Memorandum

TO: MEG LUSARDI, DEPARTMENT OF ENERGY RESOURCES

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DATE: OCTOBER 31, 2014

RE: FEASIBILITY STUDY FOR LOW GAS DEMAND ANALYSIS (RFR-ENE-2015-012)

Contents

1. Introduction

The Massachusetts Department of Energy Resources (DOER) has retained Synapse Energy Economics (Synapse) to determine, given updated supply and demand assumptions, whether or not new natural gas pipeline infrastructure is required in the Commonwealth, and if so, how to optimize investment in this new infrastructure for environmental, reliability, and cost considerations.[1] Key questions for consideration include:

1) Considering all energy resources, which resources offer the greatest net benefits when assessing for reliability needs, cost savings, and reducing environmental effects including greenhouse gas emissions?
2) In combination, how far can these alternative resources go in replacing retiring generation capacity?

Synapse's analysis will be conducted in four steps:

1. Development of base case and sensitivity assumptions
2. Feasibility study of alternative resources in a low energy demand case
3. Scenario modeling of eight scenario and sensitivity combinations
4. Assessment of natural gas capacity to demand balance in a winter peak event

Section 2 of this memo provides an overview of the model methodology for this analysis including assumptions related to the winter peak event. Section 3 describes the eight scenario and sensitivity combinations. Section 4 presents the feasibility analysis of alternative resources, and Section 5 provides detailed tables of the assumptions used in the feasibility analysis.

2. Model Overview

Synapse will analyze eight future scenario-and-sensitivity combinations (as described below) of the Massachusetts gas sector from 2015 through 2030. Our analysis will provide the following key outputs:

- Sufficiency of gas pipeline capacity under winter peak event conditions: We will model New England gas supply and demand under conditions defined by a winter peak event (as defined below), taking account of the impact on energy storage of a "cold snap" or series of winter peak days.
- Annual costs and emissions: We will model fuel use, electric generation, energy costs, and greenhouse gas emissions on an annual basis. Annual costs and emissions will be modeled based on expected (most likely) weather conditions, not extreme conditions. These expected weather conditions will include the occurrence of winter high demand events.

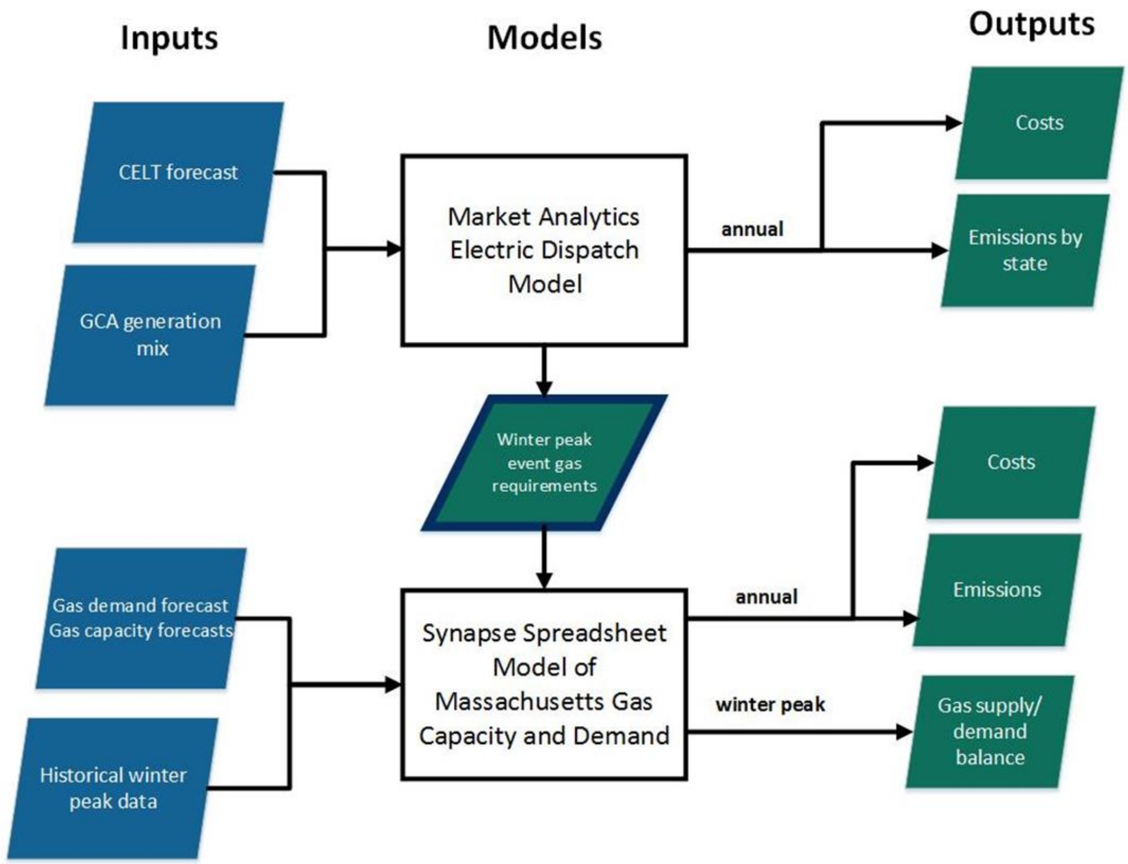
Reliability requirements will be a basic criterion for all modeled scenarios.

[1] RFR-ENE-2015-012

Model Design

Model design for this analysis will include the Market Analytics electric dispatch model and a Synapse purpose-built spreadsheet model of Massachusetts gas capacity and demand (see Figure 1).

Figure 1. Model schematic



Electric-sector greenhouse gas emissions and cost modeling in Market Analytics

Synapse will project greenhouse gas emissions, electric system gas use, and wholesale energy prices using Ventyx's Market Analytics electric-sector simulation model of ISO-New England and its imports and exports. Market Analytics uses the PROSYM simulation engine to produce detailed results for hourly electricity prices and market operations based on a security-constrained chronological dispatch model. The PROSYM simulation engine optimizes unit commitment and dispatch options based on highly detailed information on generating units.

A Synapse purpose-built model of Massachusetts natural gas capacity and demand

We will develop a dynamic spreadsheet model of natural gas needs for an indicative winter peak event in Massachusetts, with analysis extending out to 2030. Gas requirements will represent the residential, commercial, industrial, and electric-generation sectors. This model will facilitate assessment of the balance of New England's gas capacity and demand under peak conditions, utilizing key metrics including daily load thresholds, price impacts related to market constraints, and other drivers of shortage or stress conditions. Development of this model will include Massachusetts-specific analysis of historical stress and shortage gas supply conditions, historical winter peak event conditions, and diversity and reliability of supply.

In addition to modeling winter peak conditions, Synapse's spreadsheet model will estimate state and regional annual greenhouse gas emissions and costs related to Massachusetts' natural gas use.This gas-sector emissions and costs analysis will include expected displacement of other fossil fuels. While gas forecasting is typically conducted in terms of a November-October year, our analysis will be conducted in calendar years to facilitate comparisons with greenhouse gas emission reduction targets. To convert gas demand November-October years into calendar years, we have allocated split year demand into calendar year demand based on the ratio of each month's effective degree days to an annual effective degee days total using gas local distribution company (LDC) data.

Winter Peak Event

Our analysis of the sufficiency of Massachusetts natural gas capacity will be conducted through the lens of a "winter peak event"—a series of particularly cold winter days under which high gas demands have the greatest potential to exceed gas capacity. For the purposes of this analysis, a winter peak event is defined as follows:

- Capacity and demand in the peak hour of an expected future "design day". Design days are used in gas local distribution companies' (LDCs') forecasts of future natural gas demand and are determined by calculating the effective degree days expected to occur under a specified probability (from once in 30 years to once in 50 years).
- Gas requirements for electric generation will be developed in Market Analytics to represent the coincident peak with LDCs' design day: for each year, the highest gas requirement for a January day from 6 to 7pm.[2]
- LDC's five-year design day forecasts will be applied to the January of the split year and remain unadjusted from their most recent filing at provided to DOER. For those years not provided by the companies, the average annual growth rate will be used to extrapolate the design day forecast to 2030.
- Sufficiency of natural gas capacity will take into account the effects of a cold snap. Each Massachusetts LDC defines cold snaps differently using a series of the coldest days ranging from 10 to 24 days; the Commonwealth's two largest LDCs use ten and 14 days. For the purposes of this analysis, we will define a cold snap as a series of 12 cold weather days. In this model the length of the cold snap will impact the amount of natural gas in storage facilities and the resulting rate of deliverable natural gas from storage.

[2] Eastern Interconnection Planning Collaborative (EIPC) *Draft Gas-Electric Interface Study Target 2 Report*, p.64-65.

3. Scenarios and Sensitivities

Synapse will model base and low energy demand case of the future Massachusetts gas and electric systems (see Table 1); both scenarios will assume that there is no incremental transmission from Canada to New England. In addition, we will investigate model results' sensitivity to changes in the price of natural gas and to the addition of 2,400-MW in new transmission capacity from Canada to the New England hub. All scenarios and sensitivities will include the assumption of the Avoided Energy Supply Costs in New England: 2013 Report (AESC 2013) carbon price forecast[3] in the electricity sector; avoided costs (an input into the feasibility analysis for alternative resources, as discussed below) will include the avoided cost of compliance with the Global Warming Solutions Act (GWSA) for energy efficiency resources only.[4] GWSA compliance is not a criterion for scenarios and sensitivities; rather, the Massachusetts emissions associated with each scenario and sensitivity will be an output of the model.

Table 1. Scenarios and Sensitivities

	No Incremental Canadian Transmission			2,400-MW Incremental
	Reference NG Price	**Low NG Price**	**High NG Price**	**Reference NG Price**
Base Case	Base Case No Hydro Ref NG Price	Base Case No Hydro Low NG Price	Base Case No Hydro High NG Price	Base Case 2,400 MW Hydro Ref NG Price
Low Energy Demand Case	Low Case No Hydro Ref NG Price	Low Case No Hydro Low NG Price	Low Case No Hydro High NG Price	Low Case 2,400 MW Hydro Ref NG Price

Base Case

Base case energy resource mix and energy demand will model expected conditions under existing policy measures, a reference natural gas price, and the assumption that there will be no incremental electric transmission from Canada in the 2015 to 2030 period.

Base case electric and gas load will be modeled using existing, well-recognized projections, including ISO-NE's latest CELT forecast for electric demand, the Massachusetts' LDCs' gas demand forecasts, and the most up-to-date information available regarding capacity exempt customers. Where critiques of

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[3] Hornby et al. 2013. Exhibit 4-1. Column 6 "Synapse" CO2 emission allowance price.

[4] MA-DPU 14-86, Amended Direct Testimony of Tim Woolf, September 11, 2014, Figure 4 represents these costs in levelized form.

these forecasts are well known in the literature, we will incorporate appropriate adjustments to these forecasts.

Base case electric generation resource mix will be modeled using the Market Analytics scenario designed by Synapse for DOER in early 2014 to provide an accurate presentation of Green Communities Act (GCA) policies as well as the Renewable Portfolio Standards—by class—of the six New England states. Synapse's GCA analysis for DOER was developed using the NERC 9.5 dataset, based on the Ventyx Fall 2012 Reference Case. We will verify and update these data with the most current information on gas prices, loads, retirements, and additions.This case will assume all existing policies—including the ISO-NE Winter Reliability program with its current sunset date and the recent DPU Order 14-04 on time-varying rates—and forecasted LNG usage.

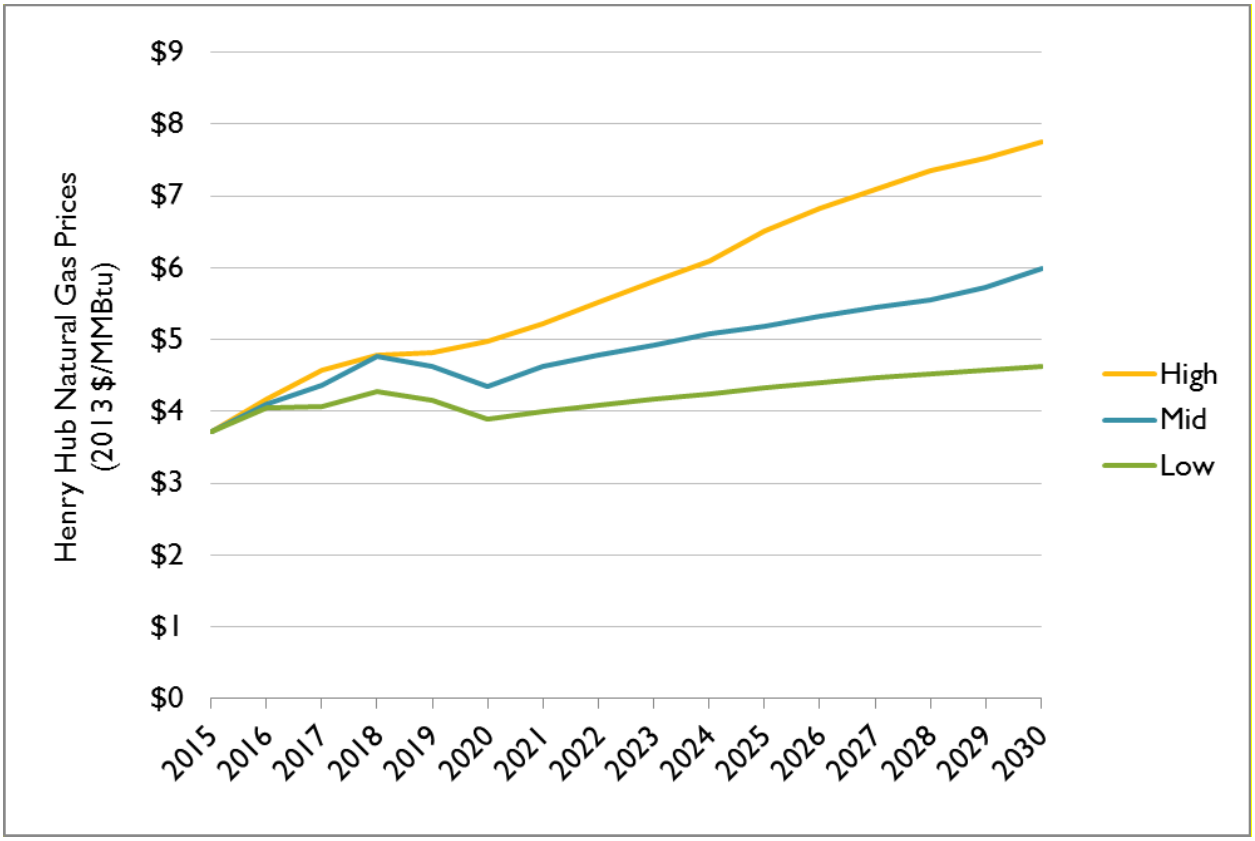
Low Energy Demand Case

The low energy demand case will be designed by making adjustments to the base case. In the low energy demand case, all alternative resources will be utilized to the greatest extent that is determined to be simultaneously technically and economically feasible (the methodology for this feasibility assessment is described below). In this scenario, changes to public policy will be assumed for Massachusetts only and not for the neighboring states.

Natural Gas Price Sensitivity

We will investigate the sensitivity of modeling results to both increases and decreases in the expected price of natural gas. Figure 2 depicts the reference, low and high natural gas price forecasts for use in this analysis.

Figure 2. Reference Henry Hub natural gas prices



These gas price projections are Henry Hub prices developed from three sources: the October 2014 Short Term Energy Outlook (STEO) and the April 2014 Annual Energy Outlook (AEO) both issued by the U.S. Department of Energy/Energy Information Administration (DOE/EIA); and the New York Mercantile Exchange (NYMEX) futures gas prices as of October 14, 2014.

In all three cases the historical monthly prices from January 2012 through October 2014 are from the STEO figure 14. Also, in all three cases the monthly price projections from November 2014 through December 2015 are from the October 14, 2014 NYMEX close. The three cases vary beginning in January 2016. For the Base Case, the monthly NYMXEX prices are escalated annually in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Reference Case (Tab 13, line 44). For the High Gas Price Scenario, the monthly NYMEX prices are escalated in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Low Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, Low Oil and Gas Resource Case Table, line 57). For the Low Gas Price Scenario, the Henry Hub prices from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57) were adjusted in 2019 and 2020 to align better with the prices from the Reference Case. The low price case was actually higher than the Reference Case in those two years. The monthly NYMEX prices are then escalated in proportion to the annual percentage changes in the adjusted Henry Hub price trajectory from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57).

The Low and High Oil and Gas Resource Cases from the 2014 AEO were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes this uncertainty and developed these alternate resource cases to address the it.

Henry Hub prices will be adjusted for projections in the basis differential between Henry Hub and the Massachusetts city gates designed to reflect the higher basis when gas demand is highest. (Pending)

Incremental Canadian Transmission Sensitivity

We will investigate the sensitivity of modeling results to the addition of 2,400 MW of new, incremental transmission from Canada to the New England hub: one 1,200 MW line by 2018 and a second by 2022. Table 2 summarizes our basic assumptions for this sensitivity. We assume that capacity on these incremental lines will be 75 percent on average on a winter peak day and 100 percent in a winter peak hour.

Table 2. Incremental Canadian transmission assumptions

CA Hydro HVDC 1	Annual Capacity Factor	Total Potential Capacity	Annual Net Levelized Cost	Annual Net Levelized Cost	Annual Energy Production	Peak Hour Gas Savings
	%	*MW*	*$/MWh*	*$/MMBtu NG*	*MMBtu NG*	*MMBtu NG*
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	67%	1,200	$100	$1,199	84,516,480	10,800
2021-2030	n/a	0	n/a	n/a	n/a	n/a
CA Hydro HVDC 2	**Annual Capacity Factor**	**Total Potential Capacity**	**Annual Net Levelized Cost**	**Annual Net Levelized Cost**	**Annual Energy Production**	**Peak Hour Gas Savings**
	%	*MMBtu / yr*	*$/MMBtu*	*$/MMBtu NG*	*MMBtu NG*	*MMBtu NG*
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	n/a	0	n/a	n/a	n/a	n/a
2021-2030	50%	1,200	$147	$1,759	63,072,000	10,800

4. Feasibility Analysis

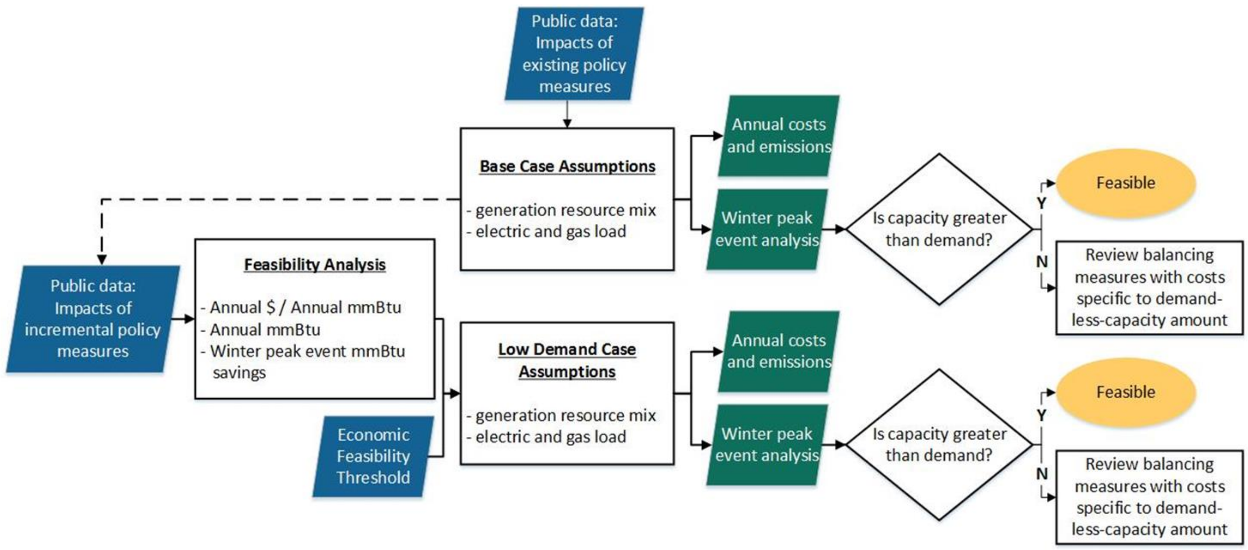
In the 2015, 2020, and 2030 feasibility analyses for alternative resources, the ratio of annual costs to annual energy in MMBtus (annual-$/annual-MMBtu) for each measure determined to be technically feasibility in the analysis year will be compared to a threshold for economic feasibility. Resources will be assessed as either less or more expensive that then selected threshold:

- ***If Annual-$/annual-MMBtu is less costly than economic feasibility threshold:*** Resources that are less expensive than the threshold will be included in the determination of the electric generation resource mix and electric and gas loads in the low energy demand case.

- ***If Annual-$/annual-MMBtu is more costly than economic feasibility threshold:*** Resources that (a) are more expensive than the threshold <u>and</u> (b) contribute MMBtu savings during the winter peak event hour will be held in reserve for use in the final gas capacity and demand balancing step of modeling.

Figure 3 provides schematic of the role of feasibility analysis in this modeling project.

Figure 3. Feasibility analysis schematic



Measures included in the feasibility analysis meet two basic criteria:

1. These measures are incremental (i.e. over and above) the amounts of the same technologies or associated with the same policy measures included in the base case.

2. These measures are associated with expected MMBtus in the analysis year; that is, they are technically feasible.

Note: Throughout the analysis presented in this memo we calculate the displaced natural gas MMBtu from MWh-producing electric resources using a 12 MMBtu/MWh heat rate. This is the heat rate associated with the generator that is marginal during the peak hours of the year. An alternate heat rate option for calculating the annual natural gas MMBtu displaced by new electric resources could be the monthly average implied marginal heat rate in ISO New England (8.4 MMBtu/MWh in 2013).[5] This change would effect annual energy produced by alternative electric resources as well as the energy produced by incremental Canadian transmission.

[5] 2013 Assessment of the ISO New England Electricity Markets. Potomac Economics. June 2014. p.44.

Avoided Costs

In this feasibility analysis all measures are assessed in terms of their total annual costs in the study year net of their avoided costs in that same year. As a proxy for analysis of avoided costs taking into consideration the load shape and year of implementation for each resource, we use the AESC 2013 avoided energy, capacity, transmission, distribution, and environmental compliance costs for each study year.[6] Avoided capacity, transmission and distribution costs are adjusted in relation to each resources ISO-NE capacity credit. For energy efficiency resources only, AESC 2013 base case avoided environmental compliance costs are adjusted to include the costs of compliance with Massachusett's Global Warming Solutions Act, as described in the current MA-DPU Docket 14-86.[7] For all resources other than energy efficiency, avoided environmental compliance costs follow the AESC 2013 base case (see Table 3). In this memo, we address feasibility at the reference natural gas price. In assessment of feasibility for the low and high natural gas price sensitivities we will recalculate avoided costs appropriate to these gas prices.

Table 3. Avoided cost assumptions

		Electric Resources			Gas Resources	
		Energy Efficiency	*Non-EE, Distributed*	*Non-EE, Utility-Scale*	*Energy Efficiency*	*Non-EE, Distributed*
Energy	$/MWh	AESC 2013 Electric	AESC 2013 Electric	AESC 2013 Electric, Adj. for line losses	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Environmental Compliance	$/MWh	DPU 14-86	AESC 2013 Electric	AESC 2013 Electric	DPU 14-86	None
Capacity	$/kW	AESC 2013 Electric	AESC 2013 Electric	AESC 2013 Electric	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Transmission and Distribution	$/kW	AESC 2013 Electric	AESC 2013 Electric	None	AESC 2013 Natural Gas	AESC 2013 Natural Gas

[6] We assume that avoided energy costs are roughly proportional to gas prices (see AESC 2013 8-2 to 8-3 in support of this assumption). Using this assumption, we have updated the AESC 2013 avoided costs to reflect the natural gas prices used in this analysis using this assumption.

[7] MA-DPU 14-86, Amended Direct Testimony of Tim Woolf, September 11, 2014, Figure 4 represents these costs in levelized form.

Resource Assessments

Synapse assessed 31 resources as potential alternative measures for inclusion in the low energy demand case. These resources are summarized in Table 4,

Electricity Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
Wind (<10 kW)	16%	1	$656	$7,866	16,819	4
Wind (<100 kW)	25%	1	$123	$1,473	26,280	4
Large Wind C5	no incremental capacity available by 2015					
Large Wind C4	no incremental capacity available by 2015					
Offshore Wind	no incremental capacity available by 2015					
Utility-Scale PV	no incremental capacity available by 2015					
Commercial PV	14%	2	$75	$905	30,275	0
Residential PV	13%	0	$100	$1,198	3,416	0
Large CHP	no incremental capacity available by 2015					
Small CHP	85%	5	-$15	-$179	446,760	57
Landfill Gas	78%	0	-$37	-$442	24,750	3
Anaerobic Digestion	90%	0	-$53	-$640	28,382	3
Biomass Power C1	no incremental capacity available by 2015					
Biomass Power C2	no incremental capacity available by 2015					
Biomass Power C3	no incremental capacity available by 2015					
Biomass Power C4	no incremental capacity available by 2015					
Pumped Hydro	no incremental capacity available by 2015					
Converted Hydro	38%	1	-$25	-$295	20,000	6
Battery Storage	15%	40	$257	$3,086	630,720	456
Res. Electric EE	55%	1	-$9	-$105	80,785	9
LI Electric EE	55%	0	$116	$1,388	24,329	3
CI Electric EE	55%	3	-$82	-$988	144,886	17
Elec DR	0%	400	$373	$4,475	115,200	4,800
Winter Reliability	no change over base case					
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
AS Heat Pump	0%	0	$0	$18	15,768	34
GS Heat Pump	0%	0	$0	$15	1,577	3
Solar Hot Water	0%	0	$0	-$3	96,726	2
Biomass Thermal	0%	0	$0	$9	31,550	83
Res. Gas EE	no savings projected over base case for 2015					
LI Gas EE	no savings projected over base case for 2015					
CI Gas EE	no savings projected over base case for 2015					

Table 5, and Table 6 and described in the sub-sections below.

Table 4. Resource assessment for 2015

Electricity Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
Wind (<10 kW)	16%	1	$656	$7,866	16,819	4
Wind (<100 kW)	25%	1	$123	$1,473	26,280	4
Large Wind C5	no incremental capacity available by 2015					
Large Wind C4	no incremental capacity available by 2015					
Offshore Wind	no incremental capacity available by 2015					
Utility-Scale PV	no incremental capacity available by 2015					
Commercial PV	14%	2	$75	$905	30,275	0
Residential PV	13%	0	$100	$1,198	3,416	0
Large CHP	no incremental capacity available by 2015					
Small CHP	85%	5	-$15	-$179	446,760	57
Landfill Gas	78%	0	-$37	-$442	24,750	3
Anaerobic Digestion	90%	0	-$53	-$640	28,382	3
Biomass Power C1	no incremental capacity available by 2015					
Biomass Power C2	no incremental capacity available by 2015					
Biomass Power C3	no incremental capacity available by 2015					
Biomass Power C4	no incremental capacity available by 2015					
Pumped Hydro	no incremental capacity available by 2015					
Converted Hydro	38%	1	-$25	-$295	20,000	6
Battery Storage	15%	40	$257	$3,086	630,720	456
Res. Electric EE	55%	1	-$9	-$105	80,785	9
LI Electric EE	55%	0	$116	$1,388	24,329	3
CI Electric EE	55%	3	-$82	-$988	144,886	17
Elec DR	0%	400	$373	$4,475	115,200	4,800
Winter Reliability	no change over base case					
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump	0%	0	$0	$18	15,768	34
GS Heat Pump	0%	0	$0	$15	1,577	3
Solar Hot Water	0%	0	$0	-$3	96,726	2
Biomass Thermal	0%	0	$0	$9	31,550	83
Res. Gas EE	no savings projected over base case for 2015					
LI Gas EE	no savings projected over base case for 2015					
CI Gas EE	no savings projected over base case for 2015					

Table 5. Resource assessment for 2020

Technology	Annual Capacity Factor	Total Potential Capacity	Annual Net Levelized Cost	Annual Net Levelized Cost	Annual Energy Production	Peak Hour Gas Savings
Electricity Technologies						
	%	MW	$/MWh	$/MMBtu NG	MMBtu NG	MMBtu NG
Wind (<10 kW)	16%	100	$557	$6,683	1,681,920	420
Wind (<100 kW)	25%	100	$68	$820	2,628,000	420
Large Wind C5	41%	200	$38	$455	8,619,840	840
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)					
Offshore Wind	44%	800	$133	$1,591	37,002,240	3,360
Utility-Scale PV	15%	16	$76	$911	309,053	0
Commercial PV	14%	50	$75	$905	946,080	0
Residential PV	13%	5	$90	$1,084	68,328	0
Large CHP	85%	25	-$52	-$621	2,233,800	285
Small CHP	85%	35	-$22	-$260	3,127,320	399
Landfill Gas	78%	20	-$46	-$552	1,650,000	228
Anaerobic Digestion	90%	20	-$67	-$807	1,892,160	228
Biomass Power C1	80%	20	$27	$322	1,681,920	228
Biomass Power C2	80%	40	$44	$530	3,363,840	456
Biomass Power C3	80%	40	$131	$1,566	3,363,840	456
Biomass Power C4	80%	50	$175	$2,102	4,204,800	570
Pumped Hydro	15%	560	$109	$1,307	8,830,080	6,384
Converted Hydro	38%	61	-$37	-$449	2,440,000	695
Battery Storage	15%	200	$217	$2,599	3,153,600	2,280
Res. Electric EE	55%	128	-$31	-$377	7,399,840	845
LI Electric EE	55%	15	$39	$469	893,944	102
CI Electric EE	55%	278	-$98	-$1,181	16,085,421	1,836
Elec DR	no incremental capacity available by 2020					
Winter Reliability	0%	0	$0	$3	29,434	0
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Net Levelized Cost	Annual Net Levelized Cost	Annual Energy Production	Peak Hour Gas Savings
	%	MW	$/MWh	$/MMBtu NG	MMBtu NG	MMBtu NG
AS Heat Pump	0%	0	$0	$20	315,360	684
GS Heat Pump	0%	0	$0	$16	63,072	137
Solar Hot Water	0%	0	$0	$3	967,262	20
Biomass Thermal	0%	0	$0	$9	15,775,000	41,325
Res. Gas EE	0%	0	$0	$4	1,275,955	80
LI Gas EE	0%	0	$0	$8	163,389	10
CI Gas EE	0%	0	$0	-$2	1,303,881	82

Table 6. Resource assessment for 2030

Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
Electricity Technologies						
Wind (<10 kW)	16%	200	$444	$5,331	3,363,840	840
Wind (<100 kW)	25%	300	$19	$226	7,884,000	1,260
Large Wind C5	42%	480	$14	$171	21,192,192	2,016
Large Wind C4	40%	800	$21	$247	33,638,400	3,360
Offshore Wind	45%	1,600	$66	$788	75,686,400	6,720
Utility-Scale PV	15%	160	$10	$116	3,090,528	0
Commercial PV	14%	800	-$4	-$48	15,137,280	0
Residential PV	13%	200	$6	$75	3,416,400	0
Large CHP	85%	50	-$76	-$918	4,467,600	570
Small CHP	85%	65	-$22	-$260	5,807,880	741
Landfill Gas	78%	6	-$68	-$820	495,000	68
Anaerobic Digestion	90%	6	-$96	-$1,155	567,648	68
Biomass Power C1	80%	20	$5	$55	1,681,920	228
Biomass Power C2	80%	40	$22	$262	3,363,840	456
Biomass Power C3	80%	60	$108	$1,299	5,045,760	684
Biomass Power C4	80%	70	$153	$1,835	5,886,720	798
Pumped Hydro	15%	560	$84	$1,007	8,830,080	6,384
Converted Hydro	38%	56	-$60	-$724	2,240,000	638
Battery Storage	15%	1,200	$122	$1,467	18,921,600	13,680
Res. Electric EE	55%	47	-$53	-$633	2,741,953	313
LI Electric EE	55%	23	$19	$224	1,353,072	154
CI Electric EE	55%	641	-$120	-$1,439	37,071,520	4,232
Elec DR	no incremental capacity available by 2030					
Winter Reliability	no incremental capacity available by 2030					
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
AS Heat Pump	0%	0	$0	$26	1,576,800	3,420
GS Heat Pump	0%	0	$0	$21	157,680	342
Solar Hot Water	0%	0	$0	$16	4,836,310	102
Biomass Thermal	0%	0	$0	$8	31,550,000	82,650
Res. Gas EE	0%	0	$0	$2	3,344,095	210
LI Gas EE	0%	0	$0	$7	591,610	37
CI Gas EE	0%	0	$0	-$4	4,721,167	296

Wind

For on-shore wind installations 10 kilowatts (kW) or less, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 16 percent. Annual levelized costs fall from $760 per megawatt-hour (MWh) in 2015 to $592/MWh in 2030.[8] (Net of avoided costs these values are $656/MWh and $444/MWh, respectively.) These assumptions are based personal communications with wind developers.[9]

For on-shore wind installation greater than 10 kW up to 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 300 MW from 2021 to 2030 with an annual capacity factor of 25 percent. Annual levelized costs fall from $218/MWh in 2015 to $156/MWh in 2030. (Net of avoided costs these values are $123/MWh and $19/MWh, respectively.) These assumptions are based on personal communications with wind developers.[10]

For Class 5 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 200 MW from 2016 to 2020, and 480 MW from 2021 to 2030 with annual capacity factors of 41 to 42 percent. Annual levelized costs fall from $113/MWh in 2020 to $111/MWh in 2030. (Net of avoided costs these values are $38/MWh and $14/MWh, respectively.) These assumptions are based on National Renewable Energy Laboratory (NREL) supply curves for New England wind regions.

For Class 4 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 0 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factors of 40 percent. Annual levelized costs are $118/MWh in 2030. (Net of avoided costs are $21/MWh in 2030.) These assumptions are based on NREL supply curves for New England wind regions.

For off-shore wind installation, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 800 MW from 2016 to 2020, and 1,600 MW from 2021 to 2030 with annual capacity factors of 44 to 45 percent. Annual levelized costs fall from $207/MWh in 2020 to $162/MWh in 2030. (Net of avoided costs these values are $133/MWh and $66/MWh, respectively.) These assumptions are based on NREL supply curves for New England wind regions.

In addition, we added costs to all large on-shore wind incremental to the base case, to represent the levelized cost of new transmission necessary to deliver incremental wind from Maine south to the major New England load centers. We assume a real, levelized cost of new transmission of $35 per MWh, based

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[8] All dollar values in the memo are report in real (inflation-adjusted) 2013 dollars

[9] Personal Communications with Katrina Prutzman, Urban Green Energy. October 2014.

[10] Personal Communications with Trevor Atkinson, Northern Power. October 2014.

on a cost of $2.15 billion for 1,200 MW of capacity recovered over 30 years. This cost assumption is from work Synapse recently performed for DOER.[11]

Solar

For residential photovoltaic (PV) installations, incremental to PV in the base case, we assume a total potential capacity addition of 20 kW by 2015, 5 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 13 percent. Annual levelized costs fall from $211/MWh in 2015 to $163/MWh in 2030. (Net of avoided costs these values are $100/MWh and $6/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER;[12] 2030 assumptions are Synapse estimates.

For commercial PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 1.6 MW by 2015, 50 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factor of 14 percent. Annual levelized costs fall from $184/MWh in 2015 to $149/MWh in 2030. (Net of avoided costs these values are $75/MWh and -$4/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

For utility-scale PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 0 MW by 2015, 16 MW from 2016 to 2020, and 160 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $162/MWh in 2020 to $118/MWh in 2030. (Net of avoided costs these values are $76/MWh and $10/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

Non-Powered Hydro Conversion

For hydro installations at dam sites that are not currently producing electricity, we assume a total potential capacity addition of 500 kW by 2015, 61 MW from 2016 to 2020, and 56 MW from 2021 to 2030 with an annual capacity factor of 38 percent. Annual levelized costs are constant over the study period at $63/MWh. (Net of avoided costs these values are -$25/MWh and -$60/MWh, respectively.) These assumptions are based on a Ohio Case study of converting a dam site to generate electricity and the EIA's *Annual Energy Outlook* capital and operating costs forecast.[13]

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[11] Hornby, Rick, et al., *Memorandum: Incremental Benefits and Costs of Large-Scale Hydroelectric Energy Imports*, prepared by Synapse Energy Economics for the Massachusetts Department of Energy Resources, November 1, 2013.

[12] http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-task-1.pdf

[13] http://www.hydro.org/tech-and-policy/developing-hydro/powering-existing-dams/
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Landfill Gas

For landfill gas installations, incremental to landfill gas in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 78 percent. Annual levelized costs are constant over the study period at $38/MWh. (Net of avoided costs these values fall from are -$37/MWh in 2015 to -$68/MWh in 2030.) These assumptions are based on the 2012 U.S. Environmental Protection Agency's *Landfill Gas Energy* study .[14]

Anaerobic Digestion

For anaerobic digestion installations, incremental to anaerobic digestion in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 90 percent. Annual levelized costs are constant over the study period at $47/MWh. (Net of avoided costs these values fall from are -$53/MWh in 2015 to -$96/MWh in 2030.) These assumptions are based on a 2003 Wisonsin case study presented in the *Focus on Energy Anaerobic Digester Methane to Energy* statewide assessment.[15]

Energy Storage

For pumped hydro installations, incremental to pumped hydro in the base case, we assume a total potential capacity addition of 0 MW by 2015, 560 MW from 2016 to 2020, and 560 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs are constant over the study period at $257/MWh. (Net of avoided costs these values fall from are $109/MWh in 2020 to $84/MWh in 2030.) These assumptions are based on a DOE and Electric Power Research Institute (EPRI) 2013 *Electricity Storage Handbook*. [16]

For battery storage installations, we assume a total potential capacity addition of 40 MW by 2015, 200 MW from 2016 to 2020, and 1200 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $381/MWh in 2015 to $295/MWh in 2030. (Net of avoided costs these values are $257/MWh and $122/MWh, respectively.) These assumptions are based on DOE/EPRI's 2013 *Electricity Storage Handbook*.

Biomass

For biomass Class 1 installations (with fuel costs of $3/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 20 MW from 2016 to 2020, and 20 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $110/MWh. (Net of avoided costs these values fall from are $27/MWh in 2020 to

[14] http://epa.gov/statelocalclimate/documents/pdf/landfill_methane_utilization.pdf

[15] http://www.mrec.org/pubs/anaerobic_report.pdf

[16] Table B-12. http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

$5/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and Office of Energy Efficiency and Renewable Energy (EERE).[17]

For biomass Class 2 installations (with fuel costs of $4/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 40 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $128/MWh. (Net of avoided costs these values fall from are $44/MWh in 2020 to $22/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

For biomass Class 3 installations (with fuel costs of $10/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 60 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $214/MWh. (Net of avoided costs these values fall from are $131/MWh in 2020 to $108/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

For biomass Class 4 installations (with fuel costs of $13/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 50 MW from 2016 to 2020, and 70 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $259/MWh. (Net of avoided costs these values fall from are $175/MWh in 2020 to $153/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

CHP

For small combined heat and power (CHP) installations (estimated as 500 kW reciprocating engines), incremental to CHP in the base case, we assume a total potential capacity addition of 500 kW by 2015, 35 MW from 2016 to 2020, and 65 MW from 2021 to 2030 with an annual capacity factor of 85 percent. Annual levelized costs rise from $103/MWh in 2015 to $118/MWh in 2030. (Net of avoided costs these values are -$15/MWh and -$22/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.[18]

For large combined heat and power (CHP) installations (estimated as 12.5 MW combustion turbines), incremental to CHP in the base case, we assume a total potential capacity addition of 0 MW by 2015, 25 MW from 2016 to 2020, and 50 MW from 2021 to 2030 with an annual capacity factor of 85 percent. Annual levelized costs rise from $71/MWh in 2020 to $78/MWh in 2030. (Net of avoided costs these values are -$52/MWh and -$76/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.

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[17] http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf; http://bv.com/docs/reports-studies/nrel-cost-report.pdf; http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

[18] http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Documents/The%20Opportunity%20for%20CHP%20in%20the%20United%20States%20-%20Final%20Report.pdf

Electric Energy Efficiency

For residential electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 128 MW from 2016 to 2020, and 47 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $109/MWh. (Net of avoided costs these values are -$31/MWh in 2020 and -$53/MWh in 2030.) These assumptions are based on the high case in the Lawrence Berkeley National Laboratory's (LBNL's) 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* together with additional building codes and efficiency standard program based achieving 50 percent of amount in the 2014 ACEEE study by 2020.[19]

For commercial and industrial electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 278 MW from 2016 to 2020, and 641 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $42/MWh. (Net of avoided costs these values are -$98/MWh in 2020 and -$120/MWh in 2030.) These assumptions are based on the high case in the LBNL's 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* together with additional building codes and efficiency standard program based achieving 50 percent of amount in the 2014 ACEEE study by 2020.

For low-income electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 15 MW from 2016 to 2020, and 23 MW from 2021 to 2030 with an annual capacity factor of xx percent. Annual levelized costs rise from $179/MWh in 20120 to $180/MWh in 2030. (Net of avoided costs these values are $39/MWh and $19/MWh, respectively.) These assumptions are based on the high case in the LBNL's 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* together with additional building codes and efficiency standard program based achieving 50 percent of amount in the 2014 ACEEE study by 2020.

Electric Demand Response

For electric demand response, incremental to demand response in the base case, we assume a total potential capacity addition of 400 MW by 2015, 0 MW from 2016 to 2020, and 0 MW from 2021 to 2030. Annual levelized costs are constant over the study period at $500/MWh. (Net of avoided costs these values are $373/MWh.)

The primary market value for demand response is the capacity market, and that market has traditionally focused on summer peak issues, not winter peak issues. The legal status of FERC Order 745 and the broader issue of FERC's jurisdiction over demand response in any of the wholesale markets further

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[19] Hayes, S., et al. Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution; costs developed from Southern California Edison. (2014, June). 2013-2014 Monthly Energy Efficiency Program Report – Report Month: June 2014. Available at: http://eestats.cpuc.ca.gov/EEGA2010Files/SCE/monthlyReport/SCE.MN.201406.1.xlsx.

complicates the issue of forecasting demand response through 2030. There are many MW of demand response that occur outside of the markets that is triggered by expected monthly peak load hours which act as triggers for large cost allocations such as transmission costs and demand charges. Even if demand response is removed from the wholesale markets, this type of demand response will continue. To the extent is has already been occurring on its own, it will be captured in the current forecast of winter peak demand.

There have been eight primary FCM auctions held, and up to three annual reconfiguration auctions for each delivery period. None of these results are reliable indicators of how much demand response is actually will to be dispatched by the ISO in any given month because these positions can be—and have been—t raded away in subsequent auctions. The reliable data must be derived only after all of these auctions have occurred, including the monthly reconfiguration auctions. This data is reported by the COO of the ISO-NE every month, and also at the Demand Resources Working Group, which meets once per month, with intermittent cancellations. There has been a steady decline in the amount of demand response willing to respond from June 2010 until the present. In the most recent winter months just over 200 MW of demand response took on an obligation to respond if called upon. Demand response providers have already taken obligations to provide capacity through May 2018, but have started to shed those obligations in reconfiguration auctions.

There is a clear trend of taking on a value in the FCA that is later traded away. This is the same trend we have seen in the first four FCAs, which then later saw the ARA3 value further reduced in the monthly reconfiguration auctions. We expect that this trend will continue.

To model demand response incremental to our base case assumptions, we assume that Order 745 remains in place and all uncertainty about demand response in the wholesale markets is resolved. Further, the demand response providers in New England have worked with ISO-NE to resolve their current issues around the enormous cost of providing baseline data which has been driving the decline in DR participation we see in Figure 1. Under this scenario we can expect demand response to return to the levels it reached in 2011/12, with 600 MW of demand response willing to respond in the winter months.

In those years the FCM prices were at administratively set floor prices that averaged near $3.50/kW-month. The most recent two FCAs have seen prices jump to $15, and the FCM PI rules that will take effect for June 2018 and beyond are expected keep prices at least this high as older, less flexible generation stations are pushed to retire and new generation is required. The FCM is the primary revenue source for demand response, and higher prices should be expected to drive greater participation.

Winter Reliability Program

For an extension to ISO-NE's Winter Reliability Program, we assume total annual energy production of 29,434 MMBtus in 2020. Annual levelized costs $3/MMBtu in 2020. (Net of avoided costs are $3/MMBtu.) Winter Reliability assumptions will be described in more detail together with a description of base case assumptions.

Heat Pumps

For air source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 15,768 annual MMBtu by 2015, 315,360 annual MMBtu from 2016 to 2020, and 1,576,800 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $18/MMBtu in 2015 to $26/MMBtu in 2030. (Net of avoided costs these values are $18/MMBtu and $26/MMBtu, respectively.) These assumptions are based on Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[20]

For ground source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 1,577 annual MMBtu by 2015, 63,072 annual MMBtu from 2016 to 2020, and 157,680 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $16/MMBtu in 2015 to $22/MMBtu in 2030. (Net of avoided costs these values are $15/MMBtu and $21/MMBtu, respectively.) These assumptions are based on the same sources used for air source heat pumps and the NREL webinar, *Residential Geothermal Heat Pump Retrofits.*[21]

Solar Hot Water

For solar hot water installation, incremental to solar hot water in the base case, we assume a total potential capacity addition of 96,726 annual MMBtu by 2015, 967,262 annual MMBtu from 2016 to 2020, and 4,836,310 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $53/MMBtu in 2015 to $86/MMBtu in 2030. (Net of avoided costs these values are -$3/MMBtu and $16/MMBtu, respectively.) These assumptions are based on information from vendors.

Thermal Biomass

For thermal biomass installation, incremental to thermal biomass in the base case, we assume a total potential capacity addition of 31,550 annual MMBtu by 2015, 15,775,000 annual MMBtu from 2016 to 2020, and 31,550,000 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at $16/MMBtu. (Net of avoided costs these values are $9/MMBtu in 2015 and $8/MMBtu in 2020.) These assumptions are based on the report to the Massachusetts legislature, *Heating and Cooling in the Massachusetts Alternative Portfolio Standard* and the *Commonwealth Accelerated Renewable Thermal Strategy* .[22]

Gas Energy Efficiency

For residential gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 1,275,955 annual MMBtu from 2016 to 2020, and 3,344,095 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the

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[20] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[21] http://energy.gov/sites/prod/files/2014/01/f7/50142.pdf

[22] http://www.mass.gov/eea/docs/doer/pub-info/heating-and-cooling-in-aps.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

study period at $12/MMBtu. (Net of avoided costs these values are $4/MMBtu in 2020 and $2/MMBtu in 2030.) These assumptions are based on the high case in the LBNL's 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025.*

For commercial and industrial gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 1,303,881 annual MMBtu from 2016 to 2020, and 4,721,167 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at $5/MMBtu. (Net of avoided costs these values are -$2/MMBtu in 2020 and -$4/MMBtu in 2030.) These assumptions are based on the high case in the LBNL's 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025.*

For low-income gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 163,389 annual MMBtu from 2016 to 2020, and 591,610 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at $16/MMBtu. (Net of avoided costs these values are $8/MMBtu in 2020 and $7/MMBtu in 2030.) These assumptions are based on the high case in the LBNL's 2013 *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025.*

Threshold for Economic Feasibility

In this memo we propose as potential thresholds for economic feasibility the average annual per MMBtu costs of incremental natural gas pipeline construction at two capacity levels: 95 percent on 80 percent of winter days (choosen to represent the level of pipeline utilitization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline) and 95 percent on 20 percent of winter days:

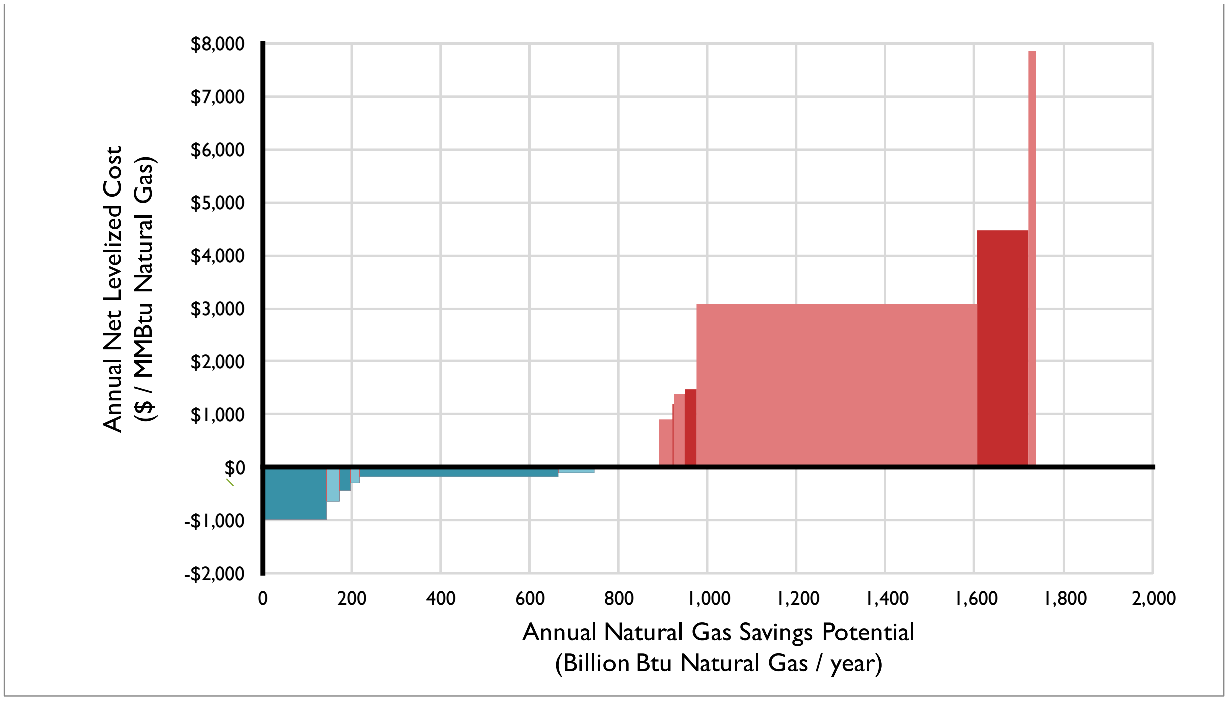
- At usage on 80 percent of winter days: $4/MMBtu
- At usage on 20 percent of winter days: $18/MMBtu

Feasibility Analysis Results

The feasilility analysis methodology employed in this memo compares measures' annual-$/annual-MMBtus to thresholds for economic feasibility in annual-$/annual -MMBtus and displays these results in the form of supply curves for 2015, 2020 and 2030 (see Figure 4, Figure 5 and Figure 6, and Table 7, Table 8 and

Table 9). Notes that inclusion of resources that are higher than the chosen economic feasibility threshold but provide winter peak event hour savings will be reconsidered in the winter peak event analysis phase of modeling.

Figure 4. Supply curve for 2015 (billion Btus)



This chart zooms in to the marginal resources. The y-axis is truncated, but the x-axis is unchanged.

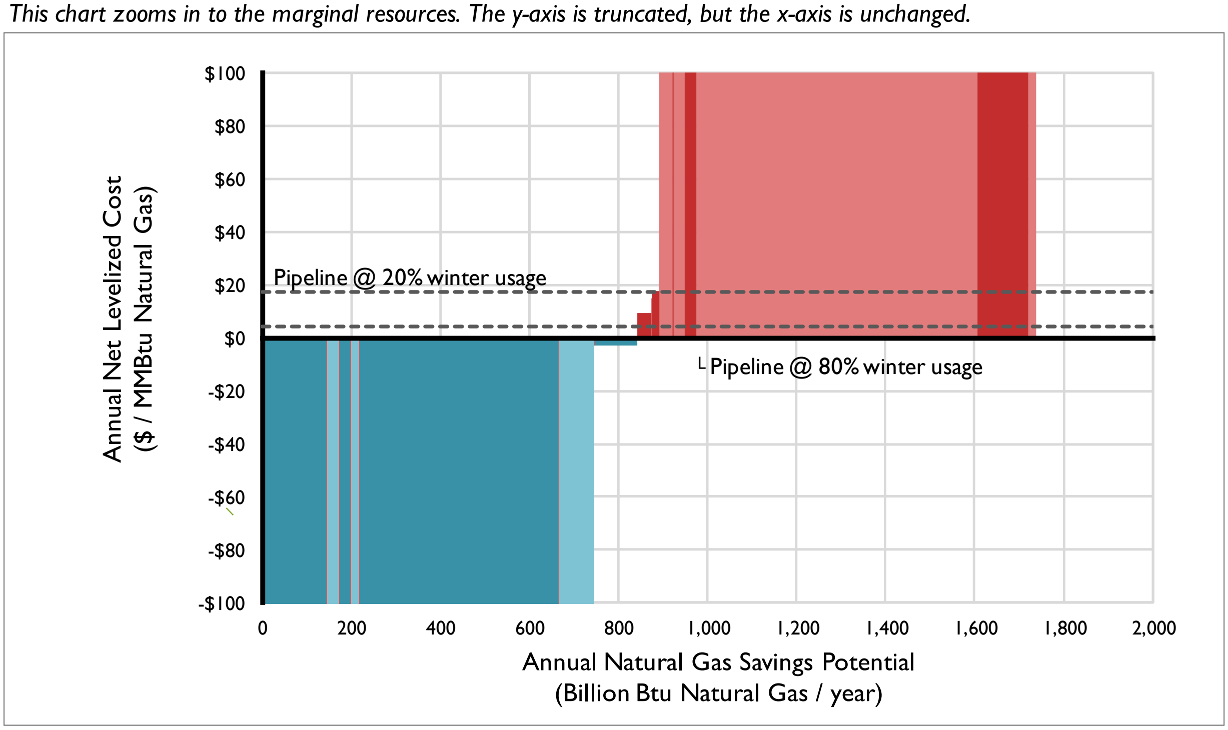
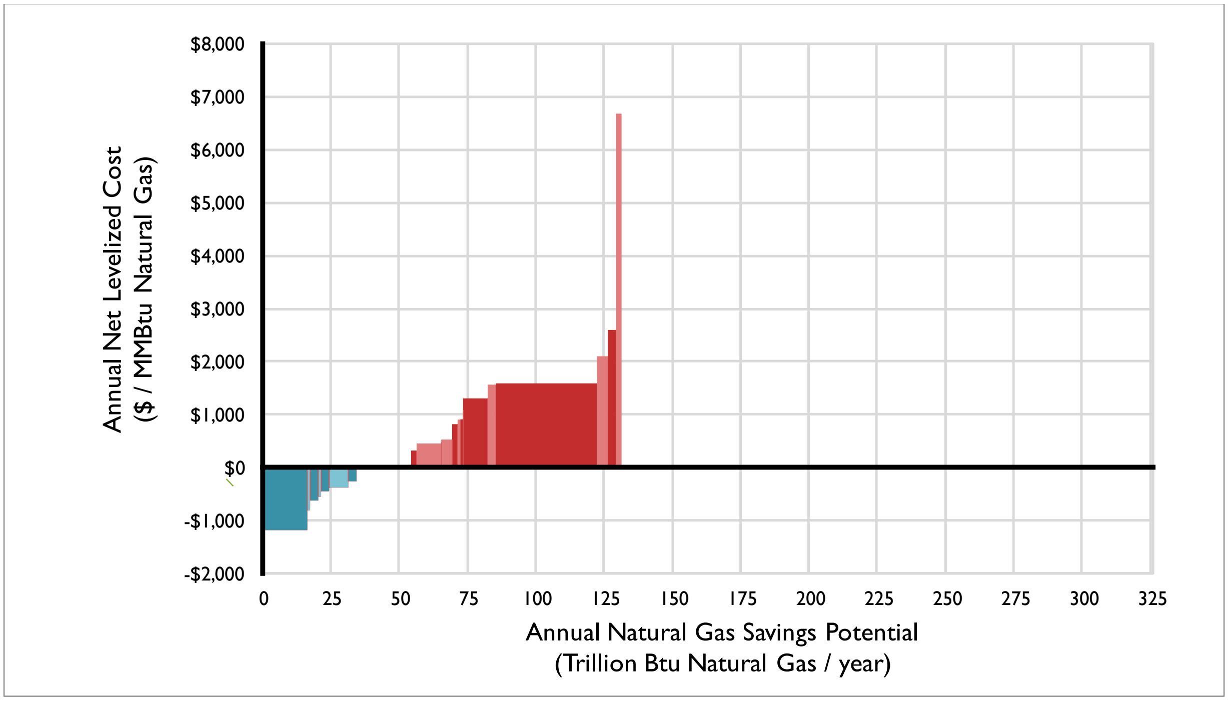


Table 7. Supply curve for 2015 (billion Btus)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (billion Btu)
1	CI Electric EE	-$988	145
2	Anaerobic Digestion	-$640	28
3	Landfill Gas	-$442	25
4	Converted Hydro	-$295	20
5	Small CHP	-$179	447
6	Res. Electric EE	-$105	81
7	Solar Hot Water	-$3	97
Pipeline @ 80% winter usage		$4	-
8	Biomass Thermal	$9	32
9	GS Heat Pump	$15	2
Pipeline @ 20% winter usage		$18	-
10	AS Heat Pump	$18	16
11	Commercial PV	$905	30
12	Residential PV	$1,198	3
13	LI Electric EE	$1,388	24
14	Wind (<100 kW)	$1,473	26
15	Battery Storage	$3,086	631
16	Elec DR	$4,475	115
17	Wind (<10 kW)	$7,866	17

Figure 5. Supply curve for 2020 (trillion Btus; note unit change from previous figures)



This chart zooms in to the marginal resources. The y-axis is truncated, but the x-axis is unchanged.

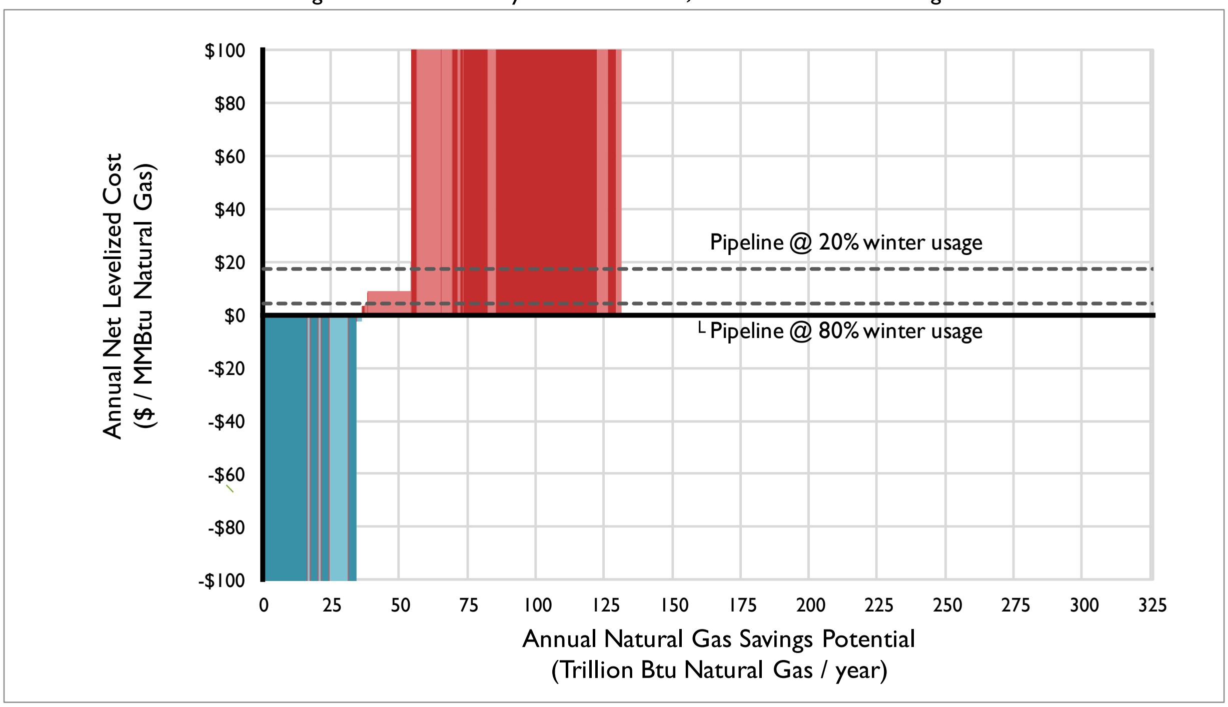
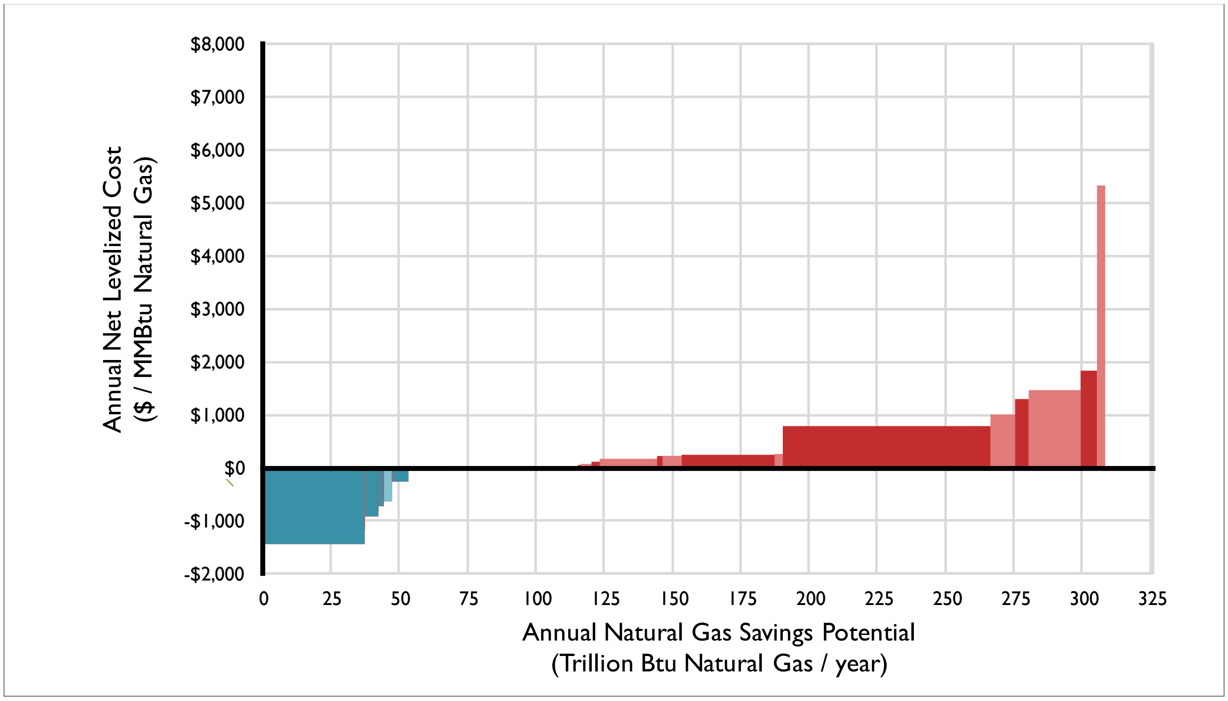


Table 8. Supply curve for 2020 (trillion Btus)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	CI Electric EE	-$1,181	16
2	Anaerobic Digestion	-$807	2
3	Large CHP	-$621	2
4	Landfill Gas	-$552	2
5	Converted Hydro	-$449	2
6	Res. Electric EE	-$377	7
7	Small CHP	-$260	3
8	CI Gas EE	-$2	1
9	Winter Reliability	$3	0.03
10	Solar Hot Water	$3	0.97
11	Res. Gas EE	$4	1
Pipeline @ 80% winter usage		$4	-
12	LI Gas EE	$8	0.16
Pipeline @ 20% winter usage		$18	-
13	Biomass Thermal	$9	15.78
14	GS Heat Pump	$16	0.06
15	AS Heat Pump	$20	0
16	Biomass Power C1	$322	2
17	Large Wind C5	$455	9
18	LI Electric EE	$469	1
19	Biomass Power C2	$530	3
20	Wind (<100 kW)	$820	3
21	Commercial PV	$905	0.95
22	Utility-Scale PV	$911	0.31
23	Residential PV	$1,084	0.07
24	Pumped Hydro	$1,307	9
25	Biomass Power C3	$1,566	3
26	Offshore Wind	$1,591	37
27	Biomass Power C4	$2,102	4
28	Battery Storage	$2,599	3
29	Wind (<10 kW)	$6,683	2

Figure 6. Supply curve for 2030 (trillion Btus)



This chart zooms in to the marginal resources. The y-axis is truncated, but the x-axis is unchanged.

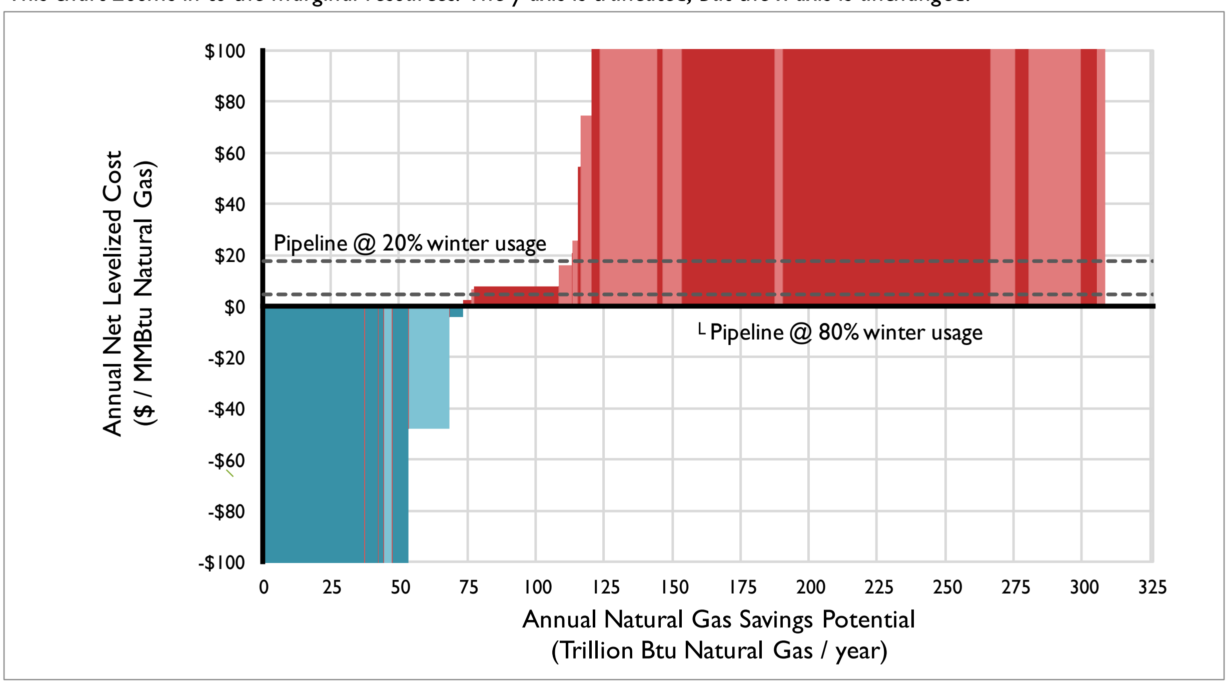


Table 9. Supply curve for 2030 (trillion Btus)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	CI Electric EE	-$1,439	37
2	Anaerobic Digestion	-$1,155	1
3	Large CHP	-$918	4
4	Landfill Gas	-$820	0.50
5	Converted Hydro	-$724	2
6	Res. Electric EE	-$633	3
7	Small CHP	-$260	5.81
8	Commercial PV	-$48	15
9	CI Gas EE	-$4	5
10	Res. Gas EE	$2	3
Pipeline @ 80% winter usage		$4	-
11	LI Gas EE	$7	1
12	Biomass Thermal	$8	32
13	Solar Hot Water	$16	5
Pipeline @ 20% winter usage		$18	-
14	GS Heat Pump	$21	0.16
15	AS Heat Pump	$26	2
16	Biomass Power C1	$55	2
17	Residential PV	$75	3
18	Utility-Scale PV	$116	3
19	Large Wind C5	$171	21
20	LI Electric EE	$224	1
21	Wind (<100 kW)	$226	8
22	Large Wind C4	$247	34
23	Biomass Power C2	$262	3
24	Offshore Wind	$788	76
25	Pumped Hydro	$1,007	9
26	Biomass Power C3	$1,299	5
27	Battery Storage	$1,467	19
28	Biomass Power C4	$1,835	6
29	Wind (<10 kW)	$5,331	3

5. Appendix: Feasibility Analysis Detailed Tables

See following 6 pages.

2015 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Electricity Technologies																	
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	MW	MWh	MMBtu NG	$/kW	Yrs	%	$/kW-yr	$/MWh	$/MMBtu	$/MWh	$/MWh	$/MWh	$/MWh	$/MMBtu NG	%	MMBtu NG
Wind (<10 kW)	16%	1.0	1,402	16,819	$11,500	20	9.0%	$25	$0	$0	$760	$79	$26	$656	$7,866	35%	4
Wind (<100 kW)	25%	1.0	2,190	26,280	$5,000	20	9.0%	$25	$0	$0	$218	$79	$16	$123	$1,473	35%	4
Large Wind C5	no incremental capacity available by 2015																
Large Wind C4	no incremental capacity available by 2015																
Offshore Wind	no incremental capacity available by 2015																
Utility-Scale PV	no incremental capacity available by 2015																
Commercial PV	14%	1.6	2,523	30,275	$2,593	25	8.0%	$25	$0	$0	$184	$79	$30	$75	$905	0%	0
Residential PV	13%	0.2	285	3,416	$2,842	25	7.6%	$25	$0	$0	$211	$79	$33	$100	$1,198	0%	0
Large CHP	no incremental capacity available by 2015																
Small CHP	85%	5	37,230	446,760	2,181	10	15.4%	$0	$11	$11	$103	$95	$23	-$15	-$179	95%	57
Landfill Gas	78%	0.3	2,063	24,750	$1,421	20	9.0%	$132	$0	$0	$38	$63	$12	-$37	-$442	95%	3
Anaerobic Digestion	90%	0.3	2,365	28,382	$4,102	20	9.0%	$0	$0	$0	$47	$79	$22	-$53	-$640	95%	3
Biomass Power C1	no incremental capacity available by 2015																
Biomass Power C2	no incremental capacity available by 2015																
Biomass Power C3	no incremental capacity available by 2015																
Biomass Power C4	no incremental capacity available by 2015																
Pumped Hydro	no incremental capacity available by 2015																
Converted Hydro	38%	0.5	1,667	20,000	$2,083	30	9.3%	$14	$0	$0	$63	$63	$24	-$25	-$295	95%	6
Battery Storage	15%	40	52,560	630,720	$3,381	15	13.1%	$6	$1	$30	$381	$63	$61	$257	$3,086	95%	456
Res. Electric EE	55%	1	6,732	80,785							$118	$90	$37	-$9	-$105	55%	9
LI Electric EE	55%	0	2,027	24,329							$243	$90	$37	$116	$1,388	55%	3
CI Electric EE	55%	3	12,074	144,886							$45	$90	$37	-$82	-$988	55%	17
Elec DR		400	9,600	115,200							$500	$90	$37	$373	$4,475	100%	4,800
Winter Reliability	no change over base case																

2015 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Direct Gas Reduction Technologies																	
Technology				Potential Energy Production *MMBtu NG*	Installed Cost *$/MMBtu*	Lifetime *Yrs*	Real Levelization Rate *%*	Annual Fixed O&M *$/MMBtu-yr*	Annual Variable O&M *$/MMBtu*	Annual Levelized Fuel Cost *$/MMBtu*	Annual Levelized Cost *$/MMBtu*	Avoided Energy Cost *$/MMBtu*	Avoided Capacity Cost *$/MMBtu*		Annual Net Levelized Cost *$/MMBtu NG*	Winter Load Carrying Capcity *%*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump				15,768	$281,898	15	11%	$2,000	$0	$50	$18	$6	$1		$18	95%	34
GS Heat Pump				1,577	$324,979	15	11%	$2,000	$0	$50	$16	$6	$1		$15	95%	3
Solar Hot Water				96,726	$53	15	11%	$0	$0	$3,250	$53	$6	$1		-$3	17%	2
Biomass Thermal				31,550	$367,964	15	11%	$879	$0	$4.63	$16	$6	$1		$9	95%	83
Res. Gas EE	no savings projected over base case for 2015																
LI Gas EE	no savings projected over base case for 2015																
CI Gas EE	no savings projected over base case for 2015																
Hydro Sensitivity																	
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Energy Production *MWh*	Annual Energy Production *MMBtu NG*	Installed Cost *$/kW*	Lifetime *Yrs*	Discount Rate *%*	Annual Fixed O&M *$/kW-yr*	Annual Variable O&M *$/MWh*	Annual Levelized Fuel Cost *$/MMBtu*	Annual Levelized Cost *$/MMBtu*	Avoided Energy Cost *$/MMBtu*	Avoided Capacity Cost *$/MMBtu*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Winter Load Carrying Capcity *%*	Peak Hour Gas Savings *MMBtu NG*
CA Hydro HVDC 1	no incremental capacity available by 2015																
CA Hydro HVDC 2	no incremental capacity available by 2015																
Economic Threshold																	
Technology				Potential Energy Production *MMBtu*	Installed Cost *$/MMBtu*	Lifetime *Yrs*	Discount Rate *%*	Annual Fixed O&M *$/MMBtu-yr*	Annual Variable O&M *$/MMBtu*	Annual Levelized Fuel Cost *$/MMBtu*	Annual Levelized Cost *$/MMBtu*				Annual Net Levelized Cost *$/MMBtu NG*	Winter Load Carrying Capcity *%*	Peak Hour Gas Savings *MMBtu NG*
Pipeline @ 80% winter usage				Unlimited							$4				$4		
Pipeline @ 20% winter usage				Unlimited							$18				$18		

(continued)

2020 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	Electricity Technologies																
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	*%*	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MMBtu NG*	*%*	*MMBtu NG*
Wind (<10 kW)	16%	100	140,160	1,681,920	$9,200	20	9.0%	$115	$0	$0	$676	$90	$29	$557	$6,683	35%	420
Wind (<100 kW)	25%	100	219,000	2,628,000	$4,000	20	9.0%	$25	$0	$0	$177	$90	$19	$68	$820	35%	420
Large Wind C5	41%	200	718,320	8,619,840	$2,359	20	9.7%	$50	$0	$0	$113	$69	$6	$38	$455	35%	840
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)																
Offshore Wind	44%	800	3,083,520	37,002,240	$5,600	20	12.2%	$115	$0	$0	$207	$69	$6	$133	$1,591	35%	3,360
Utility-Scale PV	15%	16.00	25,754	309,053	$2,202	25	8.7%	$16	$0	$0	$162	$69	$18	$76	$911	0%	0
Commercial PV	14%	50	78,840	946,080	$2,842	25	8.0%	$24	$0	$0	$199	$90	$34	$75	$905	0%	0
Residential PV	13%	5	5,694	68,328	$2,943	25	7.6%	$24	$0	$0	$217	$90	$37	$90	$1,084	0%	0
Large CHP	85%	25	186,150	2,233,800	1,750	20	9.7%	$0	$5	$7	$71	$97	$26	-$52	-$621	95%	285
Small CHP	85%	35	260,610	3,127,320	2,457	10	15.4%	$0	$11	$12	$112	$108	$26	-$22	-$260	95%	399
Landfill Gas	78%	20	137,500	1,650,000	$1,421	20	9.0%	$132	$0	$0	$38	$69	$15	-$46	-$552	95%	228
Anaerobic Digestion	90%	20	157,680	1,892,160	$4,102	20	9.0%	$0	$0	$0	$47	$90	$25	-$67	-$807	95%	228
Biomass Power C1	80%	20	140,160	1,681,920	$4,175	30	8.0%	$105	$11	$3	$110	$69	$15	$27	$322	95%	228
Biomass Power C2	80%	40	280,320	3,363,840	$4,175	30	8.0%	$105	$11	$4	$128	$69	$15	$44	$530	95%	456
Biomass Power C3	80%	40	280,320	3,363,840	$4,175	30	8.0%	$105	$11	$10	$214	$69	$15	$131	$1,566	95%	456
Biomass Power C4	80%	50	350,400	4,204,800	$4,175	30	8.0%	$105	$11	$13	$259	$69	$15	$175	$2,102	95%	570
Pumped Hydro	15%	560	735,840	8,830,080	$2,992	30	9.3%	$9	$1	$30	$257	$69	$79	$109	$1,307	95%	6,384
Converted Hydro	38%	61	203,333	2,440,000	$2,083	30	9.3%	$14	$0	$0	$63	$69	$31	-$37	-$449	95%	695
Battery Storage	15%	200	262,800	3,153,600	$3,212	15	13.1%	$6	$1	$30	$364	$69	$79	$217	$2,599	95%	2,280
Res. Electric EE	55%	128	616,653	7,399,840							$109	$98	$42	-$31	-$377	55%	845
LI Electric EE	55%	15	74,495	893,944							$179	$98	$42	$39	$469	55%	102
CI Electric EE	55%	278	1,340,452	16,085,421							$42	$98	$42	-$98	-$1,181	55%	1,836
Elec DR	no incremental capacity available by 2020																
Winter Reliability				29,434											$3		

2020 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Direct Gas Reduction Technologies																	
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*		*$/MMBtu NG*	*%*	*MMBtu NG*
AS Heat Pump				315,360	$281,898	15	11%	$2,000	$0	$59	$20	$7	$1		$20	95%	684
GS Heat Pump				63,072	$324,979	15	11%	$2,000	$0	$59	$18	$7	$1		$16	95%	137
Solar Hot Water				967,262	$62	15	11%	$0	$0	$3,824	$62	$7	$1		$3	17%	20
Biomass Thermal				15,775,000	$367,964	15	11%	$879	$0	$4.80	$16	$7	$1		$9	95%	41,325
Res. Gas EE				1,275,955							$12	$7	$1		$4	55%	80
LI Gas EE				163,389							$16	$7	$1		$8	55%	10
CI Gas EE				1,303,881							$5	$7	$1		-$2	55%	82
Hydro Sensitivity																	
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Discount Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	*%*	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MMBtu NG*	*%*	*MMBtu NG*
CA Hydro HVDC 1	67%	1,200	7,043,040	84,516,480	$1,250	30	8%				$100			$100	$1,199	75%	10,800
CA Hydro HVDC 2	no incremental capacity available by 2020																
Economic Threshold																	
Technology				Potential Energy Production	Installed Cost	Lifetime	Discount Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost				Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*				*$/MMBtu NG*	*%*	*MMBtu NG*
Pipeline @ 80% winter usage				Unlimited							$4				$4		
Pipeline @ 20% winter usage				Unlimited							$18				$18		

(continued)

2030 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Electricity Technologies																	
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	MW	MWh	MMBtu NG	$/kW	Yrs	%	$/kW-yr	$/MWh	$/MMBtu	$/MWh	$/MWh	$/MWh	$/MWh	$/MMBtu NG	%	MMBtu NG
Wind (<10 kW)	16%	200	280,320	3,363,840	$8,050	20	9.0%	$102	$0	$0	$592	$118	$30	$444	$5,331	35%	840
Wind (<100 kW)	25%	300	657,000	7,884,000	$3,500	20	9.0%	$25	$0	$0	$156	$118	$19	$19	$226	35%	1,260
Large Wind C5	42%	480	1,766,016	21,192,192	$2,359	20	9.7%	$50	$0	$0	$111	$90	$6	$14	$171	35%	2,016
Large Wind C4	40%	800	2,803,200	33,638,400	$2,460	20	9.7%	$50	$0	$0	$118	$90	$7	$21	$247	35%	3,360
Offshore Wind	45%	1,600	6,307,200	75,686,400	$4,760	$20	$0	$102	$0	$0	$162	$90	$6	$66	$788	35%	6,720
Utility-Scale PV	15%	160	257,544	3,090,528	$1,600	25	8.7%	$14	$0	$0	$118	$90	$18	$10	$116	0%	0
Commercial PV	14%	800	1,261,440	15,137,280	$2,075	25	8.0%	$22	$0	$0	$149	$118	$35	-$4	-$48	0%	0
Residential PV	13%	200	284,700	3,416,400	$2,150	25	7.6%	$22	$0	$0	$163	$118	$39	$6	$75	0%	0
Large CHP	85%	50	372,300	4,467,600	$1,750	20	9.7%	$0	$5	$8	$78	$127	$27	-$76	-$918	95%	570
Small CHP	85%	65	483,990	5,807,880	$2,457	10	15.4%	$0	$11	$13	$118	$141	$27	-$22	-$260	95%	741
Landfill Gas	78%	6	41,250	495,000	$1,421	20	9.0%	$132	$0	$0	$38	$90	$16	-$68	-$820	95%	68
Anaerobic Digestion	90%	6	47,304	567,648	$4,102	20	9.0%	$0	$0	$0	$47	$118	$26	-$96	-$1,155	95%	68
Biomass Power C1	80%	20	140,160	1,681,920	$4,175	30	8.0%	$105	$11	$3	$110	$90	$15	$5	$55	95%	228
Biomass Power C2	80%	40	280,320	3,363,840	$4,175	30	8.0%	$105	$11	$4	$128	$90	$15	$22	$262	95%	456
Biomass Power C3	80%	60	420,480	5,045,760	$4,175	30	8.0%	$105	$11	$10	$214	$90	$15	$108	$1,299	95%	684
Biomass Power C4	80%	70	490,560	5,886,720	$4,175	30	8.0%	$105	$11	$13	$259	$90	$15	$153	$1,835	95%	798
Pumped Hydro	15%	560	735,840	8,830,080	$2,992	30	9.3%	$9	$1	$30	$257	$90	$82	$84	$1,007	95%	6,384
Converted Hydro	38%	56	186,667	2,240,000	$2,083	30	9.3%	$14	$0	$0	$63	$90	$32	-$60	-$724.31	95%	638
Battery Storage	15%	1,200	1,576,800	18,921,600	$2,535	15	13.1%	$5	$1	$30	$295	$90	$82	$122	$1,467	95%	13,680
Res. Electric EE	55%	47	228,496	2,741,953							$109	$118	$44	-$53	-$633	55%	313
LI Electric EE	55%	23	112,756	1,353,072							$180	$118	$44	$19	$224	55%	154
CI Electric EE	55%	641	3,089,293	37,071,520							$42	$118	$44	-$120	-$1,439	55%	4,232
Elec DR	no incremental capacity available by 2030																
Winter Reliability	no incremental capacity available by 2030																

2030 Supply Curve

All dollar values are in 2013 dollars.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Direct Gas Reduction Technologies																	
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*		*$/MMBtu NG*	*%*	*MMBtu NG*
AS Heat Pump				1,576,800	$281,898	15	11%	$2,000	$0	$82	$26	$9	$1		$26	95%	3,420
GS Heat Pump				157,680	$324,979	15	11%	$2,000	$0	$82	$22	$9	$1		$21	95%	342
Solar Hot Water				4,836,310	$86	15	11%	$0	$0	$5,353	$86	$9	$1		$16	17%	102
Biomass Thermal				31,550,000	$367,964	15	11%	$879	$0	$5.16	$16	$9	$1		$8	95%	82,650
Res. Gas EE				3,344,095							$12	$9	$1		$2	55%	210
LI Gas EE				591,610							$16	$9	$1		$7	55%	37
CI Gas EE				4,721,167							$5	$9	$1		-$4	55%	296
Hydro Sensitivity																	
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Discount Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	*%*	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MWh*	*$/MMBtu NG*	*%*	*MMBtu NG*
CA Hydro HVDC 1	no additional incremental capacity available																
CA Hydro HVDC 2	50%	1,200	5,256,000	63,072,000	$1,833	30	0%				$0			$0	$0	75%	10,800
Economic Threshold																	
Technology				Potential Energy Production	Installed Cost	Lifetime	Discount Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost				Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*				*$/MMBtu NG*	*%*	*MMBtu NG*
Pipeline @ 80% winter usage				Unlimited							$4				$4		
Pipeline @ 20% winter usage				Unlimited							$18				$18		

(continued)