Natural Gas Long-Term Capacity Report

Technical Appendix

Revised: April 1, 2020

Contents

Demand Assumptions

Baseline Demand Assumptions

Table 1 below provides additional detail on the number of customers by type and the Design Day gas demand utilization by customer type that was modeled in Step 1: Baseline Demand as described in pages 32-34 of the Long-Term Capacity Report.

Table 1: Baseline Demand Scenario Assumptions

	Customer*	Winter			
		2019/20	2024/25	2029/30	2034/35
Number of customers ('000)	Residential non-heat	657	619	581	543
	Residential heat	1,088	1,177	1,267	1,356
	Commercial	113	116	118	121
	Multi-family	21	24	27	30
Design Day Gas demand (MDth/day)	Residential non-heat	54	50	47	42
	Residential heat	1,650	1,808	1,970	2,110
	Commercial	725	769	811	847
	Multi-family	400	484	589	688
Design Day Gas demand per customer (Therms/day/cust)	Residential non-heat	1	1	1	1
	Residential heat	15	15	16	16
	Commercial	64	66	69	70
	Multi-family	192	204	221	231

** Excludes temperature controlled customers*

Energy Efficiency Assumptions in High and Low Demand Scenarios

The Baseline scenario accounted for the rate of demand reduction driven by historic and current EE programs (pre-settlement, pre-NENY). All incremental efficiency measures driven by NENY are assumed to consist of non-behavioral solutions with average useful life of 13 years. The costs and annual savings targets associated with NENY energy efficiency programs are assumed for 2020-2025 at the levels documented in NY Public Service Commission order 18-M-0084 from January 16, 2020. We then assumed that the funding and efficiency levels targeted for 2025 would continue through 2035.

Please see attached Excel file for additional details on year-by-year impact and cost

Demand Response Assumptions in High and Low Demand Scenarios

In the High demand scenario, we assumed that Commercial & Industrial and Residential (C&I/R) demand response programs will take place, and that the existing Temperature Controlled program would remain in place. In the Low demand scenario, we assumed that on top of the C&I/R programs there will be an additional demand reduction due to an enhanced Temperature Controlled tariff. Recently proposed updates to Temperature Controlled tariffs would increase discounts to these customers, which would imply ~$1.5M incremental cost in 2020. However, as the number of temperature control customers is expected to continue its decline, corresponding annual incremental cost of these increased discounts will also decline.

Table 2: Demand Response Assumptions

Demand response lever	Cumulative Investment ($MM)	Reduction of Design Day Demand (MDth/day)			
		2019/20	2024/25	2029/30	2034/35
Enhanced Temperature controlled tariff (done in Low Demand scenario only)	15	0	16	27	33
Commercial & Industrial and Residential heat programs (done in both High and Low Demand scenarios)	94*	9	20	20	20

** Cost of C&I/R programs will be offset by $5.5 million from the settlement, which is intended to be deployed over 2019/20 and 2020/21*

Please see attached Excel file for additional details on year-by-year impact and cost

Electrification Assumptions in High and Low Demand Scenarios

The Baseline demand scenario accounted for the rate of demand reduction driven by the current rate of electrification. The incremental electrification assumed in the Low and High demand scenarios is driven by NENY electrification and Local Law 97 targets, as well as organic electrification due to future cost competitiveness/parity between electric and gas heating.

For current gas customers, we assumed that the average gas equipment replacement cycle is 20 years, leading to 5% of current customers' equipment being replaced annually. We assumed that for most of the existing gas customers' organic switching from gas to electric heat will begin in early 2030s and will ramp up to a steady state of 30-50% of annual replacements over ~10 years. However, for existing Commercial and Multi-family gas customers in KEDNY territory this transition is expected to occur 3-4 years earlier due to Local Law 97 targets.

Table 3: Electrification Assumptions

Area of Electrification	Annual heat pump installations* ('000/year)			
	2020	2025	2030	2035
Residential new construction and conversions	0.4-0.5	2.8-3.5	2.9-3.7	13-20
Commercial & multi-family gas to electric conversions	0	0	0.1-0.5	1.7-2.7
TOTAL	0	2.8-3.5	3.1-4.3	15-23

** Lower end of the range corresponds to High Demand scenario; upper end of the range corresponds to Low Demand scenario*

Please see attached Excel for additional details on NENY electrification/heat pump targets for electric utilities and total year-by-year heat pump installations in KEDNY and KEDLI territories

High Demand Scenario Assumptions by Customer Group

Table 4 below provides additional detail on the number of customers by type and the Design Day gas demand utilization by customer type that was modeled in the High Demand scenario as described in pages 34-39 of the Long-Term Capacity Report.

Table 4: High Demand Scenario Assumptions

	Customer*	Winter			
		2019/20	2024/25	2029/30	2034/35
Number of customers ('000)	Residential non-heat	657	619	581	543
	Residential heat	1088	1172	1247	1314
	Commercial	113	116	118	118
	Multi-family	21	24	27	29
Design Day Gas demand (MDth/day)	Residential non-heat	54	50	47	42
	Residential heat	1649	1772	1860	1913
	Commercial	723	756	777	776
	Multi-family	393	465	553	610
Design Day Gas demand per customer (Therms/day/cust)	Residential non-heat	1	1	1	1
	Residential heat	15	15	15	15
	Commercial	64	65	66	66
	Multi-family	189	196	208	212

** Excludes temperature controlled customers*

Low Demand Scenario Assumptions by Customer Group

Table 5 below provides additional detail on the number of customers by type and the Design Day gas demand utilization by customer type that was modeled in the High Demand scenario as described in pages 34-39 of the Long-Term Capacity Report.

Table 5: Low Demand Scenario Assumptions

	Customer*	Winter 2019/20	2024/25	2029/30	2034/35
Number of customers ('000)	Residential non-heat	657	619	581	543
	Residential heat	1088	1170	1242	1300
	Commercial	113	116	118	115
	Multi-family	21	24	27	27
Design Day Gas demand (MDth/day)	Residential non-heat	54	50	47	42
	Residential heat	1649	1764	1831	1859
	Commercial	723	750	762	734
	Multi-family	393	451	524	541
Design Day Gas demand per customer (Therms/day/cust)	Residential non-heat	1	1	1	1
	Residential heat	15	15	15	14
	Commercial	64	65	65	64
	Multi-family	189	190	198	197

** Excludes temperature controlled customers*

No Infrastructure Options

Incremental Energy Efficiency Assumptions

With the increased levels of energy efficiency budgeted within NENY already being accounted for in the demand forecasts, it was assumed that incremental energy efficiency beyond the usual set of EE measures would be required to help close the demand gap without infrastructure. It was assumed that intensive weatherization, including a suite of measures like air sealing and insulation, would act as the primary incremental energy efficiency in a non-pipe solution because it's highly coincident with the design day and not part of National Grid's current programs. The assumptions behind this weatherization program are discussed below.

Program Length and Customer Adoption

It was assumed that after a fifteen-year program, weatherization would reach roughly 33% of customers. This was reduced slightly to 30% for residential heating customers in KEDNY and increased slightly to 35% for residential heating customers in KEDLI, reflecting differences in housing types for these customer classes. The number of eligible customers is based on National Grid data and includes single family, multi-family, and commercial customers, including income qualified customers. This number excludes ineligible customer classes like temperature-controlled customers. Given the urgent nature of the need and the magnitude of the ultimate goal, a fast ramp-up is assumed that sees roughly 2,000 installations in 2021, 15,000 in 2022, and 30,000 every year after. This penetration compares to 32,000 weatherization and air sealing projects completed in Massachusetts combined in 2015 and 2016.[1] Currently there are limited weatherization contractors in downstate New York. Achieving 30,000 installations in 2023 will require just over 1,000 full time employees assuming a similar rate of FTEs per weatherization project seen in Rhode Island in 2018.[2]

Savings

A half-year convention was assumed for the first-year impact of weatherization (i.e., savings are discounted by half for first year installs, as we assume that they will occur evenly throughout the course of the year and thus, on average, be in place for six months in the first year in which they are installed). With an assumed measure life of 15 years, after the install year each installation contributes savings to all of the following years in the analysis. The weatherization program was assumed to have the following savings per customer:

- 200 therms per year for residential heating customers (~15% of annual load)
- 2,500 therms per year for commercial customers (~35% of annual load)
- 4,200 therms per year for KEDNY multi-family customers and 6,000 therms per year for KEDLI multi-family customers (~20% of annual load).

The amount of savings in these estimates are comparable with savings estimates from algorithms for weatherization and air sealing published in the New York Technical Reference manual (TRM). Given the program ramp-up, the aggregated savings across all customers leads to an annual incremental savings as a percent of sales of 0.5% from this program. When combined with base and NENY targets, this implies a maximum savings as a percent of sales of 1.3% for KEDNY and KEDLI, which occurs in 2025.

These annual savings are converted to design day savings using a design day factor of 1.3%. This is based on the ratio of heating degree days on the design day versus the total throughout the year, as energy consumption for space heating (and therefore savings from weatherization) correlate highly with heating degree days. In addition, these retail savings are converted to wholesale savings values using a factor of 102%, which is slightly higher than the service territories' LAUF to match the factors used in the demand forecasts.

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[1] "Home Energy Services Impact Evaluation, August 2018," Navigant Consulting, accessed at http://ma-eeac.org/wordpress/wp-content/uploads/RES34_HES-Impact-Evaluation-Report-with-ES_FINAL_29AUG2018.pdf

[2] Rhode Island 2018 Energy Efficiency Year-End Report dated May 15, 2019, available at: http://www.ripuc.ri.gov/eventsactions/docket/4755-NGrid-Year-End%20Report%202018%20(5-15-19).pdf

Costs

Incentive rates for weatherization were assumed as follows:

- $15/therm for residential heating customers
- $12/therm for commercial customers
- $10/therm for multi-family customers

These costs are based on estimates from the established and successful weatherization programs in Massachusetts in 2017-2019 which provide a model for the magnitude of savings we are targeting in New York. These incentives average to around 75% of the total cost of the weatherization measures. Customers would be responsible for paying for the balance of project costs.

These costs were assumed to increase 2% annually. In addition to these incentives, administrative costs were added such that 15% of the total upfront costs were attributable to administrative costs. This is in line with other weatherization programs in New England.

Summary

The key assumptions defining the savings and costs associated with an incremental energy efficiency program are shown in Table 6 below.

Table 6: Summary of Incremental Energy Efficiency Assumptions

Parameter	Assumption	Source
15-Year Weatherization Program Penetration	33%	Benchmark with MA and RI weatherization programs
Annual Savings per Res Weatherization	200 th	TRM estimates and percent savings on space heating usage
Annual Savings per COM Weatherization	2,500 th	TRM estimates and percent savings on space heating usage
Annual Savings per KEDNY MF Weatherization	4,200 th	TRM estimates and percent savings on space heating usage
Annual Savings per KEDLI MF Weatherization	6,000 th	TRM estimates and percent savings on space heating usage
Design Day Factor	1.3%	Average of Res DDF and ratio of design day HDD to annual HDD
Retail to Wholesale Factor	2%	Based on stated LAUF and effective losses from demand forecast
Incentive Rate for Res Weatherization	\$15/th	Benchmark with MA and RI weatherization programs
Incentive Rate for COM Weatherization	\$12/th	Benchmark with MA and RI weatherization programs
Incentive Rate for MF Weatherization	\$10/th	Benchmark with MA and RI weatherization programs
Administrative Cost Adder	15%	Assumption based on program experience

Incremental Electrification Assumptions

Though incentivizing electrification is not normally within the purview of a gas utility, it is assumed to be necessary here to help address the demand gap in downstate New York as energy efficiency and demand response reach their limits of achievability. While some amount of electrification is assumed within the demand forecast, it is assumed that National Grid would need to provide a separate incentive to drive enough customers to adopt electric heating. This can also facilitate adoption of cold-climate heat pumps which will have a higher impact the design day.

Our assessment is that the increased electric usage in the winter resulting from the level of electrification discussed below would not cause the winter electric peak demand to exceed the current summer electric peak demand. However, further consideration is warranted for how the electric grid would be impacted.

The assumptions surrounding this program are discussed below.

Adoption

An electrification program was assumed to be offered to residential natural gas customers in both KEDNY and KEDLI, and prospective gas customers in KEDNY (80% of oil customers in KEDNY). This would reduce the number of new gas customers in KEDNY. It was assumed that this would not be offered to prospective gas customers in KEDLI since fewer may have access to natural gas mains in the first place.

Of this population, it was assumed that roughly 5% of customers would consider replacing their heating equipment per year as their existing equipment neared the end of its useful life. Of this 5% of customers, the percentage that are assumed to install an electric heat pump rather than the typical natural gas heating equipment increases from 2% in 2021 up to 23% in 2026. This ramp up is driven by increasing customer awareness for heat pumps and is capped by the assumed customer acceptance of a 5-year payback period. This payback period is assumed to be targeted by the incentive program, discussed in the costs section below. In the end this led to roughly 13,000 electrifications per year around 2026 (after the ramp up). It was assumed that this program would have a large amount of free ridership, which was accounted for by subtracting the number of electrifications assumed in the demand forecast from the number of electrifications driven by this program during the program period.

Residential customers had three assumed paths for electrification:

1. Customers with a ducted furnace and central AC (~20% of residential customers in DNY) could switch to an air-source heat pump. It was assumed that 70% of customers with a ducted furnace and central AC who choose to electrify would choose this technology over ground-source heat pumps since it is cheaper.
2. Customers with a ducted furnace and central AC (~20% of residential customers in DNY) could also switch to a ground-source heat pump. It was assumed that the remaining 30% of customers with a ducted furnace and central AC who choose to electrify would choose this technology over air-source heat pumps since it is more expensive.
3. Customers with a boiler and room AC or PTAC (~80% of residential customers in DNY) could switch to a ductless mini split heat pump.

The heat pumps were assumed to be cold climate in order to have the full impact on the design day. The heat pump technology assumptions are shown in Table 7 below.

Table 7: Summary Electrification Technology and Cost Assumptions

Technology	Efficiency	Capacity (Tons)	Full Installed Cost	Incremental Installed Cost	Annual Gas + Electric Bill Savings (KEDNY/KEDLI)
ASHP	16 SEER/11.8 EER/10 HSPF	5	$19,500	$10,200	-$660 / -$255
GSHP	23 EER/4.2 COP	5	$47,910	$38,600	-$90 / $194
Minisplit	16 SEER/12 EER/10 HSPF	5	$17,370	$11,000	-$950 / -$480

Savings

Of the current natural gas customers converting to electric heating, 50% were assumed to keep 10% of their pre-electrification design day consumption. This remaining consumption was assumed to be from non-heating end uses like cooking that may not be electrified along with the heating. Note that the assumed pre-electrification design day consumption that's being saved is the average post-weatherization, which implicitly assumes that choosing to participate in weatherization and choosing to electrify are independent.

Costs

Achieving a 5-year payback period for electrification requires providing an upfront and ongoing incentive. An upfront incentive of 50% of the installed cost of the system was assumed, followed by an ongoing incentive of $1,500 to $4,000 per year (depending on the technology) that offsets the increase in customer bills. This increase in customer bills is due to the higher cost of electricity as compared to natural gas on a per-energy basis, even with the relatively high efficiency of heat pumps. Note that this assumes that there are no major changes to current residential electric and natural gas rates in downstate New York. Customers would receive these incentives for five years in order to achieve the payback, at which point the customer would no longer receive the ongoing incentive. In addition to these incentive costs, administrative costs were added to the upfront incentive costs such that 20% of the total upfront cost per year was attributable to fixed annual costs like training and administration.

Summary

The key assumptions defining the savings and costs associated with an incremental electrification program are shown in Table 8 below.

Table 8: Summary of Incremental Electrification Assumptions

Parameter	Assumption	Source
HVAC Turnover	5%/yr	Assumed 20-yr average life of HVAC consistent with demand forecasts
Payback Acceptance	23%	Residential payback acceptance curves
Percent Partial G2E	50%	Assumed half of customers would keep non-heating equipment during switch
Percent UPC Savings for Partial G2E	90%	Residential design day consumption by end use
Targeted Payback Period	5 Years	Targeted assumption
Upfront Incentive Percent	50%	Assumed value
Administrative Cost Adder	20%	Assumption

Incremental Demand Response Assumptions

While some amount of demand response is assumed within the demand forecast, additional demand response would be necessary to address the capacity constraint in downstate New York without infrastructure. Since the savings from these programs are so coincident with the design day by their nature, they are assumed to warrant increased focus. The key assumptions behind the incremental demand response are discussed below.

Adoption

The temperature-controlled (TC) program is assumed to keep 100% of current KEDNY customers for all supply scenarios except for NESE. Note that this accounts for the TC customers that are already assumed to stay on non-firm rates in the low demand scenario.

The thermostat direct load control (DLC) program participation was assumed to increase linearly over 4 years to reach 40% of residential heating customers by 2024 in the high gap scenario. This program was assumed to not be necessary in the low gap scenario. Achieving this level of enrollment would likely require high levels of coordination with NYSERDA, electric utilities, and other entities to increase penetration of connected thermostats in downstate New York.

Savings

The TC customers are assumed to each save 50 Dth on the design day. This is based on historical event day savings from the TC program.

For customers participating in the thermostat DLC program, it was assumed that they would save 2% of their design day usage per customer. This is based on benchmarks with other direct load control programs in New England.

Costs

It is assumed that there are fixed program costs of $2 million per year for the residential thermostat program and $4 million per year for the TC program, based on historical program costs and costs for similar DLC programs. There are also assumed to be annual participation incentives of $50 per participating thermostat per year and $6,500 per participating TC customer per year. These are assumed based on other demand response programs and doubling the incentive that is currently offered for TC programs.

Summary

The key assumptions defining the savings and costs associated with an incremental demand response program are shown in Table 9 below.

Table 9: Summary of Incremental Demand Response Program Assumptions

Parameter	Assumption	Source
TC Customers Kept on TC Rate	100%	Participation needed to meet capacity constraint
Design Day Savings per TC Customer	50 Dth	Based on historic event day savings
Percent Res Thermostat Participation	40%	Participation needed to meet capacity constraint
Percent UPC Savings	2%	Benchmark with NE DLC programs for design day
Fixed Program Costs	$6,000,000/yr	Benchmark with gas demand response programs
TC Incremental Incentive per Cust	$6,500/yr	Based on current effective participation incentives
Thermostat Incentive per Cust	$50/yr	Assumed incentive for costs

Program Design Considerations

For each of the major program areas, there are several other program design elements that will need to be developed and vetted if these plans are adopted. These issues were not factored into the current analysis. These include:

- Creation of detailed weatherization programs and implementation plans by National Grid
- Regulatory considerations to enable program deployment
- Establishing cost effectiveness of those programs as designed
- Developing a structure for home energy audits
- Size of the contractor workforce and workforce development in coordination with NYSERDA efforts in this area, including advance notice of program development to the contractor workforce; providing incentives to contractors, product and installation standards; training; coordination with NYSERDA programs; financing mechanisms; and marketing and targeting to optimize savings and equity.
- Coordination with the joint utilities on electrification programs

Infrastructure Options Cost and Net Present Value (NPV)

Infrastructure Cost Inputs and Assumptions

As discussed in section 9.1 of the Long-Term Capacity Report, the cost of each infrastructure option was assessed on multiple aspects, including Project Cost, Annual Operating Cost, Commodity Cost, and Corresponding Savings. Details for each of these aspects can be found below.

Table 10 below provides detail on the total project cost and associated annual cost to the Downstate NY customer base.

Table 10: Total Project and Annualized Cost

Option	Total Project Cost*	Annualized Cost	Annualized Project Cost Detail
Offshore LNG Port	$800M	$160M	Estimated to be 20% of the total project cost based on National Grid experience
LNG Import Terminal	$1.2B	$240M	Estimated to be 20% of the total project cost based on National Grid experience
Northeast Supply Enhancement (NESE) Project	$1B	$193M	Annual cost per negotiated agreement with Williams – roughly falls in line with the 20% estimate for other infrastructure options
Peak LNG Facility	$500M	$100M	Estimated to be 20% of the total project cost based on National Grid experience
LNG Barges (x2)	$410M	$82M	Estimated to be 20% of the total project cost based on National Grid experience
Clove Lakes Transmission Loop Project	$320M	$112M	Annual cost is made up of two charges: • $48M demand charge modelled on NESE cost structure • $64M annual cost estimated to be 20% of total project cost based on National Grid experience
Gas Compression on the Iroquois Gas Transmission System	$272M (NG portion $136M)	$24M	Annual recourse rate per the IGTS filing – which is $1.06/Dth/Day

**Details / Sources of the Total Project Cost can be found in Section 10 of the Long-Term Capacity Report*

A note about commodity costs in the NPV Analysis

To best account for commodity costs in the least complicated way, a set of simplifying assumptions were used. The NESE scenario was used as a baseline case – it is the scenario that meets the gap between demand and supply entirely with infrastructure. Every other scenario requires some amount of no-infrastructure (i.e. energy efficiency, demand response, electrification) to close this gap. As these no-infrastructure programs are put in place, the decreased demand will remove commodity from the system, as compared to the baseline case. Our model accounts for this reduction in commodity, at a rate of $2.50/Dth. This method allows us to incorporate commodity costs without adding further complexity to the cost model.

Though this is a straightforward way of modelling commodity costs, we recognize that there are additional factors that may impact overall costs which are not included in our analysis. For example, the NESE option allows us to eliminate the higher cost of CNG and contracted peaking supply (which lowers overall cost, commodity cost for these options range from approximately $8.75/Dth to $12.75/Dth), however, it also increases the amount of gas used on days when demand exceeds what we have in place with our current supply stack (which increases overall cost). Based on our initial analysis, we have concluded that there would be some modest commodity savings associated with the NESE pipeline, which was based on a high-level set of assumptions. Given the low impact of these cost differences and the additional complexity, the decision was made to exclude this additional analysis from our cost modelling.

Annual Cost Schedules in High and Low Demand Scenarios

Tables 11 and 12 below provide an annual breakdown of infrastructure, non-infrastructure, and avoided commodity cost (e.g., corresponding savings) for each supply alternative. The Net Present

Values (NPV) from the Long Term Capacity Report were calculated with these values utilizing a 6.3% discount rate.

Cost model with additional details has been provided to the Monitor via the DNY Settlement Process

Table 11: Annual Costs in the High Demand Scenario

Annual Cost of Infrastructure ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193
LNG Import Terminal	$0	$0	$0	$0	$0	$0	$0	$240	$240	$240	$240	$240	$240	$240	$240	$240	$240
Offshore LNG	$0	$0	$0	$0	$0	$0	$0	$160	$160	$160	$160	$160	$160	$160	$160	$160	$160
Peak LNG Facility	$0	$0	$0	$0	$0	$0	$0	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
LNG Barges	$0	$0	$0	$0	$0	$0	$0	$82	$82	$82	$82	$82	$82	$82	$82	$82	$82
Clove Lakes	$0	$0	$0	$0	$0	$0	$0	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112
ExC on IGTS	$0	$0	$0	$0	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
ExC + LNG Barges	$0	$0	$0	$0	$24	$24	$24	$106	$106	$106	$106	$106	$106	$106	$106	$106	$106
ExC + CL	$0	$0	$0	$0	$24	$24	$24	$136	$136	$136	$136	$136	$136	$136	$136	$136	$136
No Infrastructure	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Annual Cost of No-Infrastructure ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$2	$2	$2
LNG Import Terminal	$0	$5	$39	$152	$294	$358	$400	$67	$62	$51	$35	$15	$16	$16	$17	$17	$18
Offshore LNG	$0	$5	$39	$152	$294	$358	$400	$67	$62	$51	$35	$15	$16	$16	$17	$17	$18
Peak LNG Facility	$0	$5	$40	$157	$306	$370	$413	$421	$333	$330	$321	$37	$16	$16	$17	$17	$18
LNG Barges	$0	$5	$40	$157	$306	$370	$413	$421	$333	$330	$321	$37	$16	$16	$17	$17	$18
Clove Lakes	$0	$5	$40	$157	$306	$370	$413	$421	$333	$330	$321	$37	$16	$16	$17	$17	$18
ExC on IGTS	$0	$5	$30	$133	$264	$321	$363	$396	$307	$303	$293	$280	$266	$273	$17	$17	$18
ExC + LNG Barges	$0	$5	$29	$122	$184	$199	$206	$210	$211	$218	$225	$232	$16	$16	$17	$17	$18
ExC + CL	$0	$5	$29	$122	$184	$199	$206	$210	$211	$218	$225	$232	$16	$16	$17	$17	$18
No Infrastructure	$0	$5	$40	$163	$317	$382	$425	$459	$486	$506	$379	$367	$354	$339	$17	$17	$18

Annual Value of Avoided Commodity ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	-$4	-$4	-$3	-$3	-$2	-$2	-$2	-$1	-$1	-$1	-$1	$0	$0	$0	$0
LNG Import Terminal	$0	$0	$0	-$1	-$3	-$7	-$10	-$14	-$13	-$13	-$13	-$13	-$12	-$12	-$12	-$12	-$12
Offshore LNG	$0	$0	$0	-$1	-$3	-$7	-$10	-$14	-$13	-$13	-$13	-$13	-$12	-$12	-$12	-$12	-$12
Peak LNG Facility	$0	$0	$0	-$1	-$4	-$7	-$11	-$14	-$18	-$22	-$25	-$27	-$27	-$27	-$27	-$27	-$27
LNG Barges	$0	$0	$0	-$1	-$4	-$7	-$11	-$14	-$18	-$22	-$25	-$27	-$27	-$27	-$27	-$27	-$27
Clove Lakes	$0	$0	$0	-$1	-$4	-$7	-$11	-$14	-$18	-$22	-$25	-$27	-$27	-$27	-$27	-$27	-$27
ExC on IGTS	$0	$0	$0	-$1	-$3	-$6	-$10	-$13	-$16	-$19	-$23	-$26	-$30	-$33	-$35	-$35	-$35
ExC + LNG Barges	$0	$0	$0	-$1	-$3	-$6	-$8	-$11	-$14	-$17	-$20	-$23	-$25	-$25	-$25	-$25	-$25
ExC + CL	$0	$0	$0	-$1	-$3	-$6	-$8	-$11	-$14	-$17	-$20	-$23	-$25	-$25	-$25	-$25	-$25
No Infrastructure	$0	$0	$0	-$1	-$4	-$7	-$11	-$15	-$19	-$23	-$27	-$31	-$35	-$39	-$41	-$41	-$41

Net Cost of Supply Alternative ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$190	$190	$191	$191	$192	$192	$193	$193	$193	$194	$194	$194	$195	$195	$195
LNG Import Terminal	$0	$5	$39	$151	$291	$351	$390	$294	$289	$278	$262	$242	$243	$244	$245	$246	$246
Offshore LNG	$0	$5	$39	$151	$291	$351	$390	$214	$209	$198	$182	$162	$163	$164	$165	$166	$166
Peak LNG Facility	$0	$5	$39	$156	$302	$363	$402	$507	$415	$408	$396	$110	$88	$89	$90	$90	$91
LNG Barges	$0	$5	$39	$156	$302	$363	$402	$489	$397	$390	$378	$92	$70	$71	$72	$72	$73
Clove Lakes	$0	$5	$39	$156	$302	$363	$402	$519	$427	$420	$408	$122	$100	$101	$102	$102	$103
ExC on IGTS	$0	$5	$30	$132	$285	$338	$377	$407	$315	$308	$295	$279	$260	$264	$6	$7	$8
ExC + LNG Barges	$0	$5	$29	$121	$205	$217	$222	$305	$303	$307	$311	$315	$97	$98	$98	$99	$100
ExC + CL	$0	$5	$29	$121	$205	$217	$222	$335	$333	$337	$341	$345	$127	$128	$128	$129	$130
No Infrastructure	$0	$5	$40	$162	$313	$374	$414	$444	$467	$483	$352	$337	$319	$301	-$24	-$23	-$23

Table 12: Annual Costs in the Low Demand Scenario

Annual Cost of Infrastructure ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193
LNG Import Terminal	$0	$0	$0	$0	$0	$0	$0	$240	$240	$240	$240	$240	$240	$240	$240	$240	$240
Offshore LNG	$0	$0	$0	$0	$0	$0	$0	$160	$160	$160	$160	$160	$160	$160	$160	$160	$160
Peak LNG Facility	$0	$0	$0	$0	$0	$0	$0	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
LNG Barges	$0	$0	$0	$0	$0	$0	$0	$82	$82	$82	$82	$82	$82	$82	$82	$82	$82
Clove Lakes	$0	$0	$0	$0	$0	$0	$0	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112
ExC on IGTS	$0	$0	$0	$0	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
ExC + LNG Barges	$0	$0	$0	$0	$24	$24	$24	$106	$106	$106	$106	$106	$106	$106	$106	$106	$106
ExC + CL	$0	$0	$0	$0	$24	$24	$24	$136	$136	$136	$136	$136	$136	$136	$136	$136	$136
No Infrastructure	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Annual Cost of No-Infrastructure ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG Import Terminal	$0	$5	$38	$146	$282	$344	$72	$45	$39	$28	$12	$12	$13	$13	$14	$14	$15
Offshore LNG	$0	$5	$38	$146	$282	$344	$72	$45	$39	$28	$12	$12	$13	$13	$14	$14	$15
Peak LNG Facility	$0	$5	$38	$146	$282	$344	$72	$45	$39	$28	$12	$12	$13	$13	$14	$14	$15
LNG Barges	$0	$5	$38	$146	$282	$344	$72	$45	$39	$28	$12	$12	$13	$13	$14	$14	$15
Clove Lakes	$0	$5	$38	$146	$282	$344	$72	$45	$39	$28	$12	$12	$13	$13	$14	$14	$15
ExC on IGTS	$0	$5	$18	$105	$208	$225	$233	$241	$249	$11	$12	$12	$13	$13	$14	$14	$15
ExC + LNG Barges	$0	$5	$18	$20	$27	$34	$35	$10	$10	$11	$12	$12	$13	$13	$14	$14	$15
ExC + CL	$0	$5	$18	$20	$27	$34	$35	$10	$10	$11	$12	$12	$13	$13	$14	$14	$15
No Infrastructure	$0	$5	$32	$149	$296	$355	$398	$432	$344	$72	$55	$35	$13	$13	$14	$14	$15

Annual Value of Avoided Commodity ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	-$4	-$4	-$3	-$3	-$3	-$2	-$2	-$2	-$2	-$2	-$2	-$2	-$2	-$2	-$2
LNG Import Terminal	$0	$0	$0	-$1	-$3	-$6	-$8	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10
Offshore LNG	$0	$0	$0	-$1	-$3	-$6	-$8	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10
Peak LNG Facility	$0	$0	$0	-$1	-$3	-$6	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8
LNG Barges	$0	$0	$0	-$1	-$3	-$6	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8
Clove Lakes	$0	$0	$0	-$1	-$3	-$6	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8
ExC on IGTS	$0	$0	$0	-$1	-$3	-$7	-$10	-$14	-$17	-$19	-$19	-$19	-$19	-$19	-$19	-$19	-$19
ExC + LNG Barges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ExC + CL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
No Infrastructure	$0	$0	$0	-$1	-$4	-$7	-$11	-$15	-$19	-$21	-$21	-$21	-$21	-$21	-$21	-$21	-$21

Net Cost of Supply Alternative ($M/Year)																	
Supply Scenario	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
NESE	$0	$0	$189	$189	$190	$190	$190	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191
LNG Import Terminal	$0	$5	$38	$145	$279	$338	$64	$274	$269	$259	$242	$243	$243	$244	$244	$244	$245
Offshore LNG	$0	$5	$38	$145	$279	$338	$64	$194	$189	$179	$162	$163	$163	$164	$164	$164	$165
Peak LNG Facility	$0	$5	$38	$145	$279	$338	$64	$137	$131	$120	$104	$104	$105	$105	$106	$106	$107
LNG Barges	$0	$5	$38	$145	$279	$338	$64	$119	$113	$102	$86	$86	$87	$87	$88	$88	$89
Clove Lakes	$0	$5	$38	$145	$279	$338	$64	$149	$143	$132	$116	$116	$117	$117	$118	$118	$119
ExC on IGTS	$0	$5	$18	$104	$229	$243	$247	$251	$256	$16	$17	$18	$18	$19	$19	$19	$20
ExC + LNG Barges	$0	$5	$18	$20	$51	$58	$59	$116	$116	$117	$118	$118	$119	$119	$120	$120	$121
ExC + CL	$0	$5	$18	$20	$51	$58	$59	$146	$146	$147	$148	$148	$149	$149	$150	$150	$151
No Infrastructure	$0	$5	$32	$148	$293	$348	$387	$417	$325	$51	$34	$14	-$8	-$8	-$7	-$7	-$6