NESCOE
New England States Committee on Electricity

Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study
Base Case Results

November 17, 2016

The New England States Committee on Electricity (NESCOE) retained London Economics International (LEI) to conduct modeling in connection with NESCOE's Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study (Study). The Study's "Base Case" results are attached. The Base Case is one element of LEI's modeling that will be included in a larger report currently under development.

The Base Case represents the status quo. The Study will include similar analysis that looks at a range of hypothetical or "what if?" scenarios, and a *directional* comparison of those futures against the status quo. The Base Case and the hypothetical scenarios are informed by assumptions, many or all of which history may prove wrong. For example, due to its timing, the Base Case does not include clean energy resources recently selected for contract negotiation in the New England Three-State Clean Energy Request for Proposals or the Connecticut section 1(B) procurement.[1] The Base Case is also based on "snapshot in time" assumptions regarding proposed natural gas pipeline projects without the ability to predict their path to operation. The Study is not predictive or precise and should not be interpreted as such.

This brief memo summarizes and provides important caveats about the Base Case results. This includes information on the Base Case: 1) forecasted costs (energy, capacity, wholesale load), 2) resource mix and market dynamics (existing resources and new resources), and 3) state policy requirements (carbon emissions and renewable resources).

***Summary*:** Under Base Case assumptions, the total costs to wholesale load in the years 2025 and 2030 remain within a recent historical range, but increasingly reflect rising capacity costs. The resource mix is similar to the current generation fleet: remaining coal retires and new entry is mostly natural gas, wind, and solar photovoltaic (PV). Under Base Case assumptions, the region exceeds power sector carbon dioxide emissions targets and renewable resource additions are inadequate to achieve current Renewable Portfolio Standard (RPS) targets.

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[1] For more information, *see* https://cleanenergyrfp.com/2016/10/25/bidders-selected-for-contract-negotiation/ and http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/99f2c66070f3b7a285258059006f06ff/$FILE/2016.10.27_FINAL Small Scale Selection Notice.pdf.

Forecasted Costs:

- *Energy:* Forecasted energy market prices are closely related to assumed natural gas prices. This is due to the continued dominance of natural gas-fired generation in the regional fleet in 2025 and 2030. On a seasonal basis, winter natural gas prices affect energy prices more than the summer peak demand for electricity. **In the Base Case, forecasted annual average energy prices in 2025 and 2030 are in the $48-51/MWh range**, **compared to 2015 actual annual average energy prices of $45/MWh**.[2] For reference, assumed natural gas prices, on an annual average basis, are $5.60/mmBTU in 2025 and $6.31/mmBTU in 2030, compared to 2015 actual annual average natural gas prices of $6.10/mmBTU.[3]

- *Capacity:* In the short term, capacity market prices are likely to be set by existing resources. **By 2025, capacity prices are forecasted to converge on the assumed net cost of new entry, and rise to the $11.50-13/kW-month range**. For comparison, the most recent capacity auction for 2019-2020 cleared at $7.03/kw-month.[4]

- *Wholesale Load Costs:* The **estimated cost to wholesale load**, calculated as the sum of modeled energy and capacity market costs, **in 2025 is $10.8 billion** (energy $6.0b plus capacity $4.8b) and **in 2030 is $ 11.9 billion** (energy $6.3b plus capacity $5.6b). For reference, actual wholesale market costs in the years 2008 to 2015 have ranged from $6.4 billion to $14.0 billion.[5] In the Base Case, the ratio of energy to capacity costs in 2025 and 2030 is approximately 55% to 45%. In 2015, the actual ratio of energy to capacity costs is 84% to 16%.[6]

Resource Mix and Market Dynamics

- *Existing Resources:* Capacity revenues represent the majority of profits for natural gas- and oil-fired generators. In contrast, energy revenues represent the majority of profits for nuclear and renewable resources. By 2025, all of the existing coal-fired generation is forecasted to economically retire. **Based on LEI's estimates of net going forward fixed**

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2 *See* 2015 Report of the Consumer Liaison Group ("2015 CLG Report"), at Table 3 on page 34, available at http://www.iso-ne.com/static-assets/documents/2016/03/2015_report_of_the_consumer_liaison_group_new_template_final.pdf.

3 *See* U.S. Energy Information Administration, natural gas city gate prices, available at http://www.eia.gov/dnav/ng/hist/n3050ma3M.htm. Assumed natural gas prices are the result of LEI's Levelized Cost of Pipeline model. For reference, the 2016 NEPOOL Economic Study assumed natural gas prices are consistent with the U.S. Energy Information Administration's 2016 Annual Energy Outlook, which are $5.40/mmBTU in 2025 and $5.57/mmBTU in 2030.

4 *See* ISO New England Key Grid and Market Stats, available at http://www.iso-ne.com/about/key-stats/markets#fcaresults.

5 2015 CLG Report.

6 In 2015, actual energy and capacity costs were $5.9 billion and $1.1 billion, respectively. 2015 CLG Report.

costs and other assumptions, existing nuclear resources remain economically viable through the study period.

Importantly, the modeling is based on assumptions identified, not on facts or resource owners' business judgment. In this study, nuclear resources' forecasted economic viability is likely influenced by several factors: (1) assumed natural gas prices, (2) LEI's approach for estimating so-called "missing money" (i.e., forecasted revenues from the wholesale markets minus estimated going forward fixed cost estimates) and (3) limitations of the approach taken to model the energy market. Assumed natural gas prices are relatively moderate on an annual average basis, \$5.60-\$6.31/mmBTU, despite seasonal price volatility ranging from \$3.48 to \$12.16/mmBTU in 2025, for example. LEI applies principles of economic theory in developing its resource type-specific net going forward fixed cost estimates, which do not include so-called "avoidable costs." LEI's modeling output showing continued nuclear economic viability does not include several financial considerations: return on equity; FCM performance risk; or potential significant capital expenditures. LEI's energy market model is not configured to simulate negative energy prices in New England.

- *New Resources:* **New resources are a mix of modeled natural gas (62%) and assumed renewables (38%)**.[7] The assumed resources are 168 MW solar photovoltaic (PV) resources and 925 MW of on-shore nameplate wind resources. These assumed resources are added by 2025. Transmission system limitations inhibit further on-shore wind development in 2025 and 2030. Over the study period, the capacity market model adds 2,000 MW of natural gas-fired resources to maintain resource adequacy.

State Policy Objectives

- *Carbon Emissions:* Power sector **carbon dioxide emissions are forecasted to be 26.8 million tons in 2025 and 25.2 million tons in 2030**.[8] For reference, 2015 actual power sector carbon dioxide emissions were 30.8 million tons. Compared to the 2020 Regional Greenhouse Gas Initiative (RGGI) aggregate carbon dioxide cap for the six New England states at 26.4 million tons, **the Base Case indicates that some in-region resources may need to procure additional RGGI allowances or carbon offsets for compliance**.[9]

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7 Capacity addition percentages are based on nameplate MW.

8 Emissions results are expressed in short tons. Declining aggregate emissions in the Base Case are a function of: the declining ISO-NE long-term load forecast for energy (net of energy efficiency and solar PV), improving fuel efficiency of the generation fleet (new entry lowers system average heat rate),

9 The emissions results presented below include a small contribution from resources that are not subject to RGGI. For example, resources < 25 MW are not currently subject to RGGI. Estimating the carbon dioxide emission contributions of these resources is beyond the scope of the Study. ISO-NE economic analysis for NEPOOL suggests that an additional 2 to 5 million tons per year may be emitted by the class of resources not subject to RGGI.

- *Renewable Resources:* **Due to transmission system limitations,[10] comparative resource economics,[11] and without an increase in renewable energy imports,[12] the region is forecast to be under-supplied with Renewable Energy Certificates** (REC) relative to Renewable Portfolio Standard (RPS) targets in:
    - 2025 by 2.1 TWh, or 10.5% of Class 1 targets
    - 2030 by 3.9 TWh, or 17.0% of Class 1 targets[13]

Result Caveats and Interpretation Notes

Forecasted Costs:

- The modeling results are based on a host of assumptions. These assumptions influence which resources are dispatched, when and for how long, and, importantly, the prices at which resources produce energy and supply capacity. With time and hindsight, almost all of the assumptions may be proven wrong and may affect the models' forecasts in either direction to varying degrees.

- The energy and capacity market models are a simplified representation of the wholesale electricity markets and regional transmission system. The forward looking modeling was completed on the basis of certain assumptions which may not capture all possible operational conditions in the real world. In the model, generator availability is consistent with annual averages, the weather is always normal, and the load forecast is invariably accurate. Such a simplified representation of these markets may understate prices and emissions.[14]

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10 In the Base Case, transmission system enhancements are limited to the reliability-related upgrades that are currently in-process. LEI added on-shore wind resources to the model's northern Maine zone until the installed capacity equaled the transfer limit out of the zone.

11 Based on estimated renewable resource capital costs, LEI assumes that Alternative Compliance Payments are likely more economic than AC transmission system enhancements and other scalable RPS-eligible technologies.

12 The Base Case assumes that recent levels of imported renewable energy persist through the study period. *See* National Renewable Energy Laboratory's 2015 analysis, *Quantifying the Level of Cross-State Renewable Energy Transactions*, available at http://www.nrel.gov/analysis/policy_state_local.html. An increase in imported renewable energy may help address such a forecasted shortfall of RECs, but should be considered within the context of New York's Clean Energy Standard proposal to provide incentives for existing renewable resources that currently export to New England.

13 Class 1 Targets are defined as the sum of: Connecticut, Maine, and Massachusetts Class I; New Hampshire Class 1 and 2; Rhode Island New (including recently enacted H.B. 7413); and Vermont's Distributed Generation carve-out. These totals are estimated to be 20.1 TWh in 2025 and 22.9 TWh in 2030.

14 For more information, *see* Base Case Results slide 22. LEI analysis indicates that approximately 5% of the highest priced hours may not captured in the modeling.

Resource Mix and Market Dynamics:

- Resource retirements and new entry are based on simulated capacity market outcomes, which are primarily driven by: (1) estimated net going forward fixed costs and (2) forecasted energy market revenues.[15] Net going forward fixed costs for existing resources include fixed operations and maintenance costs; debt repayment expenses; and selling, general, and administrative expenses. All other costs (return on equity, as one example) are not included in existing resources' capacity market offers. Such other costs and financial considerations will be relevant to market participants. Exclusion of certain going forward costs from the analysis may overstate an existing resource's willingness to remain in operation. This would delay new entry and its associated impacts on energy and capacity prices and power sector emissions. Under- or over-estimated energy market revenues may delay or accelerate, respectively, some resource retirements.

- The model assumes that all market participants have a similar financial risk tolerance. This may not accurately reflect the diversity of risk tolerance among various market participants. Therefore, modeling results may under- or over-state a market participant's willingness to continue operations with an under-performing resource.

Policy Objectives:

- The model does not explicitly limit power sector air emissions. The modeling incorporates a price on carbon dioxide emissions based on current RGGI allowance secondary market prices, escalated at an assumed rate of inflation that essentially keeps carbon prices flat in real dollar terms. The price on carbon dioxide emissions, on its own, does not limit the amount of power sector air emissions. Given New England's resource mix, especially the amount of natural gas-fired generation, assumed carbon prices are unlikely to affect merit order in the dispatch.[16] A higher carbon price assumption (and all other assumptions held constant), while likely to influence prices, is unlikely to affect the region's power sector air emissions totals.[17]

- LEI's renewables development outlook and perspective on transmission system limitations directly influence the supply of RECs. LEI assumes that due to transmission system limitations, and other factors, the region may be under-supplied with RECs over the study period. The Base Case assumptions about the status quo lead to this result. To the extent the Base Case assumptions regarding renewable technology costs, energy production capabilities, and penetration are wrong, the supply of RECs may be closer to RPS targets.

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15 LEI retires resources when net going forward fixed costs exceed energy and capacity market revenues for three consecutive years.

16 *See generally* Base Case Results slide 10.

17 To the degree that higher energy prices resulting from higher carbon allowance prices increased existing resources' energy market revenues, some existing resource retirements may be delayed. The impact of potential delays in resource retirements could affect regional air emissions totals in either direction, depending on the emissions profile of the retiring resource(s) and any corresponding new entry.

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London Economics International LLC

New England Modeling:
Results of the Base Case

Prepared for NESCOE

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2016

Disclaimer notice

- ***London Economics International LLC ("LEI") was retained by the New England States Committee on Electricity ("NESCOE") to model the New England wholesale energy and capacity markets under six hypothetical policy scenarios that were developed by NESCOE. LEI has made the qualifications noted below with respect to the information contained in these slides and the circumstances under which these slides were prepared.***
- ***While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Notably:***
  - *LEI used the latest assumptions available as inputs to the Base Case as of July 2016.*
  - *LEI's analysis is not intended to be a complete and exhaustive analysis of future market dynamics (all possible factors of importance have not necessarily been considered). The provision of an analysis by LEI does not obviate the need for interested parties to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.*
  - *No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.*
  - *There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in competitive power markets and investments in such markets. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.*
- ***The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees and affiliates make no representations or recommendations to any party. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis and this report.***

LEI was retained to model the New England wholesale energy and capacity markets under six hypothetical policy scenarios that were developed by NESCOE for years 2025 and 2030

- **NESCOE is analyzing various mechanisms available to states to execute public policies, as part of its ongoing regional efforts**
- **LEI was engaged to forecast market prices and dynamics under a range of hypothetical futures that contain different resource and infrastructure expansions and potential outcomes**
  - The modeling conducted by LEI is not intended to promote a target or position on behalf of LEI or NESCOE, but rather to directionally indicate how different hypothetical scenarios could impact New England's wholesale market dynamics

Scenarios Studied

Scenario	Characteristics
Base Case	"Business as Usual" conditions under current policies and regulations to continue
Expanded RPS	Evaluate the implications of additional renewable resources with and without transmission infrastructure on power sector outcomes. RPS expansion was assumed at two different hypothetical levels
Clean Energy Imports	Examines the impacts of an additional large scale inter-regional transmission project from a neighboring system that would enable hydroelectric based energy imports into New England
Clean Energy Retirements	Examines the market impacts of retiring certain clean energy-producing generators (nuclear)
Combined Renewable and Clean Energy	Studies the market implications of creating an expanded RPS in conjunction with clean energy imports

Topics

NESCOE's Base Case outlook represents a "business as usual" perspective for the future with normal system operations, average load conditions and continuation of current market rules

Key Features of the Base Case

- **Continuation of current ISO-NE market rules, including FCM convex demand curves in the long run based on NESCOE Staff's proposed CONE values**
- **Continuation of existing state policies related to RPS and carbon allowance market (RGGI). Base Case modeling was completed before outcome of MA legislation on renewable energy procurement**
- **"Just in time" economic new entry and retirements based on the projected market dynamics (no assumed infrastructure investment based on pending state initiatives)**
- **ISO-NE's baseline expectations for load growth under weather normal (50/50) conditions and net of forecasted energy efficiency and solar PV**
- **Consideration of known and "committed to market" infrastructure projects, such as Algonquin Incremental Market, Tennessee Gas Pipeline Connecticut Expansion, and Algonquin Atlantic Bridge**
- **No transmission expansion beyond ISO-NE certified projects**
  - See ISO-NE PAC material "Transmission Transfer Capabilities Update," June 10, 2016

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Modeling exhibits convergence to more balanced conditions between 2025 and 2030, when prices reach levels consistent with “new entry trigger prices” for combined cycle plants

Modeling Summary (nominal $)

	2025	2030
Energy market cost, $m	**$6,011**	**$6,309**
Average demand-weighted system LMP, $/MWh	$48.01	$50.99
Average time-weighted LMP (Internal Hub), $/MWh	$46.13	$48.96
Demand (net of EE/PV), GWh	125,212	123,713
Capacity market cost, $m	**$4,825**	**$5,637**
Capacity price (calendar year), $/kW-month	$11.49	$12.87
Cleared capacity (calendar year), GW	35.008	36.508
Wholesale market cost, $m	**$10,836**	**$11,945**

	2025	2030
Production costs, $m	$3,056	$3,221
CO2 emissions, million short tons	26.832	25.197
System production-weighted capacity factor	32.72%	30.91%
Implied market heat rate, Btu/kWh	8,238	7,758
Delivered natural gas price, $/MMBtu	$5.60	$6.31

Key Highlights

- Base Case energy market prices increase modestly from **$48/MWh in 2025** to **$51/MWh in 2030** at a **cumulative annual growth rate of 1.2% (in nominal terms)**
- The **primary driver of energy prices are the delivered gas prices** as well as the supply and demand conditions, namely **new entry and retirements**
- The primary drivers of capacity prices are the projections of quantities and timing of supply and demand, and assumptions of the Gross Cost of New Entry (“CONE”)
- Modeled capacity clearing prices in FCAs #15 and #16 (2024-2026 delivery) are $12.0/kW-month and $10.7/kW-month respectively, while FCAs #20 and #21 (2029-2031 delivery) are $13.6/kW-month and $11.8/kW-month respectively. This results in a blended capacity price of approximately **$11.5/kW-month** for calendar year **2025** and **$12.9/kW-month** for calendar year **2030**

The Base Case results in a tighter supply and demand balance by 2025 as compared to current conditions, and a shortfall in local resources qualified for Class I RPS

Key Highlights Continued

- In the short term, New England is an over-supplied system relative to NICR, with 1.4 GW clearing above the Net ICR in FCA #10 alone; therefore, the first generic combined cycle does not clear until 2025
  - LEI assumed new gas-fired resources (combined cycle) enter when projected energy and capacity prices are sufficient to meet all-in fixed costs (gross cost of new entry), which are assumed to be $13.40/kW-month in 2025 and $14.21/kW-month in 2030
  - Long-term supply and demand balance results in capacity prices clearing along the steeper portion of the demand curve, resulting in a high degree of price sensitivity from over or under-supply
- New England is expected to fall short of Class I Renewable Portfolio Standards ("RPS") targets in the Base Case by 2.1 TWh in 2025 and 3.9 TWh in 2030 (assuming no increase in imported RECs) due to internal transmission constraints that limit onshore wind development in Maine
  - Shortage of RPS targets could be addressed through Alternative Compliance Payments or through increased imports
- CO_2 emissions levels also decline as a result of falling energy demand and an increasingly fuel-efficient system (new combined cycles plants enter the market with lower heat rates)
- The production-weighted system capacity factor is 33% in 2025 and 31% in 2030. The declining system capacity factor is partially due to falling total consumption despite rising peak demand (therefore the system continually requires new generation)

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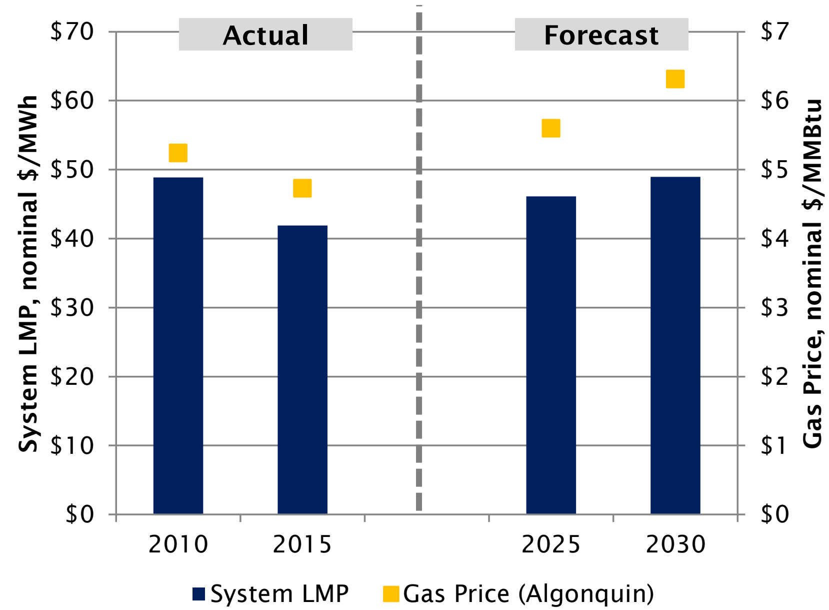
Base Case energy market prices track gas price changes but also reflect increasing efficiency of the system over time

- **LMPs generally follow trends in gas prices, which increase gradually over time at a cumulative annual growth rate of 2.4% between 2025 and 2030**
  - LEI used its Levelized Cost of Pipeline Gas model to develop gas prices
  - LEI's LCOP model accounts for the market's expectation for committed expansion of natural gas pipelines as reflected in forward prices; in the longer term, Algonquin gas prices grow in line with EIA's Henry Hub price trends
- **Implied market heat rates typically fall over time as more efficient generation is added to the system**
  - 2,000 MW of CCGTs are added between 2020 and 2030 (500 MWs each in 2025, 2027, 2028, 2030)
  - 925 MW of nameplate generic on-shore wind are added between 2020 and 2030
- **Congestion is limited due to the assumption of "normal" system operations and "economically placed" new entry, resulting in similarly priced LMPs across all zones studied**
  - LMPs presented by LEI include energy and congestion components, but not loss components. Losses are not necessary for the purpose of this analysis

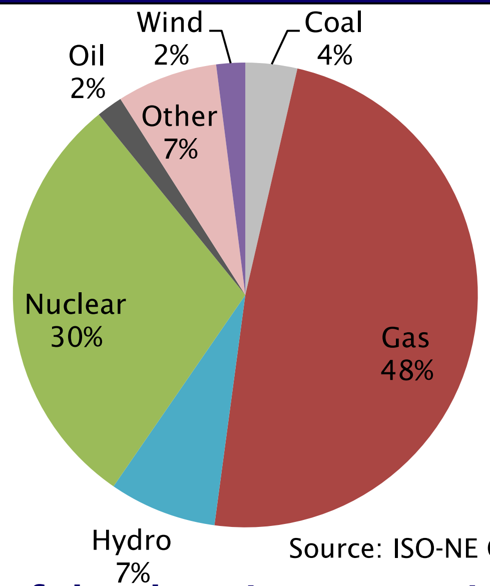
Forecast Energy Price Forecast Internal Hub (ISO-NE)

	Demand-Weighted LMP (System)	Time-Weighted LMP (Internal Hub)	Gas Price (Algonquin)	Implied Market HR
Year	$/MWh	$/MWh	$/MMBtu	Btu/kWh
2010		$48.89	$5.24	9,336
2015		$41.90	$4.73	8,856
2025	*$48.01*	*$46.13*	*$5.60*	*8,238*
2030	*$50.99*	*$48.96*	*$6.31*	*7,758*



Base Case generation mix continues to be dominated by natural gas-fired generation: operating nuclear plants remain economic while coal is retired due to modeled economics

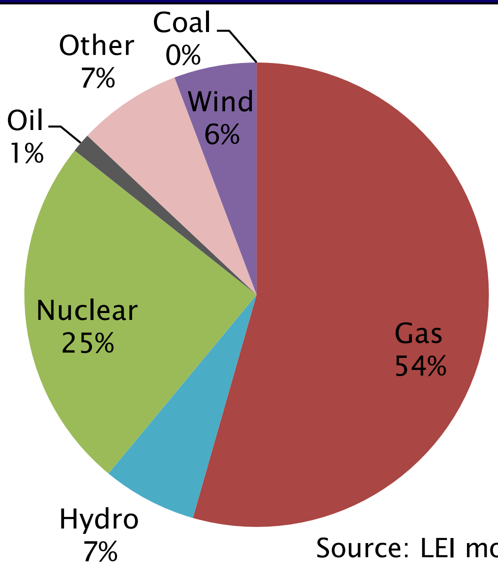
Generation Mix (MWh) – 2015



Source: ISO-NE Generation Data

Note: All figures exclude behind the meter solar PV generation. In addition, percentage differences between 2025 and 2030 are negligible when rounding to whole numbers

Generation Mix (MWh) – 2025/30

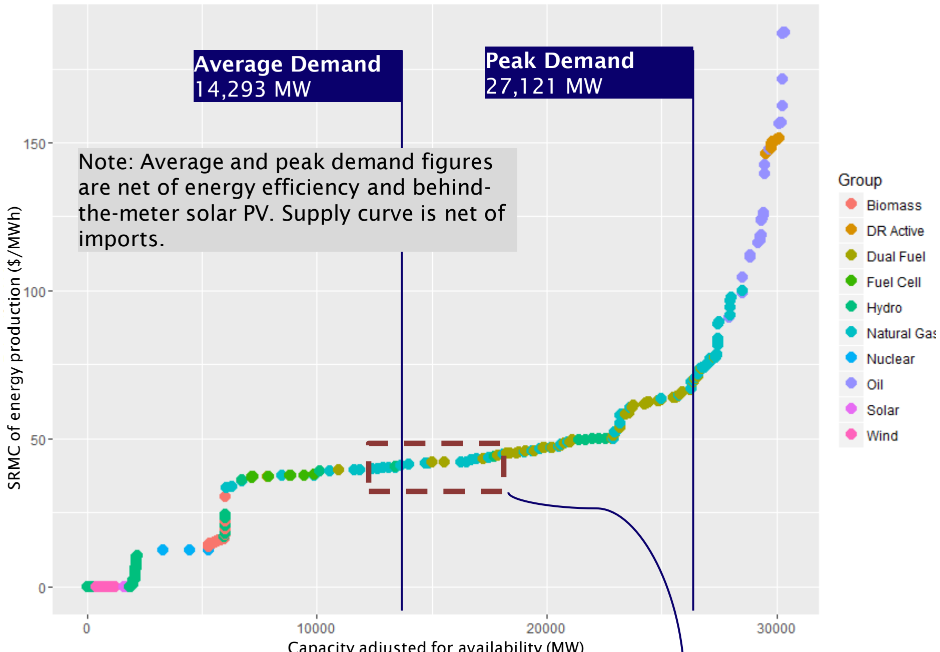


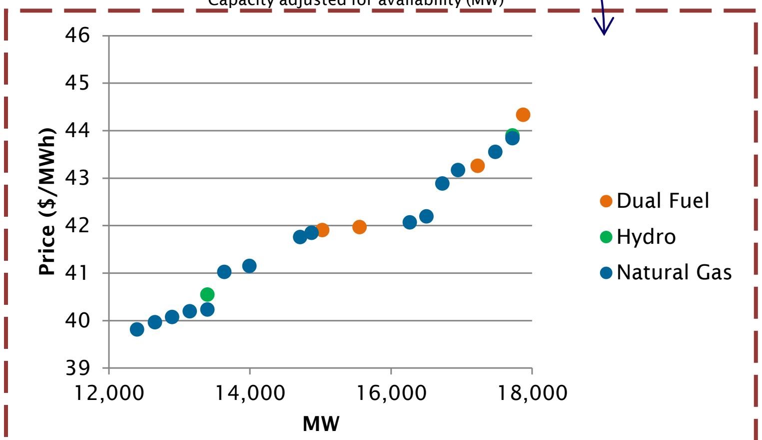
Source: LEI modeling

- **Drivers of the changing generation mix under the Base Case include supply and demand side market changes**
  - Coal is completely phased out in the Base Case before 2025 due to projected market economics (minimum going forward fixed costs exceed expected net revenues); natural gas and renewable generation replace coal generation
  - Nuclear assumed to remain economically viable because market prices cover estimated minimum going forward fixed costs on average over the modeling timeframe (but equity returns may be exhausted)
  - Onshore wind generating capacity grows from 2.2 TWh in 2015 to 6.8 TWh in 2025; however, no new wind is added beyond 2024 due to local transmission constraints, therefore the share of wind output does not grow between 2025 and 2030 in the Base Case

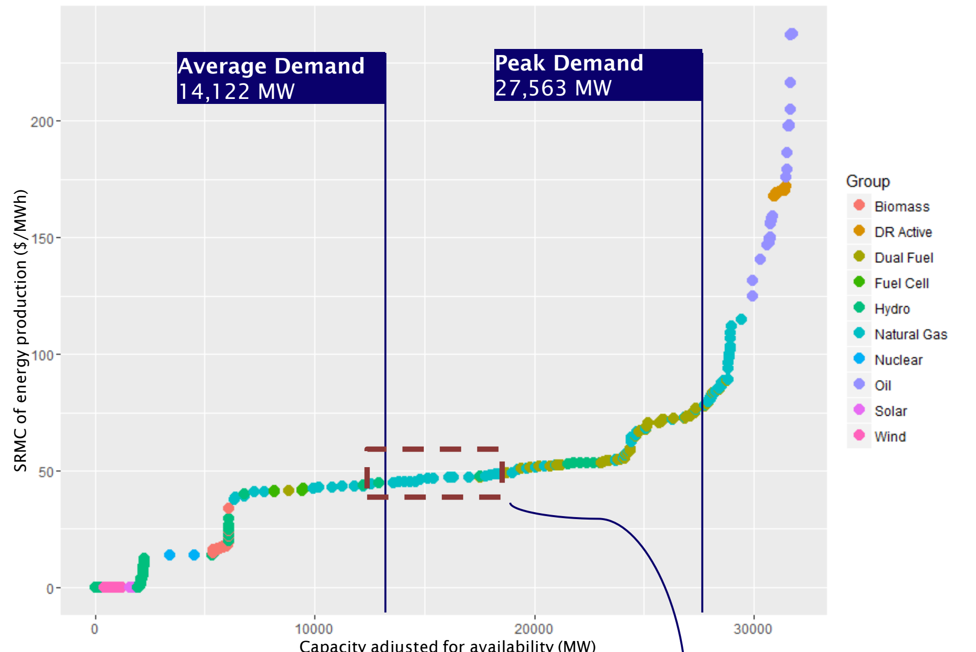
Natural gas continues to dominate the supply curve and will remain the marginal fuel source in New England for most hours

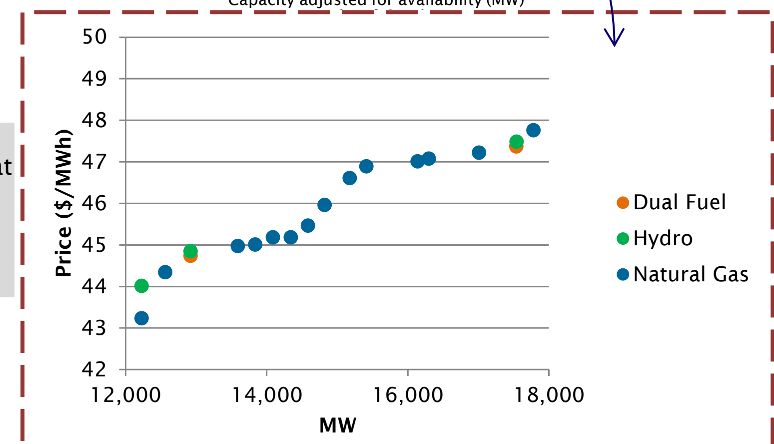
Internal Supply Curve - 2025





Internal Supply Curve - 2030

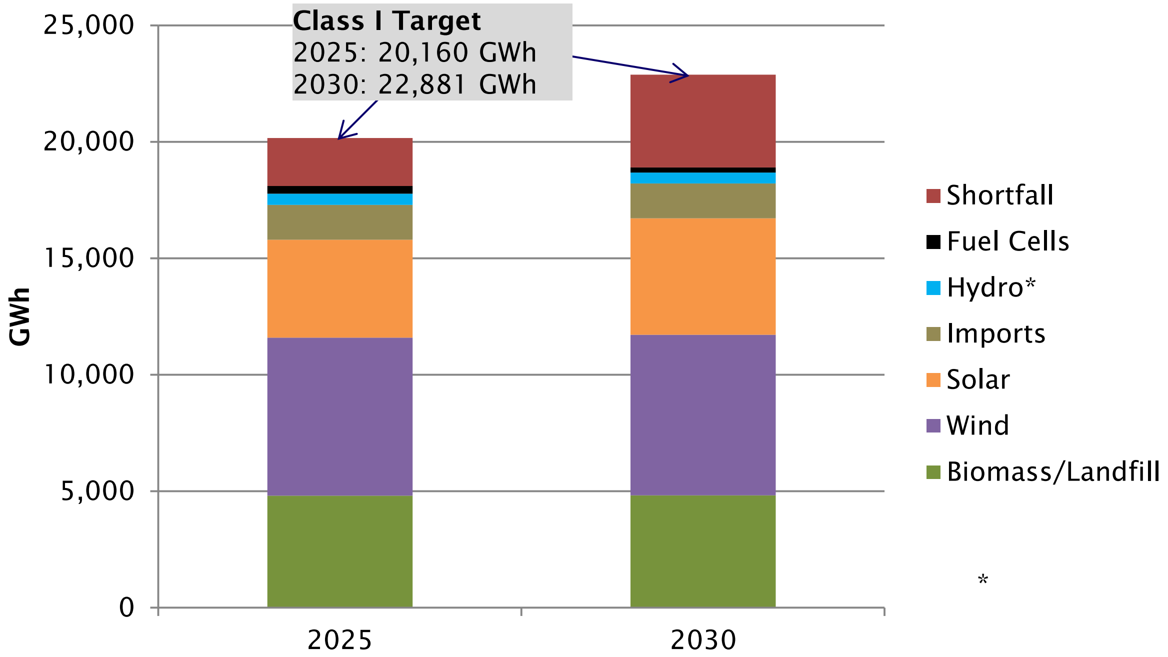




Natural gas creates the flat section of the supply curve in both 2025 and 2030

Base Case is 2.1 TWh short of Class I RPS targets by 2025 and 3.9 TWh short by 2030 (assuming no increase in imported RECs)

Modeled Supply - Class I RPS



Wind: onshore wind build out limited to 1,000 MW (including new and existing) in Bangor Hydro Electric zone

Solar: LEI has relied on ISO-NE's solar forecast (new solar also presumed to get SRECs)

*Note: Hydro output being shown constitutes only small run of river hydro production

- **The shortfall in new renewables relative to the RPS requirements does not necessarily imply large Alternative Compliance Payments ("ACP") – imported renewables may be able to reach the New England market**
  - LEI estimates that more than 500 MW and 700 MW of capacity would be available on the New Brunswick and New York interties to also help meet Class I targets (based on 2015 flows)
  - REC-qualified imports could include eligible wind, hydro, and biomass resources from New York and New Brunswick; large hydro plants are qualified to sell RECs only in Vermont and Connecticut under certain circumstances

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Capacity factors vary with the expected position in the merit order, and over time almost all existing generation will face declining capacity factors due to competition from new resources and declining electricity consumption

Capacity Factors by Technology

Generation Type	Capacity 2017	Capacity 2025	Capacity 2030	Capacity Factor 2025	Capacity Factor 2030	Generation 2025	Generation 2030
Existing (non-RPS eligible)	MW	MW	MW	%, Weighted avg	%, Weighted avg	GWh	GWh
Bio/Refuse	198	198	198	71%	71%	1,233	1,238
Coal Steam	920	0	0	0%	0%	0	0
Gas Combined Cycle	9,907	9,907	9,907	33%	26%	28,800	22,898
Gas Combustion Turbine	246	246	246	0%	0%	1	1
Hydro	1,502	1,502	1,502	41%	41%	5,373	5,379
Gas Steam	6	6	6	0%	0%	0	0
Gas/Oil Combined Cycle	4,185	4,185	4,185	25%	17%	9,065	6,227
Gas/Oil Combustion Turbine	649	649	649	1%	1%	85	49
Gas/Oil Internal Combustion	9	9	9	0%	0%	0	0
Nuclear Steam	4,041	3,358	3,358	91%	91%	26,708	26,756
Oil Combustion Turbine	2,133	2,133	2,133	2%	1%	296	184
Oil Internal Combustion	129	129	129	1%	0%	8	4
Oil Steam	2,219	2,219	2,219	2%	1%	299	169
Pumped Storage	1,735	1,735	1,735	10%	10%	1,518	1,515
Gas/Oil Steam	2,533	2,533	2,533	2%	1%	346	169
New Conventional - 2016 onwards							
New - Gas/Oil Combined Cycle	674	2,868	4,368	72%	68%	18,177	25,829
New - Gas Combustion Turbine	0	615	615	9%	5%	499	276
Existing Renewables							
Bio/Refuse	765	763	763	72%	72%	4,805	4,827
Gas Fuel Cell	79	79	79	48%	31%	336	218
Hydro	130	130	130	41%	41%	469	469
Solar*	588	588	588	18%	18%	926	926
Wind - On-Shore	1,021	1,021	1,021	34%	35%	3,041	3,098
New Renewables - 2016 onwards							
Solar*	102	379	504	18%	18%	597	794
Wind - Off-Shore	0	30	30	49%	50%	130	132
Wind - On-Shore	25	1,180	1,180	35%	35%	3,611	3,665

- **Capacity factors in table above represent average aggregates for “classes” of generation – some plants do better or worse than the average**
- **Low capacity factors units are potentially at risk for retirement as they are earning the least amount of profit margin from energy sales and may also be exposed if there are system events that trigger capacity performance incentive payments under ISO-NE’s Pay-for-Performance design**

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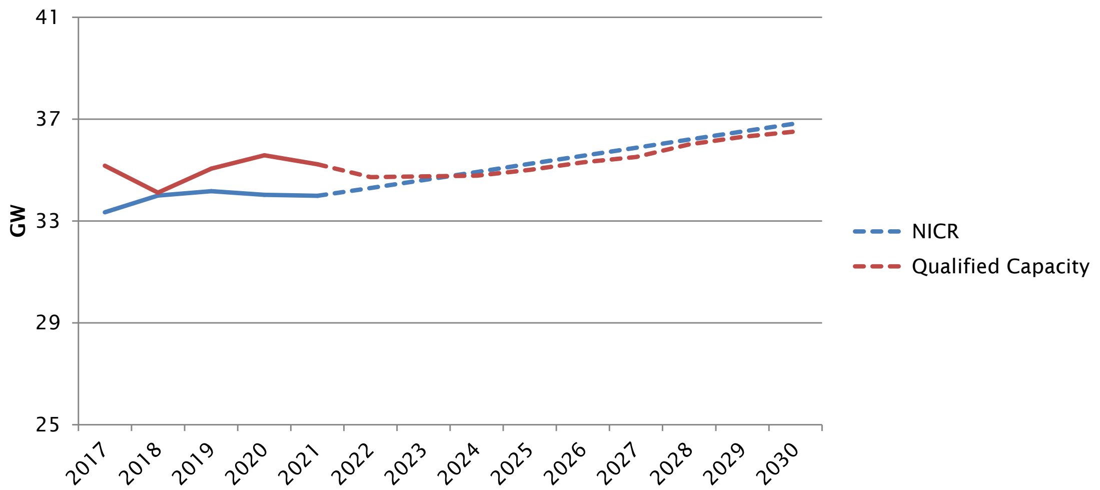
New England is an oversupplied system in the near term until relative supply and demand balance is restored by FCA #15 as a result of retirements and load growth

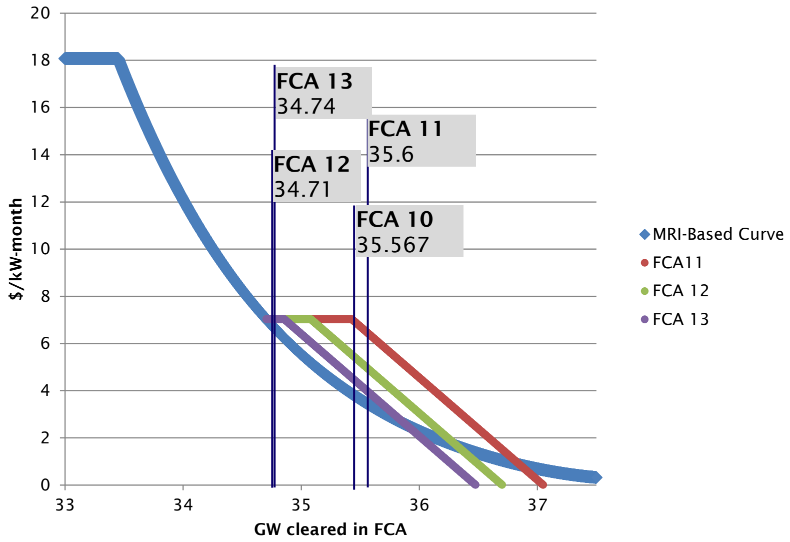
Resource Supply and Demand Balance

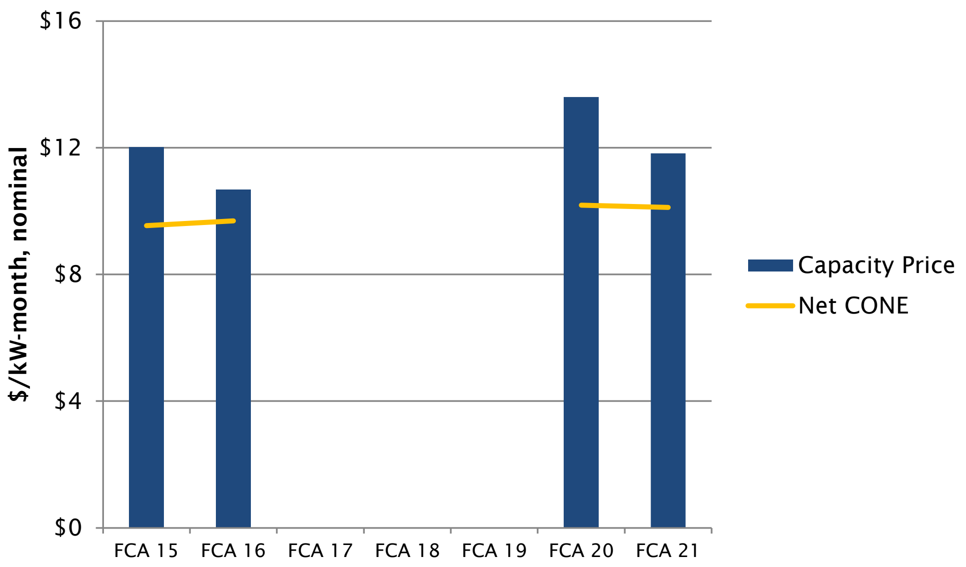


- **Net ICR ("NICR") is projected based on 14.4% reserve margin in the long run**
  - As ISO-NE's peak demand forecast declined in CELT 2016, the NICR for FCA #11 is expected to be lower than FCA #10, despite greater supply levels by 287 MW; the decline in ISO-NE's peak demand outlook is driven by increased levels of solar PV and energy efficiency
- **Capacity lost due to retirements in FCA #8 (e.g. Brayton Point) has been more than made up by new resource acquisitions in FCA #9 and #10; moreover, ISO-NE has revised down its projections for demand in its CELT 2016 (May 2016) publication**
  - New England market is expected to remain over supplied until 2024 (the first generic combined cycle plant is added in 2025)
  - LEI assumes a roughly balanced market to resume in the long run (post FCA #15)
  - If there is flatter than expected peak demand growth and/or if new resources continue to qualify in FCA #11-13, it may lead to more oversupply than modeled in the Base Case and possibly trigger more retirements

Due to economically-driven coal retirements, the transitional demand curve is a primary factor only in the next two FCAs - the convex demand curve drives outcomes by FCA #13

Modeled Capacity Prices





- **Suppliers' delist strategy in the FCM is assumed to be in line with competitive market forces – suppliers will "exit" the FCM when market prices fall below their minimum going forward fixed costs**
  - LEI's analysis of the minimum going forward costs finds that existing coal units will not be economically viable and are therefore retired by 2021(FCA 12)
  - No generic thermal generation is added between FCA #11 and FCA #14 due to the current state of oversupply and projected market dynamics

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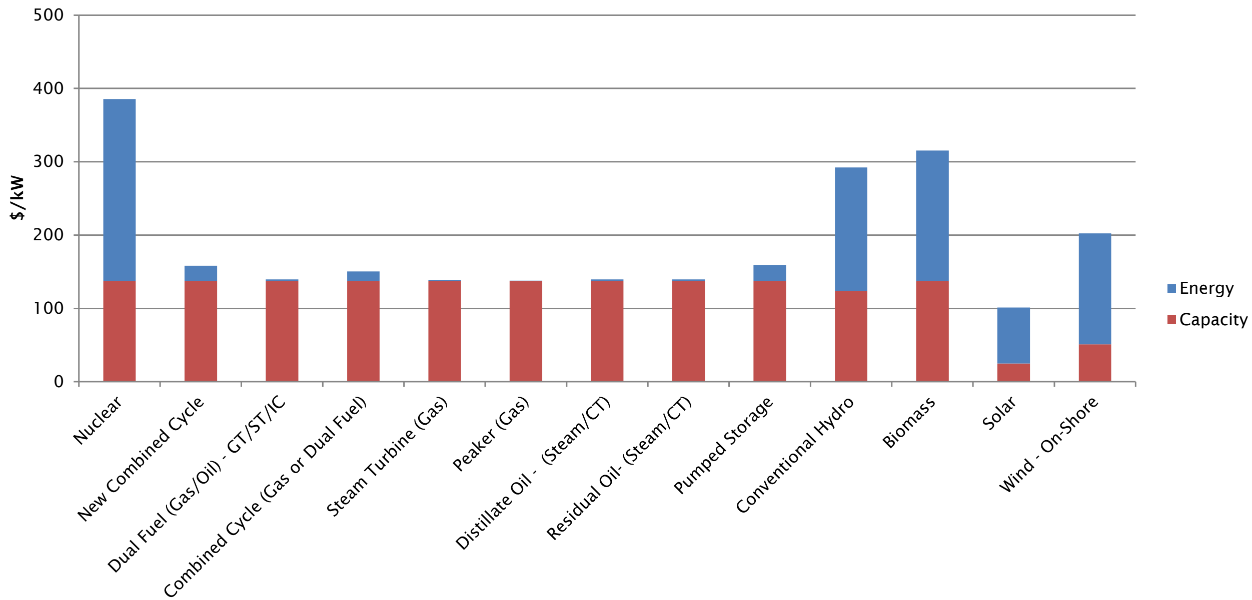
Over forecast timeframe, capacity revenues represent the majority of gross profits for most generators, except nuclear and renewables

Breakdown of Energy and Capacity gross profits, 2025

Composition of 2030 gross profits are similar across technologies although slightly higher due to higher energy and capacity prices



The reported values are for existing plants, with the exception of new combined cycle plants

- **Energy gross profits include energy market revenues less short run marginal costs – fuel costs, variable O&M, and CO_2 emissions costs (based on “RGGI” prices)**
- **Renewables are assumed to only receive a fraction of the capacity market revenues due to CSO derating relative to nameplate capacity: solar (15%), onshore wind (15%), offshore wind (40%), and conventional hydro (90%)**

By definition, the Base Case is calibrated to ensure that there is no "missing money" for non-renewable resources from energy and capacity market operations

- New England's remaining coal units are retired and therefore not included in the table on the next slide
- New combined cycle plants are roughly breaking "even" over their economic life, although some variation from year to year
- All existing wind assumed to receive some capacity revenues – but if they are energy-only, then they may have negative profits and that implies the need for REC revenues
- New wind will require approximately $34/MWh from RECs at an annual capacity factor of 37%
- Biomass profit shortfalls are equivalent to $36/MWh and $42/MWh in 2025 and 2030 respectively, which is presumed to be compensated sufficiently by RECs or other revenue streams
- The non-RPS eligible biomass resources all have positive energy market gross profits (energy revenues minus costs). The negative values are indicative of the assumed high minimum going forward costs for these biomass resources. Some of these resources may have access to other income streams. In addition, there will be plant specific differences relative to the generic fixed cost assumptions that LEI applied. Therefore plants in this category are not necessarily experiencing financial losses as suggested by the numbers.
- Under current assumptions, RECs alone will not be sufficient to recover invested capital for off-shore wind (as breakeven RECS exceed current ACP levels)

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To assess revenue sufficiency/shortfall, LEI deducted its estimate of minimum going forward fixed costs (or all-in fixed costs for new entrants) from energy market gross profits and capacity market revenues

Expected profits by fuel type, $/kW-yr

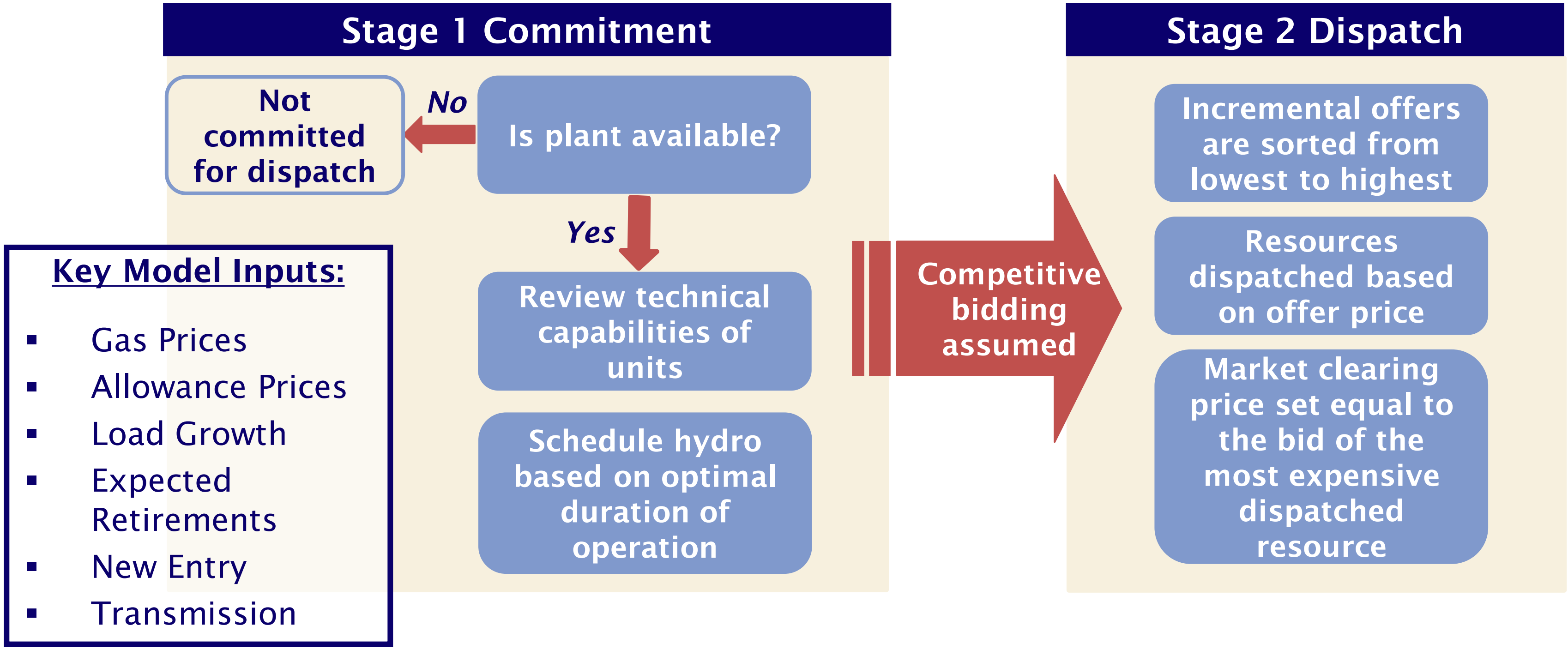
Generation Type	2025	2030
Existing (non-RPS eligible)		
Bio/Refuse	-$226	-$254
Coal Steam	-	-
Gas Combined Cycle	$75	$80
Gas Combustion Turbine	$80	$90
Hydro	$72	$75
Gas Steam	$70	$79
Gas/Oil Combined Cycle	$71	$77
Gas/Oil Combustion Turbine	$82	$91
Gas/Oil Internal Combustion	$80	$90
Nuclear	$268	$275
Oil Combustion Turbine	$90	$100
Oil Internal Combustion	$88	$99
Oil Steam	$90	$100
Pumped Storage	$118	$131
Gas/Oil Steam	$81	$91
New Conventional - 2016 onwards		
New - Gas/Oil Combined Cycle	-$3	$2
New - Gas Combustion Turbine	-$67	-$64

Generation Type	2025	2030
Existing Renewables		
Bio/Refuse	-$222	-$255
Gas Fuel Cell	-$367	-$412
Hydro	$74	$77
Solar	-$115	-$131
Wind - On-Shore	-$28	-$33
New Renewables - 2016 onwards		
Solar	-$101	-$89
Wind - Offshore	-$457	-$425
Wind - Onshore	-$110	-$106
Break-Even REC Price Needed, $/MWh		
Bio/Refuse *	$36	$42
Solar (new) **	$64	$56
Solar (existing) **	$73	$83
Wind - Onshore (new) ***	$34	$33
Wind - Onshore (existing) ***	$8	$10
Wind - Offshore (new) ****	$104	$97

"New resources" have an online date of 2016 or later
*Assuming annual average capacity factor of 70% for biomass
**Assuming annual average capacity factor of 18% for solar
***Assuming annual average capacity factor of 37% for on-shore wind
****Assuming annual average capacity factor of 54% for off-shore wind

Topics

LEI's proprietary network simulation model, POOLMod, is used to project wholesale energy prices and plant specific performance



- **Modeling is long-term focused and relies on zonal analysis that reflects major future developments, such as new transmission, generation retirements/new entry, load growth**
  - POOLMod simulates the security constrained dispatch of ISO-NE
- **POOLMod has been deployed successfully by LEI in last 20 years across North American power markets and globally, under varying local rules and in many different commercial settings**
  - for evaluation of billion dollar generation projects, in support of investors in M&A due diligence, and lenders in asset financings, for assessment of merchant transmission opportunities, and as a basis for critical regulatory decisions

LEI's capacity simulator for New England's FCM is integrated with the energy market model in order to represent the relationship between energy and capacity markets

Capacity market outcomes result in new entry and retirement decisions of generators, which then affects energy market outcomes

Clearing price in capacity market set according to rules and basic supply-demand dynamics (demand curve set by the ISO-NE) and auction clearing rules

In New England's Forward Capacity Market:

- All existing capacity offers into the market at their minimum going forward costs minus their expected energy revenues from POOLMod, and new entry will commit to market only when its expected profits are sufficient to allow for commercially reasonable return (so capacity prices converge to CONE)
- Retirements take place when expected profits from all markets are insufficient to cover going forward fixed costs for three consecutive years
- New renewable entry assumed to enter to satisfy policy objectives (such as Renewable Portfolio Standards), which is reflected in the need for REC revenue streams
- Demand-side resources and imported capacity also added to capacity market dynamics as ISO rules dictate

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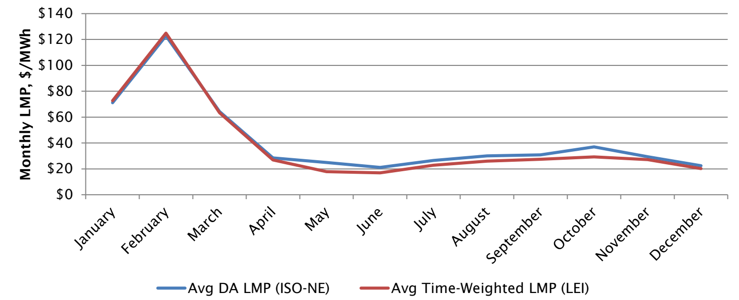
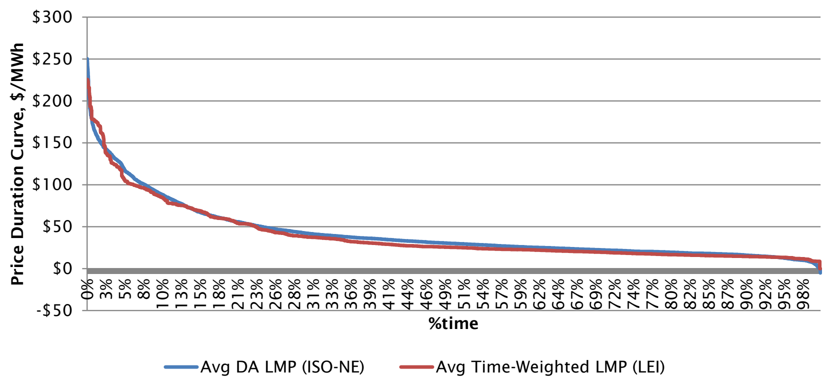
To benchmark the robustness of the model, LEI performs annual backcasts using historical inputs in order to replicate actual price levels and generation profiles

- **The backcast was done via replicating the historical actual data as closely as possible**
  - LEI used actual reported fuel prices for gas (ICE), oil (SNL Financial), coal (Ventyx), actual demand from ISO-NE, actual RGGI prices from RGGI, actual imports as reported by ISO-NE imports data, and a station database of existing plants in 2015, with seasonal capacity ratings taken directly from the 2015 CELT
- **The most recent backcast was done in spring of 2016 for the full year of 2015**
  - The actual annual DA LMP for 2015 is \$41.90/MWh for Internal Hub while POOLMod projected \$41.34/MWh on a demand-weighted basis and \$39.08/MWh on a time-weighted basis
- **LEI also compared the generation by fuel type to ensure that the backcast resulted in a reasonably close generation mix to actual generation**

Monthly LMPs, 2015, \$/MWh



Price Duration Curve, 2015, \$/MWh

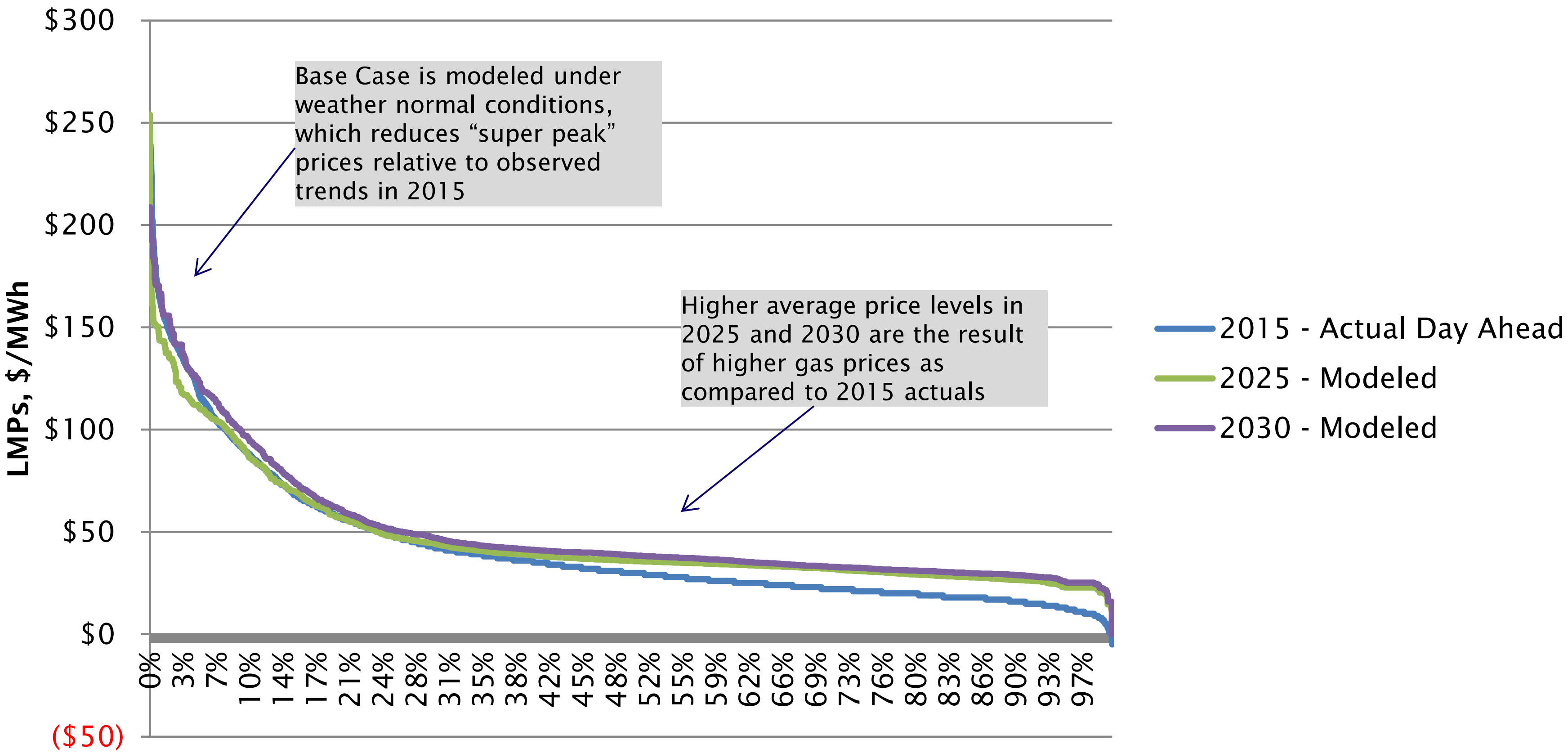


Generation Mix

	Coal	Gas	Hydro	Nuclear	Oil	Other	Wind
Actual Generation - 2015	4%	49%	7%	30%	2%	7%	2%
LEI Backcast	3%	48%	7%	31%	1%	7%	3%

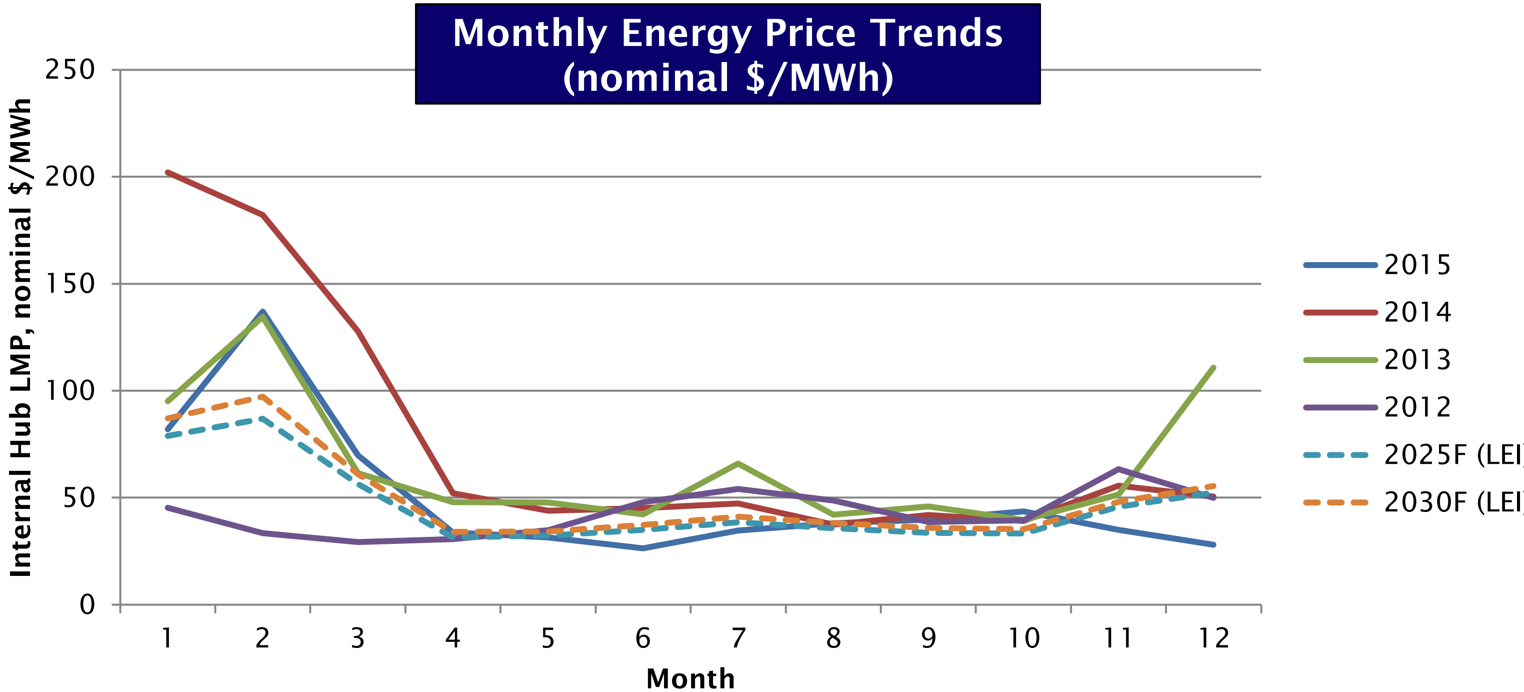
Approximately 95% of the forecasted hourly price outcomes align with the distribution of historical hourly trends

Price Duration Curve – ISO-NE (Internal Hub proxy)



- The highest 5% of hourly prices historically are caused by stochastic drivers such as higher than expected load, extraordinary outages, or extreme weather, which will not be captured under a single Base Case modeling run

LEI's model captures seasonal variance in LMPs that match historical seasonal trends under normal conditions



- **Distribution of monthly LMPs is driven by peak load and gas price trends**
  - LEI's Levelized Cost of Gas Pipeline model produces monthly gas prices, with a clear summer and winter trend to capture commodity price volatility
  - LEI also further re-scaled these monthly prices to daily forecast levels using the 2013 daily gas price pattern. A daily price profile is important to capture intra-monthly price volatility. Daily price patterns are set such that the average of the daily gas prices in each month will equal the monthly gas price
  - Monthly LMPs generally track monthly gas price trends

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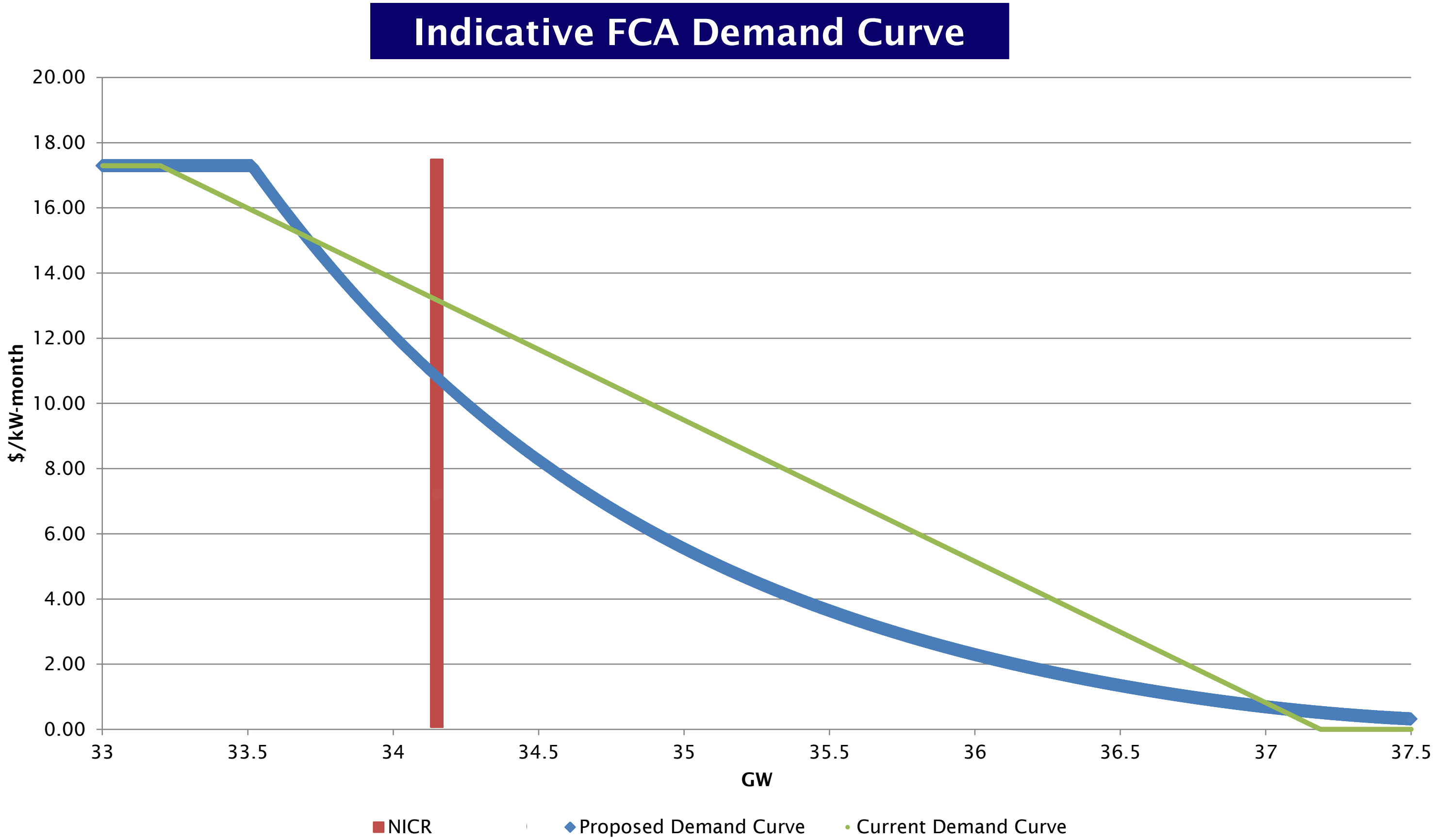
ISO-NE is changing the demand curve used in the FCA to optimize the trade-off between cost and reliability – this market rule change is reflected in the Base Case



- FCA #11-13 features a transitional curve
- Post transition (FCA #14 and onward) the new set of curves (at both the system and zonal level) are convex as shown above, resulting in lower prices when there is over-supply

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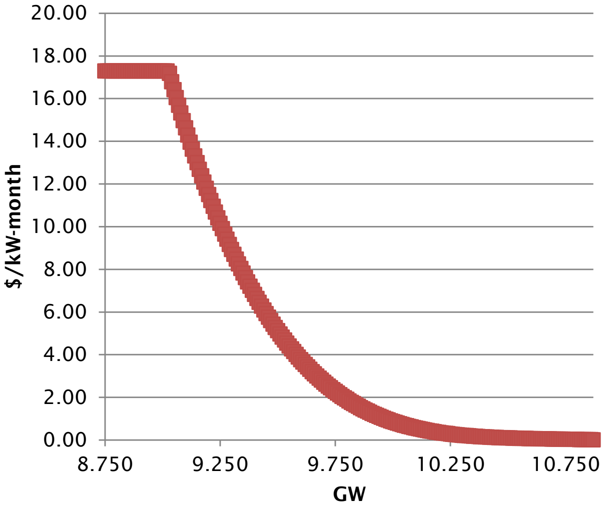
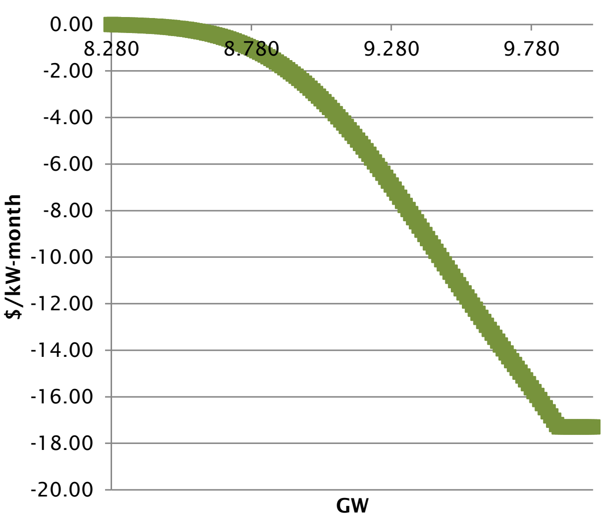
LEI used ISO-NE parameters to shift the demand curve as NICR grows and evaluated the potential for zonal price separation

- **The convex demand curve utilizes a polynomial function that is derived by ISO-NE's study of the Marginal Reliability Impact ("MRI")**
  - LEI used ISO-NE's coefficients in building the curve and shifts the curve to the right in order to capture NICR growth (due to ISO-NE's projected load growth)
  - The Net CONE and Scaling Factor is adjusted each year to obtain the appropriate "steepness" of the slope
- **Local curves for Southeast New England ("SENE") and Northern New England ("NNE") were also be considered**
  - The SENE curve reflects a declining price adder above the system price as more GWs clear (x-axis) and NNE reflects an increasing negative price adder as more GWs clear in the zone
  - LEI considered the potential for zonal price separation in the future and the location of new entry. However, in the almost all scenarios ran there was no price separation expected

SENE local curve



NNE local curve



LEI employs an iterative capacity market decision process by simulating energy market gross revenues, and subtracting these revenues from the estimated minimum going forward costs for each resource

Calibrate timing of new entry for CCGTs

Run the energy market model (POOLMod) assuming that new CCGT enters when the capacity price is at Net CONE (after incorporating their own CSO into the market).

Run the energy model and check retirement candidates

If energy and capacity market revenues are insufficient to cover the all-in fixed costs of a new CCGT for the year that it enters, LEI will delay the CCGT investment until it at least breaks even in the first year. LEI will check for retirement candidates based off preliminary energy market revenues and capacity market revenues against the minimum going forward costs.

Recalibrate the capacity model and re-run both energy and capacity models

Once it is determined that the energy and capacity revenues are approximately sufficient to meet the all-in fixed costs for new entrants, LEI re-runs both models with the updated new entry schedule. In this instance, we re-ran this for 2025-2030 only.

Review

LEI does a final review to ensure that no further retirements are needed and that new entrants are sufficiently remunerated.

Information on fixed O&M and debt re-payment components were sourced from public information, such as company financial reports, FERC, and EIA

- **Annual fixed O&M costs were estimated using technology-specific data gathered by LEI from a number of sources**
  - Some of the data is compiled via third party commercial data provider (Velocity Suite)
  - LEI typically uses aggregated estimates by technology - except when plant detail is necessary for analysis and the reliable data is available
- **LEI also takes into account annual administrative costs, estimated at 2% of market value (these cover insurance and property taxes)**
- **For annual debt payments, LEI assumed that existing plants will carry debt on a revolving basis (even after the initial construction loans are repaid) in order to optimize returns for shareholders and provide working capital**
  - Annual debt payment is a function of market value, interest rate, financing term, and capital structure (leverage)
- **The primary factor that differentiates the debt payment by plant type is market value**
  - For market value, LEI reviewed M&A transactions for generating assets; data on recent transactions was deemed more valuable as it reflects how investors value assets under current market conditions
  - Transaction values were compiled by fuel type, technology, market location, and other differentiating factors were considered

Variations across individual plants sharing a specific technology exist and plant owners could have different proprietary numbers that drive their internal analysis

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For new resources, the relevant benchmark for considering profitability are the all-in fixed cost as their invested capital is not "sunk" yet

All-In Fixed Costs and Levelized Costs of Energy for New Resources

New Resource All-in Fixed Costs, nominal $/kW-yr	2025	2030
Onshore Wind	$281	$292
Offshore Wind	$722	$714
Solar	$197	$191
Combined Cycle	$161	$171

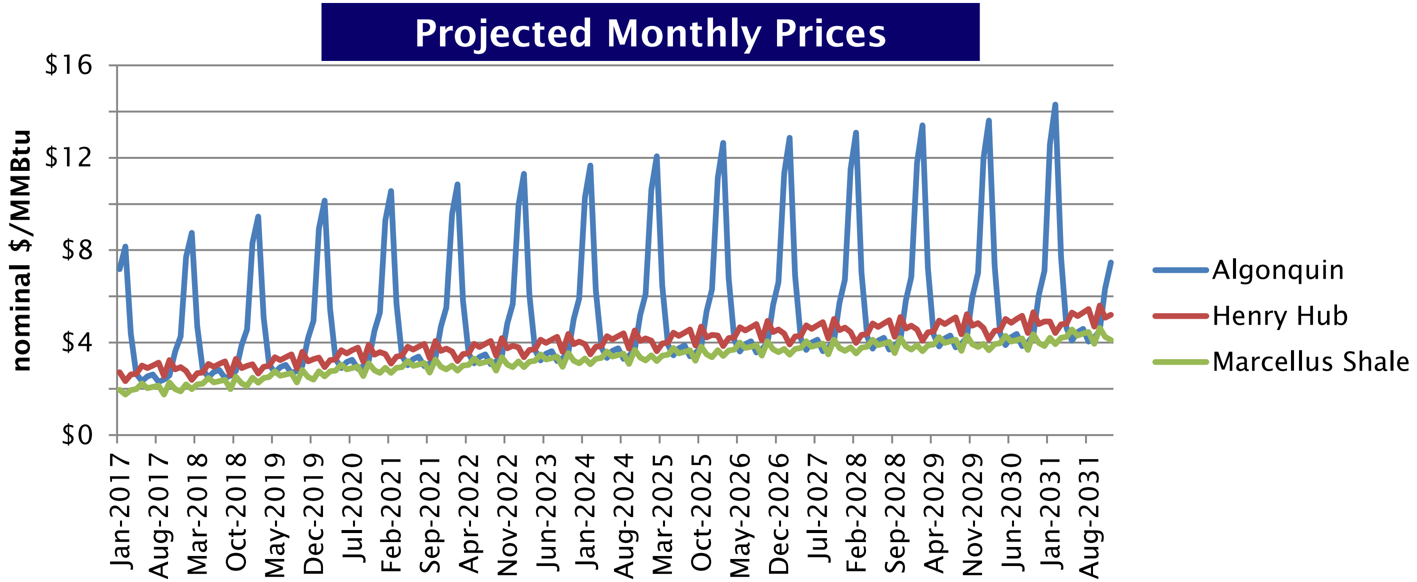
All-in fixed costs include all capital costs, fixed O&M costs, administrative costs; fuel, variable O&M, and emissions costs are not included

Levelized Cost ("LCOE"), nominal $/MWh	2025	2030
Onshore Wind	$87	$90
Offshore Wind	$153	$151
Solar	$125	$121
Combined Cycle	$64	$70

Levelized costs include all costs which are then levelized over a particular annual capacity factor (target production level)

- **Transmission costs for different resources are not included in these estimates of the all-in fixed costs. Fuel costs are also not included in the estimates of all-in fixed costs but are in the LCOE figures**
- **Key assumptions for illustrative LCOE figures:**
  - Annual capacity factors assumed for the levelized costs of energy include: onshore wind (37%), offshore wind (54%), solar (18%), and combined cycle (75%)
  - Combine cycle is assumed to have a heat rate of 6,700 Btu/kWh, variable O&M of $1.5/MWh, and the respective gas prices for 2025/2030 of $5.6 and $6.3/MMBtu

LEI's Levelized Cost of Pipeline ("LCOP") Model captures higher winter basis between delivered natural gas prices into New England and various supply hubs



- **Levelized Cost of Pipeline ("LCOP") Model looks at near-term forward markets for Algonquin Citygate and longer term price of the gas commodity (at Henry Hub and Marcellus Shale) along with the incremental costs of new pipeline capacity**
  - The LCOP Model evaluates 28 gas pricing hubs in North America, by tracking forward basis differentials and the levelized cost of building new pipeline(s) between each hub
  - Forward liquidity drops off after a few years and therefore in medium term, LEI moves to projecting gas prices based on fundamental growth rate in commodity costs (AEO 2015)
  - In the long run, the price spread between two gas pricing hubs is assumed not to exceed the levelized cost of building a new pipeline between the two hubs ($0.005/MMBtu/mile)
  - This levelized cost therefore effectively sets a long-term price cap on the transportation cost adder or basis differential between two pricing hubs
  - Monthly profile developed by looking at historical average seasonality trends

Topics

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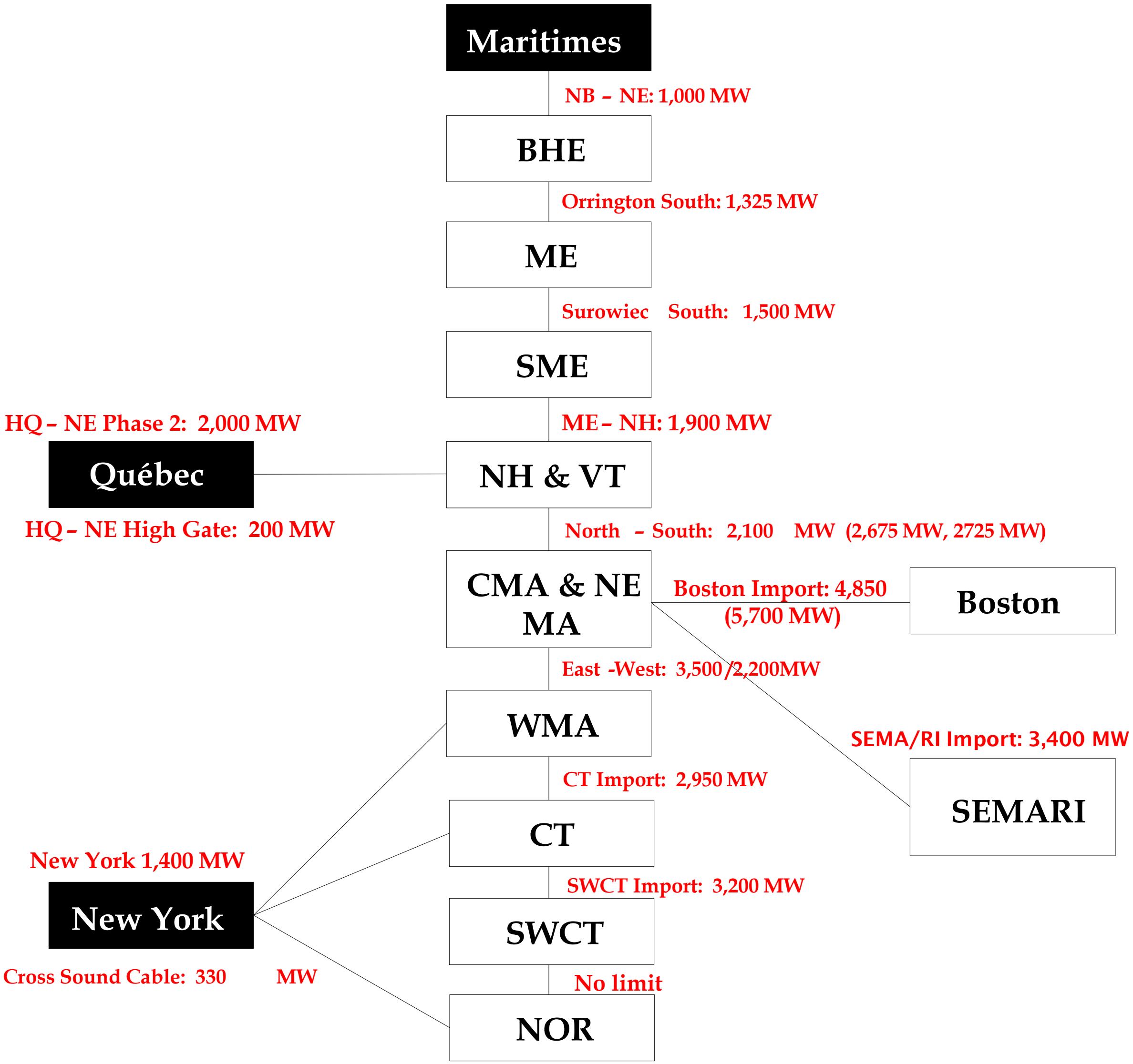
Base Case assumptions rely on the most up-to-date information, such as results from FCA #10, CELT 2016, and RSP 2015

Assumption	Approach
Network Topology	LEI divided the ISO-NE Control Area into 11 sub-zones, corresponding to oberved transmission congestion. Thermal limits were based on the ISO-NE PAC materials, "Transmission Transfer Capabilities Update, June 10, 2016" and reflected the implementation of a transmission solution in the Greater Boston Area.
Load Growth	ISO-NE's 2016 Capacity, Energy, Loads, and Transmission ("CELT") report provided the demand outlook until 2025. Beyond this, LEI extrapolated the demand for each zone using the growth rate of the three-year rolling average growth rate
Load Shape	Forecasted hourly load by ISO-NE for 2016 was used
Existing Resources	LEI used the summer and winter seasonal claimed capability published in the CELT 2016 report. Plant parameters such as fuel type, heat rate, emission rate, variable O&M, and forced outage rate were sourced from third party data providers, which aggregate data from EIA, NERC, FERC, and the EPA. Hydrology for hydro plants were developed from 10-year averages if reported. For smaller hydro plants that are not required to report, a zonal average was used
New Entry/ Retirements	Planned short term new entry was based on annoucements and included only the projects that have a high likelihood of proceeding to commercial operation (for example, resources that are cleared in the FCA, under construction, or permitted and financed). Generic renewable new entry was first added to meet RPS until 1,000 MW of wind is added in Northern Maine (due to transmission constraints). Generic gas was then added if economic, whereby projected capacity prices remunerate the Net CONE of new combined cycles
Fuel Prices	Base Case Algonquin Citygate prices were calculated using LEI's LCOP model. Residual and distillate prices were based off forwards for May 2016 for the first two years, then grown using the AEO 2015 growth rates for crude oil
Carbon Assumptions	Forwards as of May 2016 for carbon prices were used in the modeling through 2020, after which RGGI prices were escalated by 2% to keep them constant in real terms
Interchange	Imports and exports were modeled on an aggregate basis and based on inter-regional energy market dynamics benchmarked against historical patterns (2014-2015) and subject to transfer capabilities across transmission regions

ISO-NE system is modeled using a zonal approach, with key interface limits following ISO-NE's 2015 Regional System Plan and 2016 PAC materials

Modeled market topology of ISO-NE



Key interface limits (MW)

Interface	Base case
Orrington South	1,325
Surowiec South	1,500
ME-NH	1,900
North-South	2,100 2,675 (2019) 2725 (2020 and onward)
East-West	3,500
West-East	2,200
CT Import (N-1)	2,950
Boston Import (N-1)	4,850 5,700 (2019 and onward)
SEMA/RI Import	3,400
SWCT Import	3,200
Norwalk	No Limit

Source: ISO-NE PAC material "Transmission transfer capabilities update, June 10, 2016

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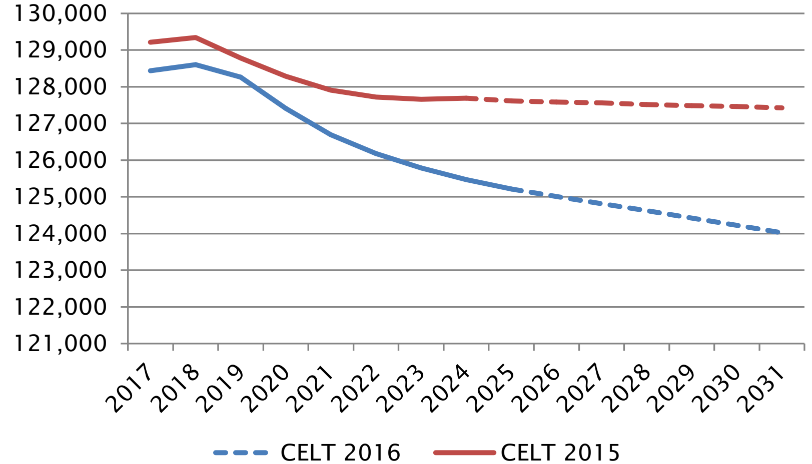
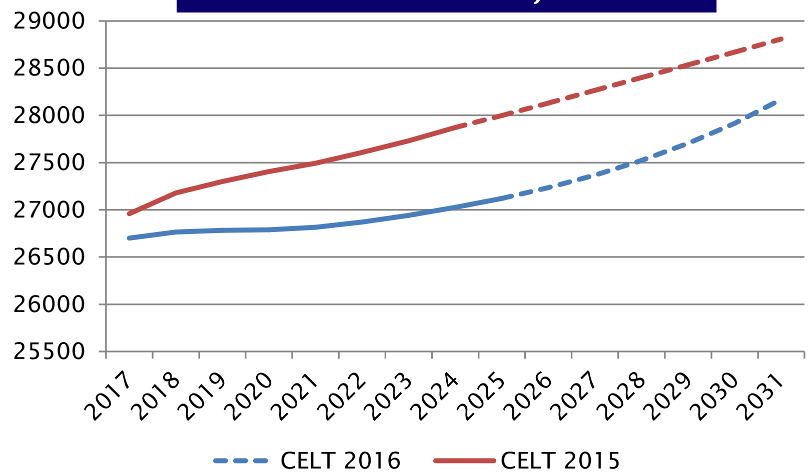
Peak demand in CELT 2016 declined by 844 MW by 2024 relative to CELT 2015 due to higher projected deployment of solar PV and passive demand response

- **The Base Case uses ISO-NE's 50/50 forecast for expected "weather normal" total demand and peak demand until 2025. Beyond that, the escalation of the previous three years growth rate is used**
  - Total demand net of solar PV and passive DR is 1.0% lower on average in CELT 2016 than CELT 2015 while peak demand is 2.1% lower during the CELT forecast period (2016 to 2025)
- **The growth of solar PV is driven mainly by policies and programs put in place by New England states, and has a significant impact of electricity demand**
  - Much of New England's distributed solar is behind the meter, and the ISO studies these trends to assess how they reduce demand
- **Passive demand response has also increased in this forecast relative to CELT 2015 by 265 MW by 2024 (system-wide)**
  - 350 MW of new passive DR cleared in FCA #10

Total Demand, GWh



Peak Demand, MW



Note: Y axis does not start from zero

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New entry from within New England is predominately wind and gas, and is driven by state RPS goals and demand growth

- **The Base Case assumes that generic renewable resources are added to meet the region's various state RPS requirements**
  - The type of technology added to meet RPS is based on pragmatic consideration of what is economic and where it is economic (i.e., LEI relies on developers' indications of preferences through the interconnection queue)
  - LEI has assumed that renewable investment would occur to meet New England RPS targets, although tx limits may limit development of onshore wind resources over time
  - Solar generation is taken into account using ISO-NE's solar PV forecast
  - Cape Wind was not modeled under the Base Case because of its withdrawal from FCM; however 30 MW of Deepwater Wind (Block Island) is included as it cleared the FCA; other generic offshore wind project were not included due to economics

- **Gas-fired generating capacity is then added to meet the ICR, as needed**
  - LEI uses Net CONE as the benchmark for economic entry and assumes this will continue to be CCGT technology (based on NESCOE's input on starting Net CONE value

- **With lower peak demand and substantial new resources (from FCA #10), the first generic new CCGT is not expected until mid 2020s**

- **Projects being proposed under the Clean Energy RFP were not included in the Base Case**

Retirements include announced retirements as well as an economic assessment going forward for existing generation

- **The Base Case includes announced retirements as of June 2016**

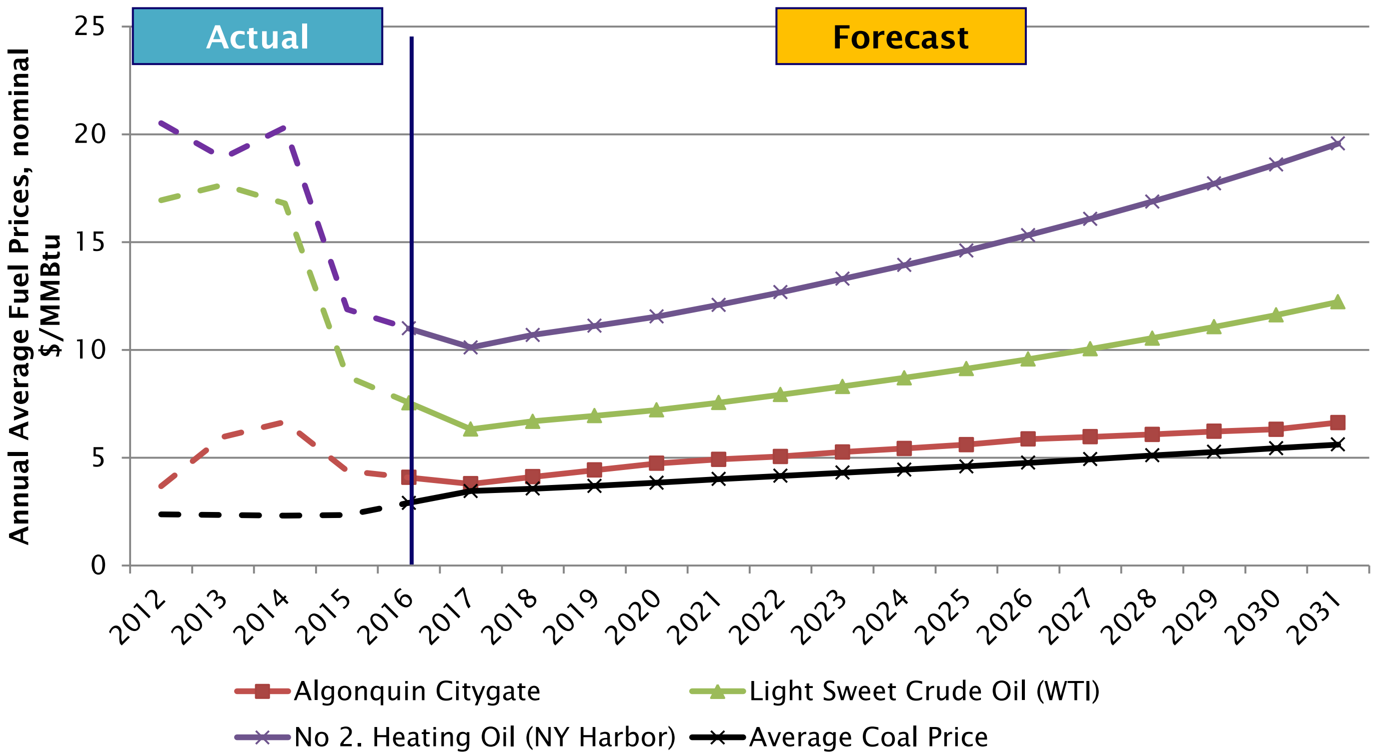
Announced Retirements 2017 - 2019

Unit	Fuel Type	Capacity	Retirement Year
Brayton Point 1-3	Coal	1,101	2017
Brayton Point 4 & Diesels	Oil	456	2017
Pilgrim	Nuclear	683	2019
Bridgeport Harbor 3	Coal	385	2019
Bridgeport Harbor 4	Oil	22	2019
Wallingford Refuse	Biomass	2	2018
Wheelabrator Claremont 5	Biomass	3	2018

- **For other projected retirements over the modeling timeframe, LEI compared the expected minimum going forward costs against projected capacity revenues and energy market gross profits to determine retirements dynamically and on an internally consistent manner**
  - Minimum going forward fixed costs are an aggregation of fixed O&M costs and debt repayment costs, based on each generator's size, technology, and current expected market valuations and financing trends
  - If a plant is 'losing' money relative to its minimum going forward fixed costs for three consecutives years, it is retired
- **The Base Case resulted in retirement of the coal units but the continued operation of the two remaining nuclear plants in the region**

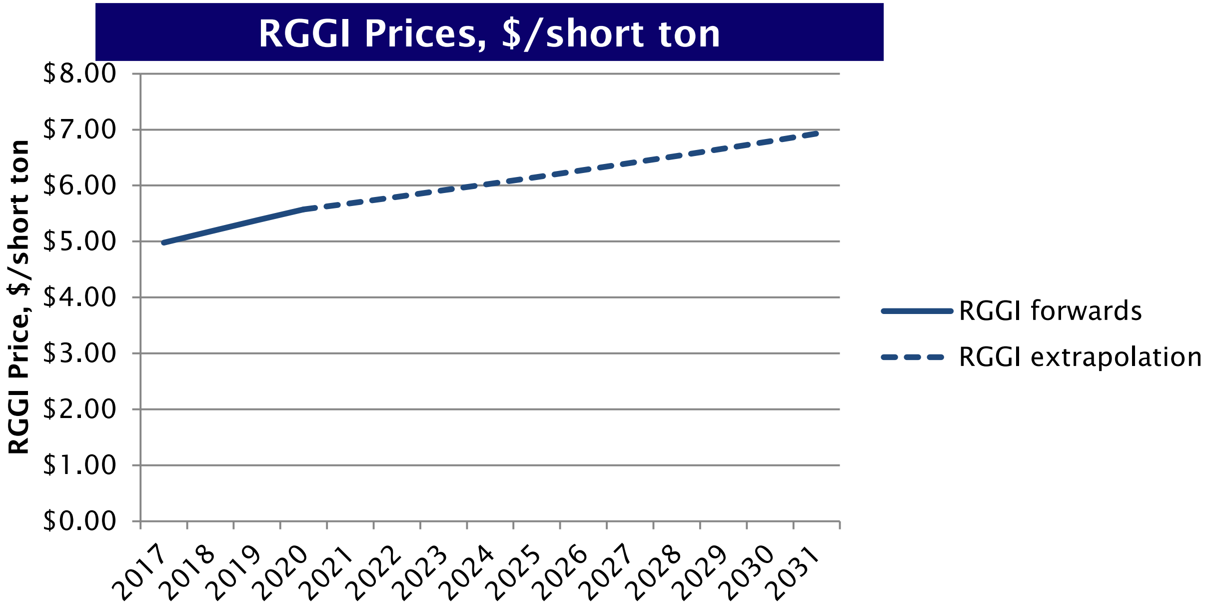
Delivered gas prices in New England start at $3.8/MMBtu in 2017 and reach $5.6/MMBtu by 2025 and $6.3/MMBtu by 2030

Modeled Fuel Prices, nominal $/MMBtu



	Historical				Forecast	
	2012	2013	2014	2015	2025	2030
Gas Prices						
Algonquin Citygate	$3.7	$6.0	$6.7	$4.4	$5.6	$6.3
Oil Prices ($/MMBtu)						
Light Sweet Crude Oill (WTI)	$16.9	$17.6	$16.8	$8.8	$9.1	$11.6
No. 2 Heating Oil (NY Harbor)	$20.5	$18.9	$20.3	$11.9	$14.6	$17.7

Base Case relied on current RGGI forwards until 2020 then assumed constant prices in real terms afterward

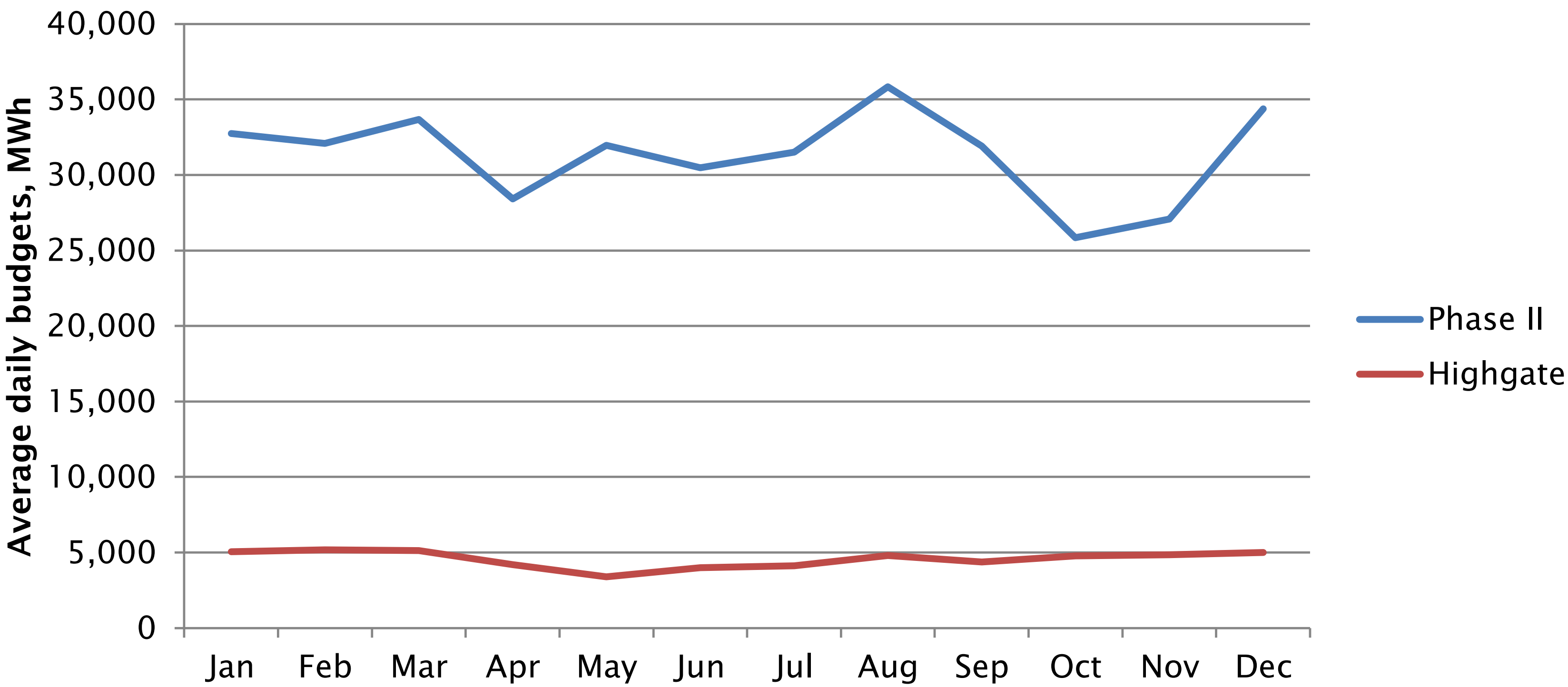


	2025	2030
RGGI Carbon Price	$6.2	$6.8

- **Currently, all states in ISO-NE participate in the Regional Greenhouse Gas Initiative ("RGGI")**
  - RGGI requires power generation facilities with an installed capacity of over 25 MW to reduce their CO2 emissions by 50% by 2020 relative to the 2005 emissions level
  - RGGI is currently deliberating over the next few years on how to proceed post 2020. For the Base Case, LEI used forwards until 2020. Beyond 2020, LEI assumed existing rules and target will remain. RGGI carbon allowance prices grow by 2% to keep up with inflation
  - New England states are in a good position to meet CPP under existing RGGI rules

Imports from Quebec into ISO-NE are modeled to target an energy profile consistent with historical levels

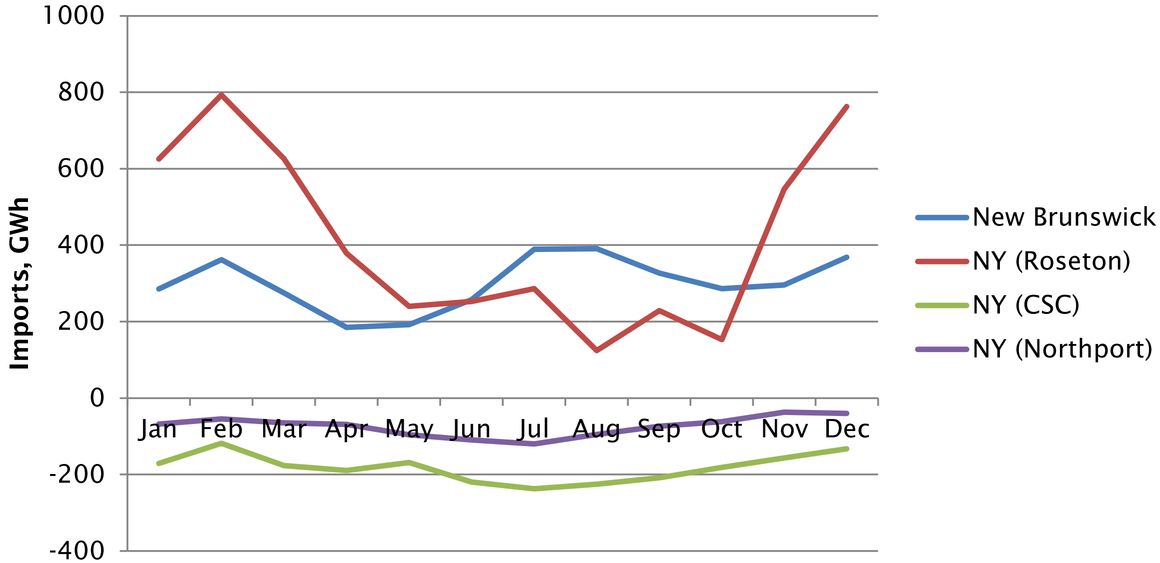
Daily historical energy imports from Hydro Quebec in 2014-2015 (MWh)



- LEI models imports from Hydro Quebec based on historical trends in recent years
- The resulting average utilization rate is about 64% on Phase II (376 GWh) and 97% on Highgate (55 GWh)

Imports from NYISO and Maritimes were also modeled on the basis of historical trends

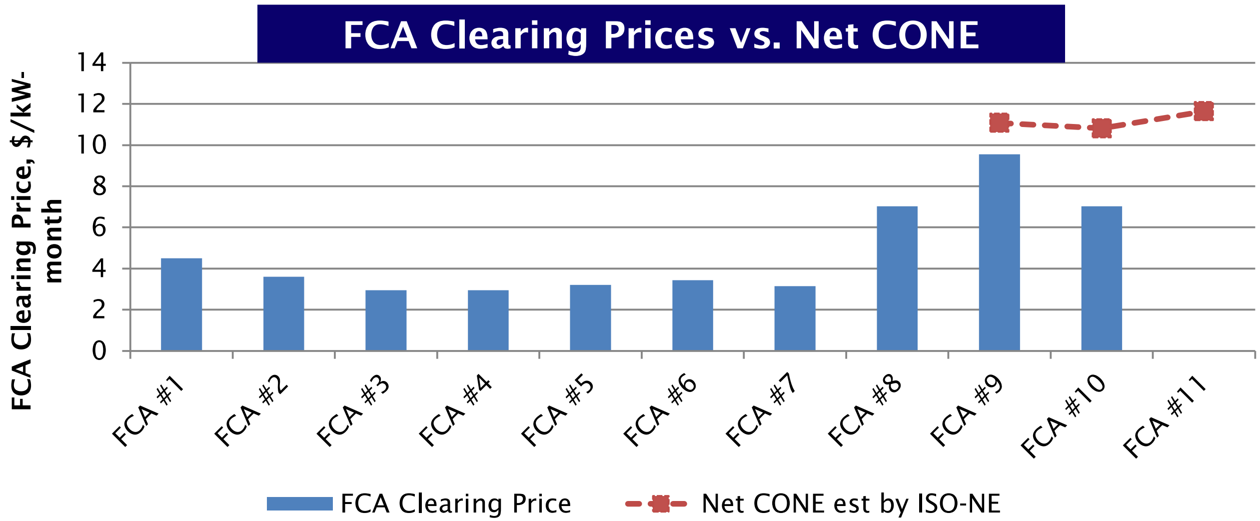
Monthly imports from NY and Maritimes in 2014-2015 (GWh)



- **Imports from New Brunswick were modeled based on 2014 and 2015 levels, after Point Lepreau came back online (it was offline due to refurbishment during 2008-2012)**
- **Roseton interface has switched from net exporting to NYISO to net importing from NYISO since 2011, and import levels have doubled in 2013; LEI expects strong import trends to continue due to higher priced opportunities in the energy and capacity market and therefore model Roseton import based on 2014 and 2015 levels; for Northport and Cross Sound Cable, net exports to New York have been relatively stable, and are also modeled based on 2014 and 2015 average flow**

Other capacity market assumptions were developed in conjunction with NESCOE and based on latest accepted (and proposed) ISO-NE market rules and on an evaluation of economic new entry

- **The Base Case assumes a Net CONE value just above the current CCGT ORTP of $9.46/kW-month starting in FCA 11**
  - Recent auctions have shown that new generation has responded to price signals in the last few FCAs
  - Additionally, recent auctions have cleared lower than Net CONE expectations
- **NET CONE for future FCAs is projected by LEI with a 2% inflation adjustment to Gross CONE and a 2% technology improvement every four years, per current market rules, to changing energy market conditions for setting the E&AS offset**
  - The Net CONE will affect the FCA starting price and the Scaling Factor in demand curve



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Topics

LEI is a global economic, financial, and strategic advisory firm specializing in energy, water, and infrastructure

About LEI

- **LEI's Analytic Approach**
  - Combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis
  - Uses a suite of proprietary quantitative models to produce reliable and comprehensible results
  - Advises private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulated markets worldwide, particularly in Canada and the Northeast US
- **Key Practice Areas**
  - Regulatory Economics and Market Design
  - Asset Valuation and Market Analysis
  - Litigation and Expert Testimony
  - Strategy and Management Consulting
  - Renewables
  - Procurement
- **Continuous Modeling Initiative ("CMI")**
  - LEI performs multi-client forecasts for eleven regional wholesale markets across North America
  - CMIs include an examination of recent market developments, key assumptions used in the modeling, a 10-year wholesale electricity price and, where relevant, capacity price forecast

Key Facts

- **LEI entered the North American market in 1996 during the birth and development of many competitive electricity markets worldwide**
- **LEI's subject matter experts come from over a dozen countries with degrees in economics, finance, public policy, engineering, mathematics, and business**
- **LEI Staff are located in Toronto, Boston, and Taipei, with strategic partners globally**

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LEI team has worked with many leading energy companies and key industry stakeholders around the world

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In the electricity sector, LEI is active across the value chain

Asset Valuation, Price Forecasting & Market Analysis

- Exhaustive sector knowledge and a suite of state-of-the art proprietary quantitative modeling tools
  - Wholesale electricity market models
  - Valuation and economic appraisal
  - Due diligence support
  - Cost of capital database
  - Contract configuration matrices

Regulatory Economics, Performance-based Ratemaking & Market Design

- Market design, market power and strategic behavior advisory services
- Incentive ratemaking
  - Quantify current and achievable efficiency levels for regulated industries
  - Convert findings into efficiency targets mutually acceptable to utilities and regulators

Expert Testimony & Litigation Consulting

- Reliable testimony backed by strong empirical evidence
- Expert witness service
  - Material adverse change
  - Materiality
  - Cost of capital
  - Market power
  - Tax valuations
  - Contract frustration

Transmission

- Creating detailed market simulations to identify beneficiaries and quantify costs and benefits from proposed transmission lines
  - Valuing transmission
  - Transmission tariff design
  - Procurement process and contract design

Renewable Energy

- Renewable energy policy design, procurement, modeling, and asset valuation
  - Solar, wind, biomass, and small hydro
  - Demand response
  - Cogeneration
  - Energy efficiency
  - Micro-grids
  - Emissions credits trading
  - Energy storage technologies

Procurement

- Designing, administering, monitoring, and evaluating competitive procurement processes
  - Auction theory and design
  - Process management
  - Document drafting and stakeholder management

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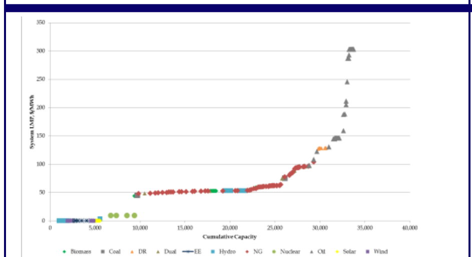
Several state-of-the art modeling tools are used in the development of LEI's analysis

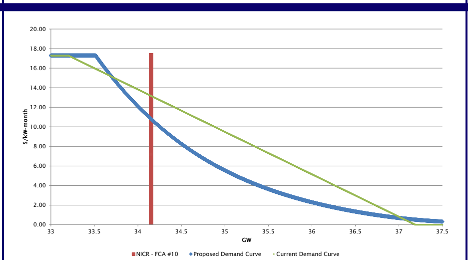
Energy Market Modeling

- LEI's proprietary dispatch simulation model is used to develop wholesale energy price forecasts
- Merit order based on marginal costs to dispatch plants, using algorithms that consider maintenance scheduling, dynamic constraints, and daily reserve margins
- Used for competitive plant valuation, emission credit market analysis, or transmission congestion analysis



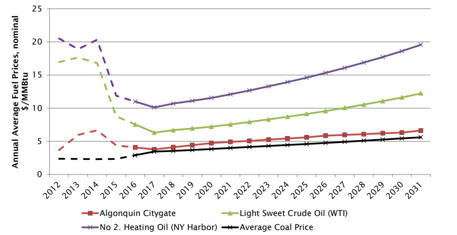
Capacity Market Modeling

- Capacity market clearing prices are set according to rules and basic supply-demand dynamics (demand curve or target reserve margin)
- Retirements take place when expected profits from are insufficient to cover going forward fixed costs
- New renewable entry assumed to satisfy policy objectives (Renewable Portfolio Standards), which is also reflected in REC revenue streams



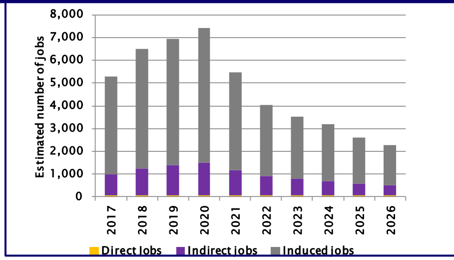
Natural Gas Modeling

- Proprietary natural gas model based on the levelized cost of pipeline ("LCOP") is used to forecast future prices
- The LCOP approach looks at the tipping point in basis – when it is sufficiently high to cover the expected cost of new capacity
- Capable of using network models based off regional supply and demand dynamics subject to the costs of transportation and marginal supply



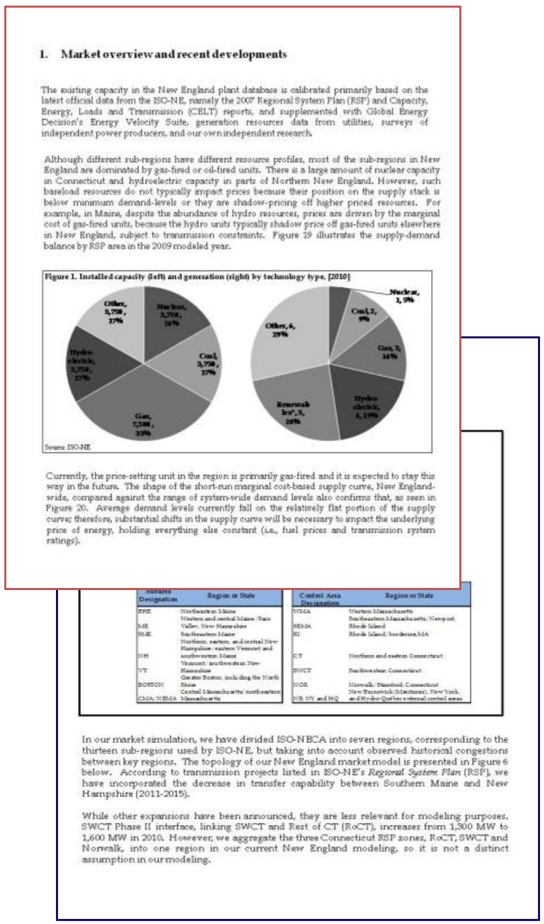
Macroeconomic Impact Modeling

- Widely used input-output models are utilized to measure the economic impact (ie GDP and jobs) of infrastructure investments on the economy
- Model inputs are based on LEI's energy market impact analysis, with some input on project characteristics and costs
- Deeply familiar with REMI PI+ and IMPLAN models



LEI publishes semi-annual price forecasts and market studies for all restructured regional power markets in North America

LEI performs multi-client forecasts for eleven regional wholesale markets across North America. The energy, and where applicable, capacity market price outlooks are updated every six months. These forecasts include an examination of recent market developments, key assumptions used in the modeling, and a 10-year wholesale electricity price and, where relevant, capacity price forecast


1. Market overview and recent developments

The existing capacity in the New England plant database is calibrated primarily based on the latest official data from the ISO-NE, namely the 2007 Regional System Plan (RSP) and Capacity, Energy, Loads and Transmission (CELT) reports, and supplemented with Global Energy Decision's Energy Velocity Suite, generation resources data from utilities, surveys of independent power producers, and our own independent research.

Although different sub-regions have different resource profiles, most of the sub-regions in New England are dominated by gas-fired or oil-fired units. There is a large amount of nuclear capacity in Connecticut and hydroelectric capacity in parts of Northern New England. However, such baseload resources do not typically impact prices because their position on the supply stack is below minimum demand-levels or they are shadow-pricing off higher priced resources. For example, in Maine, despite the abundance of hydro resources, prices are driven by the marginal cost of gas-fired units, because the hydro units typically shadow price off gas-fired units elsewhere in New England, subject to transmission constraints. Figure 19 illustrates the supply-demand balance by RSP area in the 2009 modeled year.

Figure 1. Installed capacity (left) and generation (right) by technology type, [2010]

Source: ISO-NE

Currently, the price-setting unit in the region is primarily gas-fired and it is expected to stay this way in the future. The shape of the short-run marginal cost-based supply curve, New England-wide, compared against the range of system-wide demand levels also confirms that, as seen in Figure 20. Average demand levels currently fall on the relatively flat portion of the supply curve; therefore, substantial shifts in the supply curve will be necessary to impact the underlying price of energy, holding everything else constant (i.e., fuel prices and transmission system ratings).

In our market simulation, we have divided ISO-NBCA into seven regions, corresponding to the thirteen sub-regions used by ISO-NE, but taking into account observed historical congestions between key regions. The topology of our New England market model is presented in Figure 6 below. According to transmission projects listed in ISO-NE's *Regional System Plan* (RSP), we have incorporated the decrease in transfer capability between Southern Maine and New Hampshire (2011-2015).

While other expansions have been announced, they are less relevant for modeling purposes. SWCT Phase II interface, linking SWCT and Rest of CT (RoCT), increases from 1,300 MW to 1,600 MW in 2010. However, we aggregate the three Connecticut RSP zones, RoCT, SWCT and Norwalk, into one region in our current New England modeling, so it is not a distinct assumption in our modeling.

Contents:

An overview of the market and recent developments - a discussion of the key market drivers, and developments in the previous six months, including any new entrants and retirements, new transmission lines, market rule changes, market auction outcomes, mergers and acquisitions, new state policies or initiatives, and environmental rules

Modeling assumptions in the LEI price forecast - a detailing of assumptions used for each region, including market topography, future fuel prices, emission costs, the cost of generic new entry, import and export flows, demand levels, and the breakdown of supply. For regions with multiple zones, assumptions are broken down by zone

10-year price forecast - a price forecast for wholesale electricity prices, and capacity market prices (for those regions where this is applicable). Where relevant, these price forecasts are broken down by zone

Available markets

- Alberta
- California (CAISO)
- Midwest (MISO)
- New England (ISO-NE)
- New York (NYISO)
- Pennsylvania-New Jersey-Maryland Interconnection (PJM)
- Ontario
- Southeast Reliability Council (SERC)
- Southwest Power Pool (SPP)
- Texas (ERCOT)
- Western Electric Coordinating Council (WECC)