Massachusetts Low Demand Analysis

Final Results

Updated January 7, 2015

Meg Lusardi, Acting Commissioner, DOER

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Dr. Jonathan Raab, Raab Associates, Ltd.

Dr. Elizabeth A. Stanton, Synapse Energy Economics

Welcome & Purpose of Project

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Purpose of the Project

- Consider various solutions to address Massachusetts' short and long-term energy needs, taking into account greenhouse gas reductions, economic costs and benefits, and system reliability

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Review of Agenda & Meeting Objectives

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Objectives of This Meeting

- Review finalized supply curves
- Review preliminary results for peak hour balancing, annual natural gas consumption, costs, and emissions
- Discuss initial observations from modeling results
- Caveats
- Feedback and suggestions for revisions

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Overview of Agenda

Time	Topic	Speaker
9:30 AM	**Welcome**	Meg Lusardi, DOER
9:35	**Review of Agenda & Meeting Objectives**	Dr. Jonathan Raab
9:40	**1) Summary of Key Changes to Feasibility Study and Supply Curves –** A. Synapse Presentation B. Q&A	Dr. Liz Stanton
10:15	**2) Modeling Results: Base Case, Low Demand Scenario, Sensitivity Analyses, Synapse Observations from Modeling, and Caveats—** A. Synapse Presentation B. Q&A	Synapse Team
12:00	Lunch	

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Overview of Agenda

Time	Topic	Speaker
1:30	**4) Modeling Results: Stakeholder Group Discussions** A. Stakeholder Group Discussion B. Stakeholder Group Report Out C. Synapse/DOER Response	Dr. Jonathan Raab
3:15 PM	**5) Next Steps: Stakeholders and Final Report**	Dr. Liz Stanton & Dr. Jonathan Raab
3:30 PM	**Adjourn**	

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Ground Rules

- State your name and affiliation when speaking
- Share your feedback with affirmations or alternatives
- Be succinct in your comments/questions
- Silence phones
- Dial-in participants will be muted during presentations & small group exercises; opportunity to ask clarifying questions after individuals in the room

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Overview of Stakeholder Process

- Materials will be available on Synapse's website at: http://synapse-energy.com/project/massachusetts-low-demand-analysis
- All meetings are open to the public
- High-level summaries of Stakeholder Meetings will be provided
- This is not a consensus-seeking process
  - Input will be gathered at three Stakeholder Meetings
  - Written comments can be submitted to DOER until Monday, December 22nd at 2PM
  - Email: lowdemandstudy@state.ma.us
  - Written comments will be reviewed by DOER and posted to project webpage
  - Meeting high-level summary will be posted to project website

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Overview of Stakeholder Process (cont.)

- October 15, 9am-noon – **Stakeholder Meeting**: Provide an overview of the process and key resources alternatives
  - October 20 – Written comments due to DOER (lowdemandstudy@state.ma.us)
- October 30, 9:30am-4pm – Stakeholder Meeting: Review results of feasibility study of alternative resource penetration and supply curves for 2015, 2020, 2030; Detailed discussion of modeling process
  - Nov. 4 – Written comments due
- December 18, 9:30am-3:30pm – **Stakeholder Meeting**: Review results of modeling runs and their implications
  - Location: Fort Pt. Room, Atlantic Wharf Building, 290 Congress St., 2nd Floor, Boston
  - **December 22** – Written comments due by 2 PM
- December 23 – Target date for **final report** release

Summary of Key Changes to Feasibility Study and Supply Curves

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Key Changes to Feasibility Study and Supply Curves

- Potential and net levelized cost of both small and large CHP
- Revisions to marginal heat rate
  - Now using two separate annual and peak numbers
  - Annual number has been lowered from 12 to 8.5 MMBtu/MWh
- Revisions to energy efficiency (both electric and natural gas):
  - No savings over base case in 2015
  - New costs
  - New savings
  - Integration of non-electric benefits
  - Removed standards from energy efficiency and made it into a separate measure
- Increased offshore wind potential
- Changes to savings potential for air and ground source heat pumps, solar hot water, and biomass thermal
- Removed Winter Reliability, Demand Response, Pumped Storage, and Battery Storage
  - None of these resources have annual MMBtu savings
  - All were considered as balancing measures
  - Only winter reliability and demand response were used as balancing measures due to cost compared to pipeline
- Selected threshold: pipeline at 80% winter usage

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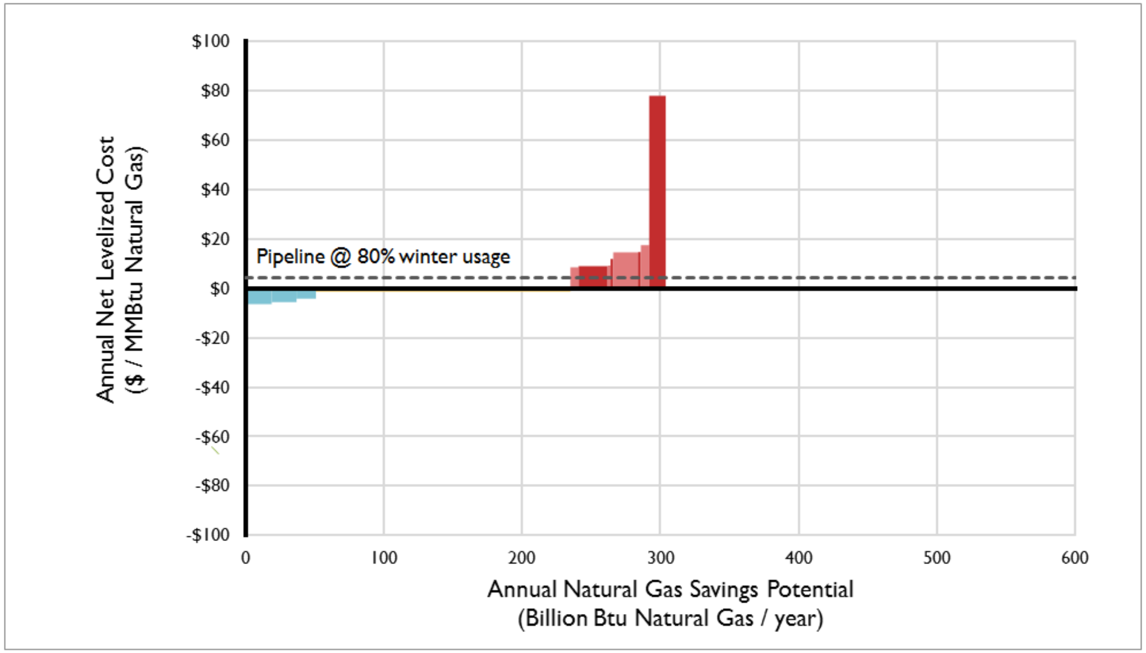
2015 Supply Curve *(Billion Btu Natural Gas Savings Potential per Year versus Annual Net Levelized Cost)*



		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (billion Btu)
1	Anaerobic Digestion	-$6	20
2	Landfill Gas	-$6	17
3	Converted Hydro	-$4	14
4	Small CHP	-$1	184
Pipeline @ 80% winter usage		$4	-
5	Biomass Thermal	$9	6
6	Commercial PV	$9	21
7	Solar Hot Water	$9	2
8	Residential PV	$12	2
9	Wind (<100 kW)	$15	18
10	GS Heat Pump	$15	2
11	AS Heat Pump	$17	6
12	Wind (<10 kW)	$78	12

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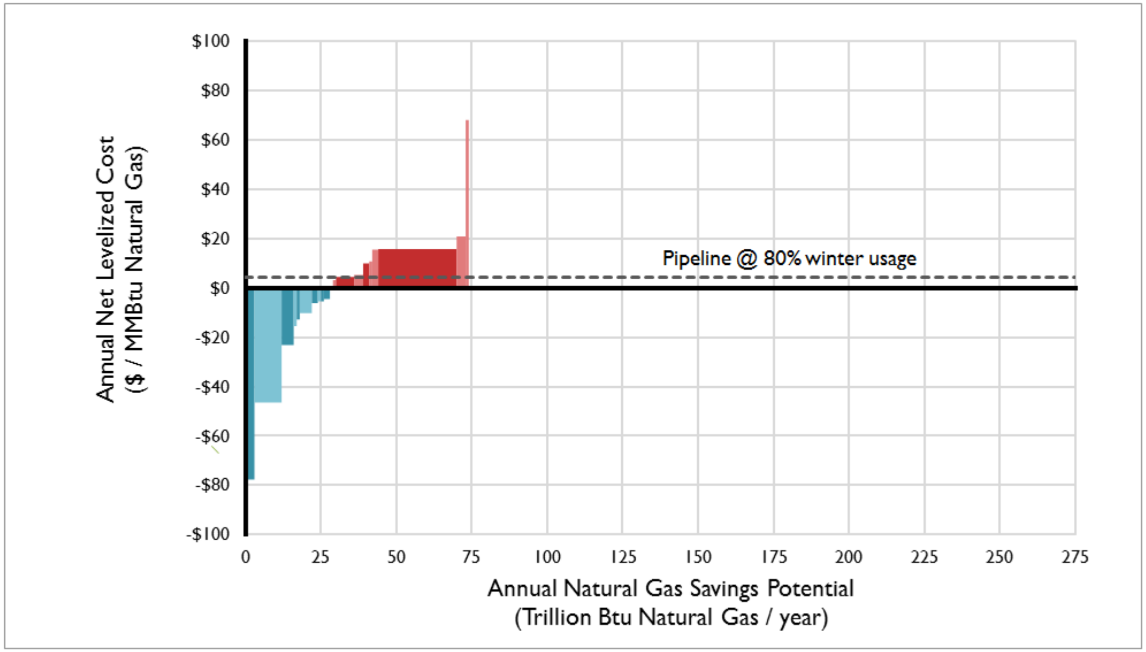
2020 Supply Curve *(Trillion Btu Natural Gas Savings Potential per Year versus Annual Net Levelized Cost)*



		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$78	4
2	Appliance Standards	-$46	9
3	CI Gas EE	-$23	4
4	LI Gas EE	-$15	1
5	Res. Electric EE	-$13	1
6	CI Electric EE	-$10	5
7	Anaerobic Digestion	-$6	1
8	Landfill Gas	-$5	1
9	Large CHP	-$5	1
10	Converted Hydro	-$4	2
11	LI Electric EE	-$2	0.1
12	Small CHP	$0.4	1
13	Biomass Power C1	$3	1
Pipeline @ 80% winter usage		$4	-
14	Large Wind C5	$5	6
15	Biomass Power C2	$5	2
16	Utility-Scale PV	$9	0.2
17	Biomass Thermal	$9	0.1
18	Wind (<100 kW)	$10	2
19	Commercial PV	$11	1
20	Residential PV	$13	0.05
21	Biomass Power C3	$16	2
22	Offshore Wind	$16	26
23	GS Heat Pump	$16	0.02
24	AS Heat Pump	$20	0.1
25	Biomass Power C4	$21	3
26	Solar Hot Water	$24	0.02
27	Wind (<10 kW)	$68	1

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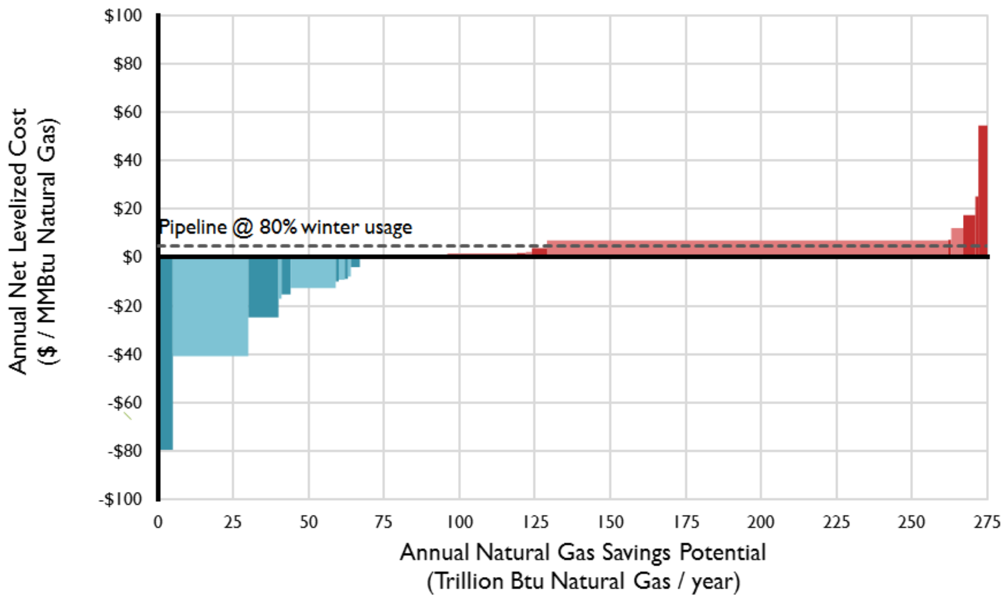
2030 Supply Curve *(Trillion Btu Natural Gas Savings Potential per Year versus Annual Net Levelized Cost)*



		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$41	25
3	CI Gas EE	-$25	10
4	LI Gas EE	-$17	2
5	Res. Electric EE	-$15	3
6	CI Electric EE	-$13	15
7	Anaerobic Digestion	-$10	0.4
8	Large CHP	-$9	2
9	Landfill Gas	-$9	0.3
10	Converted Hydro	-$8	2
11	Small CHP	-$4	2
12	LI Electric EE	-$4	0.3
13	Biomass Power C1	-$0.2	1
14	Utility-Scale PV	$0	2
15	Large Wind C5	$1	15
16	Commercial PV	$1	11
17	Large Wind C4	$2	24
18	Biomass Power C2	$2	2
19	Residential PV	$2	2
20	Wind (<100 kW)	$4	6
Pipeline @ 80% winter usage		$4	-
21	Offshore Wind	$7	132
22	Biomass Thermal	$7	1
23	Biomass Power C3	$12	4
24	Biomass Power C4	$17	4
25	GS Heat Pump	$20	0.3
26	AS Heat Pump	$25	1
27	Solar Hot Water	$32	0.3
28	Wind (<10 kW)	$54	2

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Alternative Resources included in Low Demand Case

		Total Annual Savings Potential (trillion Btu)
2015	Anaerobic digestion, landfill gas, converted hydro, small CHP	0.2
2020	Appliance standards, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, low-income electric energy efficiency, small CHP, residential gas energy efficiency, commercial and industrial gas energy efficiency, low-income gas energy efficiency, Class 1 biomass power	30.9
2030	Residential gas energy efficiency, appliance standards, commercial and industrial gas energy efficiency, low-income gas energy efficiency, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, small CHP, low-income electric energy efficiency, commercial PV, residential PV, Class 1 biomass power, utility-scale PV, small wind, Class 5 large wind, Class 4 large wind, Class 2 biomass power	129.9

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Q&A: Key Changes to Feasibility Study and Supply Curves

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Modeling Results Part 1

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Framing the Model Scope

- Massachusetts natural gas demand and capacity only
- Massachusetts natural gas capacity constraints are modeled as resolved.
- No implicit assumption that new pipeline is necessary or unnecessary
- GWSA compliance is a model output
- Modeled sensitivities:
  - Gas Price
  - 2,400 MW of incremental Canadian transmission
- Modeled 2015 through 2030
- Any interpretations of this study's results should make full consideration of all specified caveats.

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Framing the Model Scope

Caveats to Model Scope

- The scope of this study was restricted to expected Massachusetts natural gas demand and capacity only. We did not examine gas constraints in the wider region, nor did we examine the effect of expected gas demand or capacity constraints outside of the Commonwealth.
- The scope of this study was restricted to scenarios in which Massachusetts natural gas capacity constraints were resolved. We did not construct a scenario based on the assumption that incremental pipeline would necessarily be constructed.
- The scope of this study was to investigate the need for a new pipeline. We assumed neither that new pipeline and corresponding natural gas usage were necessary, nor that new pipeline and corresponding natural gas were unnecessary.
- The study determines whether or not each scenario modeled is or is not GWSA compliant. We did not assume that Massachusetts would be in compliance with GWSA.

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Framing the Model Scope (cont.)

Caveats to Model Scope (cont.)

- The study examines the sensitivity of model results to changes in the price of natural gas and the addition of 2,400 MW of incremental Canadian transmission. Potential sensitivities of interest not modeled include: the availability in the winter peak hour of existing coal, nuclear, or other potentially at-risk generation; the combined sensitivity to a low or high gas price and the addition of incremental Canadian transmission; and incremental Canadian resources assumed to be dedicated transmission of hydroelectric generation or any other resource.
- The study examined the period of 2015 through 2030. Although new natural gas infrastructure is not available until 2020, we included analysis of years 2015 through 2019 as these years include changes to the natural gas system including reduced natural gas demand as a result of energy efficiency measures, and changes to the electric system as a result of generating unit retirements, energy efficiency measures, and alternative measures. The inclusion of these years permits more thorough analysis of differences among the scenarios.

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Table of Sensitivities

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case	Base Case	Base Case	Base Case	Low Demand Case	Low Demand Case	Low Demand Case	Low Demand Case
Reference NG Price	Low NG Price	High NG Price	Reference NG Price	Reference NG Price	Low NG Price	High NG Price	Reference NG Price
No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission	No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission

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Base Case	Base Case	Base Case	Base Case	Low Demand Case	Low Demand Case	Low Demand Case	Low Demand Case
Reference NG Price	Low NG Price	High NG Price	Reference NG Price	Reference NG Price	Low NG Price	High NG Price	Reference NG Price
No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission	No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission

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Table of Sensitivities

Scenario 1		Scenario 5		Scenario 8
Base Case	→	Low Demand Case		Low Demand Case
Reference NG Price		Reference NG Price		Reference NG Price
No Canadian transmission		No Canadian transmission	→	2,400-MW Incremental Canadian transmission

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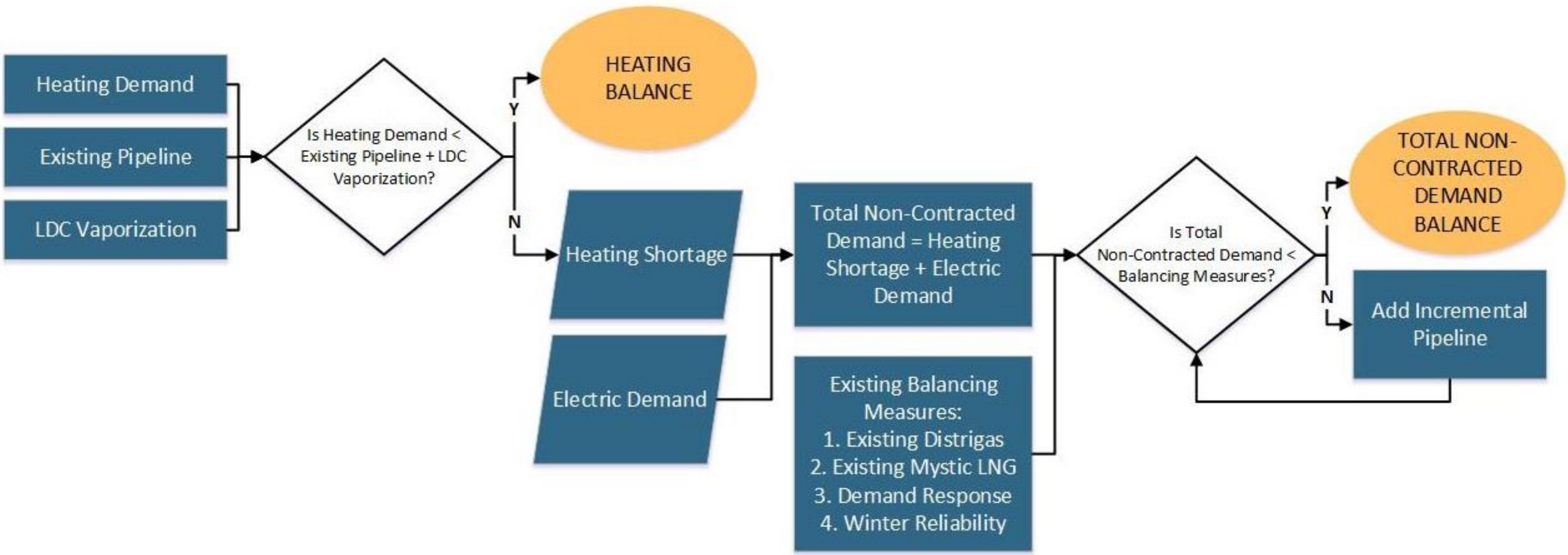
Winter peak hour gas capacity and demand balancing schematic



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Existing Demand and Capacity, Peak Hour

Gas Demand

- Heating Demand
  - LDCs in MA
  - Municipal entities in MA
  - Capacity-exempt entities in MA
  - Adjustments for energy efficiency and gas reduction measures (fuel switching, etc.)
- Electric Demand
  - Natural gas-fired electric generators in MA
  - Adjustments for energy efficiency and low demand measures

Gas Capacity

- Existing pipeline capacity
- Existing LDC-owned vaporization from storage
- Existing Distrigas-owned vaporization from storage
  - Some portion dedicated to Mystic plant
  - Some portion useable by entire electric system

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Preliminary Peak Hour Balancing of Base Case Reference Gas Price

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	Gas EE	Gas Reduction Measures	Existing Pipeline Capacity	Existing LDC Vaporization	Supply less Demand	Demand as a % of Supply	Heating Demand Shortage	MA Electric System	Existing Distrigas Vaporization	Mystic LNG Injection	Demand Response	Winter Reliability	Incremental Pipeline	Supply less Demand	Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	20	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	54	19	12			33	5	92%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	52	19	12			33	8	87%
2023	171	-16	-15	100	37	-4	103%	4	53	19	12			33	8	88%
2024	172	-16	-16	100	37	-3	102%	3	55	19	12			33	6	90%
2025	173	-17	-16	100	37	-3	102%	3	53	19	12			33	8	87%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	56	19	12			33	6	90%
2028	175	-18	-19	100	37	-2	101%	2	60	19	12			38	7	90%
2029	176	-18	-20	100	37	-2	101%	2	60	19	12			38	7	90%
2030	177	-18	-21	100	37	-2	101%	2	61	19	12			38	6	92%

Notes:
Additional unused balancing measures (battery storage and pumped storage not shown).
Our analysis is conducted in Btu as natural gas delivered from different sources can have different heat contents (i.e., different Btu / cubic feet of delivered natural gas). As a point of reference, one cubic foot of gas is about one thousand Btu. Billion Btu per hour can be converted into billion cubic feet per day by multiplying by 24 and dividing by 1,000. For example, 38 billion Btu per hour is 0.9 Bcf per day.

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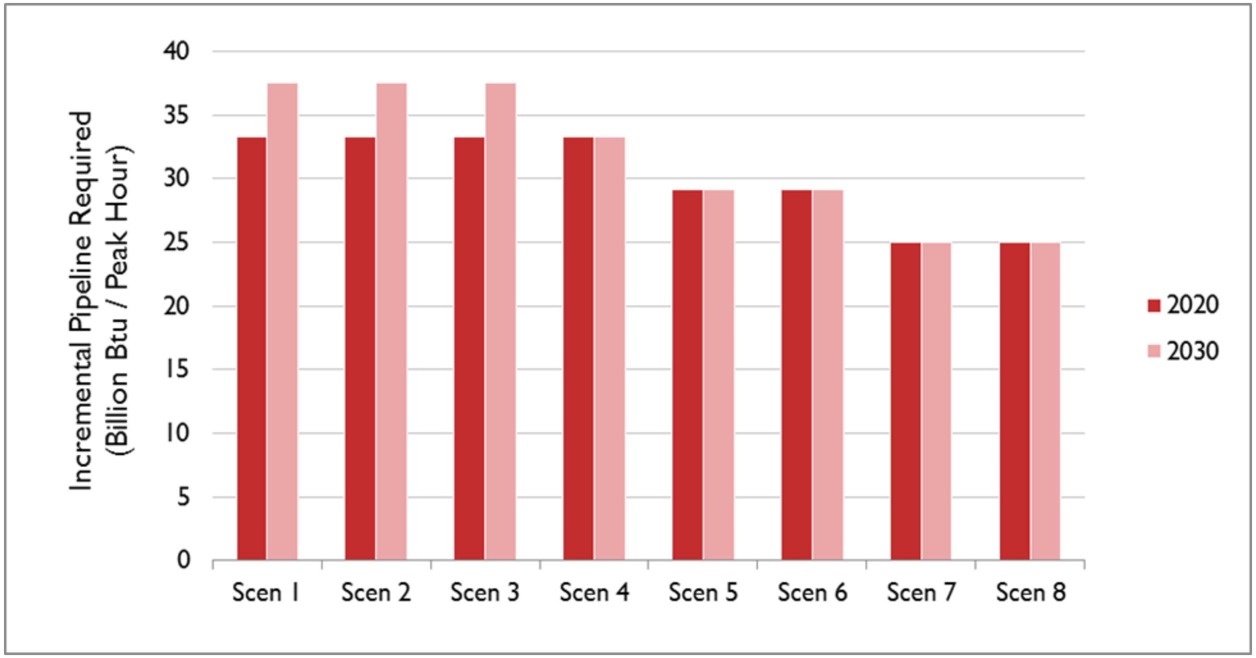
Preliminary Peak Hour Natural Gas Shortages



2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 Bcf per day to 0.8 Bcf per day).

2030 pipeline additions range from 25 billion Btu per peak hour to 38billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day).

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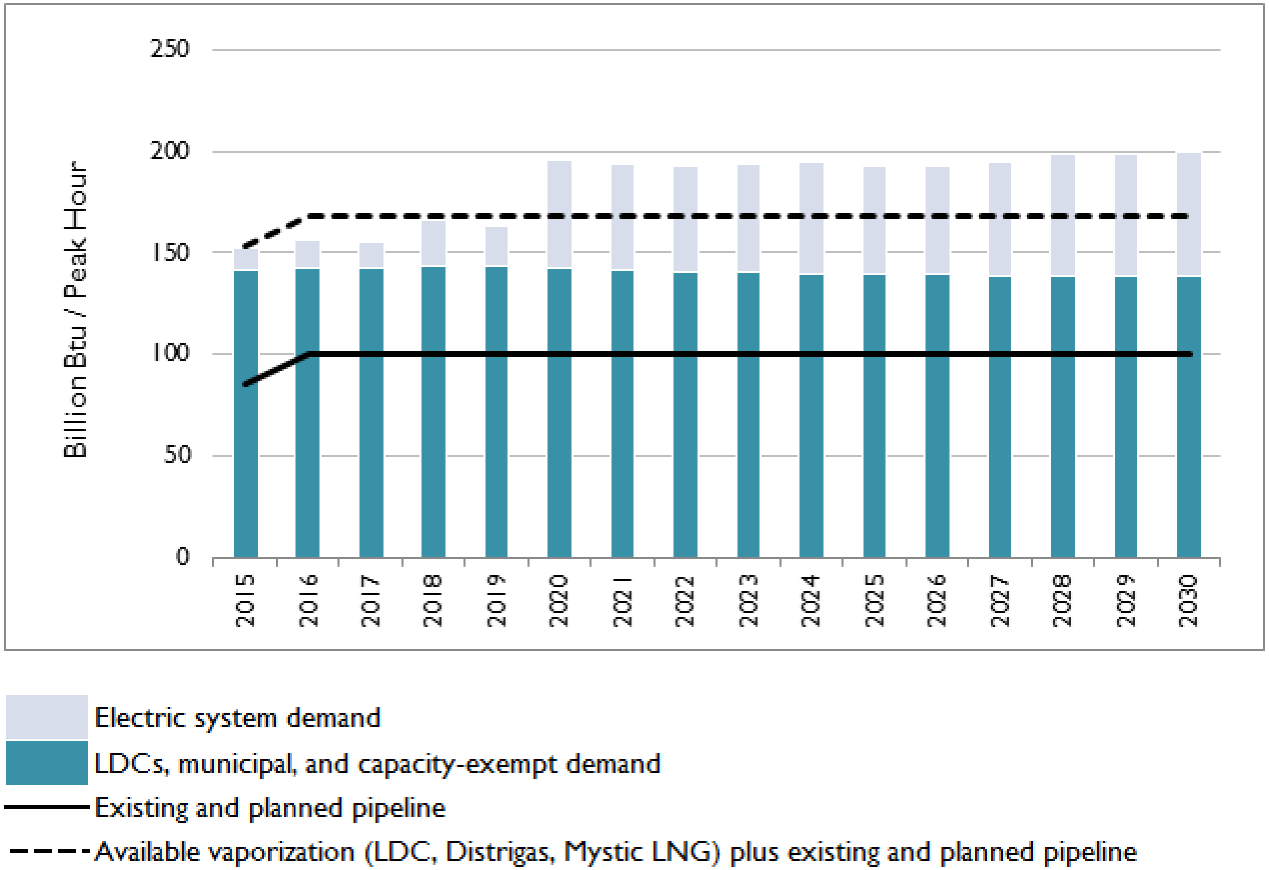
Preliminary Peak Hour Natural Gas Demand and Capacity,
Base case, Reference gas price, No Canadian transmission



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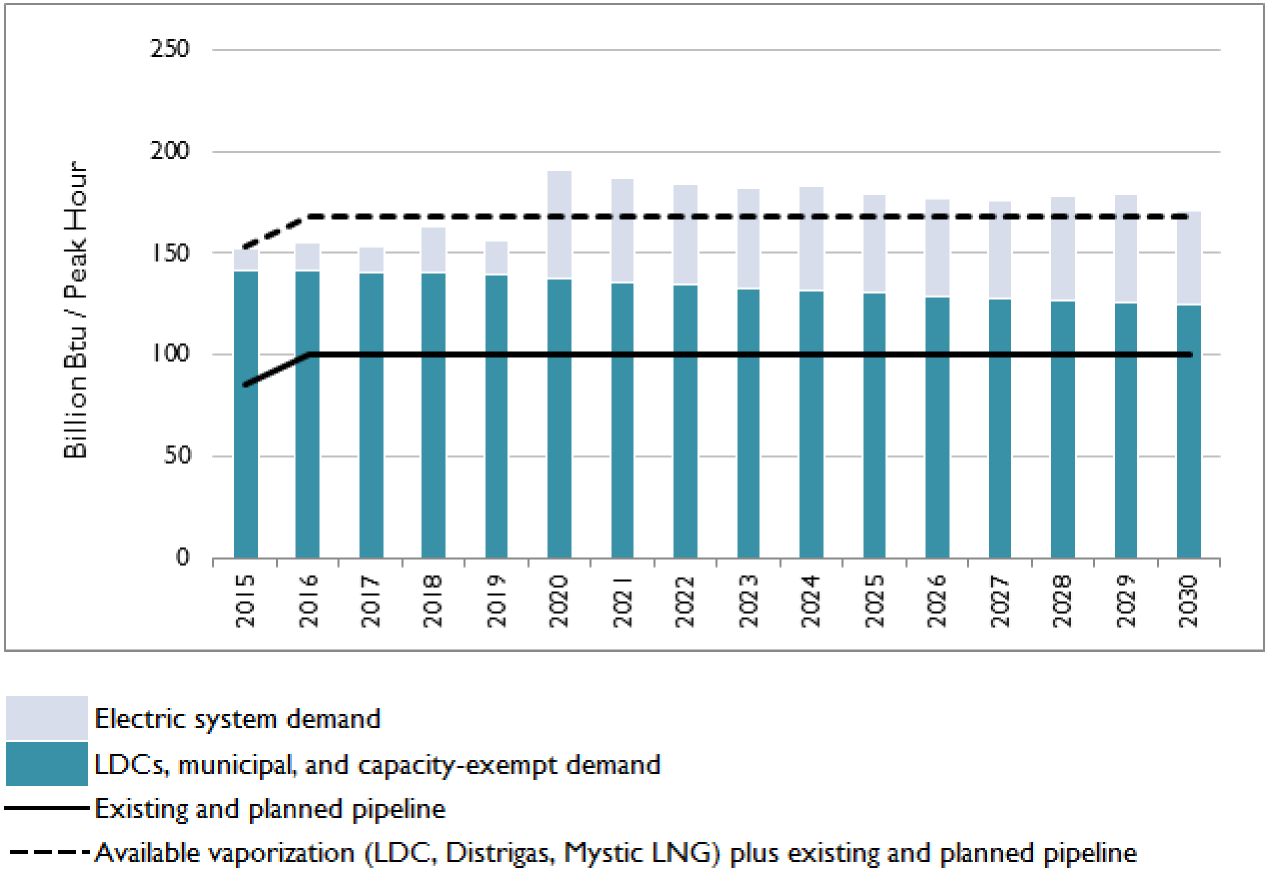
Preliminary Peak Hour Natural Gas Demand and Capacity, Low demand case, Reference gas price, No Canadian transmission



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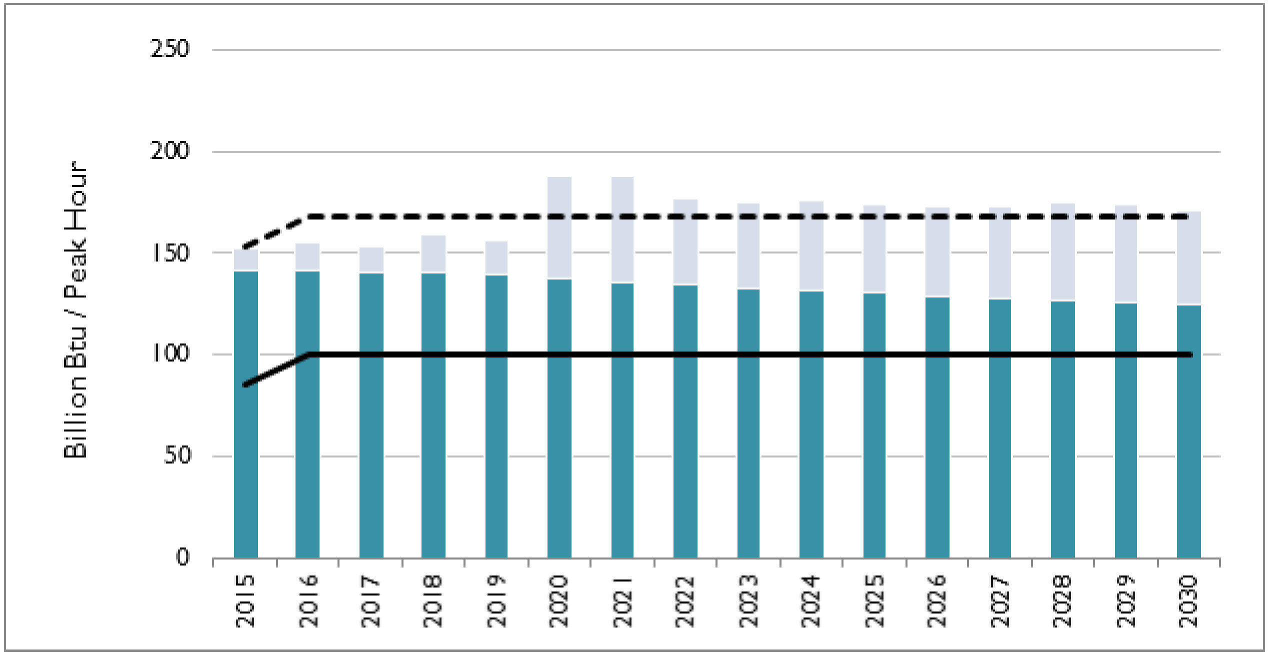
Preliminary Peak Hour Natural Gas Demand and Capacity,
Low demand case, Ref. gas price, 2,400-MW Canadian transmission



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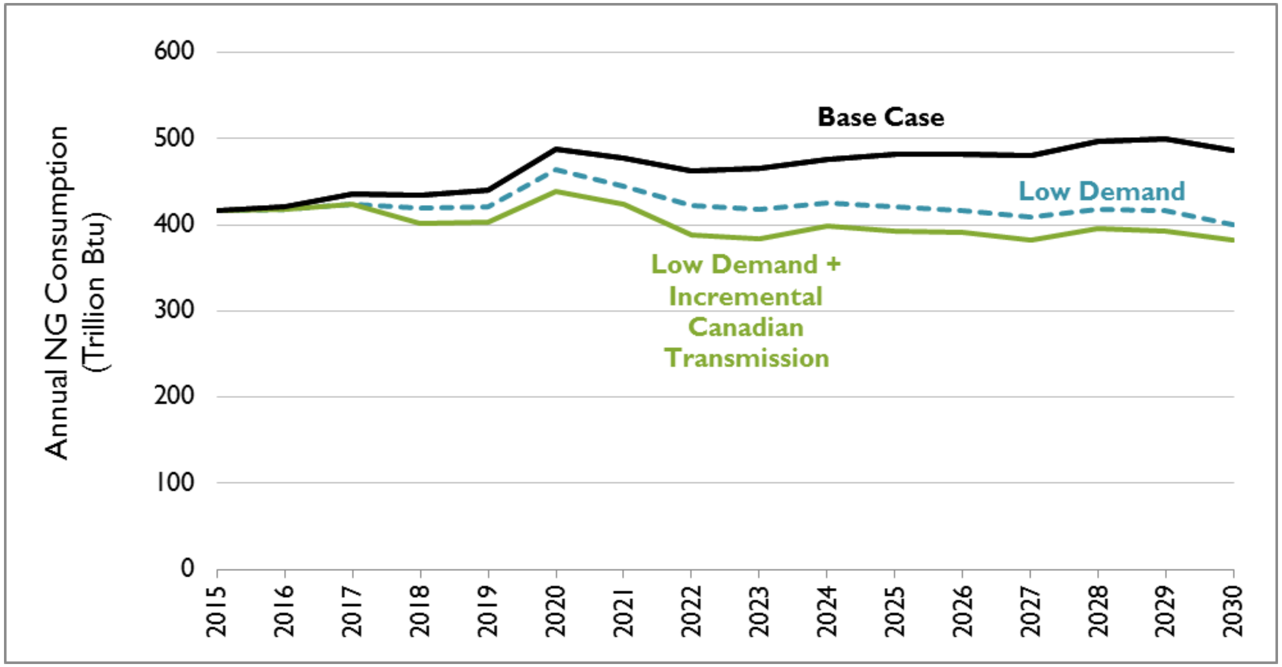
Preliminary Massachusetts Annual Natural Gas Consumption



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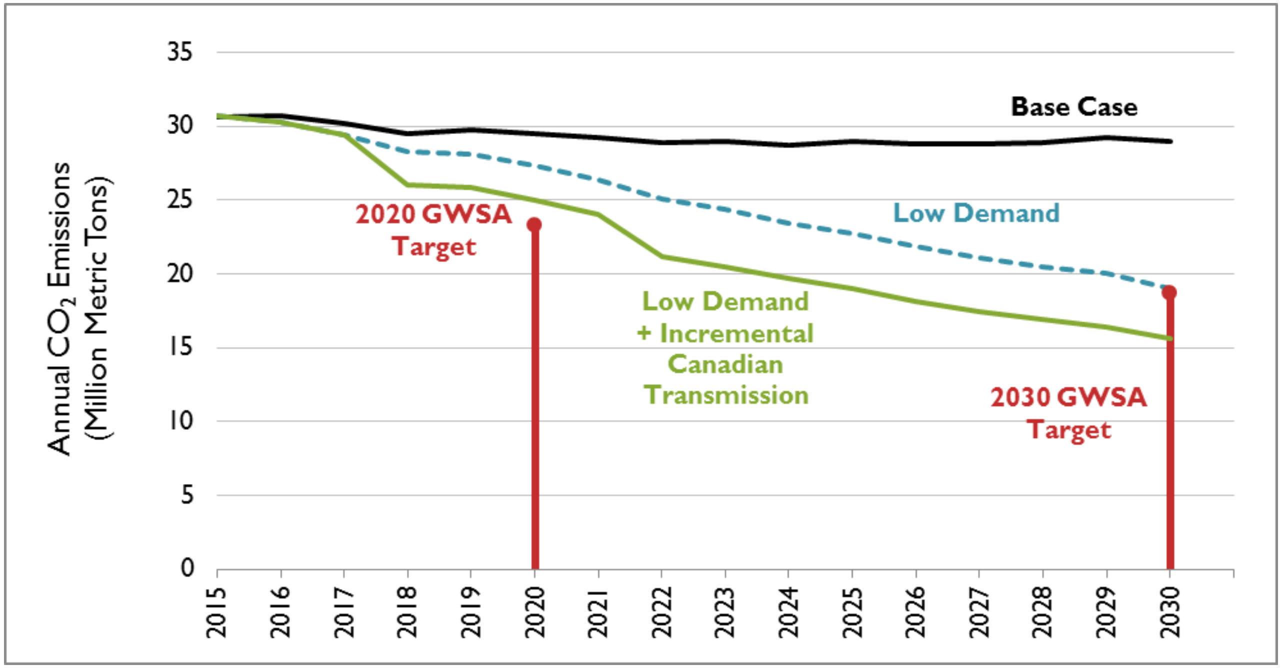
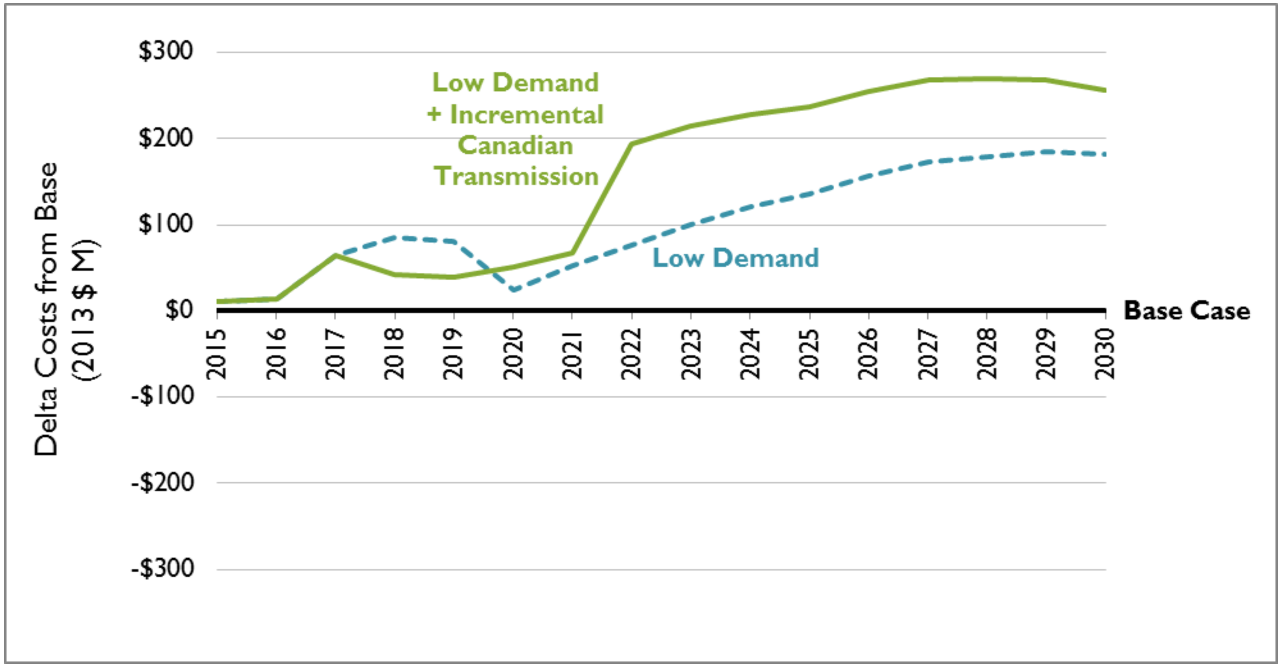
Emissions available under GWSA target

	2020	2030
GWSA Target (% reduction below 1990 statewide levels)	25%	43%
GWSA Target (million metric tons CO_2-e)	70.8	53.5
CECP Non-Energy Sector Emissions (million metric tons CO_2-e)	9.3	7.9
CECP Transportation Sector Emissions (million metric tons CO_2-e)	31.8	26.5
CECP Building and Electric Sector Target (million metric tons CO_2-e)	29.7	19.1
CECP Building Sector Oil Emissions (million metric tons CO_2-e)	6.4	0.4
Emissions Available under GWSA Gas Heating and Electric Target	23.3	18.7

Preliminary Massachusetts Emissions (natural gas heating and electric sectors)



Preliminary Massachusetts Cost Differences from Base Case (natural gas heating and electric sectors)



	Base Case	Low Demand Case	Low Demand + Inc. Canadian Trans.
NPV of Cost Deltas (2013 $ M)	$0	$1,433	$2,157

2015-2030 NPV, assuming a 1.36 percent real discount rate per AESC 2013, Appendix B

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Q&A: Modeling Results Part 1

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Modeling Results Part 2: Sensitivity Analyses and Synapse Observations from Modeling

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Table of Sensitivities

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case	Base Case	Base Case	Base Case	Low Demand Case	Low Demand Case	Low Demand Case	Low Demand Case
Reference NG Price	Low NG Price	High NG Price	Reference NG Price	Reference NG Price	Low NG Price	High NG Price	Reference NG Price
No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission	No Canadian transmission	No Canadian transmission	No Canadian transmission	2,400-MW Incremental Canadian transmission

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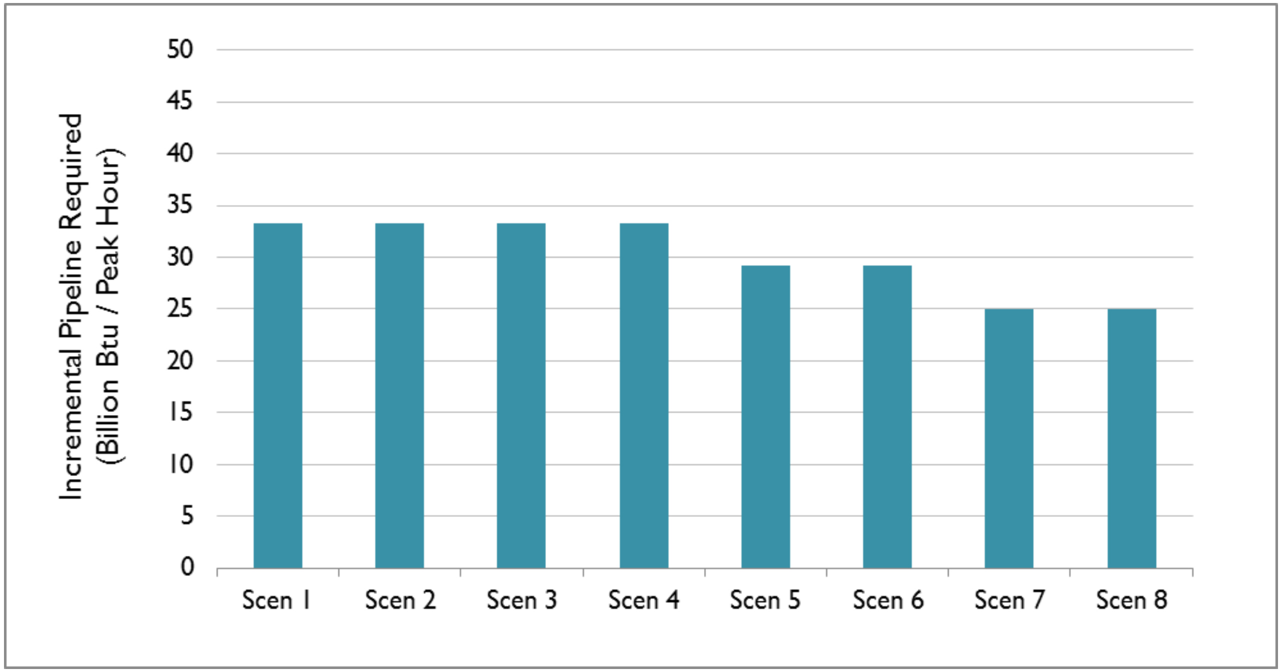
Preliminary Peak Hour Shortages - 2020



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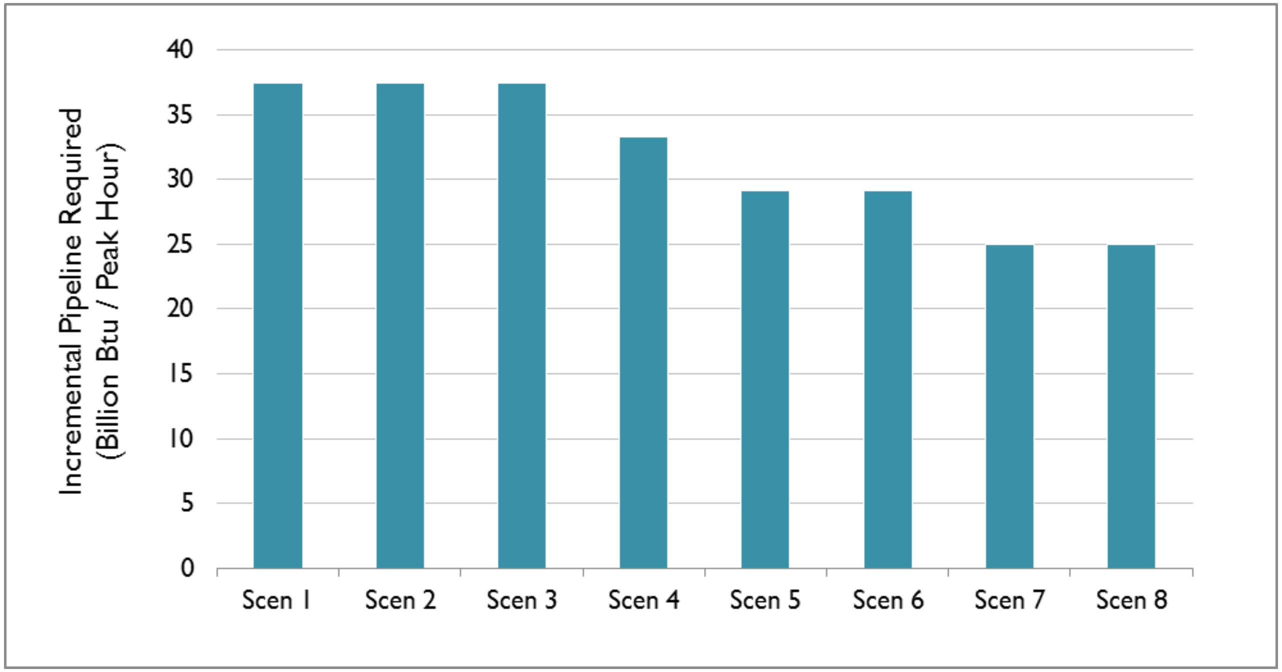
Preliminary Peak Hour Shortages - 2030



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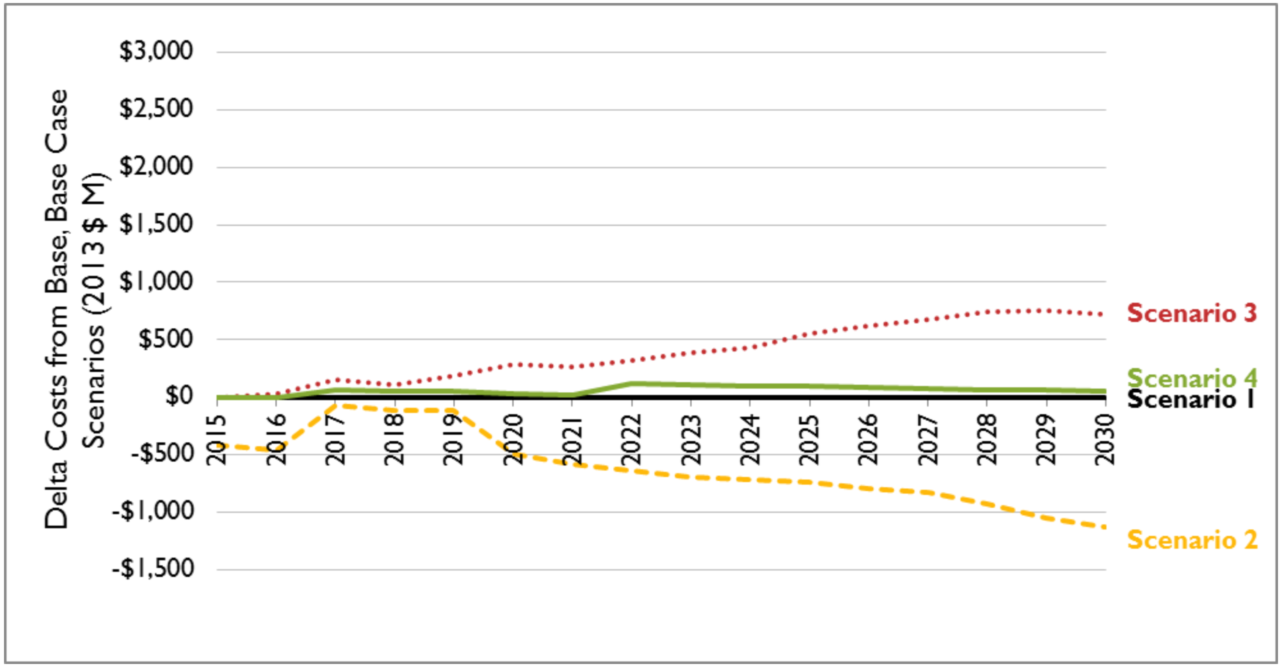
Preliminary Costs – Base Case Scenarios, Difference from Base Case



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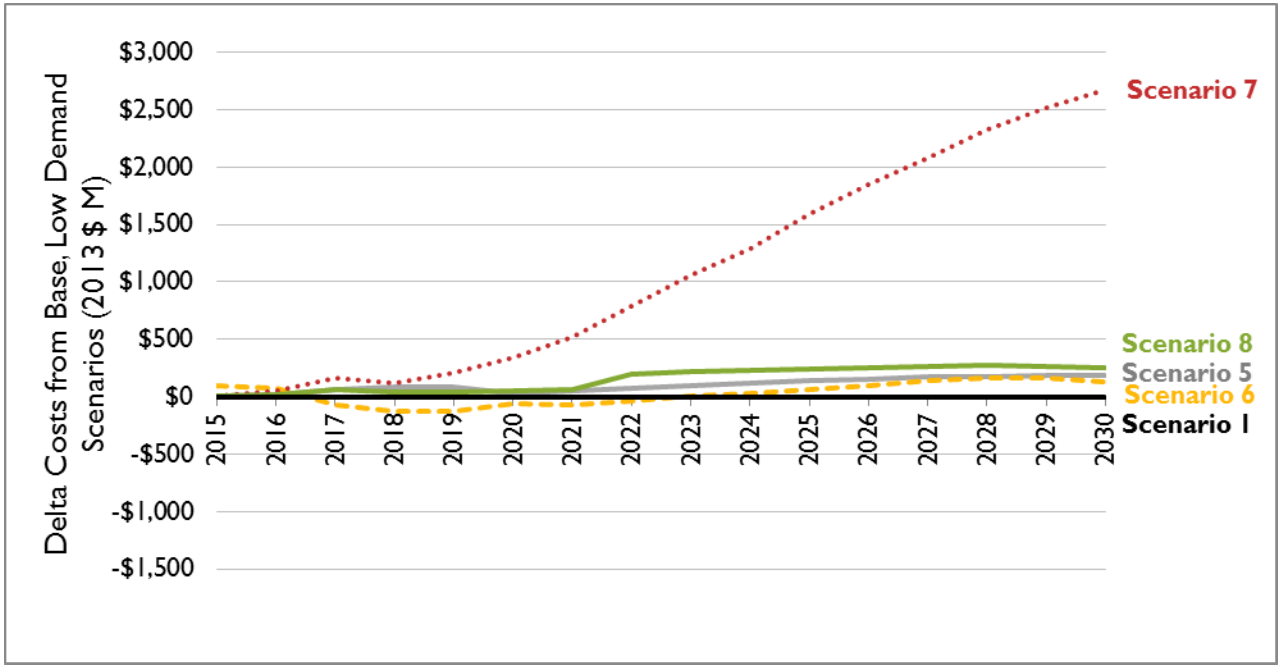
Preliminary Costs – Low Demand Scenarios, Difference from Base Case



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Preliminary Costs – Net Present Value of Difference from Base (2013 $ million)

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
$0	-$8,611	$5,384	$840	$1,433	$389	$15,112	$2,157

2015-2030 NPV, assuming a 1.36 percent real discount rate per AESC 2013, Appendix B

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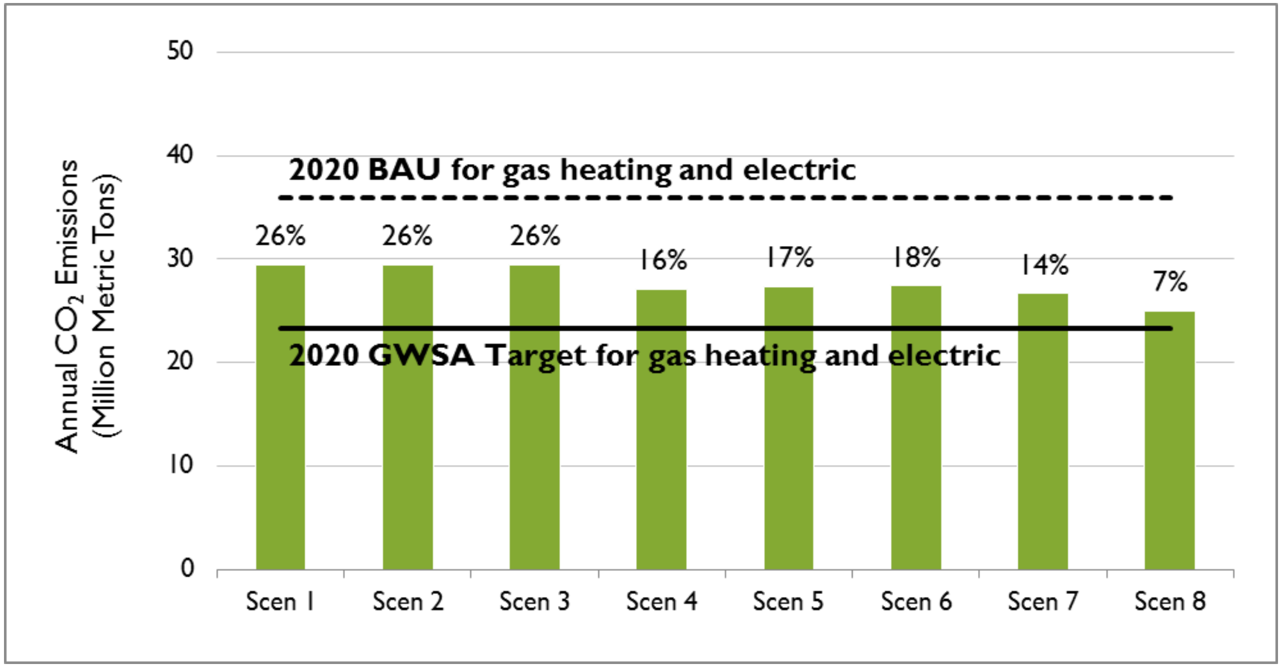
Preliminary 2020 Emissions



- 2020 GWSA target is based on a 25-percent reduction in emissions by 2020.
- 2020 GWSA target for gas heating and electric sectors (23.3 million metric tons), above, is developed assuming other sectors meet their CECP reductions.
- 26- to 7-percent overages in gas heating and electric sector emissions are equivalent to overages of 9 to 2 percent across all sectors.

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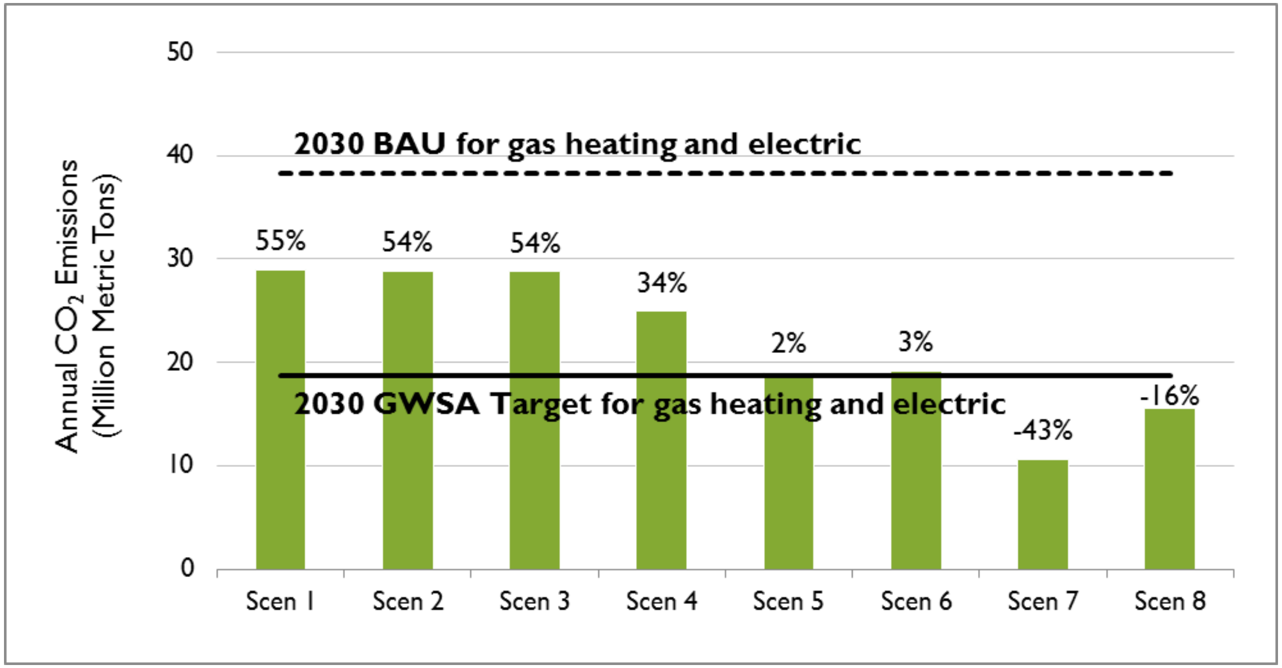
Preliminary 2030 Emissions



- 2030 GWSA target is based on a 43-percent reduction in emissions by 2030.
- 2030 GWSA target for gas heating and electric sectors (18.7 million metric tons), above, is developed assuming other sectors meet their CECP reductions.
- 55- to 2-percent overages in gas heating and electric sectors are equivalent to overages of 19 to 1 percent across all sectors.

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Preliminary Modeling Observations

Price sensitivity of winter peak hour requirements to gas prices

Massachusetts' winter peak hour gas requirements are relatively insensitive to the range of gas prices explored in this analysis. Energy services are relatively inelastic (price insensitive)—particularly in the short run—and are modeled here as such. Changes to the gas price have a limited impact on dispatch in the electric sector in the peak hour, but the dominance of gas in the dispatchable resource mix is, already well established in 2015, only increasing over time. In contrast, annual gas requirements in the electric sector—and, therefore, electric-sector greenhouse gas emissions—do exhibit some sensitivity to gas prices in the range explored. Annual scenario costs, however, are very sensitive to gas prices.

Impact of incremental Canadian transmission

Incremental Canadian transmission at the level explored in this analysis—2,400-MW—reduces Massachusetts' winter peak hour gas requirements in 2030. It also reduces annual gas requirements and electric-sector greenhouse gas emissions while increasing overall costs.

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Preliminary Modeling Observations (cont.)

Similarity in gas requirements across scenarios

Annual gas requirements across scenarios vary -10 to 7 percent per year from Scenario 1 (base case, reference gas price, no incremental Canadian transmission) in 2020 and -17 to 7 percent in 2030.

Impact of alternative measures

At the reference natural gas price, alternative measures reduce Massachusetts' gas requirements by 13 percent in 2030. The majority, or roughly 7 percentage points of this reduction, occurs in the electric sector. Capturing additional costs avoided by alternatives—such as costs of compliance with state environmental laws—has the potential to shift the economic feasibility assessments that determine this result. Also, additional program incentives or policies not currently in place as well as a different economic threshold could also impact the economic feasibility and resulting inclusion of additional alternative measures.

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Caveats

Any interpretations of this study's results should make full consideration of all specified caveats.

Caveats to Winter Peak Event

- Modeling illustrative peak hour

Caveats to Base Case

- We model only existing polices and do not consider or account for currently developing policies or new legislation
- Model uses CELT 2014
- Model uses base case projections of DG per ISO-NE's PV Energy Forecast
- Gas heating demand is assumed to be inelastic
- Study does not take into consideration MA H.4164 (legislation on gas leakages)
- Results dependent on coal unit retirement schedule assumed

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Caveats (cont.)

Caveats to natural gas price assumptions

- Only three natural gas price sensitivities modeled
- Impact of gas exports not considered
- No risk premium associated with natural gas volatility

Caveats to incremental Canadian transmission assumptions

- Imports are modeled as system power
- Generic transmission lines are modeled

Caveats to feasibility analysis assumptions and methodology

- Only resources deemed technically feasible and practically achievable are included in the low demand case
- Economic feasibility is determined by our assumed threshold
- Only modeling alternative measures that could result from changes to MA policy (other states' potential policy changes not modeled)
- Alternative resources included in this feasibility were not comprehensive

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Caveats (cont.)

Caveats to feasibility analysis assumptions and methodology (cont.)

- Avoided costs determined using AESC 2013
- Benefits to alternative measures not included are:
  - *Avoided cost of GWSA compliance*
  - *Non-energy benefits*

Caveats to capacity and demand balance assessment methodology

- No additional LNG storage facilities were modeled
- Generic pipeline costs were modeled in 4.2 peak hour MMBtu increments, based on the per-MMBtu costs of the AIM pipeline
- Study does not include the environmental impacts of pipeline siting and construction, or the environmental impacts of natural gas extraction
- Study does not consider pipeline investments' potential displacement of alternative resources
- Study assumes natural gas supply is sufficient to meet demand and is not constrained by production

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Caveats (cont.)

Caveats to capacity and demand balance assessment methodology (cont.)

- Heating demand projections rely on forecasts supplied by MA LDCs
- Study assumes full LNG availability from Distrigas imports in the peak hour

Caveats to GWSA target assumptions

- Estimates of emissions from upstream natural gas leaks and all life-cycle emission impacts were not included
- Study does not analyze impact of pipeline investments on MA's long-term reliance on natural gas
- No 2030 CECP target yet developed. Study assumes a 2030 target based on straight-line interpolation between the 2020 and 2050 goals.

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Q&A: Modeling Results Part 2

Updated January 7, 2015

Lunch

Updated January 7, 2015

Small Group Break-Out

Updated January 7, 2015

Modeling Results: Stakeholder Group Discussions

Updated January 7, 2015

Next Steps

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Schedule, Materials and Comments

- Stakeholder process materials available on the Synapse website at: http://synapse-energy.com/project/massachusetts-low-demand-analysis
- Written comment deadline for today's meeting: Monday, December 22, 2 PM
  - Send comments to: lowdemandstudy@state.ma.us
  - Comments will be compiled and reviewed by DOER
  - Comments will be posted to Synapse website
- High-level summary of today's meeting will be posted to project website
- December 23 – Target date for **final report** release

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Appendix: Caveat Detail

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Caveat Detail

Caveats to Winter Peak Event

- This study examines the difference between Massachusetts' gas demand and capacity in an illustrative winter peak event hour. We did not analyze gas constraints in a specific historical or expected future hour.

Caveats to Base Case

- The base case for this study includes only existing policies and does not consider or account for currently developing policies or new legislations.
- This study bases its base case projections of electric demand on ISO-NE's CELT 2014 forecast, with the exceptions of adjustments made to ISO-NE's energy efficiency projections (we base these instead on program administrator's latest three-year plans). Any inaccuracies in this forecast—including its accounting of new housing starts—have the potential to affect model results.
- This study bases its base case projections of distributed generation installation on ISO-NE's PV Energy Forecast Update by state, held constant after 2020.

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Caveat Detail (cont.)

Caveats to Base Case (cont.)

- This study assumes that gas heating demand is inelastic—that is, gas heating demand does not fluctuate with changes in the gas prices. While actual consumer fuel use is widely regarded to be largely insensitive to fuel prices in the short run, heating demand has the potential to exhibit more sensitivity to gas prices in the long run as customers change heating technologies.
- This study did not consider MA H.4164 expansion of gas distribution and the effect of this expansion on gas demand. Inclusion of gas distribution expansion has the potential to change model results, to the extent that this expansion is not already accounted for in the LDC's heating gas demand forecasts through 2019 and the DOER-based growth rate for heating gas demand thereafter.
- The modeling analysis presented in this study is dependent on the coal unit retirements assumed

Caveats to natural gas price assumptions

- This study explores the sensitivity of model results to the range in natural gas prices described above. Still higher or lower natural gas prices have the potential to change model results.
- This study does not include a risk premium associated with natural gas price volatility.

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Caveat Detail (cont.)

Caveats to natural gas price assumptions (cont.)

- This study does not specifically examine the impact of natural gas exports on the potential range of gas prices. The low and high gas prices used in sensitivities were the "Low and High Oil and Gas Resource Cases" from the U.S. Department of Energy (DOE) and EIA's *2014 Annual Energy Outlook* and were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes the uncertainty of gas availability from shale reserves and developed these alternate resource cases to address it.

Caveats to incremental Canadian transmission assumptions

- Both existing and incremental Canadian transmission is modeled as system power from Québec –that is, generation and its associated emissions are assumed to be an average or mix of Québécois resources, and not dedicated transmission of hydroelectric or any other resource. Average Québécois electric generation is treated as having zero greenhouse gas emissions in this study when in fact the emission rate associated with Québec imports is estimated to be 0.002 metric tons per MWh. Incorporating the actual emissions associated with these imports in our study would have no appreciable impact on total emissions or GWSA compliance.

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Caveat Detail (cont.)

Caveats to incremental Canadian transmission assumptions (cont.)

- While based on the most recent data for costs and in-service dates of proposed transmission lines, in this study, Canadian transmission lines are generic and do not represent any specific project. The costs and in-service dates of actual transmission lines would be expected to vary from the generic lines represented here. Changes to costs or in-service dates of these lines would be expected to impact model results.

Caveats to feasibility analysis assumptions and methodology

- In this study, only resources jointly deemed technically feasible and practically achievable in Massachusetts for each year, given our best understanding of the pace of policy change and resource implementation (but ignoring cost), were assessed for economic feasibility and potential inclusion in the low demand case. Technological advancements and new information regarding the expected pace of policy change and resource implementation would have the potential to result in the inclusion of different resources in the feasibility analysis, different alternative measures included in the low demand case and different model results for this case.

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Caveat Detail (cont.)

Caveats to feasibility analysis assumptions and methodology (cont.)

- In this study, resources are deemed “economically feasible” if they are less expensive than a threshold estimated as the per MMBtu cost of a generic, scalable natural gas pipeline. The choice of this threshold determines what alternative resources are or are not included in the low demand case. A different threshold for inclusion in the low demand case would result in the inclusion of different alternative measures, and different model results for the low demand case.
- This study only includes alternative measures that could potentially result from changes to Massachusetts policy, and not alternative measures brought about by policy changes in other New England states.
- The avoided costs attributed to alternative measures in this study are derived from the AESC 2013 . Since the publication of AESC 2013 there have been changes to projected fuel prices, public policy, and the market structure in ISO-NE, all of which are expected to be included in modeling for the AESC 2015 that is currently in progress. Avoided costs modeled in AESC 2015 may be different—higher or lower—than those modeled in AESC 2013.

Caveat Detail (cont.)

Caveats to feasibility analysis assumptions and methodology (cont.)

- Benefits to alternative measures not included in the low demand case include:
  - The avoided carbon cost of GWSA compliance (which was included only for energy efficiency measures in this study consistent with DPU 14-86)
  - Non-energy benefits including improved health, or reduced health costs, and new jobs related to alternative measures
- Costs to alternative measures not included in this study have the potential, if considered, to result in fewer resources deemed economic and included in the low demand case, changing the results of that case. Potential costs not included in the assessment of these measures include non-energy costs such as negative environmental impacts from alternative resource siting.

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Caveat Detail (cont.)

Caveats to feasibility analysis assumptions and methodology (cont.)

- The examination of possible alternative resources to be included in this feasibility analysis was not comprehensive. Alternatives resources that were either not deemed to be reasonably available during the time frame of this study or of limited potential capability were not included in the supply curves for economic feasibility assessment. Resources not considered in the analysis include:
  - Solar panels installed on every sunny rooftop, and on every piece of land, where the installation is technically feasible
  - Unrestricted deployment of neighborhood-shared and community-shared solar
  - Solar energy with no net-metering cap or restriction and without any type of restriction imposed by utility companies
  - Technological improvement in the lighting efficiency
  - A public education campaign in Massachusetts similar to Connecticut's "Wait 'til 8" program
  - Solar energy backed by batteries as a separate alternative resource
  - Rate reforms such as peak time rebates and demand charges
  - Transmission for wind firmed by hydro
  - Smart appliances
  - All new affordable-housing units built as zero-net-energy or net positive energy residences
  - Net zero carbon zoning codes
  - Conversion to electric vehicles

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Caveat Detail (cont.)

Caveats to capacity and demand balance assessment methodology

- This study assumes that no additional LNG storage facilities will be sited in Massachusetts during the study period. This is based on expected challenges related to permitting, siting, financing and potential public opposition.
- This study assumes additions of a generic natural gas pipeline, available in 4.2 peak hour MMBtu increments and based on the per MMBtu costs of the AIM pipeline. Although pipeline increments are added based on the requirement in the peak hour, incremental pipeline is assumed to be in use throughout the year. As a result, we have levelized the cost of these pipeline increments over an entire year. If a pipeline increment were only in use for a portion of the year, the implied levelized cost would be different.
- This study does not consider environmental impacts of pipeline siting and construction, nor does it consider the environmental impacts of natural gas extraction, such as those related to fracking.
- This study does not consider pipeline investments potential displacement of alternative resources, thereby slowing their growth.

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Caveat Detail (cont.)

Caveats to capacity and demand balance assessment methodology (cont.)

- This study analyzes Massachusetts capacity during a winter peak event hour assuming that if demand exists, market forces will make it economic to utilize existing capacity. We do not examine the ability of specific supply basins to produce natural gas, or the impact on supply to Massachusetts of demand in other regions.
- Gas capacity constraints shown in this analysis may be higher than what is shown in the Forecast and Supply Plans filed by the Massachusetts LDCs due to the inclusion of capacity-exempt customer demand. LDCs, by regulation, do not acquire gas supply resources to serve capacity-exempt customers. Those customers, however, are firm gas customers that place demands on the system. In MA-DPU 14-111, the Massachusetts LDCs petitioned the DPU to allow them to acquire resources to serve up to 30 percent of the capacity-exempt load. In that petition, the LDCs estimated that the total capacity exempt load on a design day is approximately 294,200 Dth. The total capacity-exempt load is included in our analysis.
- Our analysis assumes LNG availability from Distrigas for import in the peak hour. If natural gas from these sources are not available in the peak hour, the ability for the natural gas system to be in balance will be reduced.

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Caveat Detail (cont.)

Caveats to capacity and demand balance assessment methodology (cont.)

- For this analysis, we have assumed the full vaporization capacity of the Distrigas LNG facility and the full capacity of the Maritimes & Northeast Pipeline are available in the peak hour. In order for markets to fully utilize this capacity, there must be sufficient supply supporting those facilities. The Distrigas LNG terminal relies on imported LNG. LNG markets are influenced by world supply and demand dynamics, which most recently have made it difficult for imported LNG to compete in U.S. markets. These dynamics have caused significant disruptions in deliveries to the Distrigas LNG facility in Everett, MA over the past few years. Similarly, reductions in pipeline supply to the Maritimes & Northeast Pipeline may restrict use in future years.

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Caveat Detail (cont.)

Caveats to GWSA target assumptions

- Estimation of methane emissions from upstream leaks and other sources of emissions in the natural gas system—as well as all other life-cycle emission impacts of Massachusetts heating and electric sectors—was not in the scope of this study. Estimation of these impacts has the potential to increase greenhouse gas emissions in all scenarios. Synapse recommends that if life-cycle emission analysis is included in future scenarios it be included for all heating fuel and electric generation and alternative resources, and not for a subset of these resources.
- Estimation of emissions from leaks in Massachusetts natural gas distribution system as well as potential emission reductions available from repairs to these leaks were not included in this study. An ICF study of Massachusetts gas leaks commissioned by MA-DPU was not released in time for use in this study. Synapse recommends that this information be considered in future studies.
- This study does not analyze the impact that investments in pipeline infrastructure have on increasing the Commonwealth's long-term commitment to reliance on natural gas and the potential impact of this reliance on GWSA compliance.
- A CECP for 2030 has not yet been developed. The 2030 GWSA target is based on straight line extrapolation towards the 2050 limit and similar allocation of relative reductions from each sector as was assigned in CECP for 2020.

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