Gas Demand Growth, Load Distribution and Natural Gas Infrastructure Solutions for New England

Prepared for NESCOE
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Discussion Outline

• Phase II Objectives
• Black & Veatch Methodology Overview
• New England Demand Growth
• Geographic Load Distribution and Infrastructure
• Load Duration and Constraint Assessment
• Natural Gas Infrastructure Costs
• Power Side Solutions
• Recommended Scenarios
Phase II Objectives

• Black & Veatch study in Phase I concluded that the New England natural gas infrastructure will be increasingly under pressure from demand growth from the power sector.

• In Phase II, Black & Veatch will:
  • Analyze historical gas demand in New England by sector.
  • Project growth requirements by sector for the next 15 years.
  • Summarize announced pipeline expansion projects and generic infrastructure options and provide high level cost estimates for infrastructure options.
  • Identify demand and power side response.
  • Identify scenarios and sensitivities for further analysis.
Black & Veatch Infrastructure Adequacy Assessment Framework

- Black & Veatch has constructed a comprehensive framework to assess the natural gas adequacy on a regional basis

- **How is Adequacy Defined?**
  - Probability Risk Assessment
    - Reliability
    - Economic

- **Is the Existing NG System Adequate?**
  - Regional Load Growth by Sector
    - Geographic Load Distribution
    - Sub-region Natural Gas Infrastructure
    - Daily/Hourly Load Variation

- **What are the Alternatives?**
  - Appropriate to solve periods of capacity duration
  - Implementation feasibility

- **What are the Costs and Benefits of the Alternatives?**
  - Cost estimates
    - Regulatory vs. Commercial
  - Price impact and market benefits
    - Natural Gas Market
    - Electricity Energy Market
    - Capacity Market

- **Which Alternative(s) Best Meet Objectives?**
  - Cost Benefits Comparison
  - Strategic Considerations
Analysis Methodology – Phase II

• Black & Veatch analyzed historical natural gas demand by sector in New England by State
• Residential, commercial and industrial demand are projected as determined by
  • Weather
  • Economic Growth
  • Population Growth
  • Efficiency Gains/Usage per Customer
  • Policy Initiatives
• Demand growth from the power generation sector is projected using a combination of production simulation model ProMod IV and fundamental natural gas model GPCM
  • Consistent fuel price from GPCM inputs into ProMod
  • Customized assumptions on technology costs, environmental policies, renewable resources, transmission, which were supported by industrial knowledge and project experience
• Black & Veatch disaggregated demand into local demand centers to account for different infrastructure access
• Monthly and daily variation of demand is constructed to provide a comprehensive profile of demand requirements
Black & Veatch Analysis Tools – GPCM

• Gas Pipeline Competition Model (“GPCM”) is a network flow model of the North American natural gas market
• The model considers the entire North American natural gas market - including Alaska, Canada, US Lower 48, Mexico and LNG Imports/Exports to/from North America. Major assumptions include
  • Supply
    ➢ Production projections by type – such as shale, coal bed methane, conventional and tight sands by basin
    ➢ All major shale plays (Barnett, Haynesville, Marcellus, Eagle Ford, Utica, etc.) are covered
  • Demand
    ➢ Projections by sector and by demand area – at the state and sub-state level
    ➢ All natural gas and electric utility included
  • LNG
    ➢ Includes all LNG import/export terminals with pipeline headers
  • Infrastructure
    ➢ All existing interstate, intrastate, GOM gathering pipelines
    ➢ Operational natural gas storage fields with individual injection/withdrawal ratchets
    ➢ Proposed infrastructure is included according to the status of the project
New England Natural Gas Pipeline Infrastructure

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Natural Gas basis change across North American Market (2012–2022)

- **BC shale production grows faster than Alberta demand**

- **California basis rises with demand growth and waning supplies**

- **Moderating production, adequate market access**

- **Chicago basis rises in tandem with incremental demand for gas-fired generation in the Midwest**

- **Demand pull at station 85 will open spreads to Louisiana**

- **South Texas basis will remain stable due to strong intra-state and demand outlet in Mexico**

- **Electric sector drives rebound in demand growth**

- **Regional supply growth outpaces market outlets**

- **Continued Growth in gas-fired generation will drive basis growth in the southeast**

- **Power generation and Petrochemicals lead strong demand growth**

- **Strong power generation Growth precedes new pipeline capacity**

Source: Black & Veatch Energy Market Perspective Analysis
Ventyx PROMOD IV is a generator and portfolio modeling system, provides nodal Locational Marginal Price (LMP) forecasting and transmission analysis by producing algorithms that mimic the decision making process of investment and dispatch of electric generators.

- All generation assets and their operational characteristics
- Expected renewable resources
- Major market zones, load centers and hourly load profiles
- Major transmission capacity between market zones and constraints

For each hour of the forecast period, the model first clears the local supply and demand within each market zone, and then optimizes electricity transfers to optimize total system production costs to arrive at “arbitrage free” prices.

This simulation process is repeated for each hour of the simulation period, while at the same time capturing the chronological constraints and limitations of each generation asset.
PROMOD IV covers the entire North American Grid

Source: Black & Veatch Energy Market Perspective Analysis
Load Center and Transmission Zones in PROMOD IV

<table>
<thead>
<tr>
<th>Interconnect</th>
<th>U.S.</th>
<th>Canada</th>
<th>Mexico</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>37</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>ERCOT</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>WECC</td>
<td>21</td>
<td>2</td>
<td>1</td>
</tr>
</tbody>
</table>

Source: Black & Veatch Energy Market Perspective Analysis
Discussion Outline

• Phase II Objectives
• Black & Veatch Methodology Overview
• New England Demand Growth
  ➢ Residential, Commercial and Industrial Approach
  ➢ Demand Projections by State
  ➢ Power Modeling Assumptions
• Geographic Load Distribution and Infrastructure
• Load Duration and Constraint Assessment
• Incremental Infrastructure Costs
New England Residential, Commercial and Industrial Demand Projections – Approach

• Black & Veatch analyzed historical data to find statistical relationship of residential, commercial and industrial demand to major market drivers of demand
• Data sources reviewed and relied upon in Black & Veatch’s analysis:
  ➢ EIA monthly historical demand by sector by state (January 2000 through August 2012)
  ➢ EIA annual deliveries by state by sector and number of customers by sector – EIA 176 (2000 through 2011)
  ➢ Daily weather data at Logan International Airport (1983 through 2012), Brainard Airport (1997 through 2012) and Concord Municipal Airport (1983 through 2012)
  ➢ Gross State Product (GSP) from 2000 through 2011
  ➢ Population by state from 2000 through 2010
  ➢ Relative price of fuel (heating oil vs. natural gas price from 2000 through 2012)
• Black & Veatch analyzed average usage per customer and number of customers to create the projections by state by sector
• 20-year normal weather is utilized in the projection
• For most states, historical average population or economic growth rate, customer growth rate are assumed to continue forward for projections. Special assumptions are made to Connecticut to reflect recent policy initiatives
## Residential, Commercial and Industrial Demand Projection Assumptions

<table>
<thead>
<tr>
<th>Compound Annual Growth Rate 2013-2028</th>
<th>Connecticut</th>
<th>Massachusetts</th>
<th>New Hampshire</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential</td>
<td>Commercial</td>
<td>Industrial</td>
</tr>
<tr>
<td>Average Customer Usage</td>
<td>-0.76%</td>
<td>-1.02%</td>
<td>2.80%</td>
</tr>
<tr>
<td>No. of Customers</td>
<td>2.99%</td>
<td>3.16%</td>
<td>-3.10%</td>
</tr>
<tr>
<td>Projected Demand Growth</td>
<td>2.21%</td>
<td>2.11%</td>
<td>-0.30%</td>
</tr>
<tr>
<td>2011 Consumption (MMcf/d)</td>
<td>127</td>
<td>126</td>
<td>71</td>
</tr>
<tr>
<td>2011 Consumption as % of New England demand for sector</td>
<td>22.48%</td>
<td>30.06%</td>
<td>22.91%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Rhode Island</th>
<th>Maine</th>
<th>Vermont</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential</td>
<td>Commercial</td>
</tr>
<tr>
<td>Average Customer Usage</td>
<td>-2.30%</td>
<td>-2.94%</td>
</tr>
<tr>
<td>No. of Customers</td>
<td>3.42%</td>
<td>2.96%</td>
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<tr>
<td>Projected Demand Growth</td>
<td>1.12%</td>
<td>0.02%</td>
</tr>
<tr>
<td>2011 Consumption (MMcf/d)</td>
<td>49</td>
<td>31</td>
</tr>
<tr>
<td>2011 Consumption as % of New England demand for sector</td>
<td>8.59%</td>
<td>7.41%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch Analysis
Projection Methodology – understanding the impact of weather on residential and commercial demand

Connecticut Residential and Commercial Demand

- Actual
- Weather Normalized

Source: DOE EIA, Black & Veatch Analysis
Black & Veatch Analysis Process

• For each state and each sector, Black & Veatch has gone through the following process:
  • Analyze the historical relationship of average customer usage as related to weather or GDP growth
  • Analyze the historical relationship of number of customer growth with that of population growth or GDP growth
  • Assume the historical trend of average customer usage continues into the future under normal weather conditions
  • Assume that the number of customers grow at a rate similar to historical levels

• We have presented the next several slides for the state of Connecticut to reflect this process and in particular, the fact that our assumed residential and commercial customer growth has reflected the comprehensive energy strategy
Average residential customer usage was projected using historical weather and gross state product data.

Connecticut Average Residential Customer Usage per Customer

-Usage per customer in Connecticut is positively affected by weather and negatively impacted by economic growth, which reflects efficiency gain over time.
- In projection, Black & Veatch assumes usage per customer in CT will maintain its historical rate of decline under a normal weather condition.

Source: DOE EIA, Black & Veatch Analysis
Connecticut customer growth closely tracks population growth

Connecticut Residential Demand

Population (000's) vs Customers (000's)

Source: DOE EIA, Black & Veatch Analysis
Connecticut residential demand is expected to experience robust growth through 2020

- Historically, residential customers have grown 0.7%/year with population growth of 0.5%/year.
- However, Governor Dannel P. Malloy has outlined a plan to increase penetration from 31% to 50% of all households by 2020, implying an additional 250,000 residential customers in the next seven years. Black & Veatch assumes this program is successful.
- Black & Veatch assumes that after 2020, the number of residential customers will grow at 0.7%.

Source: DOE EIA, Black & Veatch Analysis
Historical and Projected Residential, Commercial and Industrial Demand for Connecticut

Historical and Projected Natural Gas Demand

Source: DOE EIA, Black & Veatch Analysis
Massachusetts
Historical and Projected Natural Gas Demand

2013-2028 Compound Annual Growth

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Power Gen</th>
</tr>
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<tbody>
<tr>
<td>2001</td>
<td></td>
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<td></td>
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<td>2009</td>
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<td>2011</td>
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<td>2025</td>
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<tr>
<td>2027</td>
<td></td>
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</tr>
</tbody>
</table>

Source: DOE EIA, Black & Veatch Analysis
Historical and Projected Residential, Commercial and Industrial for Rhode Island

Rhode Island
Historical and Projected Natural Gas Demand

2013-2028 Compound Annual Growth

<table>
<thead>
<tr>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Power Gen</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.12%</td>
<td>0.02%</td>
<td>2.30%</td>
<td>1.34%</td>
</tr>
</tbody>
</table>

Source: DOE EIA, Black & Veatch Analysis
Historical and Projected Residential, Commercial and Industrial and Power Generation for New Hampshire

New Hampshire
Historical and Projected Natural Gas Demand

<table>
<thead>
<tr>
<th>2013-2028 Compound Annual Growth</th>
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</thead>
<tbody>
<tr>
<td>Residential</td>
</tr>
<tr>
<td>1.82%</td>
</tr>
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</table>

Source: DOE EIA, Black & Veatch Analysis
Historical and Projected Residential, Commercial and Industrial for Maine

**Maine Historical and Projected Natural Gas Demand**

<table>
<thead>
<tr>
<th>2013-2028 Compound Annual Growth</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Power Gen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>4.18%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>3.83%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Industrial</td>
<td>9.40%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power Gen</td>
<td>0.50%</td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

Source: DOE EIA, Black & Veatch Analysis
Historical and Projected Residential, Commercial and Industrial for Vermont

Vermont Historical and Projected Natural Gas Demand

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Power Gen</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>2.78%</td>
<td>1.05%</td>
<td>0.80%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

2013-2028 Compound Annual Growth

Source: DOE EIA, Black & Veatch Analysis
Discussion Outline

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Compliance Deadline Assumptions

**REGULATORY DRIVER**

- 1-Hour NAAQS
  - 2010: Designate NAs
  - 2011: Develop SIPs
  - 2012: Compliance

- Cross State Air Pollution Rule
  - 2010: Develop Rule
  - 2011: Legal Challenge
  - 2012-2020: CAIR

- Mercury and Air Toxics Standards
  - 2010: Develop Rule
  - 2011: Compliance Prep Period
  - 2012-2020: Compliance

- Clean Water Act 316b
  - 2010: Develop Rule
  - 2011: Compliance Prep Period
  - 2012-2020: Compliance

- Effluent Guidelines
  - 2010: Develop Rule
  - 2011: Compliance Prep Period
  - 2012-2020: Compliance

- Coal Combustion Residuals
  - 2010: Develop Rule
  - 2011: Compliance Prep Period
  - 2012-2020: Compliance
Greenhouse gas Regulation Assumptions

Assumes national CO₂ reductions are called for by a cap and trade program with delays in targeted emission reductions

- Legislative delays and CO₂ reductions resulting from implementation of a regime similar to CSAPR in 2016 and other regulation drives our assumption of 2020 being the first year of implementation for a carbon policy
- Covers electric generation, transportation and other fossil fuels used by residential, commercial and industrial sectors
- Until 2020, northeastern states continue to comply with RGGI. California compliance to begin in 2013

CO₂ emission caps are estimated by some to produce stable world temperatures by 2070.

Technical assumptions inherent in Black & Veatch Baseline Forecast

- Allowances can be banked for future use
- Use of 2 billion metric tons (2.2 billion short tons) of emission offsets is allowed economy-wide
- A CO₂ cap & trade program will induce the application of the most cost-effective avoidance and abatement measures first and additional measures in order of increasing cost until total emissions are under the targeted cap – Allowance prices are determined by the marginal cost of control of the last measure required to meet the cap
- Electric industry caps and use of offsets are in proportion to economy-wide caps. Currently electric generation contributes 39% of covered emissions
- New combined cycle capital costs and lower near-term natural gas prices reduce resulting CO₂ prices

Offsets are permanent greenhouse gas emission reductions or avoidance (including sequestration) not required by any law or regulation. The offset project developer is issued one credit for each CO₂e that the project reduces, avoids or sequesters.
New England States will be subject to RGGI before national carbon legislation in 2020

- Emission allowance prices depend upon projected trading between states, coal unit retirements, and EPA regulations, among other factors

- RGGI price is an average based on IPM modeling performed for the RGGI program review

- Black & Veatch assumes that MATS compliance will be in effect from end of 2015

- Black & Veatch assumes carbon legislation will come into effect in 2020, and have assumed the CO2 prices shown to model the impact of carbon legislation on our forecast

Source: Black & Veatch Analysis
State Renewable Portfolio Standards

- Solar carve-outs modeled separately
- States with RPS Requirements meet 100% of target (including VT)
- States RPS programs meet 75% of target
- Final RPS target % are maintained for the rest of the analysis period
New England Renewable Portfolio Standards

- Vermont’s SPEED program has a voluntary goal of reaching 20% of load by 2017 being served by new (post-2005 vintage) renewables

- The Renewable Energy Certificates (RECs) generated by Vermont’s renewables projects are not used toward the state’s SPEED goals

- For the RECs that are sold to Massachusetts and Connecticut, the same number of renewable deducted from the Massachusetts and Connecticut renewable capacity additions

Source: Black & Veatch Analysis
Black & Veatch’s Approach For Plant Retirements

- Black & Veatch applies a five-stage approach to determine unit retirements for the analysis period.

- Retrofit and related economic analysis is based upon publically available information on each plant and industry average cost for retrofits.

- Oil and old natural gas units are retired according to public announcement or age.

<table>
<thead>
<tr>
<th>Stage 1</th>
<th>Stage 2</th>
<th>Stage 3</th>
<th>Stage 4</th>
<th>Stage 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Announced retirements</td>
<td>Retirements of uneconomical units</td>
<td>Assessment of units (on an individual unit basis), that would need different emission control equipment to be installed in order to be compliant</td>
<td>Retirement of old units</td>
<td>Retirement of units that are unable to recover cost of retrofits</td>
</tr>
</tbody>
</table>
Assumed ISO-NE Retirements

Source: Black & Veatch Analysis
Future Resources are likely to be an even mix of CTS and CCS

- Black & Veatch assumes new Combined Cycle and Combustion Turbine units with improved heat rates), low installation costs, and lower operating costs will be available in the region.
- New capacity is anticipated after 2020-21 when the reserve margin falls below the target level.
- Initially only CTs are built to provide peaking capacity and energy. Subsequently as energy demand goes up, CCs are added along with CTs to provide efficient baseload energy in addition to fulfilling capacity needs.
- New combined cycles are added in Massachusetts and Connecticut.
- CTs are added throughout the region.
- This capacity addition plan is based on Energy Efficiency forecast extrapolated flat after 2022, which may be revised.

Source: Black & Veatch
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Overview of Geographic demand disaggregation within New England

• Black & Veatch separated New England into 14 sub-regions to reflect physical access to natural gas supply and capacity constraints
  ➢ Black & Veatch considers VT demand in total demand for gas in New England, however, since the volume is relatively small, no separate load duration and constraint assessment is performed for VT

• The regional breakout is at an aggregated county level and considers service territories of Local Distribution Companies (“LDC”) and physical access to interstate pipelines

• The following map shows the geographic demand nodes that Black & Veatch has evaluated individually
Load Duration Curves for Each Sub-region and Existing Capacity

• Black & Veatch undertook an analysis to convert the static demand projection into a visual load duration curve over a year. The “load shape” of a region provides a summary of the range of demand experienced as well as how often various levels of demand were experienced over a period of time.

• Gas capacity is compared against with the daily load duration, Black & Veatch assessed the physical capacity on existing natural gas pipelines as well as the current firm contracted capacity to delivery points serving the sub-region.

• Black & Veatch constructed hourly load duration curves for select sub-regions that have the largest proportion of gas fired generation load to assess hourly variation of power load could exacerbate the gas infrastructure adequacy issues during summer periods of peak electric demand.
Load Duration Curves for Each Sub-region and Constraint Capacity

• Black & Veatch’s review of the historical daily and hourly load duration curves for sub-regions only identified limited occurrences of total load requirements exceeding the existing pipeline contract capacity at certain sub-regions

• This is inconsistent with the increasing New England market constraints expressed by significantly higher levels of natural gas price volatility than other parts of the US

• Black & Veatch constructed a statistical analysis to conclude that when total deliveries in a sub-region approaches 75% of existing contract capacity serving the sub-region, basis frequently spikes up

• To reflect these dynamics that are characteristic of the New England market, Black & Veatch constructed an “Existing Constraint Capacity” which is 75% of existing contracted capacity
Aggregate New England Load Duration Curve

Natural Gas Pipeline Deliveries to New England: April 2011- March 2012

- Algonquin
- Tennessee
- Maritimes & Northeast
- Portland Natural Gas
- LNG Peak-Shaving

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
New England Natural Gas Price Volatility Has Risen this Past Winter

Historical New England Basis to Henry Hub

Source: Black & Veatch Analysis, Platts Gas Daily Prices
Strong Relationship between Daily Load Duration and Natural Gas Price Basis Blowouts

Tennessee Zone 6 Basis Based on Greater Boston Load Duration Curve (2009-2012)

Source: Black & Veatch Analysis, Platts Gas Daily Prices
Pipelines & Natural Gas Power Generation
Eastern Massachusetts

- Algonquin Gas Transmission
- Tennessee Gas Pipeline
- Maritimes & Northeast Pipeline
- Portland Gas Transmission

Power Generation:
- 600 – 1200 MW
- 150 – 599 MW
- 0 – 149 MW
Eastern Massachusetts Load Duration Curve

Historical and Projected Load Duration Curves
Eastern Massachusetts

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

- Existing Capacity
- Projected Capacity
- Projected Constraint Capacity
- Existing Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve from April 2023 thru March 2024- Eastern Massachusetts

Projected Hourly Load Duration Curve - Eastern Massachusetts

- Residential, Commercial and Industrial Demand
- Power Generation Demand
- Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve for 2023 to 2024 Gas Year – Eastern Massachusetts

Projected Hourly Load Duration Curve - Eastern Massachusetts

- Residential, Commercial and Industrial Demand
- Power Generation Demand
- Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Western Massachusetts

- Tennessee Gas Pipeline
- West Massachusetts
- Power Generation: 150-599 MW
- Power Generation: 0-149 MW
Western Massachusetts Load Duration Curve

Historical and Projected Load Duration Curves for Western Massachusetts

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation Southeastern Massachusetts

- Algonquin Gas Transmission
- Tennessee Gas Pipeline
- Southeast Massachusetts

- Power Generation: 600 – 1200 MW
- Power Generation: 150 – 599 MW
- Power Generation: 0 – 149 MW
Southeastern Massachusetts Load Duration Curve

Historical and Projected Load Duration Curves for Southeastern Massachusetts

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

Legend:
- Existing Capacity (red solid line)
- Projected Capacity (red dashed line)
- Existing Constraint Capacity (black solid line)
- Projected Constraint Capacity (black dashed line)

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Southwestern Connecticut
Southwestern Connecticut Load Duration Curve

Historical and Projected Load Duration Curves for Southwestern Connecticut

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

Existing Capacity

Existing Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve from April 2023 thru March 2024 - Southwest Connecticut

Projected Hourly Load Duration Curve - Southwest Connecticut

- Residential, Commercial and Industrial Demand
- Power Generation Demand
- Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve for 2023 to 2024 Gas Year – Southwest Connecticut

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Eastern Connecticut

- Algonquin Gas Transmission
- Tennessee Gas Pipeline

Power Generation:
- 600-1200 MW
- 0-149 MW
- 150-599 MW

Legend:
- Power Generation: 600-1200 MW
- Power Generation: 150-599 MW
- Power Generation: 0-149 MW
Historical and Projected Load Duration Curves for Eastern Connecticut

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

- Existing Capacity
- Existing Constraint Capacity
- Projected Capacity
- Projected Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Northern Connecticut
Northern Connecticut Load Duration Curve

Historical and Projected Load Duration Curves for Northern Connecticut

- **2009-2010**
- **2010-2011**
- **2011-2012**
- **2018-2019**
- **2023-2024**
- **Existing Capacity**
- **Existing Constraint Capacity**
- **Projected Capacity**
- **Projected Constraint Capacity**

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Southeast Connecticut Load Duration Curve

Historical and Projected Load Duration Curves for Southeastern Connecticut

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

Existing Capacity
Existing Constraint Capacity
Projected Capacity
Projected Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Rhode Island

- Ocean States I
- Indeck North Smithfield Energy
- South Street
- Pawtucket Power Associates
- Broadrock Biopower I
- Manchester Street
- Rhode Island State Energy (FPLE)
- Tiverton Power Plant

Legend:
- Blue: Algonquin Gas Transmission
- Purple: Tennessee Gas Pipeline
- Yellow: Rhode Island
- Red Circle: Power Generation: 150-599 MW
- Black Circle: Power Generation: 0-149 MW
Rhode Island Load Duration Curve

Historical and Projected Load Duration Curves for Rhode Island

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

- Projected Capacity
- Projected Constraint Capacity
- Existing Capacity
- Existing Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve from April 2023 thru March 2024 – Rhode Island

Projected Hourly Load Duration Curve - Rhode Island

- Residential, Commercial and Industrial Demand
- Power Generation Demand
- Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Projected Hourly Load Duration Curve for the 2023 to 2024 Gas Year – Rhode Island

Projected Hourly Load Duration Curve - Rhode Island

- Residential, Commercial, and Industrial Demand
- Power Generation Demand
- Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Eastern New Hampshire

- **Portland Gas Transmission**
  - Power Generation: 600 - 1200 MW

- **East New Hampshire**
  - Power Generation: 0 - 149 MW
  - Power Generation: 150 - 599 MW

- **Tennessee Gas Pipeline**
Historical and Projected Load Duration Curves for Eastern New Hampshire

- 2009-2010
- 2011-2012
- 2013-2024
- 2025-2024
- Existing Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Southern New Hampshire
Southern New Hampshire Load Duration Curve

Historical and Projected Load Duration Curves for Southern New Hampshire

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024
- Existing Capacity
- Existing Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Northern New Hampshire

Portland Gas Transmission
North New Hampshire
Power Generation: 0 – 149 MW
Northern New Hampshire Load Duration Curve

Historical and Projected Load Duration Curves for Northern New Hampshire

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Western Maine

- Maritimes & Northeast Pipeline
- Portland Gas Transmission
- West Maine

- Power Generation: 600-1200 MW
- Power Generation: 150-599 MW
- Power Generation: 0-149 MW
Western Maine Load Duration Curve

Historical and Projected Load Duration Curves for Western Maine

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Pipelines & Natural Gas Power Generation
Northern Maine

- Maritimes & Northeast Pipeline
- Portland Gas Transmission
- North Maine
- Power Generation: 150 – 599 MW
- Power Generation: 0 – 149 MW
Northern Maine Load Duration Curve

Historical and Projected Load Duration Curves for Northern Maine

- 2009-2010
- 2010-2011
- 2011-2012
- 2018-2019
- 2023-2024

Existing Capacity
Existing Constraint Capacity

Source: Black & Veatch Analysis, Electronic Pipeline Bulletin Board
Without Spectra’s AIM Project, days with pipeline constraints range reach as high as 180 days.
With Spectra’s AIM Project, days with pipeline constraints are reduced for Connecticut, Massachusetts and Rhode Island Sub-Regions.

Frequency of Daily Load Surpassing the 75% Threshold by Region

Source: Black & Veatch Analysis
# Frequency of Daily Load Surpassing the 75% Threshold – Existing Capacity vs. With AIM Capacity

## Existing Capacity

<table>
<thead>
<tr>
<th></th>
<th>Connecticut</th>
<th>Massachusetts</th>
<th>Rhode Island</th>
<th>Maine</th>
<th>New Hampshire</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>East North Southeast Southwest</td>
<td>East Southeast West RI North West North South East</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Load as % of New England Total</td>
<td>2018-2019</td>
<td>7.6% 4.3% 0.1% 13.7%</td>
<td>32.5% 6.9% 5.1%</td>
<td>10.8%</td>
<td>4.2% 3.8%</td>
</tr>
<tr>
<td></td>
<td>2023 - 2024</td>
<td>7.7% 4.2% 0.1% 13.7%</td>
<td>31.9% 6.7% 5.0%</td>
<td>11.0%</td>
<td>4.2% 3.7%</td>
</tr>
<tr>
<td>Days Exceeding 75% Capacity</td>
<td>2018-2019</td>
<td>133 15 6 2</td>
<td>61 29 28</td>
<td>92</td>
<td>82 128</td>
</tr>
<tr>
<td></td>
<td>2023 - 2024</td>
<td>190 33 17 15</td>
<td>89 52 61</td>
<td>149</td>
<td>105 170</td>
</tr>
</tbody>
</table>

## With AIM Capacity

<table>
<thead>
<tr>
<th></th>
<th>Connecticut</th>
<th>Massachusetts</th>
<th>Rhode Island</th>
<th>Maine</th>
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</tr>
<tr>
<td></td>
<td>2023 - 2024</td>
<td>66 9 1 15</td>
<td>62 12 61</td>
<td>117</td>
<td>105 170</td>
</tr>
</tbody>
</table>

*Source: Black & Veatch Analysis*
Discussion Outline

• Phase II Objectives
• Black & Veatch Methodology Overview
• New England Demand Growth
• Geographic Load Distribution and Infrastructure
• Load Duration and Constraint Assessment
• Natural Gas Infrastructure Costs
• Power Side Solutions
• Recommended Scenarios
New England Infrastructure Construction Cost Estimates
Looping and Lift and Replace

• The following proposed projects into New England would involve looping (laying a parallel segment of new pipe and rejoin with the existing pipe at the end) of existing mainlines within or adjacent to existing rights of way
  • TGP Northeast Expansion: 200 Line Looping
  • TGP Connecticut Expansion

• Estimated project capital costs for these projects assume $3.5 million/mile, using 30” diameter pipe
  • Estimates are based on pipeline construction costs (excluding compression) for Tennessee Gas Pipeline’s recently completed 300 Line Project (~130 miles of 30” pipeline for ~$450 million)
  • Cost estimate assumes looping rather than lift-and-lay replacement of older, smaller diameter pipe with the 30” pipe
  • Cost assumption also includes additional compression at existing compressor stations

• Lift and Replace
  • Algonquin Incremental Market (AIM) Expansion
  • The cost of lift and replace is estimated to be more expensive than looping but less expensive than greenfield construction
Looping Cost Estimate Benchmark - TGP 300 Line Project

- Placed in Service in Nov. 2012
- Utilized as a benchmark for proposed expansions involving pipeline looping
- **Capacity:** 350,000 Dth/day
- ~130 miles of 30” looped pipeline
- **Capex:** $634 million
  - $585 million for incremental capacity
  - $49 million for replacement of facilities
- Involved construction of 8 looping segments across PA and NJ

Source: Black & Veatch Analysis, Kinder Morgan Investor Presentations
New England Infrastructure Construction Cost Estimates
Greenfield Construction

- New England greenfield pipeline alternatives include:
  - TGP’s Northeast Expansion – Bullet Line (proposed in-svc 2017-2018)
    - 30”, 150 miles, 1.2 Bcf/day pipeline from Wright, NY to Dracut, MA
  - Cabot Inc.’s Constitution Pipeline joint venture (proposed in-svc 2015)
    - 30”, 121 mile, 650,000 dth/d line from PA to Wright, NY interconnections with TGP and Iroquois

- Capital cost estimates of $6 to $8 million/mile for greenfield construction are derived from information publish by the Constitution Pipeline sponsors:
  - Recourse rate of $0.76/Dth
  - Assumes a 30-year levelization
  - Capital cost is estimated at $730 million to $1 billion

- Cost per mile estimate includes compression
  - Construction costs premiums for mountainous terrain, rock subsurface, regional permitting and fragmented land ownership along ROWs
  - Each project was estimated to include 5 meter stations, each constructed for $3 million
## Pipeline Cost Estimates

<table>
<thead>
<tr>
<th>Construction Type</th>
<th>Project</th>
<th>Capacity (Dth/day)</th>
<th>Estimated Cost (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Looped</td>
<td>Tennessee Gas Pipeline Northeast Expansion 200 Line Looping</td>
<td>500,000 to 1,000,000</td>
<td>$508 to $653</td>
</tr>
<tr>
<td></td>
<td>Tennessee Gas Pipeline Connecticut Expansion¹</td>
<td>72,100</td>
<td>$47 to $60</td>
</tr>
<tr>
<td>Lift and Replace</td>
<td>Algonquin Incremental Market Expansion</td>
<td>400,000</td>
<td>$861 to $1,017</td>
</tr>
<tr>
<td>Greenfield</td>
<td>Constitution Pipeline</td>
<td>650,000</td>
<td>$729 to $971</td>
</tr>
<tr>
<td></td>
<td>Tennessee Gas Pipeline Northeast Expansion Bullet Line</td>
<td>1,200,000</td>
<td>$900 to $1,200</td>
</tr>
</tbody>
</table>

¹Pipeline construction cost only. Excludes estimated cost of Thompsonville Lateral.

**Note** - The costs of recently completed projects cannot predict the construction costs of proposed projects with absolute certainty. With the exception of AIM, Black & Veatch did not verify the accuracy of these cost estimates with project sponsors.

*Source: Black & Veatch Analysis*
Proposed Pipeline Expansion Overview
TGP Connecticut Expansion Project

- **Capacity:** 72,100 Dth/d
- **Capital:** $81.2 MM
- **Estimated In-Service:** November 1, 2016
- **Project Scope:**
  - 13.3 miles of pipeline loop
  - Acquisition of Thompsonville Lateral
- **Commercial Benefit:** Additional capacity to serve New England market
- **Rate:** Negotiated
- **Current Status:** Shipper negotiations underway
- **Major Milestones:**
  - 1st Quarter 2013: Execute PAs

Source: Black & Veatch Analysis, Kinder Morgan Presentation
Proposed Pipeline Expansion Overview
TGP Northeast Expansion- Bullet Line

- 1.2 Bcf/d pipeline
- From Wright to Dracut, MA
- Backhaul existing markets
- 3rd pipeline into region
  - Benefits all existing markets
  - Enhances existing system
  - Development of new markets
- High pressure line
- Expandable
- In service 2017-2018

Source: Northeast Gas Association Pre-Winter Briefing 2012/2013 Tennessee Pipeline
Proposed Pipeline Expansion Overview
TGP Northeast Expansion- 200 Line Looping

- Lower volume scale
  - 0.5 to 1.0 Bcf/d
- Current gas infrastructure located in TGP corridor
- Increases deliverability
- Flexibility in design
- In service 2016-2018

Source: Northeast Gas Association Pre-Winter Briefing 2012/2013 Tennessee Pipeline
Proposed Pipeline Expansion Overview

Algonquin Incremental Market Expansion

**Project Details:**

- Pipeline expansion designed to move emerging production to AGT city gates
- 512 MDth/d from Ramapo to Brookfield
- 271 MDth/d from Brookfield to AGT City Gates
- 2016 In-service
Proposed Pipeline Expansion Overview
Constitution Pipeline

- **Joint Venture:**
  - Williams (51%)
  - Cabot (25%)
  - Piedmont (24%)

- **Capacity:** 650,000 Dth/day

- **Expected In-Service Date:** 2015

- **Greenfield project to stretch from Susquehanna County, PA to Schoharie County, NY**

- **Iroquois Gas Transmission and Constitution will develop the Wright Interconnect Project to deliver up to 650 MMcf/d from Constitution to Iroquois and Tennessee Gas Pipeline in Schoharie County, NY under a 15 year agreement**
LNG Peak Shaving Facility Cost Estimates

<table>
<thead>
<tr>
<th>Storage Tank Size (Barrels/Bcf)</th>
<th>New England LNG Peakshaving Facility¹</th>
<th>Black &amp; Veatch Estimate²</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>348,000 Barrels*</td>
<td>300,000 Barrels</td>
</tr>
<tr>
<td></td>
<td>1.2 Bcf</td>
<td>1.0-1.1 Bcf</td>
</tr>
<tr>
<td>Liquefaction Capacity (MMBtu/d)</td>
<td>6,000</td>
<td>8,600</td>
</tr>
<tr>
<td>Vaporization Capacity (MMBtu/d)</td>
<td>60,000</td>
<td>60,000</td>
</tr>
<tr>
<td>Total Capital Cost</td>
<td>$108M</td>
<td>$120M</td>
</tr>
</tbody>
</table>

¹ Reflects the Yankee Gas, Waterbury Connecticut facility configuration when the facility was completed in 2005. Does not reflect the 2011 Waterbury to Wallingford Line Project (WWL) expansion of vaporization capacity from 60,000 to 105,000 MMBtu/d

² Based on B&V EPC experience in North America
World LNG demand growth projections reflect aggressive growth of 5-7% annually to 2020

World LNG Demand Projections

Sources:
BP - Statistical Review 2011 and Energy Outlook 2030
CEDIGAZ - World LNG Market: Current Developments and Prospects, CEDIGAZ General Meeting (June 24, 2011)
Deloitte – Navigating a Fractured Future, Deloitte Center for Energy Solutions and Deloitte MarketPoint
Baker (Rice) - James A Baker Institute Energy Forum (Rice University), Shale Gas and U.S. National Security (July 2011)
Any LNG Imports must compete with Asian and European LNG Prices

World LNG Estimated December 2012 Landed Prices

- **Altamira**: $3.80
- **Lake Charles**: $3.23
- **Cove Point**: $4.03
- **UK**: $10.11
- **Belgium**: $9.78
- **Spain**: $11.05
- **India**: $11.55
- **Korea**: $14.10
- **Japan**: $14.10

Source: FERC, Waterborne Energy, Inc
LNG Import Contract Prices reflects a sufficient range of prices to bid away European/Asian LNG Cargoes

Probability Distribution of LNG Contract Prices

Source: Black & Veatch Analysis
LNG Import Contract Prices still closely tied to Brent Crude Prices

Source: Black & Veatch Analysis
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## Demand Response – Total Capacity and Payments

<table>
<thead>
<tr>
<th></th>
<th>Active Demand Resources</th>
<th>Passive Demand Resources</th>
<th>Total All Demand Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Real-Time Demand</td>
<td>Real-Time Emergency</td>
<td>Total Active Demand</td>
</tr>
<tr>
<td>2010 Year End</td>
<td>669</td>
<td>522</td>
<td>1191</td>
</tr>
<tr>
<td>2011 Year End</td>
<td>649</td>
<td>436</td>
<td>1085</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Capacity Payments</th>
<th>% of Total</th>
<th>DALRP Payments</th>
<th>% of Total</th>
<th>RTPR Payments</th>
<th>% of Total</th>
<th>Total Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$134,456,420</td>
<td>93.9%</td>
<td>$7,763,220</td>
<td>5.4%</td>
<td>$942,307</td>
<td>0.7%</td>
<td>$143,161,947</td>
</tr>
<tr>
<td>2011</td>
<td>$97,591,566</td>
<td>93.5%</td>
<td>$6,296,955</td>
<td>6.0%</td>
<td>$455,462</td>
<td>0.4%</td>
<td>$104,343,983</td>
</tr>
</tbody>
</table>

Source: ISO New England and Black & Veatch Analysis
Demand Response – Cleared Demand Response Resources in January 2013

Source: ISO New England and Black & Veatch Analysis
ISO-NE’s Duel Fuel Capacity Addition Schedule

Source: Ventyx and Black & Veatch Analysis
## Costs of Combined Cycle Conversion to Dual – Fuel Capacity

<table>
<thead>
<tr>
<th>Components</th>
<th>Cost Estimates (million $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conversion Material</td>
<td>$21</td>
</tr>
<tr>
<td>Conversion Labor</td>
<td>$4</td>
</tr>
<tr>
<td>Indirect Costs (such as Contingency or Construction Management)</td>
<td>$9</td>
</tr>
<tr>
<td>Other Costs (Plant Site Upgrade and Ancillary Construction)</td>
<td>$5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$39</strong></td>
</tr>
</tbody>
</table>

*Source: Black & Veatch Analysis*
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• Recommended Scenarios and Sensitivities
**Base Case Assumptions**

### Power
1. Moderate load growth at around 1% per year
2. Efficiency gains grow significantly until 2020 with an ever decreasing growth rate
3. Environmental policies triggers retirements of coal and oil capacity
4. A federal emissions program in 2022
5. Each New England state to meet its RPS standards;
6. Later period capacity additions exclusively gas based

### Natural Gas
1. Base Case Residential/Commercial and Industrial demand growth
2. LNG Export at Gulf Coast and West Coast
3. No regulation on hydraulic fracturing
4. No stricter control on usage and treatment for water used in hydraulic fracturing
5. No collapse in natural gas liquids price
6. Eastern Canadian supply decline

**New England Electricity Price**
- Run 1: No Incremental Infrastructure
- Run 2: Pipeline Infrastructure
- Run 3: LNG Imports
- Run 4: Demand Response and Dual-Fuel Capacity
- Run 5: Canadian Electric Imports

**New England Natural Gas Price**
High Demand Case Assumptions

### Power
1. Moderate load growth at around 1% per year
2. Energy efficiency does not grow
3. Some New England states do not meet 2012 RPS standards
4. Nuclear retirement earlier than expected

### Natural Gas
1. High case residential/commercial and industrial demand growth with policy incentives
2. Higher LNG export at Gulf Coast and west Coast; multiple terminals
3. No regulation on hydraulic fracturing
4. No stricter control on usage and treatment for water used in hydraulic fracturing
5. No collapse in natural gas liquids price
6. MN&P pipeline reversal

---

New England Electricity Price
- Run 1: No Incremental Infrastructure
- Run 2: Design Day Weather Sensitivity
- Run 3: Pipeline Infrastructure
- Run 4: LNG Imports
- Run 5: Canadian Electric Imports

New England Natural Gas Price
Low Demand Case Assumptions

**Power**

- Limited Demand Growth from the Power Sector

**Natural Gas**

- No Demand Growth from the Gas Sector

**Run 1:** No Incremental Infrastructure

**Run 2:** Negative Electric Sector Demand Growth

**Run 3:** Dual-Fuel Capacity

**Run 4:** Canadian Electric Imports

**Run 5:** LNG Peak Shaving

**New England Electricity Price**

**New England Natural Gas Price**
### Recommended Sensitivities for Phase III

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Sensitivities</th>
</tr>
</thead>
</table>
| **Base Case**             | - No Incremental Solutions  
- Incremental Solutions:  
  - Pipeline Infrastructure  
  - LNG Imports  
  - Demand Response and Dual Fuel Capacity  
  - Canadian Electricity Imports |
| **High Demand Case**      | - No Incremental Solutions  
- Design Day Weather Sensitivity  
- Incremental Solutions:  
  - Pipeline Infrastructure  
  - LNG Imports  
  - Canadian Electricity Imports |
| **Low Demand Case**       | - No Incremental Solutions  
- Negative Electric Sector Demand Growth  
- Incremental Solutions:  
  - Dual Fuel Capacity  
  - Canadian Electricity Imports  
  - LNG Peak Shaving |
Building a world of difference.

Together