

As shown in Tables 2 and 3, the Resource Mix results (i.e., volumes for the various resources) and the Total System Costs across all scenarios are slightly lower than the results shown in the initial filing in Docket No. DG 17-198 and in the responses to OCA 2-86 and OCA 2-106R in Docket No. DG 17-198. However, the Total System Cost of the Base Case Prime (which includes the 2.0 Bcf Granite Bridge LNG facility) is

[2] The SENDOUT® model runs denoted as "Prime" reflect the impact of the Tax Cuts and Jobs Act on the proposed Granite Bridge Project infrastructure revenue requirement.

approximately $2.645 billion over the analysis period and continues to be the lowest total cost of the resource planning scenarios and LNG tank size scenarios analyzed. The Alternative Case Prime resource planning scenario, which excludes the Granite Bridge LNG facility, results in a total system cost of approximately $2.850 billion over the analysis period, which is nearly $205 million more than the Base Case Prime scenario. The results shown in Tables 2 and 3 are consistent with the Company's prior analysis, and continue to support the conclusions regarding the Granite Bridge Pipeline and 2.0 Bcf Granite Bridge LNG facility.

II. Historical Customer Additions

In response to certain data requests in Docket Nos. DG 17-152 (e.g., CLF 1-9, Staff 2-4, and Staff 3-13) and DG 17-198 (e.g., Attachment OCA 1-12.b and CLF 1-8), the Company provided information with respect to historical customer additions. To be as responsive as possible to the specific data requests, the information provided by the Company was derived from several different internal data sources, each of which used different time periods, which best responded to the specific request. However, the use of various data sources and time periods in response to specific data requests has resulted in the need to reconcile the historical customer additions information submitted in Docket Nos. DG 17-152 and DG 17-198.

First, to be as consistent as possible with past submissions of long-term demand forecasts, the Company relied on an analytical framework and approach that has been used, vetted, and approved in several regulatory filings at the Commission. The use of a consistent framework across proceedings facilitates the comparison of results across those proceedings (e.g., please see Staff 1-11 in Docket No. DG 17-152, which asked the Company to compare the demand estimate for 2017 as produced in Docket Nos. DG 13-313 and DG 17-152). As such, for the development of the econometric models used by the Company in Docket Nos. DG 17-152 and DG 17-198, the Company used Customer Equivalent Bill data for the August 2010 to April 2017 period as the metric to represent customer numbers by segment (e.g., residential and C&I).[3] Customer Equivalent Bill data is the same customer metric used in the 2013 LCIRP in Docket No. DG 13-313, EnergyNorth's cost of gas submissions, and the Northeast Energy Direct ("NED") contract filing in Docket No. DG 14-380. Second, in response to certain data requests for historical customer additions, the Company relied on a new customer relationship management system (i.e., the ZOHO system)[4] used by its Sales and Marketing team, rather than the Customer Equivalent Bill data. Lastly, Company responses to certain data requests provided information for calendar years, while other responses provided information for different 12-month periods (e.g., April to March or November to October).

To reconcile the various information provided in the numerous data requests received by the Company with respect to historical customer additions, please find in Table 4 below a comparison of historical customer additions using the Customer Equivalent Bill metric and the annual customer additions from the ZOHO system.

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[3] Please see Bates 014 of the Company's 2017 LCIRP filed in Docket No. DG 17-152.
[4] The ZOHO system was implemented by the Company on May 30, 2014.

Table 4: Historical Customer Additions Comparison

Year	Customer Equivalent Bill[5]	ZOHO Customer Additions[6]	Difference	Percent Difference
2014	1,178	1,199	(21)	(1.8%)
2015	1,770	1,784	(14)	(0.8%)
2016	1,531	1,588	(57)	(3.6%)
2017	1,733	1,708	25	1.5%
Total	6,212	6,279	(67)	(1.1%)
Average	1,553	1,570	(17)	(1.1%)
Average (excluding 2014)	1,678	1,693	(15)	(0.9%)

As shown in Table 4 above, the use of Customer Equivalent Bill data results in a total of 6,212 customer additions over the 2014[7] to 2017 period, which compares to the total of 6,279 customer additions using the ZOHO system. The difference between the two data sources is 67 customer additions, or approximately 1.1%. Using the average customer additions over the 2014 to 2017 period results in 1,553 annual additions based on Customer Equivalent Bill data and 1,570 customer additions from the ZOHO system, or a difference of 17 customers. Therefore, a comparison of the calendar year customer additions using the Customer Equivalent Bill data (i.e., the dependent variable in the customer equations of the econometric models) is for all intents and purposes equivalent to the annual customer additions data from the ZOHO system used by the Sales and Marketing team.

III. Need for a Sales and Marketing Adjustment

During the May 23, 2018, and May 24, 2018, technical sessions, there were discussions regarding the need for an adjustment to the customer additions results from the Company's econometric model. Although the Company has provided support in its responses to various data requests in both Docket No. DG 17-152 and DG 17-198, a summary of the rationale supporting an adjustment to the econometric model results is warranted. The Company has provided the following primary reasons in support of an adjustment to the customer additions forecasted by the econometric model: (i) the actual customer additions in the existing service territory, particularly the recent trends; (ii) the customer opportunity in the new and potential

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5 To accurately compare Equivalent Bill data to the data from the ZOHO system, the Company used calendarized values and selected an appropriate reference month (i.e., December) for the Equivalent Bill data and compared that to the year-end customer count from the ZOHO system. There is a slight difference between the reported ZOHO customer count and the number of such customers from the Equivalent Bill data due to certain issues including duplication and a mis-recording of the service start date. Please note that the customer additions data provided in Figure 16 of the Direct Testimony of William R. Killeen and James M. Stephens in Docket No. DG 17-198 (see Bates 151R) were based on annual Customer Equivalent Bill data for the year-ending in March and not calendar year data.

6 Please note, in preparation of this response, the Company noted a discrepancy in the information provided in the responses to CLF 1-9, Staff 2-4, and Staff 3-13 in Docket No. DG 17-152 compared to the information provided in the responses to OCA 1-12 and CLF 1-8 in Docket No. DG 17-198. Although the ZOHO system was used to develop all these responses, the extraction parameters were not consistent thus resulting in a different number of historical customer additions. The historical customer additions data as provided in the responses to OCA 1-12 and CLF 1-8 in Docket No. DG 17-198 uses the appropriate extraction parameters and should replace the historical customer additions information provided in the responses to CLF 1-9, Staff 2-4, and Staff 3-13 in Docket No. DG 17-152.

7 Please note that the ZOHO system was placed on-line in late May 2014 so the information for that year reflects a partial year and, as such, the Customer Equivalent Bill data was presented on a similar basis.

franchise areas; (iii) the expansion of the Sales and Marketing team; (iv) innovative growth programs; and (v) past Commission precedent.

As a preliminary matter, there is academic support for adjusting econometric models to reflect information that is not otherwise captured in the historical data but is relevant to the accuracy of the forecast. For example, Michael Intriligator discusses the use of "add factors" (out-of-model adjustments) in *Econometric Models, Techniques, & Applications*:

> The add factors are based on judgments of factors not explicitly included in the model. For example, in a macroeconometric model there may be no explicit account taken of strike activity, but if major union contracts are expiring and a strike appears likely in the forecast period, the forecasts of production should be appropriately revised downward. Many other factors may not have been included in the model because their occurrence is rare or because data are difficult to obtain, but this does not mean that they must be overlooked in formulating a forecast. Indeed, it would be inappropriate to ignore relevant considerations simply because they were omitted from the model. In this sense forecasting with an econometric model is not simply a mechanical exercise but rather a blending of objective and subjective considerations. The subjective considerations embodied in the add factors, general improve significantly on the accuracy of the forecasts made with an econometric model.[8]

The factors discussed below show that the Company's recent activities and new programs will continue to promote customer growth above that found in the historical data, which supports the use of an out-of-model adjustment to appropriately reflect that information.

First, for the existing service territory, the actual or historical customer additions using Customer Equivalent Bill data is greater than the forecasted customer additions from the econometric model. Specifically, the forecast of customer additions from the econometric model results in approximately 1,180 customer additions per year for the existing service territory. However, as shown by Table 4 above, using the Customer Equivalent Bill data over the 2014 to 2017 period results in approximately 1,550 customer additions per year; and, if the partial customer additions results from 2014 are excluded, the annual customer additions over the 2015 to 2017 period for the existing service territory average approximately 1,700 customers per year.[9] Therefore, the actual customer additions information and experience in the existing service territory supports an adjustment to the customer addition results from the econometric model.

Second, in addition to the customer numbers shown in Table 4, Concord Steam has discontinued service and the Company received franchise approval for the towns of Windham and Pelham; and plans to file for approval of the potential franchise areas that would include the towns of Epping, Raymond, and Candia. None of the customers associated with the Concord Steam conversion and potential customers in the new or potential franchise areas are included in the results of the econometric model and should be considered as exogenous to the econometric model and, therefore, support the use of an adjustment to customer additions.

Third, the Company has continued to focus on growth and providing more customers with the option to choose natural gas as their fuel. As discussed in the responses to Staff 2-4 and Staff 3-13 in Docket No. DG 17-152, the Company has expanded its Sales and Marketing team by six full time equivalents ("FTEs"). These employees reside and are active in their local communities and provide "feet on the ground" with

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8 Michael D. Intriligator, Econometric Models, Techniques, & Applications, at 516-517.

9 An analysis of the information from the ZOHO system produces similar historical customer additions over the 2014 to 2017 and 2015 to 2017 time periods.

respect to participating in business organizations and town activities. This increase in number of Sales and Marketing employees and the local presence of those employees supports an adjustment to the results of the econometric models.

Fourth, the Company has proposed and received approval from the Commission for innovative expansion plans, such as revisions to the contribution-in-aid-of-construction policy (e.g., including the assumption that 60% of customers located along a main extension will take service) and the Managed Expansion Program ("MEP") approved by the Commission in August 2016. The MEP not only provides a mechanism to unitize expansion costs and collect those expenses over time, but also provides the Company an opportunity to install service lines for any end use application during the construction of a main, thus positioning the Company to add load from an existing customer. Stated differently, the Company, under MEP, can provide a service line to a customer for an end use application, such as water heating, and thus natural gas is a fuel choice for that customer when their existing heating equipment fails or needs to be replaced. Please see the response to Staff Tech 1-3 in Docket No. DG 17-152, which discusses the customer additions associated with MEP. In addition, the Company (1) eliminated the $900 flat fee for a new residential customer, (2) allowed for no-cost service connections of heating customers within 100 feet of an existing natural gas main, (3) allowed for no-cost service connections of non-heating customers within 100 feet if they commit to taking service prior to a main extension or replacement, and (4) lowered the level of revenue justification required for main and service extensions.

Fifth, the use of adjustments to improve the results of an econometric model have been presented to, and approved by, the Commission. By way of example, in the NED proceeding (i.e., Docket No. DG 14-380), the Company adjusted the results of the econometric model to reflect three markets that were exogenous to the results of the econometric model; specifically, the Company included adjustments for: (i) potential volumes to Keene, NH, as an incremental market; (ii) reverse migration of capacity exempt customers, reflecting recent market trends; and (iii) incremental volumes for iNATGAS, a new, large customer in the existing service territory. Similar to the NED proceeding, the Company in Docket Nos. DG 17-152 and DG 17-198 has adjusted the results of the econometric model to reflect incremental markets (e.g., the new and potential franchise areas), recent market trends (e.g., actual level of customer additions), and incremental volume (e.g., iNATGAS).

IV. Out-of-Model Adjustments

As discussed above, the Company has provided support for certain adjustments to the results of the econometric models. The calculated values and expected saturation levels for each of those adjustments (i.e., incremental customer additions in the existing service territory, incremental customers from new or potential franchise areas, and iNATGAS) are provided below.

First, with respect to the existing service territory, the Company has adjusted the results of the econometric models to reflect the recent historical customer additions, the investment by the Company in growth (i.e., incremental Sales and Marketing staff), and the approval of innovative programs (e.g., MEP). As such, the econometric models forecast of approximately 1,180 customers per year has been adjusted to approximately 1,625 customers per year,[10] which is aligned with the average customer additions over the 2015 to 2017 period (see Table 4 above). In addition, the Company has relied on the same transition schedule to the results of the econometric model for the period from 2023 to 2038 as originally filed.[11] As shown by Table

[10] Represents an average of the customer additions for the existing service territory over the forecast period.
[11] The transition period is discussed on Bates 154R of the Direct Testimony of William R. Killeen and James M. Stephens in Docket No. DG 17-198, and further detailed in the response to Staff 2-62 in Docket No. DG 17-198.

5 below, the Company's forecast of new residential and C&I customers in the existing service territory results in saturation levels in 2038 that are reasonable.

Second, regarding the new franchise areas (i.e., Windham and Pelham) and the potential franchise areas (i.e., Epping, Candia, and Raymond), the Company has adjusted the results of the econometric models to reflect customer additions in these areas as these towns were exogenous to the econometric model results. The Company will leverage its larger Sales and Marketing team and the approved, innovative regulatory programs to achieve the forecasted customer additions. As shown by Table 5 below, the Company's forecast of new residential and C&I customers in the new and potential franchise areas results in saturation levels in 2038 that are reasonable.

Table 5: Saturation Levels in 2038

	Residential[12]	C&I[13]	Total
Existing Service Territory	51%	84%	54%
New Franchise Areas (Windham/Pelham)	10%	20%	11%
Potential Franchise Areas (Epping /Candia/Raymond)	18%	40%	21%

Lastly, the Company adjusted the results of the econometric models to reflect the recent actual usage and contractual arrangements associated with iNATGAS, which were approved by the Commission in Docket No. DG 14-091 and reaffirmed by the Commission in the NED proceeding in Docket No. DG 14-380. At the time of the Company's initial filing in Docket Nos. DG 17-152 and DG 17-198, the Company understood the natural gas usage of iNATGAS to be minimal. Specifically, the Company in its initial filing assumed iNATGAS would consume 20 Dth on design day and approximately 1 Dth on every other day. However, this past winter iNATGAS consumed 4,251 Dth on its peak day, which supports an adjustment to the volumes used in the Company's initial filing. The Company's revised assumption for iNATGAS volumes based on the contractual arrangements and actual usage by iNATGAS is summarized in Table 6.

[12] To calculate the residential saturation levels, the Company increased the number of residential customer prospects from ICF using certain information from Moody's (i.e., increased by the growth rate of the Total Households variable). Please see the response to Staff 2-4 in Docket No. DG 17-152 and the responses to Staff 1-8 and Staff 1-9 in Docket No. DG 17-198 for certain ICF customer prospect data.

[13] To calculate the C&I saturation levels, the Company increased the number of commercial customer prospects from ICF using certain information from Moody's (i.e., increased by the growth rate of the Total Employment variable). Please see the response to Staff 2-4 in Docket No. DG 17-152 and the responses to Staff 1-8 and Staff 1-9 in Docket No. DG 17-198 for certain ICF customer prospect data. Please note that the total number of commercial customer prospects from ICF is conservative when compared to data from the U.S. Census Bureau, thus resulting in C&I saturation rates that are higher than rates based on data from the U.S. Census Bureau.

Table 6: iNATGAS Volumes (Dth)

Split Year	Annual Volume	Design Day
2017/18	266	20
2018/19	300,000	4,251
2019/20	300,000	4,251
2020/21	500,000	4,251
2021/22	500,000	4,251
2022/23	1,300,000	8,800
2023/24	1,300,000	8,800
2024/25	1,300,000	8,800
2025/26	1,300,000	8,800
2026/27	1,300,000	8,800
2027/28	1,300,000	8,800
2028/29	1,300,000	8,800
2029/30	1,300,000	8,800
2030/31	1,300,000	8,800
2031/32	1,300,000	8,800
2032/33	1,300,000	8,800
2033/34	1,300,000	8,800
2034/35	1,300,000	8,800
2035/36	1,300,000	8,800
2036/37	1,300,000	8,800
2037/38	1,300,000	8,800

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

PLAN Data Requests - Set 5

Date Request Received: 7/9/18
Request No. PLAN 5-7

Date of Response: 7/23/18
Respondent: William R. Killeen

REQUEST:

Reference: Attachment CLF Tech 1-2.1, page 8. Please provide a table showing the quantity of gas delivered to iNATGAS each day from December 1, 2016 through June 30, 2018.

RESPONSE:

The gas delivered to iNATGAS each day from December 19, 2016, to July 11, 2018, is shown in Table PLAN 5-7 below. Prior to December 19, 2016, there was no functional meter and no usage.

iNATGAS's usage in the table below is confidential customer information protected from disclosure by RSA 363:38 and RSA 91-A:5, IV. Therefore, pursuant to Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion seeking confidential treatment prior to the final hearing in this docket.

Table PLAN 5-7

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	12/19/16	[redacted]	1.032	[redacted]
iNATGAS	12/20/16		1.04	
iNATGAS	12/21/16		1.035	
iNATGAS	12/22/16		1.035	
iNATGAS	12/23/16		1.032	
iNATGAS	12/24/16		1.032	
iNATGAS	12/25/16		1.03	
iNATGAS	12/26/16		1.03	
iNATGAS	12/27/16		1.03	
iNATGAS	12/28/16		1.031	
iNATGAS	12/29/16		1.031	
iNATGAS	12/30/16		1.031	
iNATGAS	12/31/16		1.031	
iNATGAS	1/01/17		1.03	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	1/02/17	[redacted]	1.031	[redacted]
iNATGAS	1/03/17		1.031	
iNATGAS	1/04/17		1.031	
iNATGAS	1/05/17		1.033	
iNATGAS	1/06/17		1.034	
iNATGAS	1/07/17		1.033	
iNATGAS	1/08/17		1.041	
iNATGAS	1/09/17		1.046	
iNATGAS	1/10/17		1.04	
iNATGAS	1/11/17		1.033	
iNATGAS	1/12/17		1.032	
iNATGAS	1/13/17		1.032	
iNATGAS	1/14/17		1.032	
iNATGAS	1/15/17		1.032	
iNATGAS	1/16/17		1.031	
iNATGAS	1/17/17		1.03	
iNATGAS	1/18/17		1.03	
iNATGAS	1/19/17		1.032	
iNATGAS	1/20/17		1.031	
iNATGAS	1/21/17		1.03	
iNATGAS	1/22/17		1.03	
iNATGAS	1/23/17		1.03	
iNATGAS	1/24/17		1.03	
iNATGAS	1/25/17		1.03	
iNATGAS	1/26/17		1.03	
iNATGAS	1/27/17		1.03	
iNATGAS	1/28/17		1.03	
iNATGAS	1/29/17		1.031	
iNATGAS	1/30/17		1.03	
iNATGAS	1/31/17		1.031	
iNATGAS	2/01/17		1.031	
iNATGAS	2/02/17		1.031	
iNATGAS	2/03/17		1.033	
iNATGAS	2/04/17		1.037	
iNATGAS	2/05/17		1.033	
iNATGAS	2/06/17		1.034	
iNATGAS	2/07/17		1.032	
iNATGAS	2/08/17		1.031	
iNATGAS	2/09/17		1.039	
iNATGAS	2/10/17		1.054	
iNATGAS	2/11/17		1.044	
iNATGAS	2/12/17		1.041	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	2/13/17	[redacted]	1.032	[redacted]
iNATGAS	2/14/17		1.035	
iNATGAS	2/15/17		1.0335	
iNATGAS	2/16/17		1.035	
iNATGAS	2/17/17		1.034	
iNATGAS	2/18/17		1.031	
iNATGAS	2/19/17		1.03	
iNATGAS	2/20/17		1.034	
iNATGAS	2/21/17		1.032	
iNATGAS	2/22/17		1.031	
iNATGAS	2/23/17		1.032	
iNATGAS	2/24/17		1.0315	
iNATGAS	2/25/17		1.03	
iNATGAS	2/26/17		1.031	
iNATGAS	2/27/17		1.03	
iNATGAS	2/28/17		1.03	
iNATGAS	3/01/17		1.0305	
iNATGAS	3/02/17		1.03	
iNATGAS	3/03/17		1.032	
iNATGAS	3/04/17		1.028	
iNATGAS	3/05/17		1.032	
iNATGAS	3/06/17		1.032	
iNATGAS	3/07/17		1.031	
iNATGAS	3/08/17		1.03	
iNATGAS	3/09/17		1.03	
iNATGAS	3/10/17		1.0305	
iNATGAS	3/11/17		1.032	
iNATGAS	3/12/17		1.032	
iNATGAS	3/13/17		1.034	
iNATGAS	3/14/17		1.037	
iNATGAS	3/15/17		1.041	
iNATGAS	3/16/17		1.041	
iNATGAS	3/17/17		1.037	
iNATGAS	3/18/17		1.034	
iNATGAS	3/19/17		1.033	
iNATGAS	3/20/17		1.033	
iNATGAS	3/21/17		1.03	
iNATGAS	3/22/17		1.032	
iNATGAS	3/23/17		1.03	
iNATGAS	3/24/17		1.03	
iNATGAS	3/25/17		1.03	
iNATGAS	3/26/17		1.03	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	3/27/17	[redacted]	1.03	[redacted]
iNATGAS	3/28/17		1.03	
iNATGAS	3/29/17		1.03	
iNATGAS	3/30/17		1.03	
iNATGAS	3/31/17		1.03	
iNATGAS	4/01/17		1.03	
iNATGAS	4/02/17		1.03	
iNATGAS	4/03/17		1.03	
iNATGAS	4/04/17		1.03	
iNATGAS	4/05/17		1.029	
iNATGAS	4/06/17		1.029	
iNATGAS	4/07/17		1.029	
iNATGAS	4/08/17		1.029	
iNATGAS	4/09/17		1.029	
iNATGAS	4/10/17		1.029	
iNATGAS	4/11/17		1.029	
iNATGAS	4/12/17		1.029	
iNATGAS	4/13/17		1.029	
iNATGAS	4/14/17		1.029	
iNATGAS	4/15/17		1.029	
iNATGAS	4/16/17		1.029	
iNATGAS	4/17/17		1.029	
iNATGAS	4/18/17		1.029	
iNATGAS	4/19/17		1.029	
iNATGAS	4/20/17		1.029	
iNATGAS	4/21/17		1.029	
iNATGAS	4/22/17		1.029	
iNATGAS	4/23/17		1.029	
iNATGAS	4/24/17		1.029	
iNATGAS	4/25/17		1.029	
iNATGAS	4/26/17		1.029	
iNATGAS	4/27/17		1.029	
iNATGAS	4/28/17		1.029	
iNATGAS	4/29/17		1.029	
iNATGAS	4/30/17		1.029	
iNATGAS	5/01/17		1.029	
iNATGAS	5/02/17		1.029	
iNATGAS	5/03/17		1.029	
iNATGAS	5/04/17		1.029	
iNATGAS	5/05/17		1.029	
iNATGAS	5/06/17		1.029	
iNATGAS	5/07/17		1.029	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	5/08/17	[redacted]	1.029	[redacted]
iNATGAS	5/09/17		1.029	
iNATGAS	5/10/17		1.029	
iNATGAS	5/11/17		1.03	
iNATGAS	5/12/17		1.03	
iNATGAS	5/13/17		1.03	
iNATGAS	5/14/17		1.029	
iNATGAS	5/15/17		1.029	
iNATGAS	5/16/17		1.029	
iNATGAS	5/17/17		1.029	
iNATGAS	5/18/17		1.029	
iNATGAS	5/19/17		1.028	
iNATGAS	5/20/17		1.029	
iNATGAS	5/21/17		1.029	
iNATGAS	5/22/17		1.029	
iNATGAS	5/23/17		1.029	
iNATGAS	5/24/17		1.028	
iNATGAS	5/25/17		1.029	
iNATGAS	5/26/17		1.029	
iNATGAS	5/27/17		1.029	
iNATGAS	5/28/17		1.028	
iNATGAS	5/29/17		1.029	
iNATGAS	5/30/17		1.028	
iNATGAS	5/31/17		1.0285	
iNATGAS	6/01/17		1.029	
iNATGAS	6/02/17		1.0285	
iNATGAS	6/03/17		1.029	
iNATGAS	6/04/17		1.028	
iNATGAS	6/05/17		1.028	
iNATGAS	6/06/17		1.028	
iNATGAS	6/07/17		1.029	
iNATGAS	6/08/17		1.029	
iNATGAS	6/09/17		1.0285	
iNATGAS	6/10/17		1.029	
iNATGAS	6/11/17		1.029	
iNATGAS	6/12/17		1.029	
iNATGAS	6/13/17		1.028	
iNATGAS	6/14/17		1.029	
iNATGAS	6/15/17		1.029	
iNATGAS	6/16/17		1.029	
iNATGAS	6/17/17		1.029	
iNATGAS	6/18/17		1.028	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	6/19/17	[redacted]	1.029	[redacted]
iNATGAS	6/20/17		1.028	
iNATGAS	6/21/17		1.029	
iNATGAS	6/22/17		1.029	
iNATGAS	6/23/17		1.028	
iNATGAS	6/24/17		1.029	
iNATGAS	6/25/17		1.029	
iNATGAS	6/26/17		1.029	
iNATGAS	6/27/17		1.029	
iNATGAS	6/28/17		1.029	
iNATGAS	6/29/17		1.029	
iNATGAS	6/30/17		1.029	
iNATGAS	7/01/17		1.029	
iNATGAS	7/02/17		1.029	
iNATGAS	7/03/17		1.029	
iNATGAS	7/04/17		1.029	
iNATGAS	7/05/17		1.029	
iNATGAS	7/06/17		1.029	
iNATGAS	7/07/17		1.029	
iNATGAS	7/08/17		1.029	
iNATGAS	7/09/17		1.029	
iNATGAS	7/10/17		1.029	
iNATGAS	7/11/17		1.029	
iNATGAS	7/12/17		1.029	
iNATGAS	7/13/17		1.0285	
iNATGAS	7/14/17		1.029	
iNATGAS	7/15/17		1.029	
iNATGAS	7/16/17		1.029	
iNATGAS	7/17/17		1.029	
iNATGAS	7/18/17		1.029	
iNATGAS	7/19/17		1.028	
iNATGAS	7/20/17		1.027	
iNATGAS	7/21/17		1.0265	
iNATGAS	7/22/17		1.028	
iNATGAS	7/23/17		1.029	
iNATGAS	7/24/17		1.029	
iNATGAS	7/25/17		1.029	
iNATGAS	7/26/17		1.029	
iNATGAS	7/27/17		1.029	
iNATGAS	7/28/17		1.029	
iNATGAS	7/29/17		1.029	
iNATGAS	7/30/17		1.029	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	7/31/17	[redacted]	1.029	[redacted]
iNATGAS	8/01/17		1.027	
iNATGAS	8/02/17		1.0285	
iNATGAS	8/03/17		1.028	
iNATGAS	8/04/17		1.028	
iNATGAS	8/05/17		1.029	
iNATGAS	8/06/17		1.029	
iNATGAS	8/07/17		1.029	
iNATGAS	8/08/17		1.029	
iNATGAS	8/09/17		1.029	
iNATGAS	8/10/17		1.029	
iNATGAS	8/11/17		1.029	
iNATGAS	8/12/17		1.0295	
iNATGAS	8/13/17		1.029	
iNATGAS	8/14/17		1.029	
iNATGAS	8/15/17		1.0295	
iNATGAS	8/16/17		1.029	
iNATGAS	8/17/17		1.03	
iNATGAS	8/18/17		1.029	
iNATGAS	8/19/17		1.029	
iNATGAS	8/20/17		1.029	
iNATGAS	8/21/17		1.029	
iNATGAS	8/22/17		1.029	
iNATGAS	8/23/17		1.029	
iNATGAS	8/24/17		1.029	
iNATGAS	8/25/17		1.029	
iNATGAS	8/26/17		1.029	
iNATGAS	8/27/17		1.029	
iNATGAS	8/28/17		1.029	
iNATGAS	8/29/17		1.029	
iNATGAS	8/30/17		1.029	
iNATGAS	8/31/17		1.0295	
iNATGAS	9/01/17		1.03	
iNATGAS	9/02/17		1.03	
iNATGAS	9/03/17		1.029	
iNATGAS	9/04/17		1.029	
iNATGAS	9/05/17		1.029	
iNATGAS	9/06/17		1.029	
iNATGAS	9/07/17		1.03	
iNATGAS	9/08/17		1.03	
iNATGAS	9/09/17		1.0295	
iNATGAS	9/10/17		1.029	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	9/11/17	[redacted]	1.029	[redacted]
iNATGAS	9/12/17		1.029	
iNATGAS	9/13/17		1.029	
iNATGAS	9/14/17		1.029	
iNATGAS	9/15/17		1.0295	
iNATGAS	9/16/17		1.029	
iNATGAS	9/17/17		1.029	
iNATGAS	9/18/17		1.029	
iNATGAS	9/19/17		1.029	
iNATGAS	9/20/17		1.029	
iNATGAS	9/21/17		1.029	
iNATGAS	9/22/17		1.029	
iNATGAS	9/23/17		1.029	
iNATGAS	9/24/17		1.029	
iNATGAS	9/25/17		1.028	
iNATGAS	9/26/17		1.027	
iNATGAS	9/27/17		1.027	
iNATGAS	9/28/17		1.028	
iNATGAS	9/29/17		1.029	
iNATGAS	9/30/17		1.029	
iNATGAS	10/01/17		1.029	
iNATGAS	10/02/17		1.029	
iNATGAS	10/03/17		1.029	
iNATGAS	10/04/17		1.03	
iNATGAS	10/05/17		1.03	
iNATGAS	10/06/17		1.03	
iNATGAS	10/07/17		1.03	
iNATGAS	10/08/17		1.03	
iNATGAS	10/09/17		1.027	
iNATGAS	10/10/17		1.026	
iNATGAS	10/11/17		1.029	
iNATGAS	10/12/17		1.029	
iNATGAS	10/13/17		1.029	
iNATGAS	10/14/17		1.029	
iNATGAS	10/15/17		1.029	
iNATGAS	10/16/17		1.029	
iNATGAS	10/17/17		1.029	
iNATGAS	10/18/17		1.03	
iNATGAS	10/19/17		1.03	
iNATGAS	10/20/17		1.03	
iNATGAS	10/21/17		1.0295	
iNATGAS	10/22/17		1.0295	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	10/23/17	[redacted]	1.029	[redacted]
iNATGAS	10/24/17		1.0285	
iNATGAS	10/25/17		1.028	
iNATGAS	10/26/17		1.029	
iNATGAS	10/27/17		1.03	
iNATGAS	10/28/17		1.03	
iNATGAS	10/29/17		1.03	
iNATGAS	10/30/17		1.03	
iNATGAS	10/31/17		1.029	
iNATGAS	11/01/17		1.03	
iNATGAS	11/02/17		1.03	
iNATGAS	11/03/17		1.03	
iNATGAS	11/04/17		1.029	
iNATGAS	11/05/17		1.029	
iNATGAS	11/06/17		1.029	
iNATGAS	11/07/17		1.029	
iNATGAS	11/08/17		1.029	
iNATGAS	11/09/17		1.0295	
iNATGAS	11/10/17		1.028	
iNATGAS	11/11/17		1.032	
iNATGAS	11/12/17		1.032	
iNATGAS	11/13/17		1.032	
iNATGAS	11/14/17		1.032	
iNATGAS	11/15/17		1.032	
iNATGAS	11/16/17		1.031	
iNATGAS	11/17/17		1.031	
iNATGAS	11/18/17		1.031	
iNATGAS	11/19/17		1.03	
iNATGAS	11/20/17		1.032	
iNATGAS	11/21/17		1.031	
iNATGAS	11/22/17		1.03	
iNATGAS	11/23/17		1.03	
iNATGAS	11/24/17		1.03	
iNATGAS	11/25/17		1.0295	
iNATGAS	11/26/17		1.03	
iNATGAS	11/27/17		1.03	
iNATGAS	11/28/17		1.03	
iNATGAS	11/29/17		1.03	
iNATGAS	11/30/17		1.03	
iNATGAS	12/01/17		1.03	
iNATGAS	12/02/17		1.03	
iNATGAS	12/03/17		1.03	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	12/04/17	[redacted]	1.0305	[redacted]
iNATGAS	12/05/17		1.03	
iNATGAS	12/06/17		1.031	
iNATGAS	12/07/17		1.03	
iNATGAS	12/08/17		1.03	
iNATGAS	12/09/17		1.03	
iNATGAS	12/10/17		1.03	
iNATGAS	12/11/17		1.03	
iNATGAS	12/12/17		1.03	
iNATGAS	12/13/17		1.03	
iNATGAS	12/14/17		1.03	
iNATGAS	12/15/17		1.031	
iNATGAS	12/16/17		1.038	
iNATGAS	12/17/17		1.036	
iNATGAS	12/18/17		1.033	
iNATGAS	12/19/17		1.032	
iNATGAS	12/20/17		1.034	
iNATGAS	12/21/17		1.033	
iNATGAS	12/22/17		1.032	
iNATGAS	12/23/17		1.032	
iNATGAS	12/24/17		1.032	
iNATGAS	12/25/17		1.034	
iNATGAS	12/26/17		1.036	
iNATGAS	12/27/17		1.036	
iNATGAS	12/28/17		1.036	
iNATGAS	12/29/17		1.036	
iNATGAS	12/30/17		1.036	
iNATGAS	12/31/17		1.036	
iNATGAS	1/01/18		1.036	
iNATGAS	1/02/18		1.036	
iNATGAS	1/03/18		1.046	
iNATGAS	1/04/18		1.044	
iNATGAS	1/05/18		1.045	
iNATGAS	1/06/18		1.045	
iNATGAS	1/07/18		1.047	
iNATGAS	1/08/18		1.046	
iNATGAS	1/09/18		1.043	
iNATGAS	1/10/18		1.035	
iNATGAS	1/11/18		1.032	
iNATGAS	1/12/18		1.03	
iNATGAS	1/13/18		1.033	
iNATGAS	1/14/18		1.034	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	1/15/18	[redacted]	1.035	[redacted]
iNATGAS	1/16/18		1.038	
iNATGAS	1/17/18		1.036	
iNATGAS	1/18/18		1.036	
iNATGAS	1/19/18		1.033	
iNATGAS	1/20/18		1.031	
iNATGAS	1/21/18		1.03	
iNATGAS	1/22/18		1.03	
iNATGAS	1/23/18		1.03	
iNATGAS	1/24/18		1.033	
iNATGAS	1/25/18		1.034	
iNATGAS	1/26/18		1.034	
iNATGAS	1/27/18		1.034	
iNATGAS	1/28/18		1.034	
iNATGAS	1/29/18		1.034	
iNATGAS	1/30/18		1.034	
iNATGAS	1/31/18		1.034	
iNATGAS	2/01/18		1.034	
iNATGAS	2/02/18		1.034	
iNATGAS	2/03/18		1.037	
iNATGAS	2/04/18		1.034	
iNATGAS	2/05/18		1.035	
iNATGAS	2/06/18		1.036	
iNATGAS	2/07/18		1.0375	
iNATGAS	2/08/18		1.038	
iNATGAS	2/09/18		1.036	
iNATGAS	2/10/18		1.035	
iNATGAS	2/11/18		1.033	
iNATGAS	2/12/18		1.034	
iNATGAS	2/13/18		1.036	
iNATGAS	2/14/18		1.033	
iNATGAS	2/15/18		1.031	
iNATGAS	2/16/18		1.031	
iNATGAS	2/17/18		1.031	
iNATGAS	2/18/18		1.031	
iNATGAS	2/19/18		1.031	
iNATGAS	2/20/18		1.03	
iNATGAS	2/21/18		1.03	
iNATGAS	2/22/18		1.03	
iNATGAS	2/23/18		1.03	
iNATGAS	2/24/18		1.03	
iNATGAS	2/25/18		1.03	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	2/26/18	[redacted]	1.03	[redacted]
iNATGAS	2/27/18		1.03	
iNATGAS	2/28/18		1.03	
iNATGAS	3/01/18		1.03	
iNATGAS	3/02/18		1.03	
iNATGAS	3/03/18		1.03	
iNATGAS	3/04/18		1.03	
iNATGAS	3/05/18		1.031	
iNATGAS	3/06/18		1.031	
iNATGAS	3/07/18		1.031	
iNATGAS	3/08/18		1.032	
iNATGAS	3/09/18		1.032	
iNATGAS	3/10/18		1.031	
iNATGAS	3/11/18		1.031	
iNATGAS	3/12/18		1.031	
iNATGAS	3/13/18		1.035	
iNATGAS	3/14/18		1.033	
iNATGAS	3/15/18		1.031	
iNATGAS	3/16/18		1.033	
iNATGAS	3/17/18		1.032	
iNATGAS	3/18/18		1.032	
iNATGAS	3/19/18		1.034	
iNATGAS	3/20/18		1.033	
iNATGAS	3/21/18		1.034	
iNATGAS	3/22/18		1.0315	
iNATGAS	3/23/18		1.032	
iNATGAS	3/24/18		1.031	
iNATGAS	3/25/18		1.032	
iNATGAS	3/26/18		1.032	
iNATGAS	3/27/18		1.033	
iNATGAS	3/28/18		1.031	
iNATGAS	3/29/18		1.031	
iNATGAS	3/30/18		1.03	
iNATGAS	3/31/18		1.03	
iNATGAS	4/01/18		1.03	
iNATGAS	4/02/18		1.032	
iNATGAS	4/03/18		1.032	
iNATGAS	4/04/18		1.032	
iNATGAS	4/05/18		1.032	
iNATGAS	4/06/18		1.033	
iNATGAS	4/07/18		1.031	
iNATGAS	4/08/18		1.032	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	4/09/18	[redacted]	1.032	[redacted]
iNATGAS	4/10/18		1.033	
iNATGAS	4/11/18		1.031	
iNATGAS	4/12/18		1.031	
iNATGAS	4/13/18		1.031	
iNATGAS	4/14/18		1.031	
iNATGAS	4/15/18		1.034	
iNATGAS	4/16/18		1.034	
iNATGAS	4/17/18		1.031	
iNATGAS	4/18/18		1.031	
iNATGAS	4/19/18		1.031	
iNATGAS	4/20/18		1.03	
iNATGAS	4/21/18		1.03	
iNATGAS	4/22/18		1.029	
iNATGAS	4/23/18		1.029	
iNATGAS	4/24/18		1.029	
iNATGAS	4/25/18		1.03	
iNATGAS	4/26/18		1.03	
iNATGAS	4/27/18		1.029	
iNATGAS	4/28/18		1.029	
iNATGAS	4/29/18		1.029	
iNATGAS	4/30/18		1.03	
iNATGAS	5/01/18		1.029	
iNATGAS	5/02/18		1.029	
iNATGAS	5/03/18		1.029	
iNATGAS	5/04/18		1.029	
iNATGAS	5/05/18		1.029	
iNATGAS	5/06/18		1.029	
iNATGAS	5/07/18		1.029	
iNATGAS	5/08/18		1.029	
iNATGAS	5/09/18		1.029	
iNATGAS	5/10/18		1.029	
iNATGAS	5/11/18		1.029	
iNATGAS	5/12/18		1.029	
iNATGAS	5/13/18		1.029	
iNATGAS	5/14/18		1.0285	
iNATGAS	5/15/18		1.029	
iNATGAS	5/16/18		1.029	
iNATGAS	5/17/18		1.029	
iNATGAS	5/18/18		1.029	
iNATGAS	5/19/18		1.029	
iNATGAS	5/20/18		1.029	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	5/21/18	[redacted]	1.029	[redacted]
iNATGAS	5/22/18		1.029	
iNATGAS	5/23/18		1.029	
iNATGAS	5/24/18		1.029	
iNATGAS	5/25/18		1.029	
iNATGAS	5/26/18		1.029	
iNATGAS	5/27/18		1.029	
iNATGAS	5/28/18		1.029	
iNATGAS	5/29/18		1.029	
iNATGAS	5/30/18		1.029	
iNATGAS	5/31/18		1.029	
iNATGAS	6/01/18		1.03	
iNATGAS	6/02/18		1.03	
iNATGAS	6/03/18		1.029	
iNATGAS	6/04/18		1.029	
iNATGAS	6/05/18		1.029	
iNATGAS	6/06/18		1.029	
iNATGAS	6/07/18		1.029	
iNATGAS	6/08/18		1.029	
iNATGAS	6/09/18		1.029	
iNATGAS	6/10/18		1.029	
iNATGAS	6/11/18		1.029	
iNATGAS	6/12/18		1.029	
iNATGAS	6/13/18		1.029	
iNATGAS	6/14/18		1.029	
iNATGAS	6/15/18		1.0285	
iNATGAS	6/16/18		1.028	
iNATGAS	6/17/18		1.029	
iNATGAS	6/18/18		1.029	
iNATGAS	6/19/18		1.029	
iNATGAS	6/20/18		1.029	
iNATGAS	6/21/18		1.028	
iNATGAS	6/22/18		1.029	
iNATGAS	6/23/18		1.029	
iNATGAS	6/24/18		1.029	
iNATGAS	6/25/18		1.029	
iNATGAS	6/26/18		1.03	
iNATGAS	6/27/18		1.03	
iNATGAS	6/28/18		1.029	
iNATGAS	6/29/18		1.029	
iNATGAS	6/30/18		1.029	
iNATGAS	7/01/18		1.029	

Docket No. DG 17-198 Request No. PLAN 5-7 (Redacted)

Customer	Date	MCF	BtuFactor	Dth
iNATGAS	7/02/18	[redacted]	1.029	[redacted]
iNATGAS	7/03/18		1.029	
iNATGAS	7/04/18		1.028	
iNATGAS	7/05/18		1.0285	
iNATGAS	7/06/18		1.029	
iNATGAS	7/07/18		1.029	
iNATGAS	7/08/18		1.029	
iNATGAS	7/09/18		1.029	
iNATGAS	7/10/18		1.029	
iNATGAS	7/11/18		1.029	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 2

Date Request Received: 4/5/18
Request No. OCA 2-21

Date of Response: 4/27/18
Respondent: Francisco C. DaFonte
James M. Stephens

REQUEST:

Direct Testimony of Mr. Killeen and Mr. Stephens: Bates page 152, lines 6-9. As for other LDCs that are party to the precedent agreement with PNGTS, please provide the planning horizons that those LDCs have relied on.

RESPONSE:

The Company is aware that the Massachusetts LDCs have indicated in their contract filings with the Massachusetts Department of Public Utilities that their respective contract decisions are the result of the cancellation of the Northeast Energy Direct ("NED") project and, thus, the planning horizons are generally consistent with the planning horizon used in their evaluation of the NED project capacity (i.e., a planning horizon through 2028/29). In addition, the Company is aware that Heritage Gas Limited used a planning horizon of 22 years to evaluate a capacity contract associated with the PXP Project.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 2

Date Request Received: 4/5/18
Request No. OCA 2-37

Date of Response: 5/9/18
Respondent: Francisco C. DaFonte

REQUEST:

Direct Testimony of Mr. Killeen and Mr. Stephens: Bates page 169, lines 3-7. Please briefly discuss the "issues" faced by customers with high-efficiency equipment.

RESPONSE:

Please see the Company's response to Staff 2-12 in Docket No. DG 17-152, which is provided as Attachment OCA 2-37.

High-efficiency furnaces are simply less tolerant of Btu and specific gravity variances in the fuel mix. These furnaces operate around 95% efficiency and have a modulating valve to allow for better control of the fuel mix and, thus, better efficiency. Because they are tuned specifically to the typical natural gas quality standards, the introduction of propane-air into the Company's distribution system causes the gas quality to fall outside of the tolerable range for the high-efficiency furnaces and they can and do shut down as discussed in the Company's prior responses.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-152
Least Cost Integrated Resource Plan

Staff Data Requests - Set 2

Date Request Received: 4/10/18
Request No. Staff 2-12

Date of Response: 4/27/18
Respondent: Francisco C. DaFonte

REQUEST:

Re: the Company's *Least Cost Integrated Resource Plan*, as filed in Docket No. DG 17-152, at page 48 the Company reports "the Company's customers have experienced problems with their high efficiency furnaces at various times when these propane facilities are used extensively." Please provide details of these problems, including:

a. How many customers have experienced problems?

b. What has(ve) been the nature(s) of the problems?

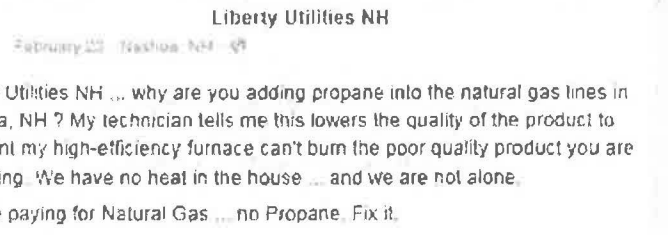
c. Where have the problems been relative to the locations of the propane facilities?

RESPONSE:

a. The Company has received customer complaints at various times over the past few years. The exact number is not known as many of the calls are simply "no heat" calls and the customer is generally unaware of what has caused their furnace to stop working. However, the Company has previously discussed this issue at length in Docket No. DG 14-380 in the Rebuttal Testimony of Mr. DaFonte at Bates 051:

> "...In addition, from a system operations perspective, the Company has received multiple complaints from customers with new high-efficiency heating equipment as a result of EnergyNorth's use of the propane facilities. These complaints are generally attributable to the limited tolerance of more modern equipment to varying natural gas heating values, and at times has led to "no heat" calls by customers. As an example, the Company received the following complaint from a customer via Facebook in February 2015:

Docket No. DG 17-152 Request No. Staff 2-12



> Additionally, the Company has received reports from HVAC contractors that service accounts near to one of EnergyNorth's propane facilities who indicated they had received numerous customer calls due to noise from their high-efficiency boilers, including certain customers that were uncomfortable remaining in their homes while this was occurring. One of the HVAC contractors noted that it was "selling more and more" of the high efficiency boilers "due to rebates that incent their installation."

Just this past winter, the Company received calls from St. Anslem's College in Manchester, which lost heat to five buildings, and the City of Manchester, which also lost heat to several buildings including City Hall and one of the city schools. All of the affected equipment was high-efficiency.

With the incentives for customers to replace older, less efficient furnaces, the conversion of oil and propane customers to higher efficiency natural gas heating equipment, and simply the phasing out of the manufacturing of low efficiency heating equipment, this issue will only get worse unless propane can be phased out of the Company's resource portfolio. Further, it may act as a deterrent for customers who want to be more energy efficient and, quite frankly, take advantage of the Company's award winning energy efficiency programs.

b. Please see the Company's response to part (a) above.

c. The problems have occurred in Nashua and Manchester where the Company has two of its three propane facilities.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 3

Date Request Received: 5/4/18
Request No. OCA 3-1

Date of Response: 5/18/18
Respondent: Francisco C. DaFonte

REQUEST:

Refer to the Company's Response to OCA 1-2.

a. Please provide the list of customer complaints that Liberty has received over the last ten years with respect to the "comingling of propane". Please provide supporting documentations corroborating those complaints.

b. Also, if the information is available, provide the details on instances where the customers remedied the "comingling" concerns.

c. Does the Company have an estimate for the typical remediation cost? If yes, please provide that estimate.

RESPONSE:

a. The Company does not have data going back ten years. Please see Attachment OCA 3-1.xlsx, which is a list of customer complaints requiring service calls that the Company has extracted from its service order list. The Company has attempted to correlate these complaints with the dates that propane was comingled with natural gas in its distribution system. It is difficult to ascertain with complete certainty that each service call was specifically related to propane injections but there are many clear instances where propane was specifically identified as having caused the heating equipment malfunction. Included in the service order list are a delineation of the "Day of" propane injections and the "Day after" propane injections. It is also important to note that not all customer equipment issues get reported to the Company as many homeowners and businesses deal directly with plumbers. Please see the Company's response to OCA 2-37 and, specifically, Attachment OCA 2-37, which provides additional details on historical customer outages related to the comingling of propane.

b. Please see the Company's response to OCA 2-38.

c. Other than the cost of sending out a service technician to check and relight the equipment, it is difficult to estimate what the full remediation costs might be as the Company has no way of knowing what the long-term impacts are to the customer's equipment or what the financial implications might be to a business with no heat. More

Docket No. DG 17-198 Request No. OCA 3-1

importantly, one cannot put a price on the potential health impact to anyone experiencing no heat during a cold winter day.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 5

Date Request Received: 6/14/18
Request No. OCA 5-3

Date of Response: 6/28/18
Respondent: Francisco C. DaFonte

REQUEST:

Refer to Company's response to DR OCA 2-37.

a. Does the Company have record of specific instances when the introduction of propane-air into the Company's distribution system caused gas quality to fall outside the tolerable range for the high efficiency furnaces? If so, please provide the mentioned record, if possible in Excel format. List the times and days as well as the location of the affected furnaces. Clearly indicate whether the Company specifically verified the instances listed in the record.

b. Please indicate at what fuel mix, i.e. propane-air and natural gas, would high-efficiency furnaces cease to operate.

c. Please list the instances when the Company's injection of propane-air into its distribution system impacted the fuel-mix enough that the gas quality fell outside the "tolerable range" for high-efficiency furnaces. Provide the record verifying the instances.

d. Does the company have a policy for what percentage of the fuel mixture can be satisfied by propane at any given place on the distribution system? If so, please provide a copy of and explain this policy. If not, please explain why not.

RESPONSE:

a. Please see Attachment OCA 3-1 provided in the Company's response to OCA 3-1.

b. As previously discussed in the Liberty's response to OCA 2-38, the Company maintains an appropriate propane-air mix to achieve as close to a manageable Btu and specific gravity level as possible. The Company does not know what the tolerances of high efficiency heating equipment are to comingled propane-air and natural gas and it may vary based on the type of equipment and by manufacturer. Further, the Company cannot completely control the propane-air to natural gas mix ratio as it has to rely on propane-air to meet the peak needs of its customers and, thus, cannot always choose when and what ratio of propane-air to introduce into its distribution system. It is also important to note that the Company's propane facilities are used to "balance" its system requirements with its scheduled deliveries on the Tennessee Concord Lateral. That is, the Company

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attempts to schedule its upstream supplies to match its daily forecast of customer requirements. Often times during peak periods, the Company is limited to a 2% tolerance between its scheduled upstream supplies and its actual usage on the Concord Lateral. Scheduling of supplies must be made 24 hours in advance of the Gas Day (the 24-hour period from 9 AM to 9 AM Central time) and three days in advance for a Monday or as much as four days in advance for a Tuesday following a Monday holiday. Of course the weather forecast can change significantly over a 24-hour period and one can imagine how much it can change over a four-day period. When actual weather is colder than initially forecasted, the Company becomes more reliant on its on-system LNG and propane resources to balance its scheduled supplies and customer usage. For these reasons, the Company simply does not have the flexibility needed to precisely manage its propane-air to natural gas mix ratio. Moreover, as stated in the Company's response to Staff 2-12 in Docket No. DG 17-152, with the incentives for customers to replace older, less efficient furnaces, the conversion of oil and propane customers to higher efficient natural gas heating equipment, and simply the phasing out of the manufacturing of low efficiency heating equipment, this issue will only get worse unless propane can be phased out of the Company's resource portfolio. It should also be remembered that, as stated in the Company's response to OCA 1-5, the Company's two largest propane facilities are over seventy years old and should not be relied on as long-term reliable supply resources.

c. See the Company's response to part a above which addresses the instances when customer heating equipment was impacted by propane-air to natural gas fuel mix ratio. Also, as stated in its response to part b above, the Company does not know what the tolerances of high efficiency heating equipment are to comingled propane-air and natural gas, nor could it adjust its propane-air to natural gas mix ratio to accommodate every manufacturer's specifications for fuel mix ratio tolerances.

d. The Company has no such policy nor could it for the reasons stated in the Company's response to parts b and c above.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

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OCA Data Requests - Set 5

Date Request Received: 6/14/18
Request No. OCA 5-4

Date of Response: 6/28/18
Respondent: Francisco C. DaFonte

REQUEST:

Refer to Company's response to DR Staff 2-12 in DG 17-152.

a. Did the Company track customer complaints to determine how many complaints were received and addressed over the "past few years"?

b. If the response to part a. above is yes, did the Company verify whether the furnaces were stopped because of specific instances of injection of propane-air into the distribution system?

c. If the response to part b. above is yes, please provide the listing of such occurrences, noting the times and addresses impacted. Please, also list clearly the distances between the associated propane facility and the addresses reporting the occurrences.

RESPONSE:

a. Please see the Company's responses to OCA 3-1 and OCA 5-3.

b. Please see the Company's response to part a above.

c. Please see the Company's response to part a above.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 5

Date Request Received: 6/14/18
Request No. OCA 5-5

Date of Response: 6/28/18
Respondent: Francisco C. DaFonte

REQUEST:

Please refer to the Company's response to DR Staff 2-12.a in DG 17-152.

a. With respect to the Facebook posting, did the Company confirm whether the technician was correct in identifying that the stoppage was attributable to propane-air injection into the distribution system?

b. If there was any follow up with the complainant, please provide supporting documentation.

c. If the response to part a. is yes, please provide specific evidence supporting that finding.

d. Please list clearly the distance between the associated propane facility and the address reporting the occurrence.

e. Please provide specific proof verifying that the instances reported by HVAC contractors were due to the injection of propane-air into the distribution system. Please list clearly the distances between the propane facility and the addresses associated with the reported instances.

f. Please provide specific proof verifying that the instances reported at Anselm's College in Manchester were due to injection of propane-air into the distribution system. Please provide the distance between the involved propane facility and the College.

RESPONSE:

a. To the Company's knowledge the customer reached out to their technician and not to the Company directly so it does not have a record of a specific service call. The Company did have direct complaints from other customers regarding heating equipment issues related to propane on the same date and those are documented in the Company's response to OCA 3-1. As was the case with this customer, many customers reach out to their own HVAC contractors for heating equipment problems and, thus, the Company would not be aware of these problems.

b. Please see the response to part a above.

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c. NA.

d. St. Anselm's College is located just over 2 miles from the Company's propane facility in Manchester.

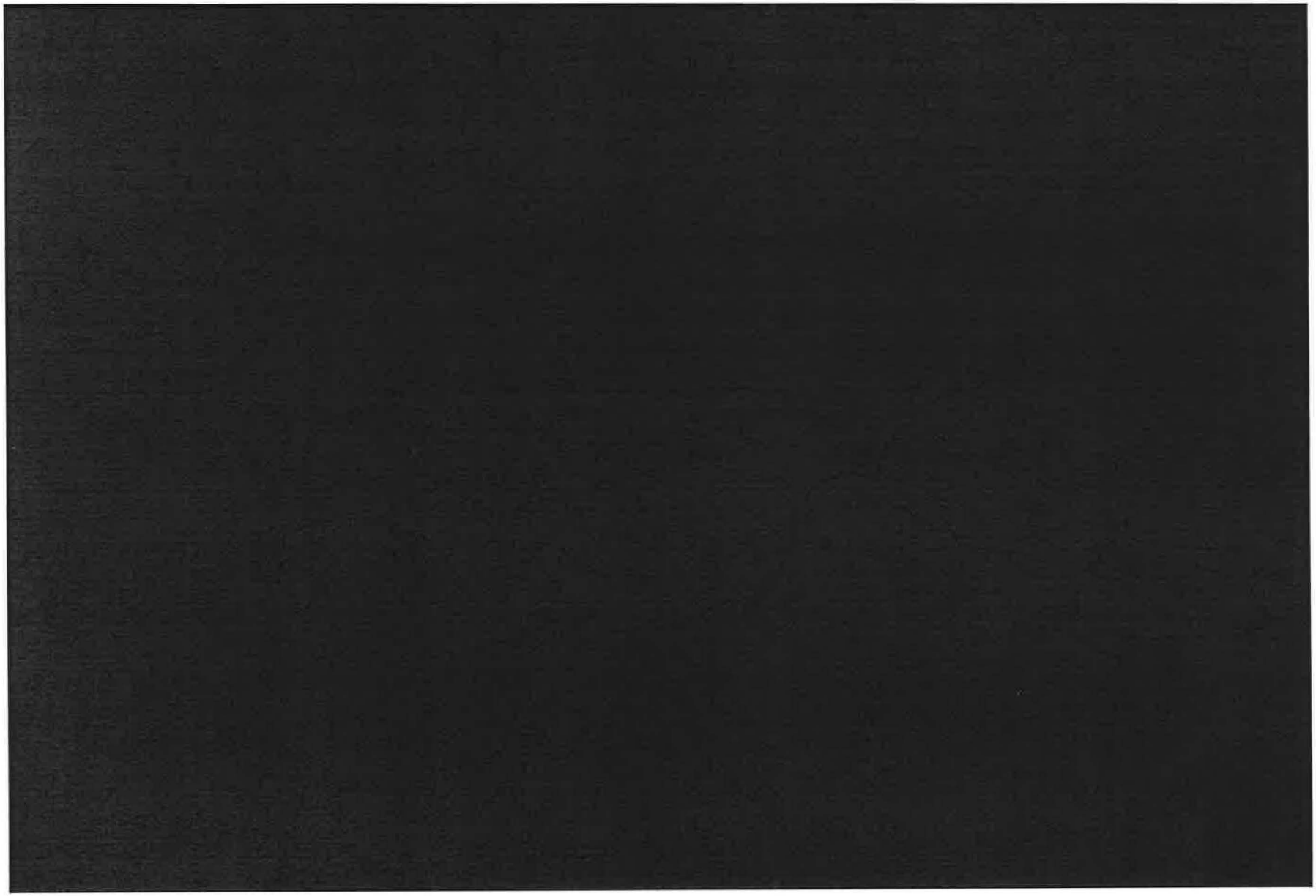
e. Please see the response to part a above.

f. St. Anselm's personnel reached out directly to the Company's key account representative responsible for the St. Anselm's account. They indicated that earlier in the day they had five buildings go down. They asked if the Company was putting propane in the distribution system that could have caused these issues. Their equipment went down for one to two hours. No service call was requested as the equipment had returned to service when the St. Anselm's personnel made the call.

While the Company does not have any physical documentation of the discussion between St. Anselm's personnel and Liberty's key account representative, it has no reason to doubt the validity of the complaint from St. Anselm's. As noted in the response to Staff 2-12 in Docket No. DG 17-152, the City of Manchester also experienced heating equipment malfunctions to several buildings due to propane injections.

REDACTED
Docket No. DG 17-198
Attachment OCA TS 1-3.b

	A	B (A x C)	C	D	E (C xD)	F (E-B)	G	H	I	J (F+H+I-G)	K	L (K+H+I-G)
	LNG WACOG	LNG Cost	Baseload Purchase Volume (Dth) Dec-Feb	Baseload Purchase WACOG Dec-Feb	Baseload Purchase Cost Dec-Feb	LNG Savings Dec-Feb	LNG Revenue Requirement	Customer Benefit Guarantee	Dracut Capacity Cost Savings	Net Customer Savings/(Cost)	Exhibit FCD/WRK-8 LNG Savings	Net Customer Savings/(Cost) Dracut Purchases
2013-14	$ 4.32	$ 6,095,727	1,410,045	[redacted]	[redacted]	[redacted]	$ 29,410,226	[redacted]	$ 5,501,592	[redacted]	$ 41,137,022	[redacted]
2014-15	$ 3.02	$ 4,260,995	1,412,000	[redacted]	[redacted]	[redacted]	$ 29,410,226	[redacted]	$ 5,501,592	[redacted]	$ 29,284,095	[redacted]
2015-16	$ 1.87	$ 2,662,423	1,427,000	[redacted]	[redacted]	[redacted]	$ 29,410,226	[redacted]	$ 5,501,592	[redacted]	$ 16,156,869	[redacted]
2016-17	$ 1.93	$ 2,725,035	1,411,553	[redacted]	[redacted]	[redacted]	$ 29,410,226	[redacted]	$ 5,501,592	[redacted]	$ 12,790,242	[redacted]
2017-18	$ 2.95	$ 4,163,764	1,412,000	[redacted]	[redacted]	[redacted]	$ 29,410,226	[redacted]	$ 5,501,592	[redacted]	$ 22,776,752	[redacted]
TOTAL		$ 19,907,943	7,072,598		[redacted]	[redacted]	$ 147,051,130	[redacted]	$ 27,507,960	[redacted]	$ 122,144,980	[redacted]



Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

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Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

OCA Data Requests - Set 13

Date Request Received: 5/3/19
Request No. OCA 13-2

Date of Response: 5/17/19
Respondent: Francisco C. DaFonte

REQUEST:

Refer to Company's Response to OCA 12-15. Please update the response to also reflect the latest distribution rates.

RESPONSE:

Please see Confidential Attachment OCA 13-2.xlsx, which updates the Company's response to OCA 12-15 to reflect the most recent distribution rates.

Confidential Attachment OCA 13-2.xlsx contains the estimated costs for TGP to upgrade the Concord Lateral, and other information derived from those estimated costs, which information is protected from disclosure by RSA 91-A:5, IV, as "confidential, commercial, or financial information" of a third party. TGP provided this estimate to Liberty under the terms of a non-disclosure agreement which requires the Company to maintain its confidentiality, and the Commission found the TGP information to be confidential in Order No. 26,166 (Aug. 1, 2018). Because Confidential Attachment OCA 13-2.xlsx is an Excel file, the confidential information cannot be redacted in a manner that would preclude one from being able to "back into" the confidential information. The Company thus asserts confidentiality as to the entire Excel file and a redacted version will not be provided. Therefore, pursuant to that statute, the Order, and Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion confirming confidential treatment prior to the final hearing in this docket.