



**Connecticut
Light & Power**

The Northeast Utilities System

The Brattle Group



Comprehensive Electricity Resource Plan

Pursuant to PA 07-242 §51

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Introduction

Objective

- Develop a joint comprehensive electricity resource plan in conformance with Section 51 of PA 07-242

Study Sponsors

- The Connecticut Light & Power Company
- The United Illuminating Company

Consultant

- *The Brattle Group*

Agenda

Study Scope

Analytic Methodology

Findings

Recommendations

Study Limitations and Further Analysis

Study Scope

Study Components

1. Quantify the need for additional resources across a range of scenarios.
2. Identify potential resource solutions (supply & demand-side) to meet needs.
3. Evaluate the performance of resource solutions.
4. Recommend resource strategies.

Regional Scope & Time Horizon

- ISO-New England electric market simulation
- Modeled years 2011, 2013, 2018 and 2030

Study Architecture

4 Resource Solutions

4 Scenarios

	Current Trends	Strict Climate	High Fuel/ Growth	Low Stress
Conventional Gas	Metrics	Metrics	Metrics	Metrics
DSM-Focus	Metrics	Metrics	Metrics	Metrics
Nuclear	Metrics	Metrics	Metrics	Metrics
Coal	Metrics	Metrics	Metrics	Metrics

2030
2018
2013
2011

Metrics:

- Customer Cost
- Market Price
- Gas Dependence
- Emissions
- ...

Construct Scenarios

We designed four scenarios to evaluate resource solutions across a broad range of plausible economic futures

Scenario Name	Fuel Prices	Load	Cost / Siting	CO₂ Price
“Current Trends”	Moderate	Moderate	Nominal (high)	Moderate (high)
“Strict Climate”	Slightly High	Slightly Low	Nominal (high)	High
“High Fuel/Growth”	Very High	High	Higher	Somewhat Higher
“Low Stress”	Low	Very High	Moderate	Moderate (high)

Quantify Resource Needs in Each Scenario

Compare Electricity Demand Projections to Existing/Planned Resources

Demand: varies by scenario

Resources (existing/planned) include:

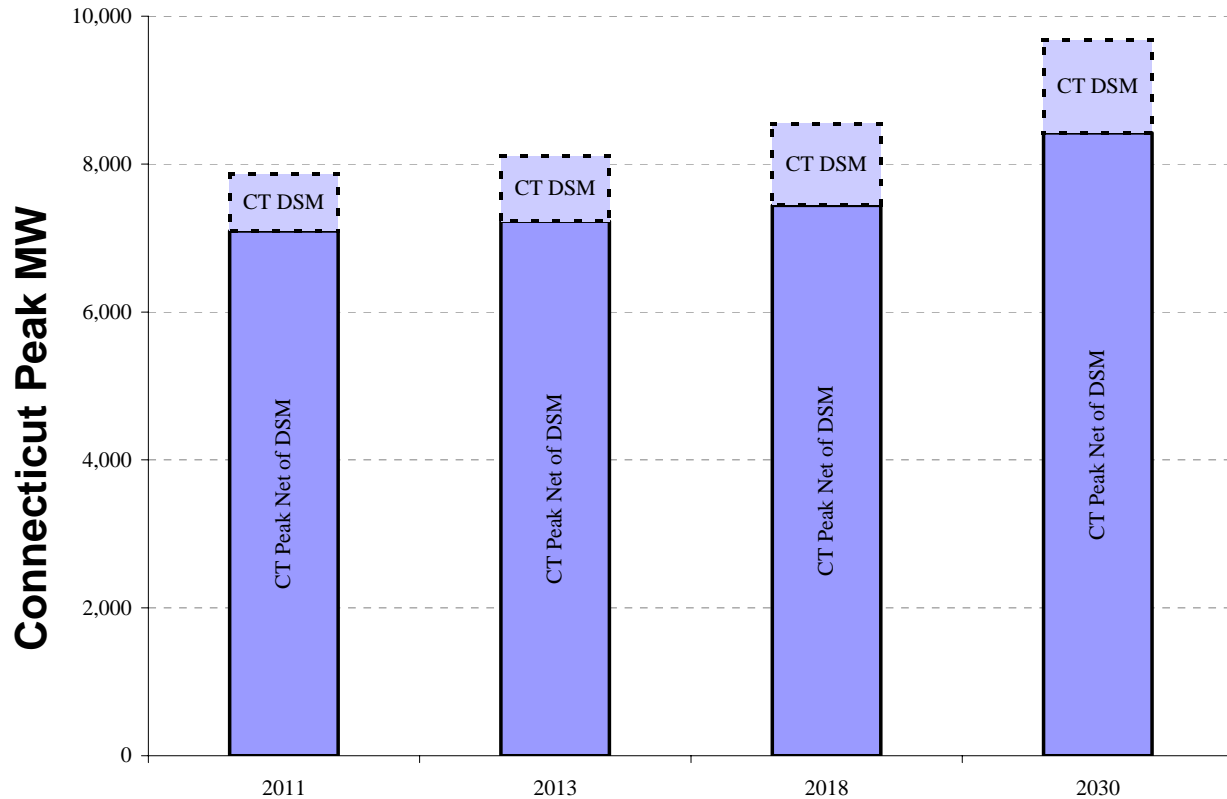
- Existing generation (no retirements, based on screening analysis)
- New generation under construction/contract: 1,107 MW in Connecticut
- Assumed 279 MW to meet Local Forward Reserve Market (LFRM) requirement
- Planned DSM in CT: 700 MW in 2011, >1000 in 2018 (varies by scenario)
- DSM in Rest of New England: half as aggressive as in Connecticut

Projected Resource Gap (based on resource adequacy criteria for reliability):

- The ISO-NE Installed Capacity Requirement (ICR)
- The Connecticut Local Sourcing Requirement (LSR)

Resource Solutions must fill expected gaps

Planned DSM is Aggressive



Planned DSM (energy efficiency & load response) substantially reduces peak load growth

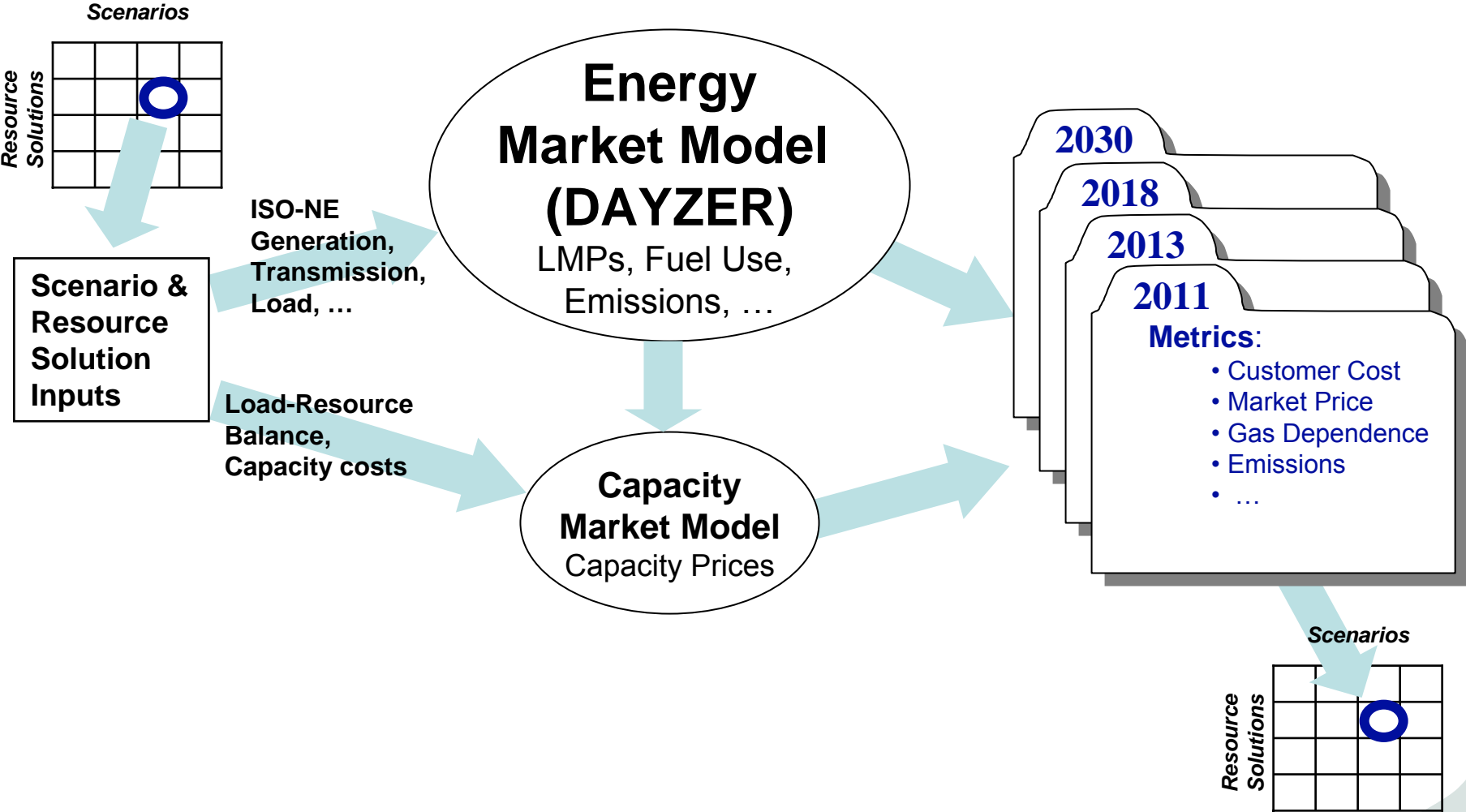
Identify Candidate Resource Solutions

Resource Solution	Planned DSM *	Candidate Resources	Additional Gas
“Conventional Gas”	Aggressive	Gas-fired CCs and CTs Economic mix of technologies	As needed to fill rest of gap
“DSM-Focus”	Aggressive	Additional DSM** by 2011: +160 MW, 370 GWh by 2013: +320 MW, 1000 GWh by 2018: +603 MW, 2600 GWh	As needed to fill rest of gap
“Nuclear”	Aggressive	1 Nuclear Unit in 2018 (1200 MW)	As needed to fill rest of gap
“Coal”	Aggressive	1 Coal Unit in 2018 (1200 MW)	As needed to fill rest of gap

* DSM effectiveness (on reducing peak load MW & energy GWh) depends on scenario.

** Values shown are for Current Trends scenario.

Analysis Flow Chart



Summary of Findings

1. Regional resource adequacy needs are satisfied for the next several years.
2. Connecticut's local resource adequacy needs are satisfied for the foreseeable future.
3. Market prices will continue to be high and volatile.
4. Natural gas dependence will persist.
5. External, uncontrollable factors are the primary drivers of customer costs.

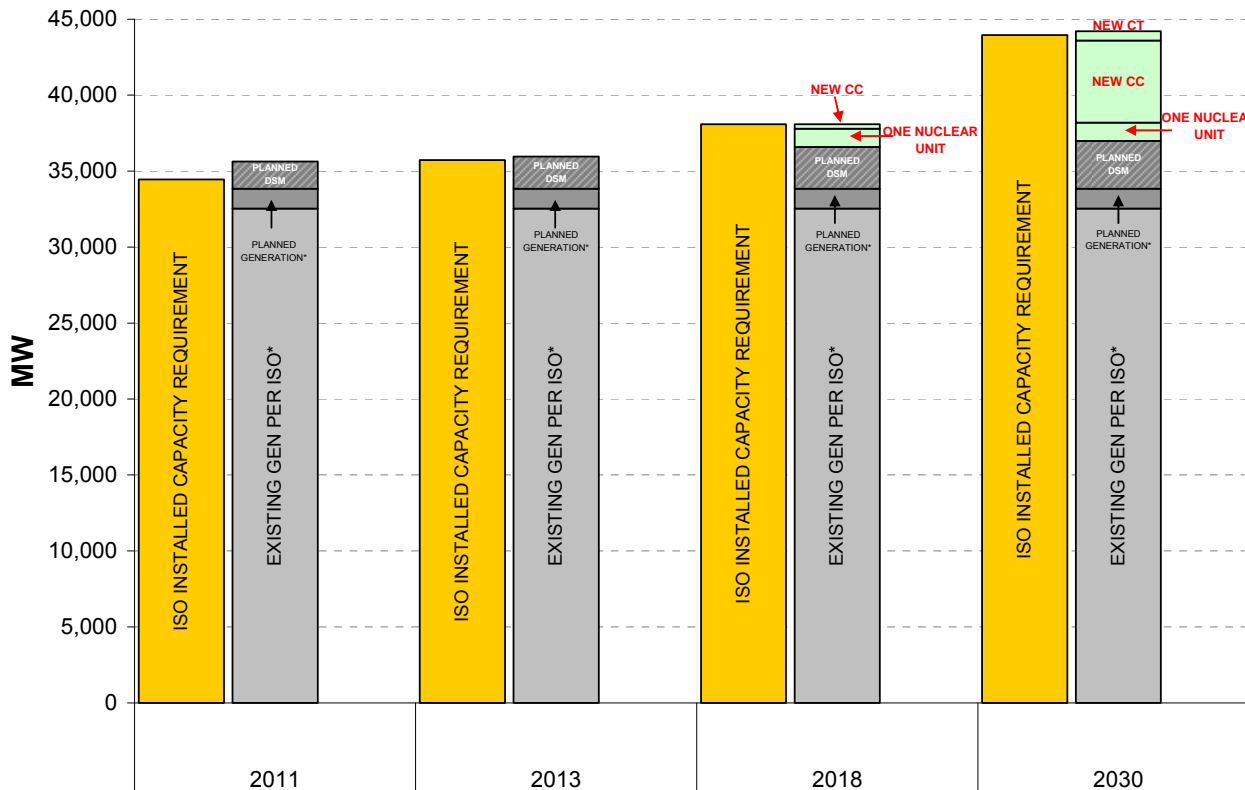
Summary of Findings (cont.)

6. Renewable Portfolio Standards are unlikely to be fully met with renewable generation.
7. Nuclear and DSM mitigate CO₂ emissions more effectively than other resource solutions.
8. Increased DSM could reduce customer Costs, CO₂ emissions, and gas usage.
9. Non-gas baseload generation would reduce dependence on natural gas.
10. “Market Regime” vs. “Cost-of-Service” affects rate stability, and may have future customer cost implications.

1. Regional Resource Adequacy Needs are Satisfied for the Next Several Years

ISO-NE Supply-Demand Balance

Example: Nuclear solution shown to fill resource gap in 2018+ in Current Trends scenario



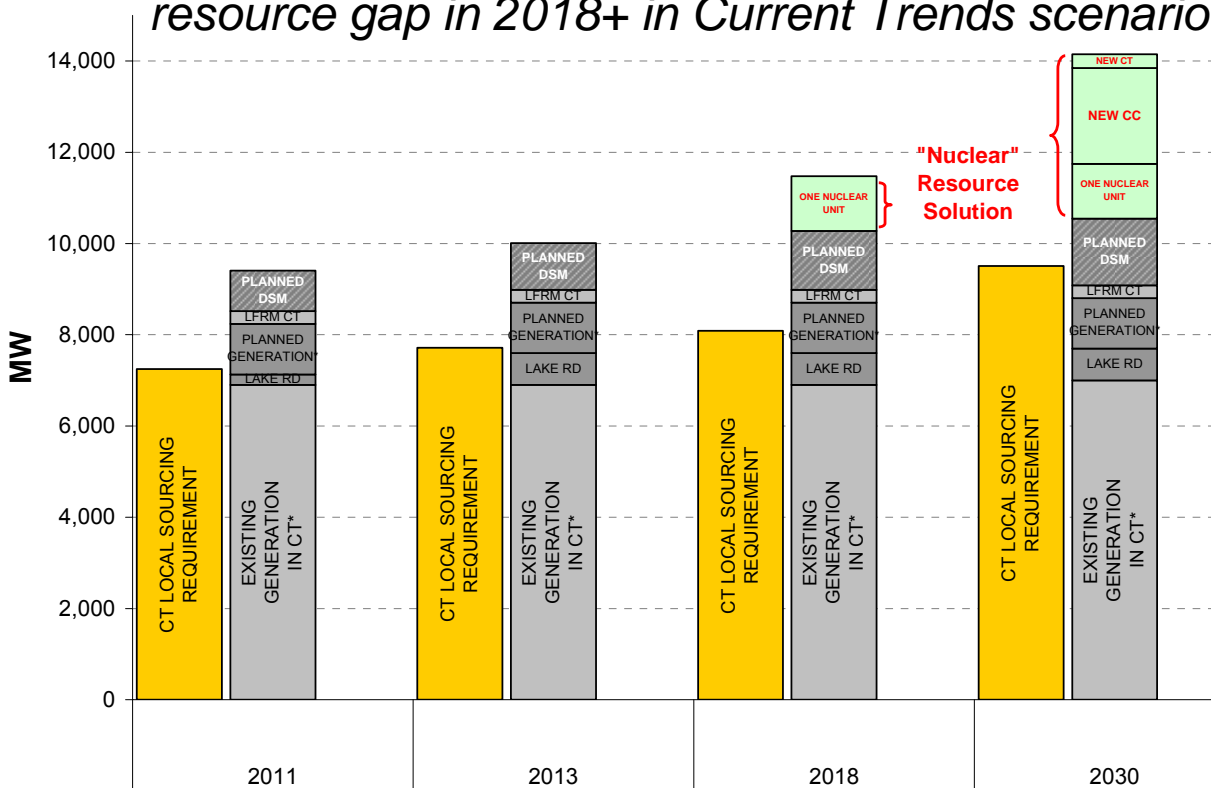
- This example solution has 1 nuclear unit supplemented by gas capacity to fill ISO-NE resource gap. (See report for other scenarios and resource solutions.)
- Accounts for planned generation, transmission, DSM.
- Assumes no retirements.

*Existing generation includes imports, net purchases, and New Boston retirement. All planned generation includes Waterbury, Kleen, Additional LFRM Required CT, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

2. Connecticut's Local Resource Adequacy Needs are Satisfied for the Foreseeable Future

CT Supply-Demand Balance

Example: Nuclear solution shown to fill ISO-NE resource gap in 2018+ in Current Trends scenario



- This example solution has 1 nuclear unit supplemented by gas capacity to fill ISO-NE resource gap.
- Accounts for planned generation, transmission, DSM. Assumes no retirements.
- No significant congestion price differentials are forecast within CT nor between CT and the rest of New England.

*Existing generation is net of sales. Other planned generation includes Waterbury, Kleen, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

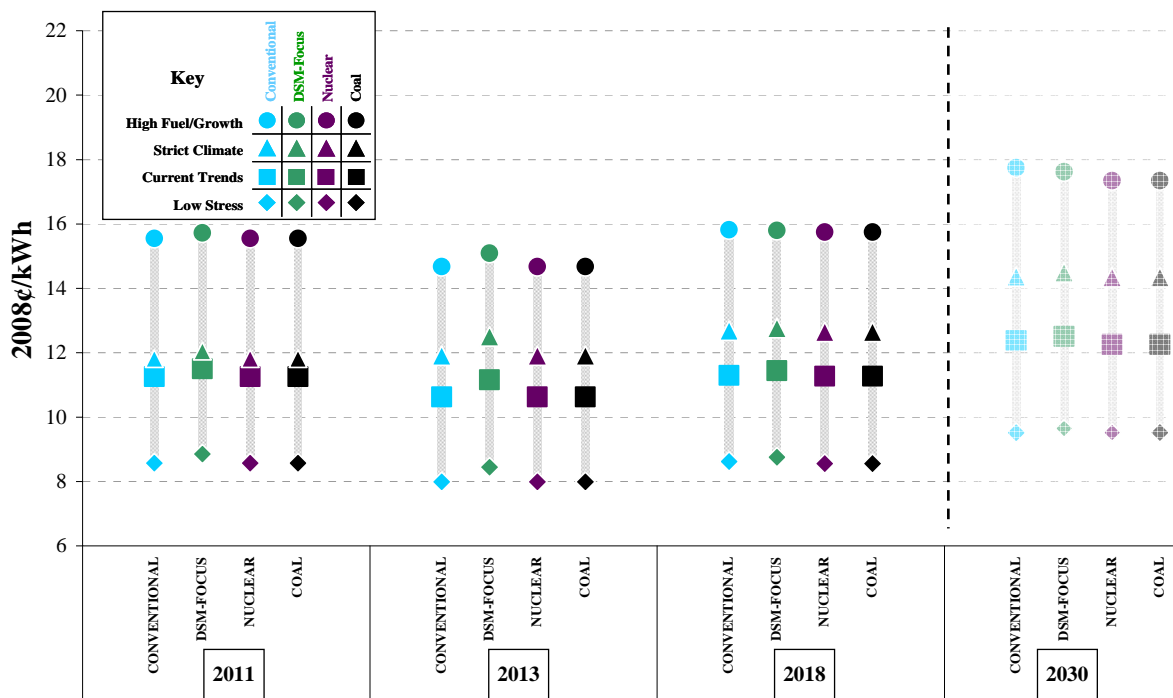
1&2: Resource Needs Summary

ISO-NE Resource Shortfall (Surplus) Relative to ISO-NE Installed Capacity Requirement (MW)				
Scenario	2011	2013	2018	2030
Current Trends	(1,163)	(225)	1,492	6,957
Strict Climate	(1,402)	(525)	1,030	6,423
High Fuel/Growth	(805)	557	3,389	9,144
Low Stress	48	1,476	4,504	10,433
Connecticut Shortfall (Surplus) Relative to CT Local Sourcing Requirement (MW)				
Scenario	2011	2013	2018	2030
Current Trends	(2,229)	(2,376)	(2,295)	(1,159)
Strict Climate	(2,297)	(2,462)	(2,426)	(1,307)
High Fuel/Growth	(2,120)	(2,140)	(1,708)	(494)
Low Stress	(1,881)	(1,890)	(1,443)	(194)

- **ISO-NE needs new resources in several years.**
- **Connecticut will satisfy its LSR for many years under these scenarios, assuming no retirements.**
- **See Tables 2.2 and 2.3 of Report.**

3. Market Prices Will Continue to be High and Volatile

Average Unit Cost in Market Regime

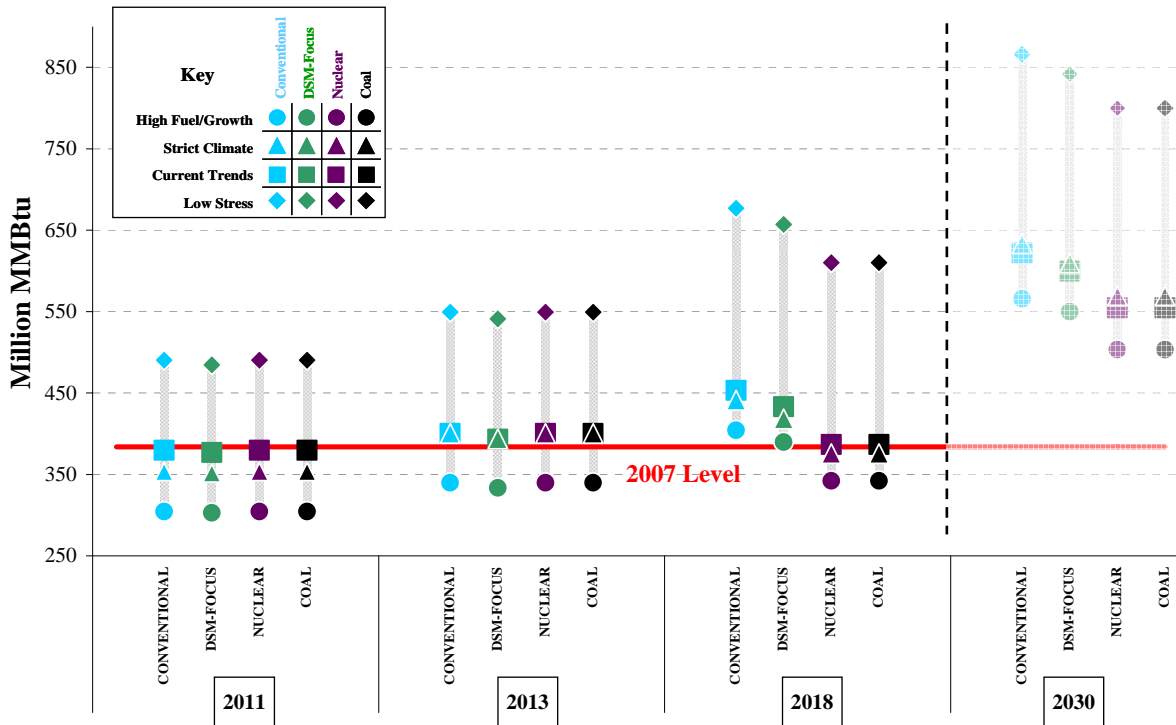


- Average unit costs vary substantially based on scenario drivers, especially the price of gas.
- Resource solutions have almost no impact on the unit cost.
- The total cost savings available from DSM is not apparent from unit costs.

*Average Unit Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

4. Natural Gas Dependence Will Persist

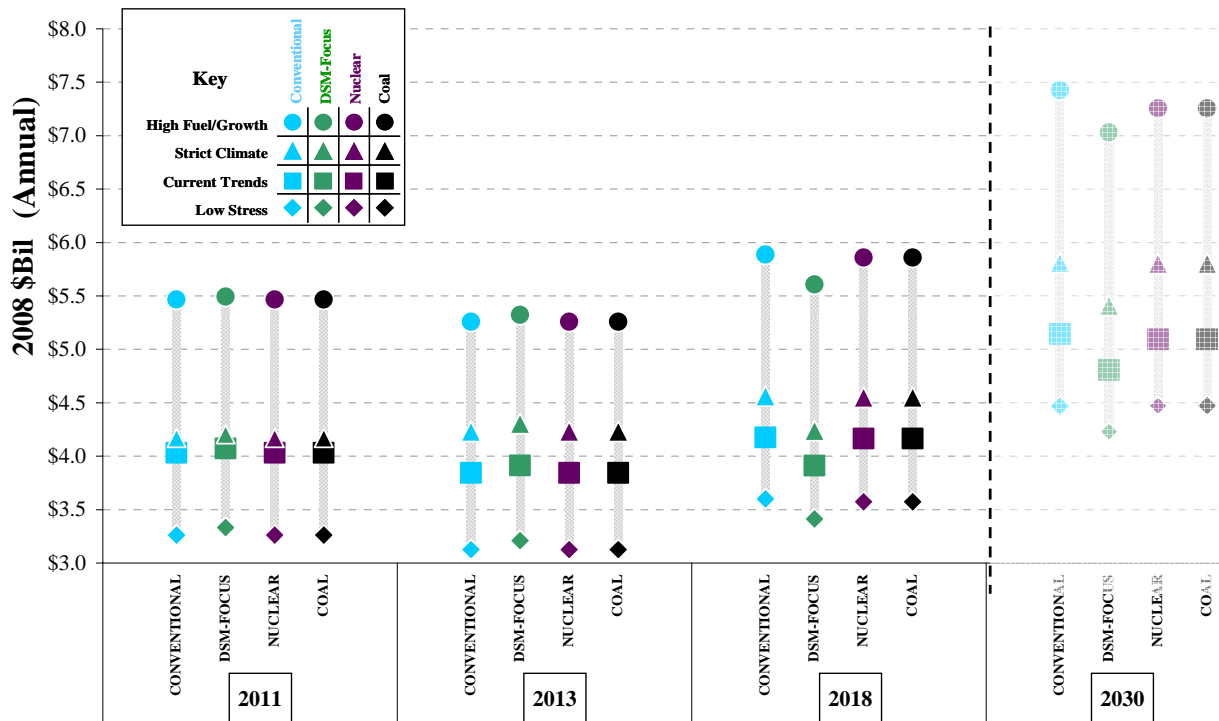
Annual Power Sector Gas Use in ISO-NE



- Gas usage will increase in virtually all cases, due to load growth.
- A baseload resource solution (coal or nuclear) reduces the growth in gas usage.
- DSM also helps.
- Previous graph showed the high impact of gas on market prices.

5. External, Uncontrollable Factors are the Primary Drivers of Customer Costs

Total Customer Cost in Market Regime



- Costs vary more by scenario (i.e., external factors) than by resource solution.
- Gas price is especially important.

*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

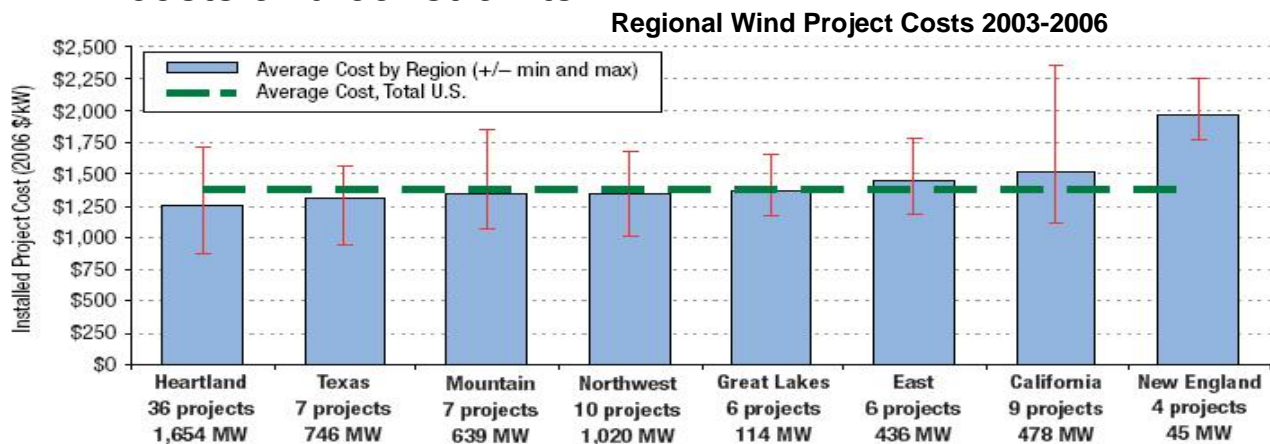
6. Renewable Portfolio Standards are Unlikely to be Fully Met with Renewable Generation

Connecticut Renewable Portfolio Standard (RPS):

- Escalating requirements similar to other New England states
- Can use New England renewable energy credits (RECs)
- Alternative payments (for REC shortfall) of \$55/MWh, not adjusted for inflation as other New England States

Renewable Costs

- Connecticut renewables limited and/or expensive compared to New England renewables
- New England targets may not be met fully with renewables, due to costs and constraints



Source: Berkeley Lab database.

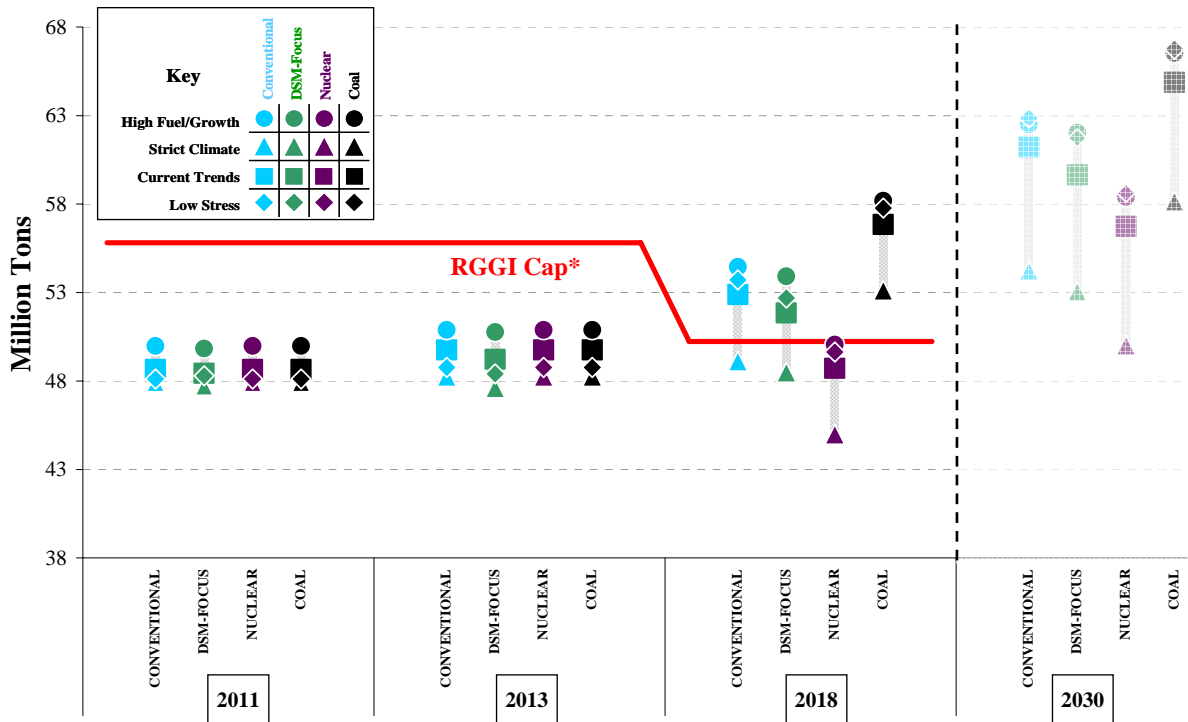
*New England:
\$2000/kW
45 MW
Developed*

6. Renewable Portfolio Standards are Unlikely to be Fully Met with Renewable Generation (cont.)

- Regional shortfalls and competition for RECs may drive prices higher than \$55/MWh price cap
- Companies may increasingly rely on alternative compliance payments (ACP) for shortfall
- Overall annual customer costs may rise to \$200 million by 2011, \$300+ million in 2018 (\$2008)
 - ▶ Some RECs at/near price cap level
 - ▶ Significant portion in ACP – large revenue stream
- This outlook deserves additional study at the regional level to evaluate current policy

7. Nuclear and DSM Mitigate CO₂ Emissions More Effectively than Other Resource Solutions

CO₂ Emissions in ISO-NE



- CO₂ emissions are expected to increase as load grows.
- Nuclear displaces significant fossil CO₂.
- Coal raises emissions substantially above New England's share of the RGGI cap.
- Increased DSM (that includes energy efficiency) also reduces CO₂ emissions.

*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

8. Increased DSM Could Reduce Customer Costs, CO₂ Emissions, and Gas Usage

DSM is effective in mitigating future peak and energy growth.

DSM also reduces CO₂ emissions and physical gas dependence.

Increased DSM could reduce customer costs and total resource costs.

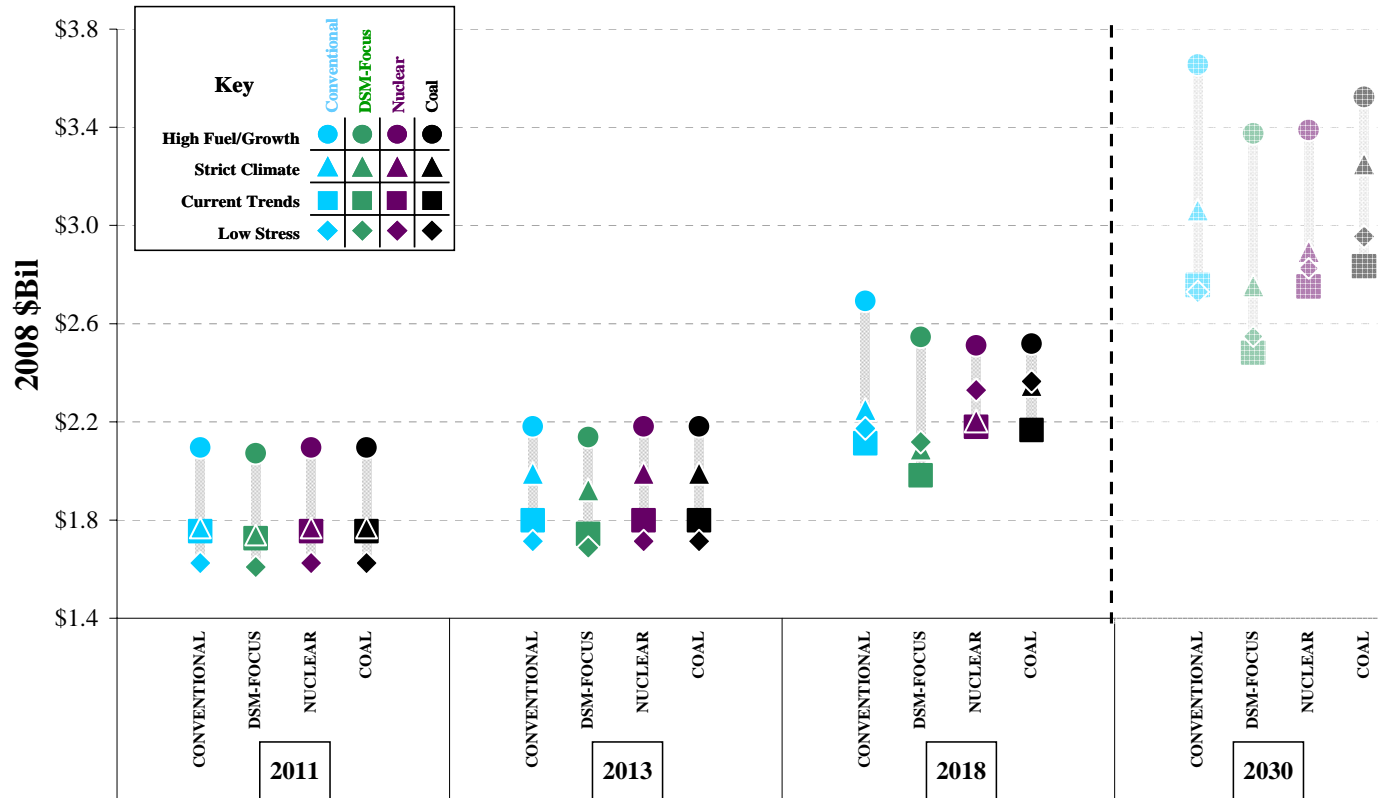
- While prices are difficult to influence, DSM reduces overall costs by addressing the volume.

Under some circumstances, DSM could increase average unit costs (¢/kWh) even while reducing total customer costs.

- When consumption volumes are changing, unit costs may not accurately reflect impacts.
- Customer costs higher in early years because DSM investments are assumed to be *expensed* in rates.

8. Increased DSM Could Reduce Customer Costs, CO₂ Emissions, and Gas Usage (cont.)

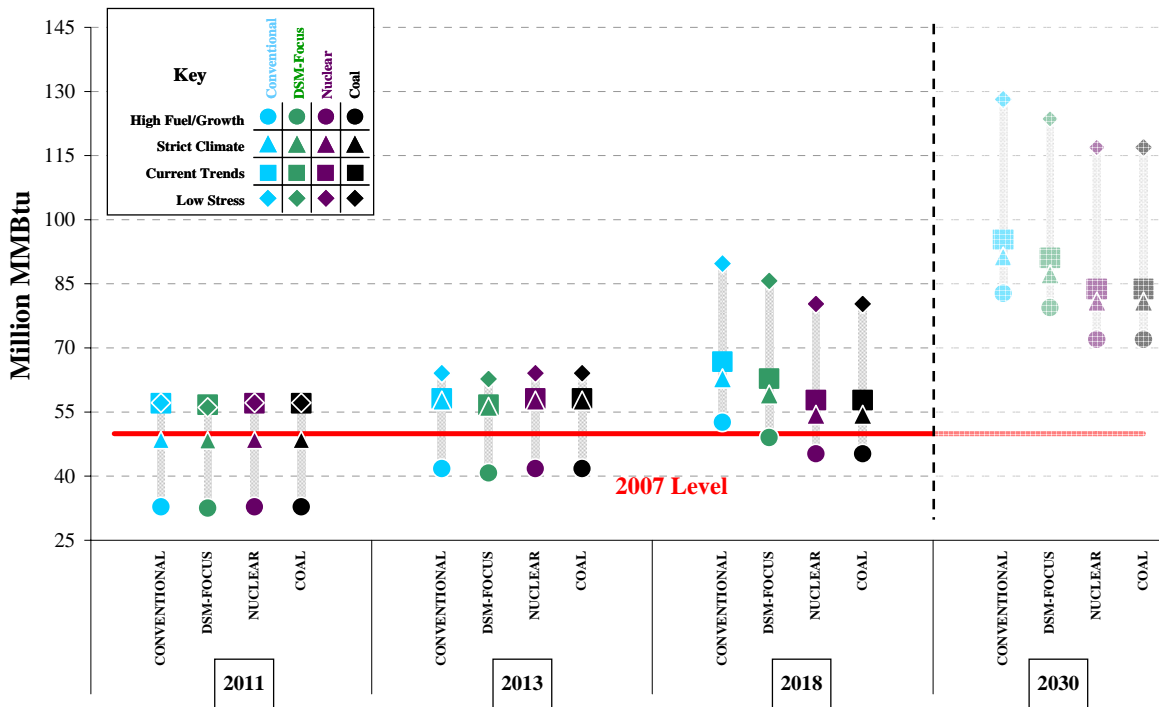
Total Going-Forward Resource Cost



*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

9. Non-Gas Baseload Generation Would Reduce Dependence on Natural Gas

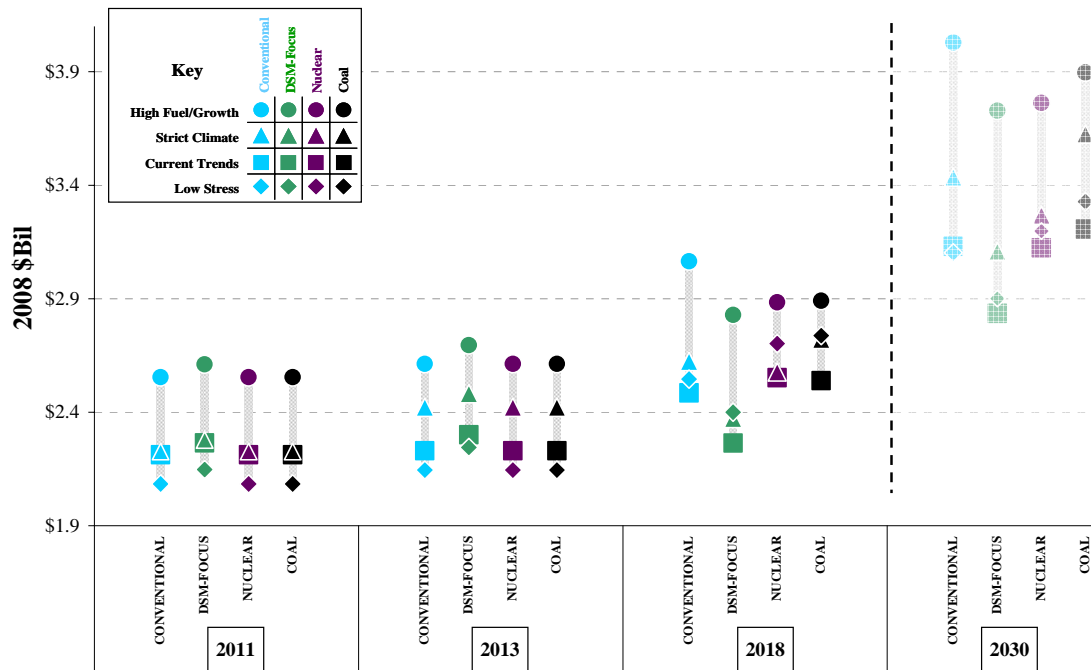
Jan-Feb Gas Use in ISO-NE Power Sector



- Under Cost of Service, baseload reduces customer exposure to gas costs.
- Under a market regime, baseload offers no customer cost protection.
- But nuclear and coal are not equivalent on other dimensions (CO₂).

10. “Market Regime” vs. “Cost-of-Service” Affects Rate Stability ...

Customer Cost in Cost-of-Service Regime

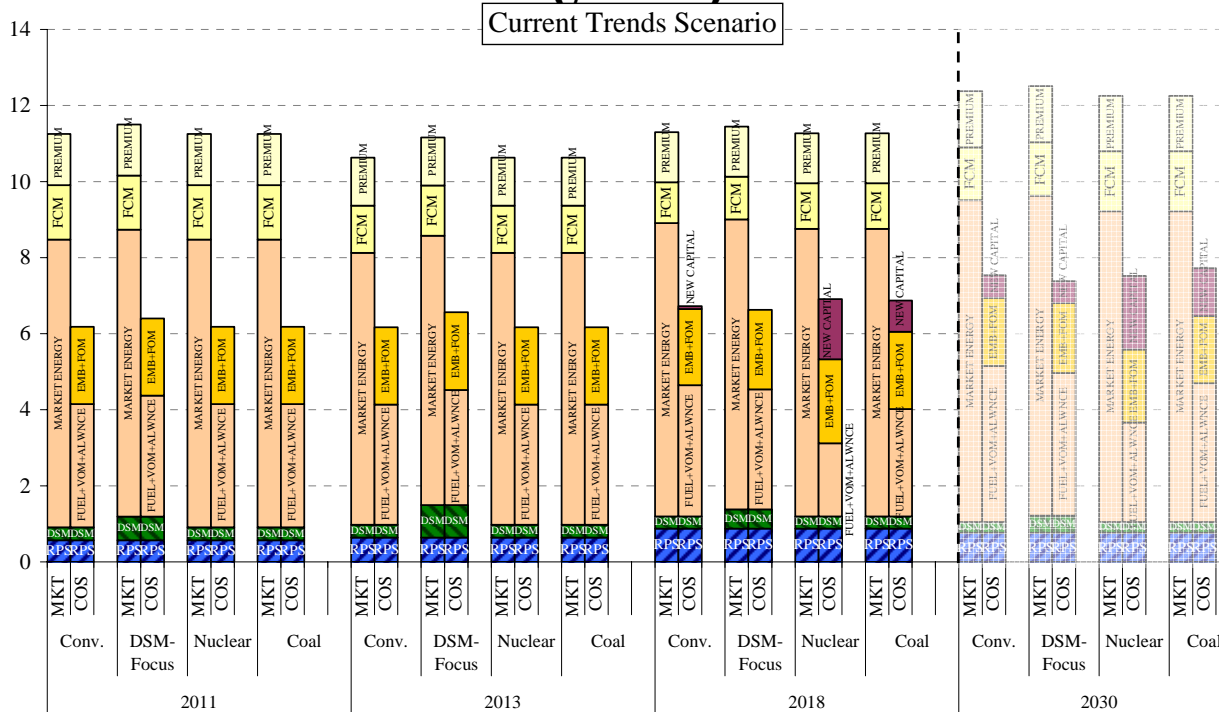


*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

- Range of costs is much smaller under Cost of Service.
- This is primarily because under a market regime, the market price for all power is determined by the last unit of supply. In very simple terms, if the cost of the last unit of supply increases by 10%, then under a market regime customer costs increase by 10%. But the total cost of generating power from all sources varies by much less than 10% (many of these costs are fixed and don't vary with the last unit's costs).
- Even if only some assets are procured on a cost basis, this will reduce customers' exposure to uncertain and volatile prices.

10. “Market Regime” vs. “Cost-of-Service” ... May Have Future Customer Cost Implications

Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime (“EMB+FOM”) includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime (“FUEL+VOM+ALWNC”) includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

- As constructed/assumed, the hypothetical “Cost-of-Service” regime has substantially lower costs than the “Market” regime, across all scenarios and strategies studied; however, these results indicate more analysis is warranted.
- The overall cost levels used in the analysis may not offer a realistic comparison on a regional market basis, because it is probably not possible to put all generating assets back under cost of service regulation at historic embedded costs. The actual purchase costs for existing generation would not likely be at the levels assumed in the Cost of Service results because the fixed costs for some of the existing assets assumed in the Cost of Service analysis are below current market values.
- Output from new construction owned outright and output from new assets acquired via long-term contracts could potentially be obtained at prices reflecting Cost of Service, but this was not evaluated in this study.
- Long-term contracts for the output of new or existing assets can reduce uncertainty which can lower costs. Such questions of procurement and risk management are beyond the scope of this resource planning effort, but are likely to be important issues to consider in addressing the concerns of Connecticut customers.

Recommendations

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.
2. Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.
3. Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.
4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence).

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Companies to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

2. Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation

At the present time, the Companies are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Companies greater flexibility in the structures and duration of their power supply arrangements on behalf of customers.

Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

3. Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England

Connecticut's renewable portfolio standard as currently structured, while supporting Connecticut's renewable goals, may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence)

Non-gas baseload generation (e.g., coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (e.g. heating). Both the cost and CO₂ emissions implications of all non-gas options should be considered.

Study Limitations

This study contains only limited analysis related to transmission.

This is not a siting analysis for new generation capacity.

This is not a procurement risk management study.

This is not a regional renewable energy market study.

Recommended Further Analysis

The analysis can be refined or extended if such enhancements are deemed helpful.

- Additional sensitivity/scenario analysis
- Expanding the suite of evaluation metrics to address additional issues and concerns
- Evaluation of blended resource solutions, e.g., DSM and nuclear
- Evaluation of resource solutions at different scales/levels
- Evaluation of hybrid market/cost-of-service procurement strategies
- Examining how periods of market disequilibrium (e.g., capacity market boom-bust cycles) might affect the evaluation of resource solutions
- Harmonizing electricity market price outlooks used in previous DSM evaluations with those in this study to explore the impact on cost-effectiveness tests
- Examining the interplay between market (price-induced) conservation and the incremental impact of DSM programs
- Additional optimization of DSM program elements to enhance overall effectiveness and to maximize desired impacts on energy and peak load
- Additional refinement of resource characterization and potential in light of rapidly changing technology, cost and performance; for example, an examination of the potential of combined heat and power (CHP) and distributed resources to contribute to power supplies over the long run.