

2014

INTEGRATED RESOURCES PLAN

FOR CONNECTICUT

PREPARED BY:

**THE CONNECTICUT DEPARTMENT OF ENERGY
AND ENVIRONMENTAL PROTECTION**



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EXECUTIVE SUMMARY

In 2013, the Connecticut Department of Energy and Environmental Protection (DEEP or Department) released the state's first-ever Comprehensive Energy Strategy (2013 CES), which detailed dozens of policy recommendations to secure a cheaper, cleaner, more reliable energy future for Connecticut. Analysis prepared for this Integrated Resources Plan (IRP) confirms that several of the key policy recommendations of the 2013 CES related to the electric sector — many of which have been enacted into statute and implemented by the Department and its Public Utilities Regulatory Authority (PURA), as well as the Energy Efficiency Board (EEB), and the Connecticut Green Bank — are providing important benefits.

These programs are more critical than ever now, as Connecticut ratepayers are being affected by critical developments in New England's wholesale electricity markets that are challenging the affordability and reliability of the region's electric system. The 2014 IRP analyzes these trends in the region's electricity system over the next decade (out to 2024), and proposes eight key recommendations. These recommendations meet the state's electricity needs in a way that provides affordable electricity to Connecticut customers over time and creates consumer benefits consistent with the state's environmental goals and standards.

CONNECTICUT ENERGY POLICIES ARE SECURING CHEAPER, CLEANER, MORE RELIABLE ELECTRICITY

Connecticut's Expanded Energy Efficiency Investment Is Flattening Electricity Demand Investment in the state's popular energy efficiency and conservation programs nearly doubled in 2014, following the recommendations of the 2013 CES and 2012 IRP, and enactment of Public Act 13-298. Over the next ten years, this expanded efficiency investment is expected to nearly eliminate growth in the state's annual electricity consumption (projected to rise an average of only 0.05% per year), and reduce growth in electricity consumption during peak demand periods to 0.5% per year. This is significant progress compared to the 2012 IRP, which projected an increase in consumption at approximately 1% per year and slightly higher growth rates for the annual peak load.

Connecticut's Renewable Procurements and Programs Are Delivering Cheaper, Cleaner Electricity. Since 2011, Connecticut has taken a more proactive role in the marketplace to keep the state on track to meet its renewable energy commitments and seek the cleanest resources at a lower cost to ratepayers. Long-term contracts signed with large wind, solar, and biomass facilities under Public Act 13-303 Sections 6 and 8 are expected to save Connecticut ratepayers more than \$235 million over the next two decades. Renewable development within the state has grown since 2011 as a result of programs such as the Low and Zero Emissions Renewable Energy Credit (LREC/ZREC) program; Project 150; the Connecticut Green Bank's Residential Solar Incentive Program (Section 106 of Public Act 11-80); and the utility-owned renewable energy program (Section 127 of Public Act 11-80). Altogether, these programs and procurements

will provide about 2,400 GWh of renewable energy by 2020, or about 40% of Connecticut's Class I Renewable Portfolio Standard (RPS) goal of 20% by 2020.¹

Replacement of Coal and Oil Generation with Natural Gas Generation Has Lowered Costs And Emissions from Historic Highs. Air pollution emissions in Connecticut have decreased markedly, as low-cost natural gas-fired generation continues to displace coal and oil-fired generation. In 2013, natural gas generated 45% of the energy used in New England, a proportion that reflects the current generation capacity without additional gas infrastructure build-out. As a result of this move to gas generation, air pollution emissions from the electricity sector in Connecticut have decreased markedly: emissions of NO_x, SO₂, and CO₂ fell 71%, 95%, and 28%, respectively, between 2007 and 2012.

REGIONAL AND NATIONAL CHALLENGES AFFECTING CONNECTICUT RATEPAYERS

While Connecticut's energy policies to date have delivered significant benefits to the state, the New England electric system is facing critical challenges that threaten to undermine the progress Connecticut has made.

Inadequate Natural Gas Delivery Infrastructure Is Threatening the Reliability and Affordability of New England's Gas-Dependent Electric System During Peak Winter Periods. Due to market structure, gas-fired generators — who now produce more than half of the region's electricity — are not contracting directly for the gas capacity they need to run. Demand for natural gas in New England has increased to a point that there is no longer enough "excess" pipeline capacity in the region to deliver the gas needed for reliable, competitively-priced electricity generation, particularly in the winter months when existing gas capacity is needed for building heating. Consequently, the wholesale spot market price of natural gas *delivered* to New England is significantly higher — from only about \$1-3/MMBtu before 2012/13 to \$8/MMBtu in 2012/13, and almost \$14/MMBtu in December through February of 2013/14 — than the price of gas delivered to other regions in the country.² During the winter of 2013/14, these increased delivered gas prices cost the New England region an additional \$3 billion in wholesale electricity costs, driving up retail generation rates for families and businesses across the region.

This infrastructure challenge is expected to worsen as thousands of megawatts of non-gas power plants retire and are replaced with new gas generation. Gas pipeline capacity expansions that are expected to enter service in November 2016 as part of Connecticut's Natural Gas Expansion Plan will provide some relief as gas demand continues to increase, but only temporarily. Near- and

¹ Renewable procurements and programs to date will have attracted enough new resources to provide about 1,900 GWh by 2016, or approximately a third of Connecticut's 20% Class I requirement in 2020.

² This has also lifted annual average basis differentials from about \$1/MMBtu before 2013 to about \$3/MMBtu in 2013 and higher in 2014. Such high recent prices were driven largely by the extended "polar vortex" cold snap, but also by growing weather-normalized demand. Wholesale spot market prices have only a minimal impact on building heating rates.

longer-term measures instituted by the ISO New England (ISO-NE) rely primarily on backup oil generation to address the problem; these measures are likely to increase both emissions and electricity costs. Neither ISO-NE, the Federal Energy Regulatory Commission (FERC), nor key market actors such as electric generators or gas pipeline developers have proposed any meaningful market reforms that will cause electric market participants to invest in urgently needed, cost-effective gas pipeline infrastructure. Unless new infrastructure is built, the 2014 IRP projects average basis differentials of \$4.6/MMBtu for winter months, or about \$2/MMBtu on average annually (and this is roughly consistent with current futures prices for basis swaps as of the time of this writing). That exceeds historical annual average basis differentials by about \$1/MMBtu, which adds as much as \$8/MWh to wholesale electricity prices, 0.8¢/kWh to customer rates and approximately \$250 million per year to Connecticut customer bills.³ If prices turn out to be higher, each additional \$1/MMBtu would add up to another \$250 million per year to Connecticut customer bills.

New Power Plant Needs Will Drive Up Capacity Prices for the Region. For more than a decade, the New England region has enjoyed a surplus of electric generating capacity needed to meet reliability objectives. The 2014 IRP projects that Connecticut will continue to have plenty of capacity through 2024 and beyond, due to ample in-state generation, low demand growth, and new transmission built to reduce congestion.⁴ At the regional level, however, the New England capacity surplus is rapidly dwindling. Beginning in 2017, the region will face a capacity shortage of 143 MW, primarily due to the announced retirement of 4,100 MW of non-gas generation resources and a reduction in capacity imports.⁵ But that slight shortage should be only temporary. More than 1,400 MW of new supply has committed to enter the market by June of 2018, having “cleared” in ISO New England’s 9th forward capacity auction (FCA9).⁶ Capacity prices for 2018/19 cleared at \$9.55/kW-mo (i.e., \$8.81/kW-mo in terms of 2014 dollars). Prices could temporarily decrease thereafter, due to the large amount of capacity cleared for 2018/19. However, this IRP projects prices rising to \$11/kW-mo (in 2014 dollars) in the long-term, corresponding to the Net Cost of New Entry when new generation is needed again. That level of capacity price will contribute 4.0¢/kWh to retail rates, compared to 2.2¢/kWh in 2017/18 and roughly half that in 2014.⁷

New England Needs More Class I Renewable Supply to Meet Regional RPS Targets. As noted above, Connecticut’s renewable programs and procurements are helping to meet the state’s renewable (RPS) targets, but as state RPS targets rise across the region, Connecticut will compete with other states for a limited supply of new renewable resources. The 2014 IRP

³ Assuming 8,000 Btu/kWh average market heat rate and natural gas as the marginal fuel.

⁴ Connecticut is also expected to have enough local fast-start generation capability to meet its Locational Forward Reserve Market requirements through 2024.

⁵ ISO New England, *Forward Capacity Auction 2017-2018 Totals Flow Diagram*, http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp18/fca18/fca_8_cso_flow_diagram.pdf.

⁶ New supply includes 1,060 MW of new generation and 367 MW of new demand response. In addition, imports increased by 212 MW.

⁷ Figures in the text are presented in nominal dollars; in real dollars, the expected increase is about 4¢/kWh in 2018/19 through 2024.

estimates that rising RPS requirements will add approximately 0.3¢/kWh⁸ to retail generation rates between 2017 and 2024, but this increase is smaller than predicted in earlier IRPs due to the cost savings achieved by Connecticut's renewable procurements under Sections 6 and 8 of Public Act 13-303. The 2014 IRP projects that Connecticut will face a shortage of Class I renewable resources starting in 2015. Beginning in 2017, the region as a whole will face shortages of Class I renewables unless additional supply is procured or otherwise added to the market.

Natural Gas Commodity Prices Are Expected To Increase Modestly From Historic Lows.

Due to the composition of New England's generation fleet, wholesale electricity costs are closely tied to fluctuations in natural gas commodity prices. Nationally, natural gas commodity prices have remained relatively low due to continued shale gas development, and New England enjoys these prices most of the year, when the region's gas pipelines are not constrained. The 2014 IRP estimates that natural gas commodity prices will increase by a modest 3% per year (adjusted for inflation), adding 1¢/kWh in real, inflation-adjusted growth to customer electric rates between 2017 and 2024. Over the IRP study period, natural gas commodity prices (from outside of New England) are assumed to start at about \$4/MMBtu in 2014 and escalate at an average 4.7% nominal rate to about \$6.2/MMBtu by 2024 (only about 3% real escalation, when adjusted for inflation), well below the high historical price levels of 2007 and 2008. Even with these expected increases, gas commodity prices should remain well below the high historical price levels of 2007 and 2008.

Overall, the combination of increasing natural gas prices, capacity prices, and RPS requirements are likely to contribute to an increase in generation rates. In combination, these factors are likely to increase the Generation Service Charge component of customer bills from approximately 9.2¢/kWh in 2014 to 10.8¢/kWh by 2017, 13.5¢/kWh in 2019, and 15.9¢/kWh in 2024 in nominal terms.⁹

Emissions. Going forward, although far below historical levels, emissions are expected to increase slightly as the region's gas infrastructure constraints spur an increase in generation from Connecticut's remaining coal-fired capacity. The stringency of forthcoming federal and state emissions rules, the retirement of coal, oil and nuclear units in the region, and the need for new generation capacity in the region may attract new natural gas fired generation to Connecticut, which could cause additional in-state emissions increases in the near term. DEEP is evaluating the NOx emissions limitations for existing power plants and industrial boilers and will seek to adopt any regulatory changes necessary no later than December 31, 2016.

⁸ Figures in the text are presented in nominal dollars; in real dollars, the expected increase is about 0.2¢/kWh in 2018/19 through 2024.

⁹ Figures in the text are presented in nominal dollars; in real dollars, rates are expected to increase from about 9.2¢/kWh in 2014 to 10.2¢/kWh in 2017, 12.2¢/kWh in 2019, and 13.1¢/kWh in 2024. DEEP recognizes that generation service charges (GSC) increased in January 2015 to 12.8¢/kWh for the first half of the year, which is above the levels forecasted for 2017. There are two reasons for this: First, the first half of 2015 reflects expectations for very high prices in January and February. This shows up in futures for 2015 deliveries. Second, is that the natural gas basis differential futures used was \$2/MMBtu (annual average). Basis futures as of February, 2015 are almost 3\$/MMBtu; updated projections of 2017 average GSC rates would be closer to 11¢/kWh.

Through 2024, state and regional CO₂, NO_x, and SO₂ emissions are projected to remain much lower than historical levels. NO_x is projected to be well below state seasonal and daily targets. CO₂ is projected to be well below near-term state Global Warming Solutions Act (GWSA) targets¹⁰ and will approximately track recently-tightened Regional Greenhouse Gas Initiative (RGGI) caps.¹¹ Connecticut is a net energy exporter. Consequently, increasing in-state fossil fired generation that primarily serves out-of-state load may lock in a level of CO₂ emissions that forces Connecticut to reevaluate its planning to meet long-term, economy-wide emission reduction mandates under the Global Warming Solutions Act.

CONNECTICUT’S PLAN FOR ACHIEVING RELIABLE, CLEAN, AND COST-EFFECTIVE ENERGY SUPPLY: RECOMMENDED RESOURCE STRATEGIES:

RESOURCE STRATEGY #1: CONTINUE TO IMPROVE COST-EFFECTIVENESS AND INCREASE ENERGY SAVINGS FROM CONSERVATION & LOAD MANAGEMENT PROGRAMS AND STATE BUILDINGS

Connecticut will continue to invest in cost-effective energy efficiency. The 2014 IRP projects that Connecticut’s increased investment in popular energy saving programs will nearly eliminate growth in state’s annual electricity consumption (projected to rise an average of only 0.05% per year), and reduce the growth in electricity consumption during peak demand periods to 0.5% per year. The Department recommends several actions to increase the savings from these programs, including (1) continuing to improve efficiency program design to deliver greater savings at lower costs, (2) continuing to focus energy efficiency programs on cost effective measures that provide values to customers by reducing energy and/or peak demand; and (3) continuing to invest in efficiency measures for state buildings. In addition, the Department and other agencies will continue their diverse efforts to pursue energy efficiency improvements through codes and standards. The Department also plans to study potential new opportunities in energy efficiency deployment, program design, and technology in an effort to identify future savings opportunities.

RESOURCE STRATEGY #2: PURSUE OPTIONS TO RETAIN DEMAND RESOURCES

Connecticut will advocate for resolution of legal issues and, as needed, revive state programs to retain cost-effective demand response. Demand response (DR) — energy reduction that can be activated when demand for electricity is at its peak — saves consumers money by avoiding the need for new generation and lowering energy prices. A recent decision from the D.C. Circuit Court of Appeals has created legal uncertainty about whether DR can continue to participate in the ISO-NE wholesale electricity markets, and this uncertainty could drive up costs and

¹⁰ See Conn. Gen. Stat. § 22a-200a (mandating emissions reductions for 2020 and 2050).

¹¹ Conn. Agencies Regs. § 22a-174-31, *et seq.*

compromise reliability if it affects DR's participation future capacity auctions. DEEP will advocate for speedy resolution of the federal jurisdictional issues, and proposes reviving and improving state programs that support demand response in the event DR is effectively shut out of the ISO-NE wholesale markets.

RESOURCE STRATEGY #3: MONITOR CAPACITY MARKET AND PLAN FOR CONTINGENCIES

Connecticut will be prepared to procure new generation if the capacity market fails. Under our deregulated market system, the ISO-NE annual capacity auction was set up to procure capacity for the region. The Department is encouraged that the forward capacity auction conducted in January 2015 attracted and retained more than sufficient supply for 2018/19. If conditions tighten in the future and subsequent auctions do not attract new capacity when needed, DEEP may pursue options within state authority to procure capacity resources to mitigate adverse reliability and economic consequences.

RESOURCE STRATEGY #4: PROCURE RESOURCES TO ADDRESS WINTER PEAK DEMAND

Connecticut will advance regional solutions to address natural gas infrastructure constraints. The inadequate supply of infrastructure to meet the needs of New England's increasingly gas-dependent generation fleet is the most pressing problem facing Connecticut and New England at this time, threatening the reliability of the grid during cold winter weather and causing generation rates to nearly double across the region. In the absence of a credible market solution, the problem is left to the states to solve in several possible ways: by building out about 1.0 Bcf/day of natural gas capacity, by procuring approximately 5,000 MW of non-gas fired generation or measures that reduce demand for electricity, or by procuring a combination of these solutions.

This problem is too big for any one state to solve alone, and all New England states should contribute to a solution. Since 2013, all six New England Governors have been working closely on a regional energy infrastructure initiative to address this problem. The Department proposes to (1) utilize existing state authority under Public Act 13-303 to solicit Class I and/or large-scale hydropower that can offset some amount of natural gas demand, and (2) seek new authority from the legislature to run a competitive procurement open to a broad range of resources (including Liquefied Natural Gas (LNG) and gas pipeline capacity; transmission for large-scale hydropower or Class I renewables; and demand response, energy efficiency, and combined heat and power) that can cost-effectively resolve the gas infrastructure constraint, up to an amount that is proportional to Connecticut's share of regional electric demand.

RESOURCE STRATEGY #5: PROVIDE SUPPORT FOR INCREASED CHP DEPLOYMENT

Connecticut will seek support for the increased deployment of combined heat and power (CHP) systems. CHP systems can help participating customers reduce their energy bills and provide benefits to the electric system by reducing capacity needs and emissions. Connecticut deployed 91 MW of CHP through a capital grant program that was discontinued in 2011. The Department estimates that there is another 170 MW of cost-effective CHP potential in the state. DEEP proposes to revitalize incentive programs to help deploy this CHP potential, recognizing that CHP systems can provide special value in locations where it can power microgrids and/or avoid costly upgrades to the utilities' electric distribution systems.

RESOURCE STRATEGY #6: SUPPORT DEPLOYMENT OF ADDITIONAL CLASS I RENEWABLES

Connecticut must promote development of additional Class I renewable energy sources to achieve Class I Renewable Portfolio Standard requirements. The 2014 IRP projects that new Class I resources will be needed to help Connecticut meet its Class I RPS requirements, which are projected to be short starting in 2015. The procurements described in the 2014 IRP could potentially bring forward a significant amount of new Class I renewable projects, addressing the regional natural gas infrastructure constraint while helping to satisfy regional demand for renewables. While those procurements are ongoing, DEEP recommends continuing to refine and extend programs to support in-state Class I renewable generation at the lowest cost to ratepayers.

RESOURCE STRATEGY #7: RE-EVALUATE REGULATORY POLICIES AND INCENTIVES FOR GRID MODERNIZATION

Connecticut must modernize regulatory policies and incentives for better integration of distributed resources. As part of an ongoing and evolving process, the Department will initiate a proceeding to evaluate the value of distributed generation.

RESOURCE STRATEGY #8: GRADUALLY PHASE-DOWN REC VALUES FOR CLASS I BIOMASS AND LANDFILL METHANE GAS, BEGINNING IN 2018

Connecticut will gradually phase down Renewable Energy Credit (REC) values for Class I biomass and landfill methane gas beginning in 2018. In response to the statutory requirement for developing a phase-down schedule, this IRP conducted an analysis of the role of biomass and landfill gas in meeting RPS requirements. The Department proposes to monitor RPS compliance and the capacity market and in the next IRP will establish a schedule that reduces REC values for these resources beginning in 2018. This approach appropriately reflects the resource adequacy concerns arising from the announced retirements of other major non-gas generation resources and a projected shortage of Class I resources.

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Appendix A: Detailed Tables

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I. INTRODUCTION

PROCEDURAL BACKGROUND

The 2014 Integrated Resources Plan (IRP) is the fifth IRP prepared for Connecticut, and the second IRP prepared by the Department of Energy and Environmental Protection (DEEP or the Department) since the Department was given the responsibility of preparing the IRP pursuant to legislation enacted in 2011.¹² Connecticut law requires that an IRP be prepared every two years, and that it assess the state's energy and generation capacity needs and provide a plan to meet those needs, lower costs, and advance the state's environmental goals, giving priority to resources that reduce demand for electricity (including conservation, load management, distributed generation, combined heat and power facilities, demand response, and distributed generation) over resources that increase electric supply, such as transmission lines and power plants.¹³ The IRP must identify strategies to eliminate growth in electric demand, including demand during peak periods, and it must evaluate how different resources could help achieve compliance with environmental standards. The IRP must also consider the reliability of the electric system, including the diversity, availability, security, and environmental impacts of different fuel types, and the appropriate reliance on electricity imported into the region. Additionally, legislation enacted in 2013 specifically requires the Department's 2014 IRP to propose a schedule for gradually phasing down the value of renewable energy credits assigned to biomass and landfill methane gas resources under Connecticut's Renewable Portfolio Standards (RPS).¹⁴

This 2014 IRP is a ten-year plan to ensure that Connecticut's electric ratepayers have access to cheaper, cleaner, more reliable electricity. The 2014 IRP analyzes trends in electric supply and demand, customer costs and rates, and environmental impacts over the 2014-2024 timeframe to identify strategies to secure an adequate supply of the optimal mix of electric generating resources to meet forecasted annual peak and energy demand in a way that minimizes costs and environmental impacts and keeps the state on track to meet its energy efficiency and renewable energy goals. The 2014 IRP also assesses risks to reliable electricity supply in Connecticut and strategies to effectively manage the state's increased commitments to energy efficiency programs and renewable energy procurements.

The Department developed the 2014 IRP with analytical assistance from Connecticut's Electric Distribution Companies (EDCs) and The Brattle Group, an economic consulting firm. On

¹² DEEP issues this IRP pursuant to section 16a-3a of the 2012 Supplement to the General Statutes of Connecticut as amended by sections 89 and 90 of Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future and Public Act 13-298, An Act Concerning Implementation of Connecticut's Comprehensive Energy Strategy and Various Revisions to the Energy Statutes.

¹³ See 2012 Supplement to the General Statutes of Connecticut, Section 16a-3a(a).

¹⁴ Public Act 13-303, An Act Concerning Connecticut's Clean Energy Goals.

September 11, 2013, the Department conducted a public meeting to obtain stakeholder feedback on the proposed scope of the 2014 IRP. Stakeholders provided comments both at the meeting and afterwards through written submissions. DEEP took these scoping comments into account when outlining the 2014 IRP structure and analytical approach.¹⁵ While conducting the analysis for the 2014 IRP, DEEP staff also met regularly with subject area experts from the EDCs, Connecticut’s natural gas local distribution companies (LDCs), the Office of Consumer Counsel (OCC), and the Office of Attorney General to obtain feedback on analytical assumptions related to resource adequacy and electricity market modeling, energy efficiency, renewable deployment, energy infrastructure (including transmission and natural gas supply), environmental issues, emerging technology, and macroeconomic analysis.

On December 11, 2014, the Department released the 2014 IRP Draft for Public Comment. The Department held a technical meeting on January 12, 2015 to answer stakeholder questions about Draft IRP. The Department, also, held a public hearing on January 22 and heard oral comments on the Draft IRP. The Department accepted written comments from interested stakeholders through February 11, 2015. The Department received comments from 37 stakeholders on the Draft IRP on a variety of topics and important updates, including the results of the recent Forward Capacity Auction (FCA) 9 and the uncertain status of Cape Wind. DEEP took these comments into account when drafting this Final IRP and includes a summary of those comments in Appendix H.

MARKET AND REGULATORY CONTEXT OF THE 2014 IRP

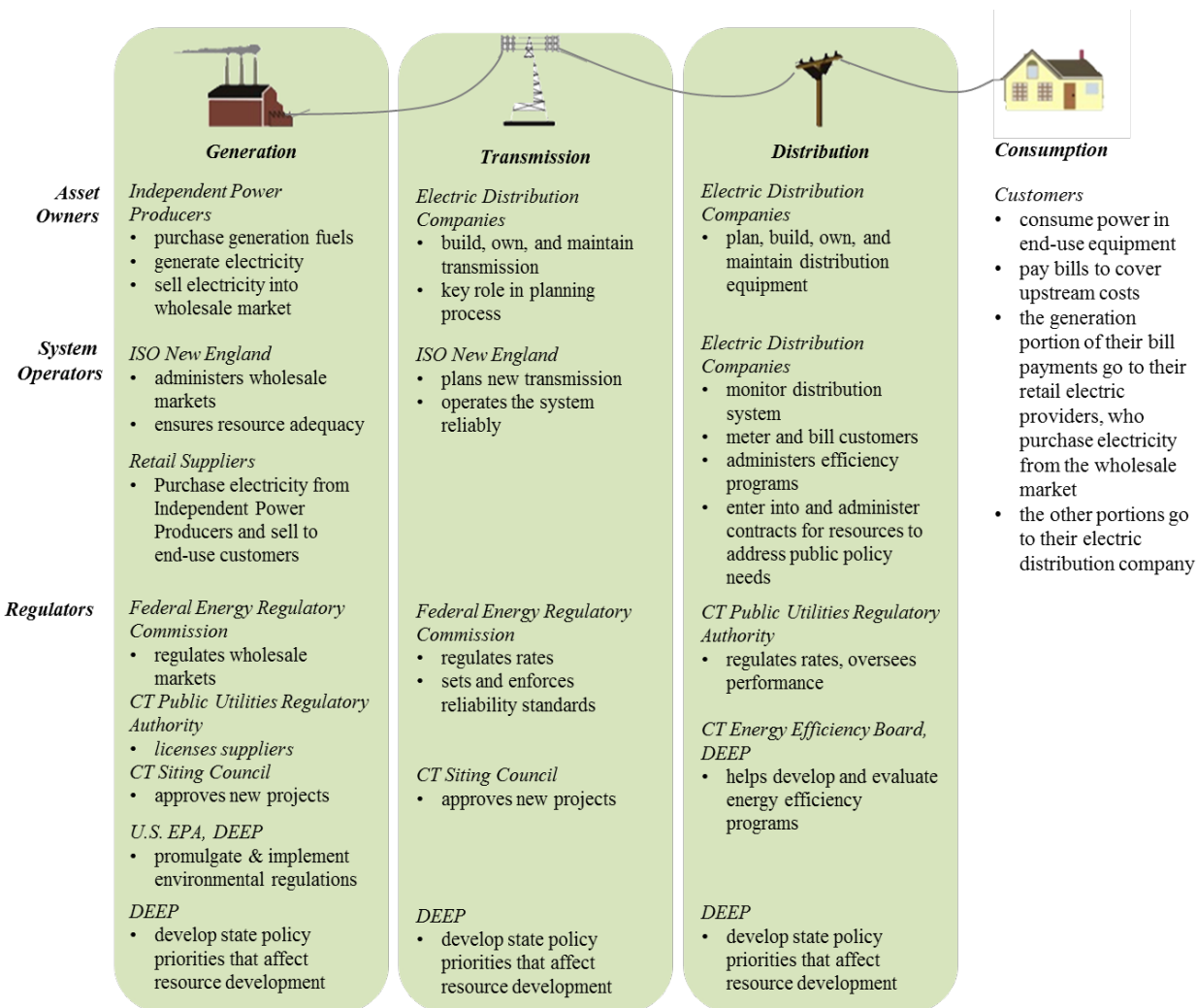
Connecticut and most other states in New England opted in 1998 to pursue a market-based approach to generation supply. Electric ratepayers were no longer required to cover the investment, contracting, and operational costs of a single regulated provider. Instead, multiple independent generators were allowed to compete to sell electricity into a regional wholesale market, and thereby to take on the risk (or reward) of bad investments and poor performance. Under this deregulated paradigm, the State does not determine how electricity is generated and transmitted, nor does it set prices for generation or transmission services. Both the wholesale market and the transmission system are administered by the New England Independent System Operator (ISO-NE) and regulated by FERC. Together, ISO-NE and FERC provide for open transmission access so that the lowest-cost available resources can be utilized (subject to transmission constraints), and ensure that market price outcomes are competitive.

The State’s role focuses on regulating the distribution system and some components of retail rates, overseeing energy efficiency programs, implementing environmental policies, setting renewable targets for the types of supply purchased by retail electric suppliers, occasionally soliciting contracts for particular generation resources on behalf of all customers, and engaging with ISO-NE in the development of rules for the generation market and in transmission planning processes.

¹⁵ Comments are available on the Department’s website under “CT General Statute – Section 16a-3a – 2014 Integrated Resources Plan,” at <http://www.ct.gov/deep/energyfilings>.

Figure 1 provides a basic illustration of the electricity system and the roles of the primary players that influence each component of the system, from generation to transmission to distribution to the customer. In addition to the entities depicted, there are many important financial players and service providers not included in the figure, such as lenders, energy traders, energy service companies, and curtailment service providers (who help customers manage their peak loads and sell load reductions as supply into the wholesale markets).

Figure 1
The Electricity System



Each of the parties identified in **Figure 1** contribute in different ways to the cost, environmental impacts, and reliability (*i.e.*, resource adequacy, transmission security, and distribution resiliency) of the electricity system. **Figure 2** describes these contributions.¹⁶

¹⁶ “Approximate Current Rates” are based on a weighted average residential rate between Eversource (Rate 1) and United Illuminating (Rate R), as of January 1, 2015.

Figure 2
Costs, Reliability, and Environmental Impacts of Electricity

	Generation	Transmission	Distribution	Other Delivery Charges
Costs/Rates				
<i>Determinants</i>	Wholesale Market Conditions <ul style="list-style-type: none"> • gas prices • Supply-demand fundamentals Special Contract Costs	Embedded Costs <ul style="list-style-type: none"> • historic capital expenditures • cost allocation Going Forward Costs <ul style="list-style-type: none"> • new investment • operations & maintenance 	Embedded Costs <ul style="list-style-type: none"> • historic capital expenditures Going Forward Costs <ul style="list-style-type: none"> • new investment • operations & maintenance 	Embedded Costs <ul style="list-style-type: none"> • Conservation and Load Management (C&LM) • Competitive Transition Assessment (CTA) • Federally Mandated Congestion Cost- Delivery (FMCC-Del) • Renewables • Systems Benefit Charge (SBC)
<i>Approximate Current Rates</i>	12.77¢/kWh (varies)	2.08¢/kWh	6.61¢/kWh	1.58¢/kWh
Reliability				
<i>Criteria</i>	Resource Adequacy <ul style="list-style-type: none"> • enough resources to meet peak loads and prevent shedding firm load more than once in ten years, with margin for forecast uncertainty and outages 	Transmission Security <ul style="list-style-type: none"> • protect individual facilities and maintain the voltage and stability of the system in the face of contingencies 	Distribution Resiliency <ul style="list-style-type: none"> • deliver customer power under all load conditions • storm preparedness and response 	Conservation Capability <ul style="list-style-type: none"> • recover costs associated with reliability and ISO-NE • ensure funding for public outreach, education, and conservation programs • pay reasonable and necessary financing costs
<i>Who Enforces</i>	ISO New England	ISO New England	CT Public Utilities Regulatory Authority	CT Public Utilities Regulatory Authority
Environment				
<i>Air</i>	<ul style="list-style-type: none"> • NO_x, SO_x, CO₂, particulates, mercury, other 	<i>Land Use Impacts</i>	<i>Aesthetics</i> <ul style="list-style-type: none"> • overhead lines vs. underground • tree trimming 	<i>Renewables</i> <ul style="list-style-type: none"> • promote investment in renewable energy
<i>Water</i>	<ul style="list-style-type: none"> • cooling water intake, discharge 			

It is important to note that the structure of the New England electric system is evolving, and the roles of the parties identified above are gradually being restructured, refined, and modernized to capitalize on emerging technologies and shifting consumer demands. The traditional utility model – one in which electricity is centrally generated, transmitted over high voltage power lines, stepped down in voltage, and locally distributed to customers – is facing a new set of challenges and opportunities that could initiate another period of innovation that propels the electric industry forward. Aging transmission infrastructure, more weather disruptions, and grid insecurity have threatened this system’s reliability and hampered its resiliency. The emergence of distributed, cost-competitive generation is challenging the incumbent, centralized model. These challenges, however, may revolutionize how utilities operate and deliver value to their customers as well as how utilities are regulated.

Information technology improvements have given electric utilities more agility to reroute power loads and diagnose disruptions in real-time. These improvements provide an opportunity for customers to manage their electricity usage more effectively than ever before and next-generation smart appliances will have the capacity to communicate directly with utilities for greater efficiencies. A mature industry is developing around these technologies to improve building system management and industrial system controls. Green banks, here in Connecticut and elsewhere, are closing the deployment gap of distributed generation technologies that are becoming more efficient and less expensive. New, supportive regulatory regimes and rate structures could reorganize utility revenue streams and accommodate these emerging trends. All

of these market trends allow utilities to supplement and diversify their generation options while building a more resilient and efficient distribution system.

On the regional and federal levels, regulatory uncertainty is creating disruptive and potentially costly threats to the reliability of the ISO-NE system and the economies of New England. The past year has seen FERC and court decisions that: 1) dramatically affect the role of Demand Response (DR) in the markets (court decision on Order 745); 2) foster substantial uncertainty regarding the states' ability to contract for renewables to meet state mandates (various court decisions); 3) question FERC's ability and willingness to ensure that competitive markets exist (Commissioner statements on the Forward Capacity Auction (FCA) 8 results); and 4) create regulatory gaps that do not leave a clear path to solve New England's inadequate gas infrastructure.

OVERVIEW OF THE 2014 IRP

The 2014 IRP is organized into sections, beginning with an overview of the market and regulatory structure of the electric sector. Sections II-V describe a Base Case ten-year forecast of trends in the electricity sector that the Department believes are most likely based on publicly available data about electricity markets in Connecticut and the rest of New England, and models of capacity prices, capacity additions and retirements, and energy market dynamics.¹⁷ These sections describe: critical risks affecting key aspects of the electric sector, including the adequacy of generating resources to meet summer peak and total demand (Section II); adequacy of resources — including natural gas pipeline capacity — to meet the region's winter peak demand (Section III); adequacy of renewable generation supply that has been procured to meet regional and state RPS targets (Section IV); the Base Case forecast for meeting electricity sector emission reduction targets (Section V); emissions from the electric sector in light of our climate and air quality goals (Section VI); and grid security and resiliency (Section VII). Section VIII outlines potential outcomes under alternative market scenarios modeled for the 2014 IRP. Section IX then introduces several Resource Procurement Strategies designed to mitigate the critical risks identified in the 2014 IRP.

¹⁷ With the 2014 IRP modeling system and analysis of key issues, the Department developed a Base Case, representing a foundational ten-year electricity outlook. Projections begin with the “known and knowable” about today and the near-future, based on publicly available data about electricity markets in Connecticut and the rest of New England. Projections also rely on a modeling system with three major interconnected components, including a demand forecast; a capacity model used to simulate capacity prices in ISO-NE's Forward Capacity Market and to project new resource entry and retirement decisions; and the DAYZER model used to simulate ISO-NE's energy market, generator operations, and locational marginal prices (LMPs).

II. FORECAST OF RESOURCE ADEQUACY TO MEET AVERAGE AND SUMMER PEAK DEMAND

This section describes a Base Case ten-year forecast of trends in the electricity sector that the Department believes are most likely, based on publicly available data about electricity markets in Connecticut and the rest of New England, and models of capacity prices, capacity additions and retirements, and energy market dynamics.¹⁸ The goal of this section is to first predict the likely demand for electricity in Connecticut and across the region over the next ten years, and then to assess whether there is adequate supply of generation to meet that demand during the summer peak, which is the traditional resource planning focus. This section also evaluates the adequacy of flexible generation supply needed to meet system operational needs in the event of sudden generator outages or other contingencies.

FORECAST: ANNUAL PEAK AND TOTAL DEMAND, 2014-2024

Background and Context

Since 2007, Connecticut's electricity consumption has declined sharply due to several factors, including the continued implementation of energy efficiency measures, and the economic recession. This trend manifested itself in reduced total annual demand and, to a proportionally smaller extent, reduced peak demand on the hottest weekday of the year (when all air conditioners are on).

The 2012 IRP projected that Connecticut, and the New England region, would have adequate generating resources to serve electricity loads reliably through 2022. The 2012 IRP also predicted that New England as a whole also would have adequate resources and likely not need new generation until 2022. The 2012 IRP did suggest that depending on market conditions, new generation could be needed as early as 2018. These findings were based on reasonable assumptions about market conditions, the completion of planned transmission projects, and generation retirements considered likely to occur given compliance with stricter rules for air emissions being promulgated by the U.S. Environmental Protection Agency (EPA).

¹⁸ With the 2014 IRP modeling system and analysis of key issues, the Department developed a Base Case, representing a foundational ten-year electricity outlook. Projections begin with the "known and knowable" about today and the near-future, based on publicly available data about electricity markets in Connecticut and the rest of New England. Projections also rely on a modeling system with three major interconnected components, including a demand forecast; a capacity model used to simulate capacity prices in ISO-NE's Forward Capacity Market and to project new resource entry and retirement decisions; and the DAYZER model used to simulate ISO-NE's energy market, generator operations, and locational marginal prices (LMPs).

One of the key recommendations of the 2012 IRP was to increase the state's investment in additional energy efficiency to save money and reduce emissions. Connecticut law requires that any needs for new generation resources must "first be met" by procuring all cost-effective programs that reduce electric demand. Based largely on the findings of a 2010 study of electric efficiency potential in the state,¹⁹ the 2012 IRP recommended that budgets for the electricity portion of the state's utility-administered Conservation and Load Management (C&LM) programs be increased to \$206 million to achieve approximately 2% energy savings each year, reducing energy consumption by 0.4% per year on net if the economy grows as expected.

Consistent with that recommendation, Connecticut's EDCs submitted an expanded budget for C&LM programs. Public Act 13-298, enacted in June 2013, directed the Public Utilities Regulatory Authority (PURA) to establish a Conservation Adjustment Mechanism (CAM) to collect up to 0.3¢/kWh to support increased investment in a C&LM Plan approved by DEEP.²⁰ In October 2013, DEEP approved a three-year (2013-2015) C&LM Plan to achieve average annual energy savings of 1% through a budget of approximately \$180 million per year, as well as a natural gas C&LM budget for the same period ranging from \$44 million to \$51 million per year. Although the C&LM Plan addresses implementation of energy efficiency to achieve both electric and natural gas savings, this IRP only addresses electric energy savings. While the electric portion of the budget is not at the "all cost-effective level" recommended in the 2012 IRP, this budget level fell within the range that could be readily funded through a CAM under Public Act 13-298, and would allow for a controlled ramp-up of program activity.²¹

2014 IRP Forecast

Looking forward, the 2014 IRP projects that summer peak electricity consumption will grow both in Connecticut and across the region, while total annual consumption will remain essentially flat over the study period due to energy efficiency programs that impact annual consumption more than peak consumption. Connecticut's summer peak demand is expected to surpass pre-recession levels by 2015. Thereafter, factoring in continued energy efficiency, summer peak consumption is expected to increase in the 2017–2024 timeframe at a rate of 0.5% per year for Connecticut and 0.6% for New England, as shown in **Figure 3**.²² By contrast, total annual energy

¹⁹ KEMA, *Connecticut Electric Residential, Commercial, and Industrial Energy Efficiency Potential Study*, April 2010, prepared for the Connecticut Energy Conservation Management Board

²⁰ The revenues collected through a CAM would be incremental to the 0.3¢/kWh charge already dedicated to C&LM programs.

²¹ PURA established the electric CAM in an interim ruling December 23, 2013 and in a final decision May 2, 2014, with the CAM set at 0.3¢/kWh to fully fund the DEEP-approved budget. *See* Docket No. 13-11-14 (electric) and 14-03-1 (natural gas).

²² Although these peak load projections account for the load-reduction effects of energy efficiency, ISO-NE's Forward Capacity Market counts energy efficiency as a supply resource that receives capacity payments to help meet the gross, pre-efficiency forecast peak load. The IRP supply-demand projections shown later in this report are consistent with the ISO's treatment, with efficiency treated as a supply resource, and with peak load shown as a pre-efficiency gross value.

consumption is expected to grow only 0.05% per year in the 2017–2024 timeframe in Connecticut and to decline slightly in the region, as shown in Figure 4.^{23,24}

Figure 3
Peak Load (net of Energy Efficiency) — Historical and Projected

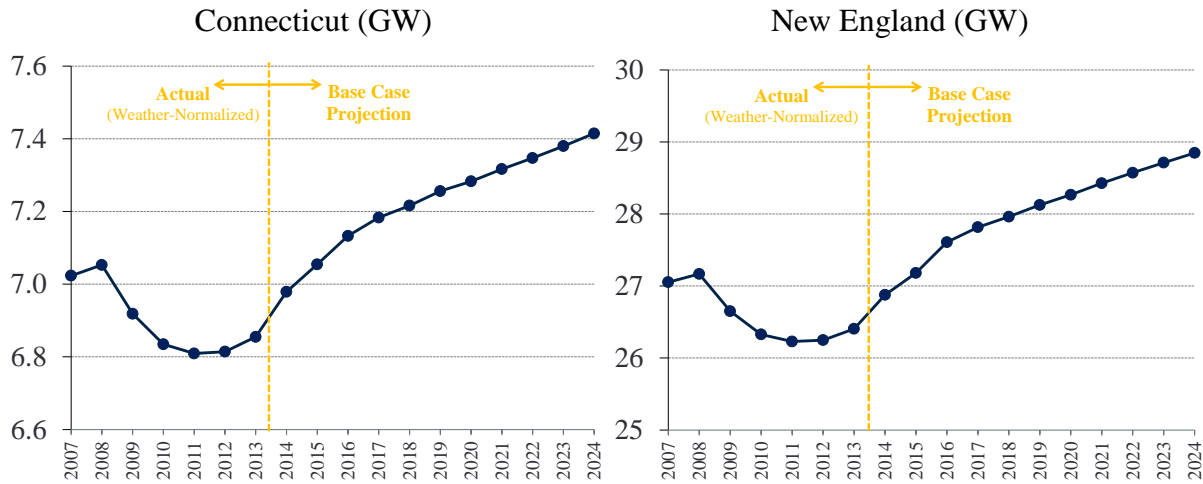
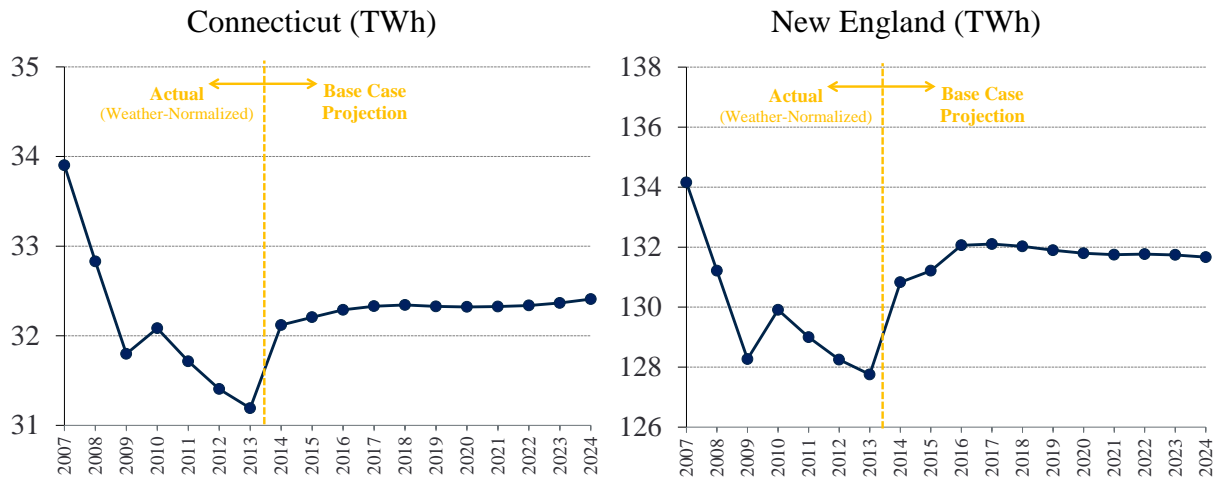


Figure 4
Annual Energy Consumption — Historical and Forecast for CT and New England



²³ **Figure 3** and **Figure 4** are based on ISO-NE, *2013-2022 Forecast Report of Capacity, Energy, Loads and Transmission*, May 1, 2013 (“2013 CELT Report”), with adjustments to energy efficiency projections for Connecticut. A more recent version of this ISO-NE report was published during final production of this IRP. That report reflects only slightly lower loads that would not materially change the IRP’s conclusions.

²⁴ Historical weather-normalized energy consumption figures for Connecticut are estimates provided by The Brattle Group, based on ISO-NE data.

Expanded Efficiency Investments are Driving Projected Reductions in Demand

Declining energy consumption in the region is driven by growth in each state’s energy efficiency programs, as projected by the ISO-NE Energy Efficiency Forecast Working Group.²⁵ In some states, particularly in Rhode Island and Vermont, new energy efficiency is projected to outpace load growth, leading to overall reductions in net demand.

The 2014 IRP assumes energy efficiency savings in Connecticut consistent with the 2013-2015 C&LM Plan,²⁶ and a future IRP will update this assumption upon the completion of future potential opportunity assessments.²⁷ The assumed savings reflects the 2007 and 2013 statutory requirements to achieve all cost-effective efficiency and ensure C&LM Plan budgets are “sufficient to fund all energy efficiency that is cost-effective or lower cost than acquisition of equivalent supply.”²⁸ This is the basis for the expectation that annual electric program budgets of \$180 million supported by a 6 mils systems benefits charge will continue. At this budget level, Connecticut’s electric C&LM programs are expected to reduce energy consumption by an incremental 290 GWh per year, on average.²⁹ C&LM programs are assumed to experience diminishing returns, however, with costs per unit saved increasing at 5.3% (nominal) per year according to the assumed schedule described in Appendix C. As a result, the IRP forecasts 3,194 GWh and 413 MW of total energy efficiency savings between 2014 and 2024. While these estimates were used for the IRP, DEEP will revisit these assumptions for the next IRP.

The impact of new energy efficiency measures on Connecticut’s projected energy requirements has important implications for Connecticut families and businesses. While average customer rates (¢/kWh) for power supply may increase, customers’ monthly bills could stay the same — or even decline — because of their energy efficiency.

²⁵ ISO New England Energy-Efficiency Working Group, *Final 2013 Energy-Efficiency Forecast 2016-2022*, February 22, 2013. Projected demand in states other than Connecticut is based on the 2013 CELT Report, which incorporates demand reductions due to the ISO’s 2013 EE forecast. Note that a more recent version of this ISO-NE EE report was published during final production of this IRP. See ISO New England, Inc System Planning, *ISO-New England Energy Efficiency Forecast Report for 2018-2023*, June 3, 2014. The newer report assumes more energy efficiency compared to the prior report, but overall demand projections are similar to what was assumed in this IRP.

²⁶ DEEP, 2013-2015 Electric and Natural Gas Conservation and Load Management Plan, available under “Public Act 11-80 – Section 33 – 2013-2015 Conservation and Load Management Plan” at <http://www.ct.gov/deep/energyfilings> [hereinafter “C&LM Plan”].

²⁷ The resulting demand forecast shown in **Figure 3** and **Figure 4** is derived from ISO New England’s own forecast, but with the following two modifications: (1) the forecast is extended to 2024 by continuing growth rates from the last year; and (2) the ISO-NE forecast includes an explicit estimate of energy efficiency savings in each state.

²⁸ Section 16 of Public Act 13-298.

²⁹ IRP assumptions differ slightly from the actual C&LM decision because the IRP analysis was completed before the C&LM decision and its implications were finalized. The budget and savings reflect an approximation of the C&LM budget approved by DEEP for 2014 and 2015, as at the time of the construction of the Base Case EE model, the C&LM Plan was not final and approved by DEEP. For that reason, the cost rates assumed to derive the Base Case EE program savings also slightly differ from those assumed in the final C&LM Plan for 2014 and 2015.

FORECAST: ADEQUACY OF ELECTRIC SUPPLY TO MEET SUMMER PEAK DEMAND, 2014-2024

Having assessed the likely trends in demand for electricity overall and during summer peaks, the 2014 IRP next analyzes resource adequacy — in other words, whether Connecticut and the New England region will have enough generating capacity to meet expected summer peak loads, plus a reserve margin for supply outages and above-normal weather conditions. Overall resource adequacy is designed to ensure that the expected frequency of shedding load is only about 1 day in 10 years. Due to transmission constraints, ISO-NE sets resource adequacy requirements at both the regional and the sub-regional level:

- At the sub-regional level, the **Connecticut Local Sourcing Requirement** is composed of a Local Resource Adequacy (LRA) requirement and the Connecticut requirement under the Transmission Security Analysis (TSA).³⁰ Whichever requirement is more stringent determines the applicable local requirement. Because the capacity required under the Transmission Security Analysis has historically been greater than the capacity required under the Local Resource Adequacy requirement, and recent ISO-NE values for the two have been nearly identical, the 2014 IRP’s Connecticut resource adequacy analysis focuses on the Transmission Security Analysis.
- At the regional level, the **Net Installed Capacity Requirement (NICR)** determines the total amount of capacity needed to achieve the so-called “1-in-10” reliability target specified in ISO-NE’s Planning Procedures (and by the North American Electric Reliability Corporation) to limit the probability of disconnecting non-interruptible customers due to resource deficiency to no more than once in ten years. The NICR sets the total demand for capacity in ISO-NE’s forward capacity auctions. Notably, the ISO-NE has reduced its projection of the Net Installed Capacity Requirement from 14.4% above forecast gross peak load to 13.6% above peak. This change represents a decrease of approximately 240 MW.

To estimate whether the region and Connecticut will have adequate supply to meet the NICR and Connecticut reliability requirements over the next ten years, the Department first considered “known” generating and demand-side resources, *i.e.*, those that already exist or new resources expected to be online, based on currently available information:

³⁰ The LRA is established probabilistically to limit the expected load shed frequency to approximately one day in ten years (local loss of load expectation of 0.105), and the TSA is defined deterministically based on the amount of supply needed to meet a high summer peak load, 10% chance of being exceeded, under various assumptions of transmission and supply availability. See Appendix B and http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2011/icr_2014_2015_final_report.pdf.

- **Existing Generating Capacity.** As of May 1, 2013, there was 7,897 MW available in the Connecticut sub-area and 31,759 MW available region-wide in the summer of 2013 to meet reliability requirements.³¹
- **Planned Conventional Additions.** Planned conventional additions include the 674 MW Footprint gas combined-cycle plant in Massachusetts and a 48 MW expansion to the Northfield Mountain pump-storage plant, also in Massachusetts, scheduled to be in service on June 1, 2016. The most recent forward capacity auction conducted in January 2015 for delivery year 2018/19 committed an additional 1,060 MW of new conventional generation, including the 725 MW CPV Towantic, LLC (Towantic) combined-cycle plant two LS Power 45 MW combustion turbines in Connecticut. The outcome of FCA 9 is not incorporated into the supply-demand projections shown in this IRP.
- **Planned Renewable Additions.** This IRP accounts for new renewable resources that Connecticut and other states have procured to satisfy RPS requirements. These additions include 591 MW (77 MW capacity value) of onshore wind, located mostly in Maine and will begin operating by 2017.^{32,33} This includes including a 250 MW project in Maine that Connecticut procured under Section 6 of Connecticut's PA 13-303, a 5 MW project in Connecticut that Connecticut procured under Section 127 of PA 11-80, 334 MW of projects that Massachusetts procured under Section 83(a) of the Green Communities Act, and 2 MW installed in 2013 in Massachusetts and Rhode Island.^{34,35} Apart from onshore wind, this IRP projects nearly 2,700 MW (1,059 MW capacity value) of other renewable generation by 2017, from new biomass, anaerobic digestion, grid-connected solar PV, distributed solar, offshore wind,³⁶ and fuel cell projects.³⁷ The Department expects that some of

³¹ Capacity online is documented in the 2013 CELT Report. In the 2013 CELT Report, capacity at Bridgeport Harbor 2 is not included as existing capacity, *i.e.*, that unit is given a zero Seasonal Claimed Capability. The more recent CELT report shows 7,627 MW in Connecticut and 31,173 MW region-wide available in summer 2014.

³² Differences between equipment capacity ratings and capacity values assigned by ISO-NE in resource adequacy analysis occurs because some resources (e.g., solar and wind) frequently are not fully available during defined reliability hours.

³³ In Maine, planned new onshore wind resources will cause Maine's in-state generation to approach its Maximum Capacity Limit (MCL), *i.e.*, the maximum amount of capacity that can clear given local load plus export constraints on the transmission system. However, this IRP assumes additional transmission is developed in Maine to integrate new renewable resources. Such upgrades, if built, are expected to reduce the likelihood of Maine reaching its MCL.

³⁴ Massachusetts announced approximately 565 MW of wind resources under Section 83(a) of the Massachusetts Green Communities Act, but several projects subsequently dropped out of the proposed power purchase agreements, leaving only 334 MW procured.

³⁵ These additions are also described in Appendix D (Renewable Energy), p. D-15 and D-16.

³⁶ These figures precede the news in January 2015 that the 363 MW Cape Wind offshore wind project did not secure financing and the project's long-term buyers cancelled their contracts, rendering that project unlikely to be completed by 2016, as assumed in this IRP.

³⁷ These additions are also described in Appendix D (Renewable Energy), p. D-15 and D-16.

these resources will clear in the Forward Capacity Market as part of the Demand Curve exemption provided for in the decision issued by FERC.³⁸ Note that some of the distributed renewables (mostly distributed solar in Massachusetts and Connecticut, and some fuel cells in Connecticut) that this IRP projected to develop but not count toward resource adequacy requirements might help meet the region's capacity need under the new exemptions. Renewable supply and demand are discussed in more detail in Section III.C below.

- **Planned Retirements.** Based on retirement announcements, including “Non-Price Retirement Requests” made to ISO-NE, the Base Case assumes about 1,540 MW in near-term retirements (Vermont Yankee, Salem Harbor units 3 & 4, Norwalk Harbor units 1, 2, & 10), and an additional 1,621 MW in retirements (mostly Brayton Point) by the summer of 2017. Only 348 MW of these regional retirements take place in Connecticut, including 342 MW at Norwalk Harbor 1, 2, and 10, and 6 MW at John Street (Wallingford) units 3–5.
- **Demand Resources.** Demand resources in the ISO-NE Forward Capacity Market are categorized as “active demand resources” or “passive demand resources.” “Active demand resources” have the ability to reduce participating customers’ loads when called upon by ISO-NE. If committed generating resources are insufficient to meet the peak demands, curtailment service providers sell these active demand resources, so-called “negawatts,” into the forward capacity auctions. “Passive demand resources” primarily reflect energy efficiency measures. Both active and passive demand resources are treated as supply resources in the capacity market. However, the ability of demand response resources to participate in the forward capacity market could be complicated by the recent court decision on FERC Order 745. Although the court decision has been stayed pending possible appeal, the ramifications of the court order to vacate Order 745 is still being analyzed, and the risks to demand response and the willingness of demand response to participate in the capacity market may have materially changed.
 - For the 2014 IRP analysis, the Department counted all *active demand resources* committed in the forward capacity auction for delivery year 2016/2017, less Non-Price Retirement Requests submitted prior to the forward capacity auction for the delivery year 2017/18. This results in 904 MW of active demand resources region-wide, including 333 MW in the Connecticut sub-area.³⁹

³⁸ See ISO New England Inc., and New England Power Pool Participants Committee., FERC ¶ 61,173(2014), (May 30, 2014 Order).

³⁹ More recent market data shows slightly more active demand resources cleared in the 2017/18 auction: 1,080 MW region-wide, including 380 MW in Connecticut. Details of the active demand resources included in this IRP are shown in Figures 15 and 16 on p. B-22 and B-23 in Appendix B (Resource Adequacy).

- For *passive demand resources*, the Department counted all resources projected by ISO-NE, including resources cleared in the forward capacity auction for delivery year 2016/2017, and additional energy efficiency estimated by the ISO-NE Energy Efficiency Forecast Working Group. In addition, the Department counted incremental measures due to recently-approved expanded CL&M funding that exceeded that Working Group’s estimates for Connecticut, as discussed in the Demand Forecast section above. As a result, passive demand resources total 3,013 MW region-wide by 2024 (compared to about 1,150 MW region-wide in 2013), including 822 MW in Connecticut and 2,191 MW in the other states.
- **New England East-West Solution (NEEWS)** In general, ISO-NE reconfirmed the need for the components of NEEWS. ISO-NE incorporated the Central Connecticut Reliability Project component of NEEWS as part of a more comprehensive study, the Greater Hartford/Central Connecticut Study (GHCC). The GHCC was completed in 2013, and found system overloads in areas across the State. ISO-NE identified the preferred solution to address the system overloads in 2014.⁴⁰
- **Net Imports.** Net imports into New England are assumed to be constant at 1,730 MW for years 2016 through 2024, consistent with amounts cleared in ISO-NE’s forward capacity auction for the delivery year 2016/2017.⁴¹ This reflects 1,830 MW of imports and 100 MW of exports. No new transmission projects (such as Northern Pass) are assumed.

As noted above, past IRPs, including the 2012 IRP, projected sufficient supply throughout the ten-year time horizon. The 2014 IRP foresees a supply shortage much sooner, due primarily to recently-announced generation retirement. On February 5, 2014, ISO-NE announced that the results of the auctions for the 2017-2018 capacity commitment period failed to procure the resources required. ISO-NE stated that “The slim capacity margin and the resulting auction prices are a clear signal to the marketplace that the region needs more power generation and demand reduction capacity.”⁴²

Connecticut Resource Adequacy

Resources within Connecticut are expected to be sufficient to meet Connecticut’s Local Sourcing Requirement as defined by the Transmission Security Analysis criteria through 2024. Within the Connecticut sub-area specifically, no new capacity will be needed because existing resources, planned transmission, and energy efficiency will exceed the local requirement beyond the ten-year IRP horizon. Local electric supply should be adequate barring the unexpected loss of

⁴⁰ Vijayan, Pradip, Greater Hartford and Central Connecticut Area (GHCC) Solutions Study II, Planning Advisory Committee meeting, July 15, 2014

⁴¹ More recent market data shows only 1,237 MW imports cleared in the 2017/18 auction.

⁴² ISO-NE Press Release, (2014) (February 5, 2014), available at http://iso-ne.com/static-assets/documents/nwsiss/pr/2014/fca8_initial_results_02052014.pdf.

approximately 2,000 MW of supply. However, Connecticut reliability and generation prices would be as affected as other states if the entire region as a whole had insufficient supply.

As shown in **Figure 5**, Connecticut is projected to exceed the minimum requirement by 1,843 to 1,962 MW in 2017 through 2024 due primarily to three factors (and these surpluses would increase by 815 MW after counting the Towantic and LS Power generation units, which just committed to enter the market by June 2018; this recent development is not accounted for in **Figure 5** or in the rest of the discussion in this paragraph). First, Connecticut's investment in energy efficiency measures (about 40 MW per year) — including the expansion of funding for efficiency beginning in 2014 — will offset more than half of the state's annual peak load growth (about 70 MW per year). Second, installation of components of the Interstate Reliability Project, a major transmission project for reliability, will bring 745 MW of existing generation at Lake Road⁴³ electrically into Connecticut in 2017, and increase Connecticut's import capability by 150 MW in 2018.⁴⁴ In addition, outside of Connecticut, the planned exit of significant quantities of demand response and generation will make the region more dependent on Connecticut's existing surplus capacity. Due to these tightened regional supply conditions, capacity prices are expected to *increase* to levels that will prevent further retirements in Connecticut and in the rest of the region.

⁴³ Lake Road is physically located in Connecticut but does not currently count as a Connecticut resource.

⁴⁴ The need for the Interstate Reliability Project has been reaffirmed by ISO-NE and the project was approved by the Connecticut Siting Council in January 2013. The Interstate Reliability Project is part of a larger transmission project, the New England East-West Solution (NEEWS). The NEEWS project is planned to address several transmission security reliability issues, and will also support local resource adequacy in Connecticut as a side benefit.

Figure 5⁴⁵
Locational Resource Adequacy in Connecticut (MW)

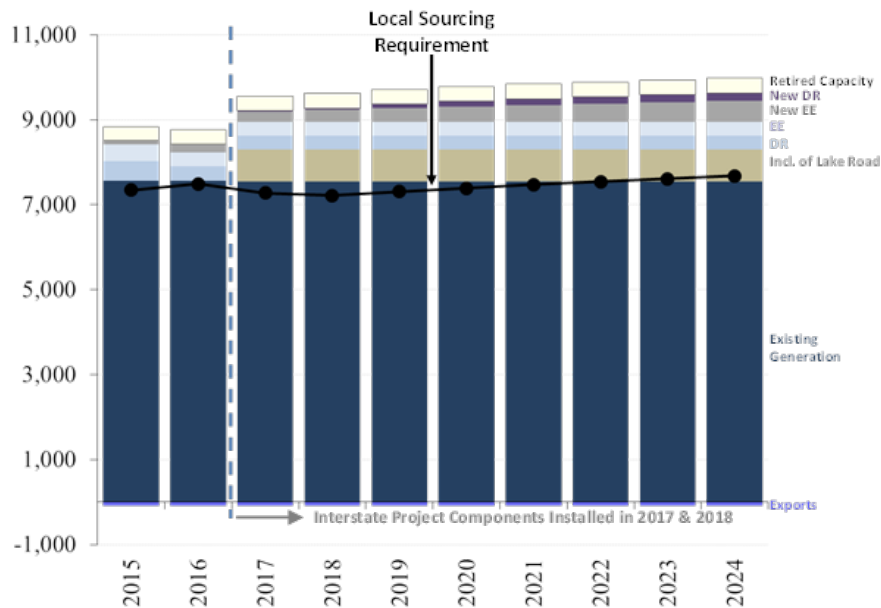


Figure 5 Notes:
 CCs = Gas-fired Combined Cycle
 EE = Energy Efficiency
 DR = Active Demand Response

Critical Risk: Potential Loss of Critical Assets in Connecticut

Although the 2014 IRP projects that Connecticut will have sufficient generating resources to meet the Local Source Requirement, it is important to highlight critical risks that could adversely affect resource adequacy in the state. Only one plant in Connecticut is large enough to potentially leave Connecticut impaired if one or all its units were to retire: the approximately 2,100 MW Millstone nuclear plant. Millstone is the largest electric generating facility in New England and contains the second and third largest individual generating units.

There is no indication that the Millstone units will retire within the 2014 IRP study horizon and, in fact, both units have been relicensed to operate until 2035 and 2045, respectively. However, with units that have been operating from 1975 and 1986 it is worth assessing the risk in case any unexpected factors caused it to shut down.

In all Market Scenarios examined in this IRP, Connecticut is projected to have sufficient capacity to meet its local resource adequacy requirement under the Transmission Security

⁴⁵ Each year indicated on the figure refers to June of that year through May of the following, e.g. “2017” refers to June 2017 through May 2018, corresponding to the delivery year for ISO-NE’s eighth forward capacity auction. Figure does not include the 725 MW Towantic plant or the two 45 MW units that cleared in FCA 9.

Analysis through the end of the study period, with a cushion of 1,375 to 2,097 MW in 2024.⁴⁶ However, the loss of even one of the units at Millstone could substantially reduce this surplus, with Millstone Unit 2 rated at 870 MW and Millstone Unit 3 rated at 1,210 MW. Under the ISO-NE Transmission Security Analysis, enough resources are already required in Connecticut to cover the *temporary* loss of either of those units. However, a permanent loss of supply of this magnitude could raise resource adequacy concerns for the Connecticut sub-area. This analysis was conducted before the results of FCA9, in which 815 MW committed to enter the market. That additional capacity would provide greater cushion.

At this time, there are no known immediate threats to Millstone's viability in the marketplace. However, the future evolution of water quality regulations brings some uncertainty. In 2012, Millstone Station was required to suspend operations at least twice due to high ambient temperatures in Long Island Sound because intake water temperatures exceeded the maximum allowed limit of 75 degrees Fahrenheit in its National Pollutant Discharge Elimination System (NPDES) permit. In response, Dominion requested and was granted approval to increase the intake water permit limit from 75 degrees to 80 degrees Fahrenheit. Although this particular issue was addressed, it draws attention to other potential impacts of water quality regulations in the future. Federal activity on the promulgation of new water quality standards, their impacts on NPDES permits, and any site-specific technical barriers to implementing standards should be closely monitored in future IRPs.

Regional Resource Adequacy

Resource adequacy picture is tighter at the regional level. Existing and planned supply should reliably meet summer peak loads only until about 2017, when the New England region will become just slightly short of its resource adequacy target. But that slight shortage should be only temporary. ISO-NE's most recent forward capacity auction cleared more than 1,400 MW of new supply, including 1,060 MW of new generation, and 367 MW of new demand response; imports increased by 212 MW as well. These very recent positive developments are not shown in **Figure 6**, which shows earlier projections.

As **Figure 6** shows, committed supply will satisfy the requirement through the summer of 2016 (despite the loss of about 900 MW of demand response between the summer of 2015 and the summer of 2016). Thereafter, with the already-announced exit of 3,160 MW of generation and about 200 MW of expected further demand response exit, new supply would be needed to meet load growth (and to offset any further retirements). The 2014 IRP modeling system forecasts new demand response (and possibly uprates and increased imports) entering to compensate for load growth through the summer of 2019. To meet the NICR for New England, the region will need new generation capacity, increased transmission capability, or demand reductions starting in the summer of 2018. By the summer of 2020, new generation entry, as well as additional demand response, will begin to become economic with approximately 860 MW of new

⁴⁶ This assumes a total of 356 MW active demand resources in Connecticut cleared in FCA 8 for the 2017/18 capacity delivery year. Actual FCA 8 results saw 380 MW active demand resources cleared.

generation and 700 MW of new demand response projected to enter by 2024.⁴⁷ These projections were conducted before the recent results of FCA9 were known. The capacity attracted and retained by that auction provides enough capacity for 2018/19 and likely several years beyond unless existing resources unexpectedly exit.

Figure 6
Resource Adequacy in New England (GW)⁴⁸

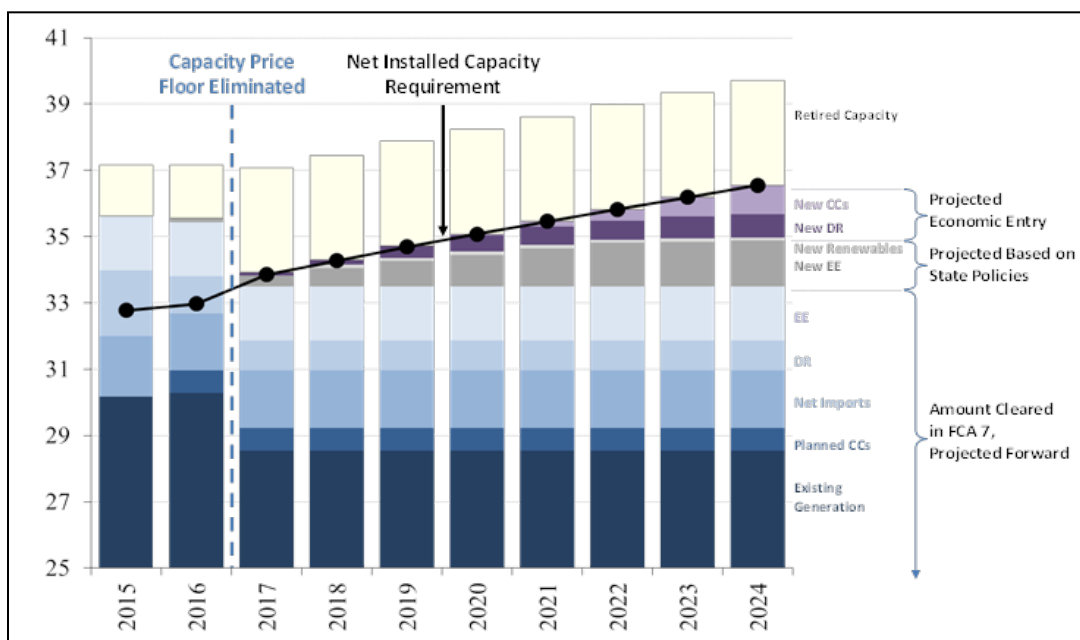


Figure 6 Notes:

CCs = Gas-fired Combined Cycle

EE = Energy Efficiency

DR = Active Demand Response

Existing generation includes 48 MW of planned uprate to Northfield Mountain and 95 MW of assumed economic retirements

The economic retirement projections described above are driven largely by expected energy margins and capacity market prices, versus expected going-forward costs, including variable costs, fixed operations and maintenance, and the cost of major capital upgrades.

The 2014 IRP relies on estimates about when active demand resources would enter and exit the capacity market, largely based on capacity prices. Intuitively, one would expect that supply of demand response would decrease when capacity prices fall and increase when they rise. For

⁴⁷ See Appendix B (Resource Adequacy) for a detailed description of the methodology used to model retirement, entry, and demand response. These projections are subject to uncertainties, including the load growth rate, the 1,500 MW of projected economic entry and a few additional retirements by 2024, the assumption that regional imports remain constant at 1,730 MW, etc.

⁴⁸ Figure 6 does not incorporate the latest auction results from FCA8 and FCA9.

forecasting purposes, the IRP analysis utilized a demand response supply curve with a fixed cost component, and a variable cost component (per MWh of expected interruption) that increases as total market demand response penetration increases to account for a greater probability of being called. Including this supply curve in the capacity market simulations caused projected demand response to increase. The 728 MW of demand response (excluding real time emergency generation) projected to clear in the capacity auction for 2017/18 is an 86 MW increase above the quantity remaining from the 2016/17 auction after excluding cleared resources that submitted non-price retirement requests. By 2024, when capacity prices are expected to be substantially higher, approximately 1,350 MW of demand response is projected to clear.⁴⁹ This projection does not appear unrealistic considering that even larger amounts of demand response have cleared in past auctions.

New generation entry is assumed to occur only when the capacity price rises to the Net Cost of New Entry (Net CONE) of the most economic generation technology in New England: a gas-fired combined-cycle plant. The Net CONE of a new combined-cycle plant is provided by the annual capital carrying charges and fixed operating and maintenance costs, minus the energy margins and ancillary services revenues the plant would earn, as estimated in the DAYZER model. The annual capital carrying charges and fixed operating and maintenance costs are assumed to be \$133/kW-year or \$11.08/kW/month, based on the values for a new combined-cycle plant in ISO-NE's 2014 Net CONE study.⁵⁰ In the most recent capacity auction (FCA9), capacity prices rose to just under Net CONE given the system shortage caused by retirements in the prior auction (FCA8). At this higher price level, a new combined-cycle generator in Connecticut cleared 725 MW of capacity, which will contribute toward regional resource adequacy needs into the future.

Impact of Environmental Regulations on Retirement Projections

Environmental regulations can have a significant impact on generator economics. The Department's analysis assumes the U.S. EPA's Mercury and Air Toxics Rule (MATS) will require a handful of coal-fired generators in New England without certain pollution controls to install costly retrofits (Maximum Achievable Control Technology, or MACT) or retire in 2015. The EPA has proposed other regulations including the 111(d) rule to reduce emissions of carbon dioxide from existing power plants, but none of these yet clearly impose widespread, inflexible requirements for retrofits and compliance on par with the rule that controls hazardous air pollutant emissions.⁵¹ After consulting with Connecticut generation owners and other states'

⁴⁹ The details of this analysis are provided on p. B-19 through B-21 of Appendix B.

⁵⁰ The key parameters are \$1,178/kW overnight cost, level-real annualized cost based on 8.0% nominal after-tax weighted average cost of capital and 20-year economic life, and \$29/kW-year fixed operations and maintenance costs, for a 715 MW (with duct firing) combined cycle plant. These estimates are based on ISO-NE's 2014 Net CONE study, conducted by The Brattle Group.

⁵¹ The US Supreme Court upheld the Cross State Air Pollution Rule, but it is not expected to drive generator retirements in the region. The EPA's plan to tighten ozone standards, which could lead to strict emissions rate limits, has been delayed and will likely not have a significant impact until the near the end of the 10-year study horizon. However, Connecticut intends to tighten its Reasonably Available Control Technology for Control of Nitrogen Oxides emissions. The emission limits contemplated (0.10 -0.15 lb/MMBtu, 24-hr block average) could have serious implications for generators in Connecticut; however no rule has been drafted yet. The

environmental agencies, DEEP estimated that three coal-fired generator sites will likely require costly retrofits to comply with EPA's MACT requirements for hazardous air pollutants:⁵²

- Bridgeport Harbor 3 (383 MW)⁵³ in Connecticut would need dry sorbent injection (DSI) to control acid gas emissions, at an estimated cost of \$54/kW.
- Schiller 4 and 6 (collectively 95 MW)⁵⁴ in New Hampshire would need activated carbon injection (ACI) to improve the effectiveness of their fabric filters, electrostatic precipitator (ESP) upgrades for capturing mercury, and DSI to control acid gas emissions. The upgrades are estimated to cost \$306/kW.
- Merrimack 1 and 2 (collectively 438 MW)⁵⁵ in New Hampshire would need ESP upgrades for capturing mercury; Merrimack 2 is also assumed to need ACI to improve the effectiveness of their fabric filters. The upgrades are estimated to cost \$87/kW for unit 1, and \$100/kW for unit 2.

The 2014 IRP analysis results in only 95 MW of economic retirements regionally (in addition to the 3,160 MW already planning to retire) in 2015, the assumed compliance deadline for hazardous air pollution rules. None of these economic retirements are projected to occur in Connecticut.⁵⁶ The Bridgeport Harbor 3 coal unit is expected to remain online despite the cost of installing dry sorbent injection.

Critical Risk: If Capacity Market Fails to Attract and Retain Sufficient Capacity to Meet Summer Peak Loads

In theory, the ISO-administered wholesale capacity markets are supposed to provide appropriate price signals so that prices can rise to a level sufficient to retain and attract enough capacity to maintain the target reserve margin. For example, if there were not enough supply available on a 3-year forward basis, the forward capacity auction price would clear at the price cap, which is supposed to be substantially above the long-term average price needed to support new entry. That prospect ought to be attractive to suppliers. To make investment even more attractive to new entrants, ISO-NE offers a seven-year guaranteed lock-in of the price earned in the first auction (which reduces the effect of a large unit crashing its own price in future auctions).

proposed rules under the Clean Water Act Sections 316(a) and 316(b) on cooling water intake structures appear to have flexible compliance mechanisms, and confer discretion to states on implementation.

⁵² The estimated capital costs of such retrofits range from \$54/kW to \$306/kW, as documented in Appendix E (Environmental Regulations).

⁵³ 2013 CELT Report, *supra* note 24.

⁵⁴ *Id.*

⁵⁵ *Id.*

⁵⁶ The old steam units in Connecticut that are not projected to need capital-intensive controls to comply with the hazardous air pollution rules would likely remain online because their going-forward fixed operations and maintenance costs are less than the projected capacity price. These units include the Middletown 2-3, Montville 5, and New Haven Harbor steam oil units.

Some market observers claim that future prices in New England are too uncertain for investors to build a capital-intensive generation asset with a 20–30 year economic life. It is too early to tell. The capacity market has not been fully tested, since surplus capacity conditions have prevailed since the inception of the Forward Capacity Market. An important exception is in NEMA/Boston, where the retirement of the Salem Harbor generation facility threatened to leave the area in a capacity deficit. In response, the 674 MW Footprint Power gas-fired combined-cycle generation plant did offer and clear at a price just below the price cap, with a 5-year lock-in.

The Department is concerned that ISO-NE’s new Performance Incentives (PI) program will introduce substantial and difficult-to-quantify risks that could deter entry (especially of demand resources) while inducing existing resources to retire. The ability of demand response resources to participate in the forward capacity market is further complicated by the recent court decision on FERC Order 745. While the ramifications of the court order to vacate Order 745 are still being analyzed, and although the court decision has been stayed pending possible appeal, the risks to demand response and the willingness of demand response to participate in the capacity market may have materially changed.

In summary, there is no guarantee that the New England capacity market will succeed. Connecticut will continue to participate in the ISO-NE stakeholder process to ensure that the market rules provide appropriate price signals and address investor risks that might unnecessarily discourage investment. The recent decisions from FERC regarding Pay-for-Performance (PFP) and the demand curve, along with recent federal court orders have greatly complicated the analysis of the wholesale markets. The PFP decision is expected to set a higher effective floor on the system wide, or zonal, demand curve, since the risks of PFP will be priced into the bids that units place. Further, the impact of PFP on zonal pricing will depend on the particular resource mix in each capacity zone and the shape of zonal demand curves, which have yet to be filed at FERC. The combination of all of the FERC and federal court decisions creates a very uncertain market future with substantial price and reliability risks for ratepayers that may require coordinated state actions.

FORECAST: SUPPLY AND DEMAND FOR FLEXIBLE CAPACITY TO MEET OPERATIONAL NEEDS

In order to maintain continuous real-time supply-demand balance, ISO-NE needs to be able to compensate for rapid changes in system conditions by having fast-acting, flexible resources at its disposal. To ensure it has enough of the right kinds of flexible resources available at every moment, ISO-NE sets a hierarchy of different types of ancillary services, including: regulation (the fastest-responding, able to ramp quickly up and down); ten-minute spinning reserve; ten-minute non-spinning reserves; thirty-minute operating reserves; and replacement reserves (essentially, additional thirty-minute reserves).⁵⁷

⁵⁷ See “ISO New England Operating Procedure No. 8: Operating Reserve and Regulation, located at: http://www.iso-ne.com/rules_proceeds/operating/isone/op8/op8_rto_final.pdf.

ISO-NE also procures non-spinning reserves on a semi-annual basis through the Forward Reserve Market to ensure that it will have enough fast-starting resources available to meet its daily ten-minute non-spinning reserves (TMNSR) and thirty-minute operating reserves (TMOR) requirements. Resources providing forward reserves agree to remain offline and available to provide reserves whenever asked by ISO-NE. In exchange, they receive a Forward Reserve Market payment in addition to any payments received from the capacity market and any payments received on a daily basis from the energy or reserves markets.⁵⁸ ISO-NE then procures in the real-time market ancillary services to meet its operational needs including any non-spinning reserve not covered by the forward reserve purchase.

Connecticut's Locational Forward Reserve Market requirement is set equal to the 95th percentile daily local thirty-minute operating reserve requirement over the prior two like-season periods adjusted for known system condition changes. In the past, the lack of economic generation and fast-start capability in Connecticut resulted in limiting energy imports into Connecticut so that spare import capability could serve as reserves. Through a series of state-sponsored capacity procurements Connecticut has increased quick start resources by about 600 MW and increased generally economic generation by about another 600 MW.

With these resources, other existing resources, and new transmission, the 2014 IRP projects more than adequate resources to meet Connecticut's Locational Forward Reserve Market requirement over the study horizon. ISO-NE's 2013 Regional System Plan indicates that Greater Connecticut may have a need of up to 900 MW through 2016. This need declines to about 600 MW in 2017 following the expected commissioning of the 345 kV Lake Road-Card transmission line (part of the Interstate Reliability Project), which would bring the Lake Road generating facility electrically into Connecticut and reduce the need for local reserves.⁵⁹ The resulting demand is substantially less than the 1,470 MW of quick-start capable generation now available in Greater Connecticut.

It should be noted that in 2013, to address quick-response resources' performances during regionally-stressed conditions in 2010 and 2011, ISO-NE undertook a number of changes in the forward reserve market to improve reliability.⁶⁰ On the requirement side, ISO-NE increased the

⁵⁸ The Forward Reserve Market purchases ahead of time pool wide and locational operating reserve requirements. It purchases pool-wide ten minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) and also purchases TMOR on a locational basis. Pool wide forward reserve requirements are patterned on real-time operating reserve requirements and are specified in memo ISO-NE issues prior to each forward reserve market auction. See http://www.iso-ne.com/markets/othrmkts_data/res_mkt/cal_assump/2013/index.html. Auctions are held twice a year; in April for the delivery period June through September (the summer period) and in August for the delivery period October through the following May (the winter period).

⁵⁹ See http://www.iso-ne.com/trans/rsp/2013/rsp13_final.docx p.54.

⁶⁰ In the following linked filing, among other topics, ISO-NE explains the history leading to the filing's specific request to increase TMNSR to be purchased in the forward reserve market. Subsequent filings were made to change 1) how resources establish the amount of capacity available for TMNSR and thirty minute reserve (TMOR), and 2) the failure to reserve penalty rate and when penalties are triggered. Lastly ISO-NE increased the amount of replacement reserves, a form of TMOR, to be procured in the forward reserve market. http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-465-000_11-27-2012_proc_ten-min_rule.pdf.

amount of pool wide TMNSR and TMOR purchased in the forward reserve market. On the supply side, ISO-NE changed the method for determining the amount of capacity a resource can claim to meet TMNSR and TMOR. These latter changes have resulted in resources being less confident in how many megawatts can be offered into the market. Thus the requirements are up and the supply is down, driving up forward reserve market prices. TMNSR prices have gone from \$0.35/kW-mo net of the capacity price for winter 2012/13 to \$5.50/kW-mo net of the capacity price for winter 13/14 and TMOR has gone from \$0.35/kW-mo net of the capacity price for winter 2012/13 to \$3.34/kW-mo net of the capacity price for winter 2013/14. Until offered supply increases and requirements decrease, forward reserve market prices will remain higher than seen in the past. Due to the small volume of capacity receiving these payments, the cost contributes a very small amount to customer rates.

III. MEETING THE REGION'S WINTER PEAK DEMAND RELIABLY AND AFFORDABLY

Although past IRPs have traditionally focused on supply adequacy for meeting summer peaks, the adequacy and cost of delivered natural gas supply to serve winter electric demands has recently become a reliability issue and a costly challenge given New England's limited interstate gas pipeline capacity and electric generators' reliance on non-firm gas purchases. The following section examines the details of supply and demand and then presents the resulting outlook for electricity reliability and prices.

NEW ENGLAND'S GAS-ELECTRIC MARKET STRUCTURE

A SHIFT TOWARDS MORE GAS-FIRED GENERATION

Over the past decade, the mix of fuels used to generate electricity has changed significantly, due to dramatic shifts in relative fuel prices (reflecting low natural gas prices coupled with high coal and oil prices), recession impacts, the development of demand-side resources, and the incorporation of those resources in electricity markets. Oil-fired generation decreased after 2007 partly because of the increased availability of lower-cost natural gas-fired generation and renewables, but also because of changes in fuel prices: oil prices have risen dramatically relative to natural gas prices, and are expected to remain high. By 2012, regional coal-fired generation decreased dramatically due to fuel-switching to relatively cheaper natural gas-fired generation.

More than 50% of New England's electricity needs are now generated with natural gas, compared to only 5% in 1990 and 15% in 2000, with even more growth in the use of natural gas-fired generation anticipated. Natural gas generation has many advantages over other conventional fossil fuel generation resulting in a growing shift in generation resources to natural

gas over the past twenty years. Natural gas fired generation is less capital intensive to build than other fossil plants and historically fuel costs have been lower. Natural gas generators have lower emissions and are also very flexible, allowing them to ramp up and down quickly in response to changes in load. But there is growing concern over New England's increasing dependence on natural gas as an electric generation fuel, and the implications resulting from such dependence in terms of reliability and cost.

CONTRACTING FOR NATURAL GAS SUPPLY

Most of the natural gas supply in New England is contracted for by the LDCs to serve their firm residential, commercial, and industrial customers. The LDCs engage in long-term planning processes that are regulated by the state to ensure that they have adequate capacity available to serve their firm customers under conditions equivalent to the coldest day in 30 years. The LDCs develop and operate diverse portfolios of firm pipeline capacity and local peaking facilities to reliably supply customers under all weather conditions. Local gas distribution company loads and other firm customers get first priority access to gas supply because they hold long-term rights to the existing pipeline capacity.

Gas-fired generators, on the other hand, do not contract for firm gas deliveries. Gas generators generally purchase gas on a daily basis after they have been selected by the ISO-NE to generate power that day. They obtain transportation or spot gas only to the extent it is available when firm subscribers — such as LDCs — are not using it to serve their customers. Plenty of capacity is available on a non-firm⁶¹ basis most of the year, but not during many days in the winter. Gas prices increase on the spot market when supplies are limited and may not be available at all for use by generators during peak winter months. Some gas generators do purchase firm gas transportation service. This provides greater reliability but at a higher cost than non-firm service, as gas pipeline developers require long-term contracts to expand or add new pipeline capacity. Under the ISO-NE market structure, gas generators must bid their marginal cost into the energy market and are not allowed to pass on the fixed cost of firm transportation service; therefore most contract for non-firm service. This short-term oriented market structure does not encourage or properly incent long-term fuel supply planning or contracting for the resources necessary to reliably and cost effectively access gas firm supply such as gas pipeline capacity or storage.

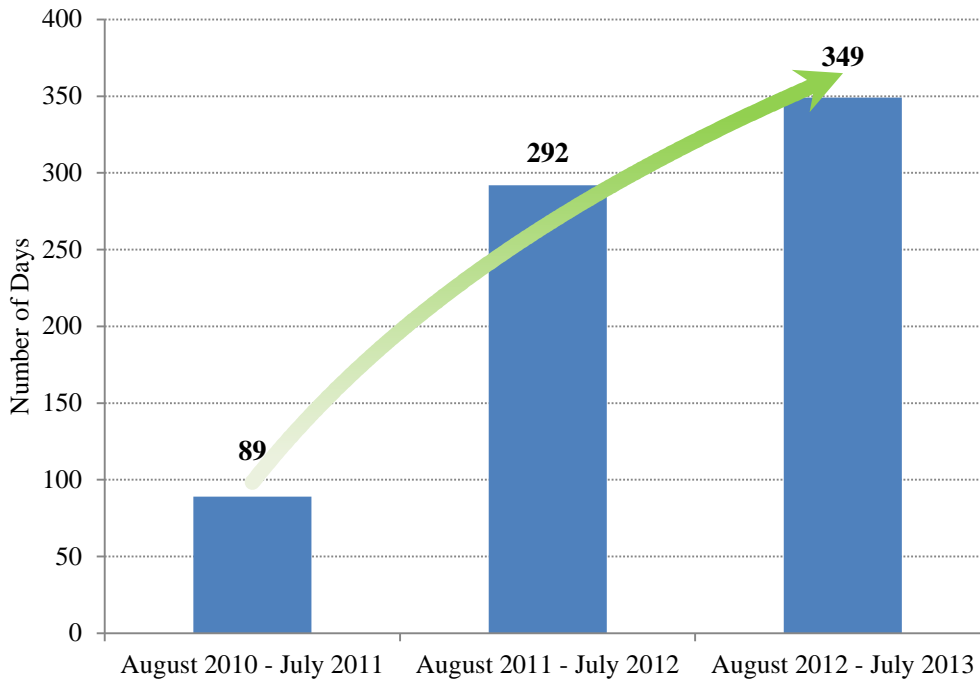
New England LDCs are experiencing higher growth in gas demand due to the low price of wellhead gas supplies which is incenting customers to switch from oil to natural gas. Low-cost Marcellus gas provides an excellent opportunity for many families and businesses to reduce their heating costs. For this reason, the 2013 CES identified that approximately 280,000 homes and businesses in Connecticut could cost-effectively switch to natural gas, and recommended that Connecticut's LDCs develop a plan to provide natural gas access to those prospective new customers by 2024. This expansion plan was mandated by Public Act 13-298 and was subsequently approved by PURA in 2013. Other New England states are pursuing similar

⁶¹ “Non-firm” refers to as-available interruptible capacity, short-term pipeline capacity released by firm capacity holders, and delivered gas bought on a spot basis.

expansions of their LDC customer base. Maine plans to bring 15,000 new customers online by 2017.⁶²

While this expansion of the LDC customer base provides significant benefits to new gas customers and to society, the growth in demand by firm customers means there is little excess capacity available for generators to purchase on cold winter days when electric demand for gas is at its peak. The number of days in which no interruptible capacity is available for electric generators are becoming more frequent as **Figure 7** clearly demonstrates.⁶³

Figure 7
Days with Zero Interruptible Capacity Available on the Algonquin Pipeline⁶⁴



At the same time, most of the non-peak-shaving Liquefied Natural Gas (LNG) import capacity is underutilized due to low natural gas prices in the region remaining below higher international prices. Two LNG terminals, Northeast Gateway and Neptune Deepwater that make up roughly 1.2 Bcf/d of LNG import capacity in New England, have not received any LNG shipments from

⁶² State of Maine Public Utilities Commission (PUC). 2013 Annual Report. Augusta, ME: State of Maine PUC. 2014, available at http://www.maine.gov/mpuc/about/annual_report/documents/attach.pdf

⁶³ See Sussex Economic Advisors, LLC. *Maine Public Utilities Commission, Review of Natural Gas Capacity Options*. Framingham, MA: Sussex Economic Advisors, LLC., 2014, available at <http://www.sussex-advisors.com/wp-content/uploads/2014/03/Maine-PUC-Final-Report-February-26-2014.pdf>.

⁶⁴ See Sussex Economic Advisors, LLC. *Maine Public Utilities Commission, Review of Natural Gas Capacity Options*. Framingham, MA: Sussex Economic Advisors, LLC., 2014, available at <http://www.sussex-advisors.com/wp-content/uploads/2014/03/Maine-PUC-Final-Report-February-26-2014.pdf>.

September 2010 through the winter of 2013/14, and Neptune has since suspended operations.⁶⁵ Capacity utilization at the 1.0 Bcf/d Distrigas LNG facility, the only active terminal in New England, was only 24% in 2012.⁶⁶

GAS-ELECTRIC RELIABILITY SOLUTIONS IMPLEMENTED BY ISO-NE

The issue of gas-electric reliability was first identified following a cold snap in 2004. Since then, ISO-NE and NEPOOL committees have examined the issue and some modifications have been implemented. ISO-NE periodically makes changes to various planning processes and market rules that affect the resources in Connecticut and New England. The changes made by ISO-NE are typically aimed at improving market efficiencies or system reliability. In 2013, ISO-NE implemented a number of market rule changes including the 2013/2014 winter reliability program and changes to the day-ahead energy market schedule.

ISO-NE has implemented several initiatives to address risks associated with unit performance and gas dependency.⁶⁷ These initiatives include:

- **Winter Reliability Program:** In 2013, ISO-NE introduced a one-year, out-of-market Winter Reliability Program to ensure the availability of certain non-gas resources to maintain reliability during the winter of 2013/2014. This program was intended to operate as a temporary, one-time measure for the winter months. The program included: (a) incentives for oil-fired generators to increase their fuel oil inventory; (b) a winter demand response program; (c) payments to dual fuel units for testing their fuel-switching capability; and (d) changes to market monitoring to increase generators' flexibility.⁶⁸ Through this program, ISO-NE procured roughly 1.951 million MWh of demand response and oil inventory service (over 99.8% of the procured energy was the oil inventory service) at a cost of \$75.1 million.⁶⁹ The 2013-14 Program did not include measures to encourage firm gas deliverability or holding LNG in inventory. ISO instituted modifications to the Winter Reliability Program for 2014-15 which includes

⁶⁵ Neptune LNG received approval from US Department of Transportation's Maritime Administration (MARAD) in July 2013 to suspend operations at its LNG import facility for 5-years. See http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/neptune-lng-allowed-suspend-lng-operations-5-years-usa_21161.html.

⁶⁶ Peak-shaving capacity is owned or contracted for by LDCs for service to retail gas customers during the coldest days of the year, and is generally not available to other customers such as electric generators. The 1.0 Bcf/d Distrigas LNG terminal imported roughly 86.5 Bcf (or 0.24 Bcf/d) in 2012.

⁶⁷ These initiatives address: "1) filling information gaps with better and timely information to manage the power system; 2) enhancing market mechanics to better enable resource performance; 3) improving market incentives for resources to perform; and 4) procuring sufficient reserves for reliability." See *Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency*, ISO-NE, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

⁶⁸ See ISO-NE Transmittal, Docket No. ER 13-2266-000, June 28, 2013, p. 4.

⁶⁹ See Filing in Compliance with Order Conditionally Accepting Bid Results; Docket No. ER 13-2266-000, October 15, 2013, p.7, 18-22.

cost recovery for LNG and other modifications. The Winter Reliability Program is only intended as a temporary measure to ensure reliability of the electric system but does not address the fundamental problem of dependence on non-firm gas purchases or implement long-term solutions to improve the reliability of gas generators at a reasonable cost.

- **Increased Coordination and Communication with Gas Pipelines:** ISO-NE received approval from the FERC on March 6, 2014 to modify the tariff to allow ISO-NE to share forecasted schedule and real-time information about specific gas generators with the region's gas pipelines.⁷⁰ This measure is intended to enhance reliability by improving communication and coordination between electric and gas control room operators. Communication of operational information between gas industry and transmission operators are currently being explored through FERC's NOPR in Docket No. RM13-17-000.
- **Improved Scheduling:** ISO-NE accelerated the deadlines for the Day-Ahead Market (DAM) and Reserve Adequacy Analysis (RAA) effective May 23, 2013. Now, the DAM offer closes at 10:00 a.m. with results posted at 1:30 p.m., and the initial RAA process is completed by 5:00 PM. This earlier clearing of the DAM and RAA will provide ISO-NE more time to commit long lead-time resources if necessary. The earlier bidding window and RAA will improve gas-fired generation's ability procure fuel, for example by providing them access to the most liquid gas trading period in the day.⁷¹
- **Allow Hourly Re-Offers:** In an Order issued on April 29, 2014, FERC approved ISO-NE's proposed market rules to allow participants to update their offers in real-time to reflect changing fuel costs. These changes allow participants to better reflect actual fuel or other operational costs, improving market pricing and incentives to perform.⁷²
- **Increased Flexibility To Manage Fuel Contingencies:** In 2013, ISO-NE also made various changes to the reserve markets to provide greater flexibility to generators and operators to manage fuel contingencies and to produce prices that more accurately reflect actual costs. The changes implemented include: ISO-NE procures more 10 minute non-spinning reserves; increasing the amount of replacement reserves required; increasing the reserve constraint penalty factor (RCPF), which affects prices during reserve shortages, to decrease the need for units being committed out of merit. The proposed changes are intended to provide a financial incentive for generators to follow dispatch and to have market prices more accurately reflect the costs to produce energy. Among the proposed changes, which were considered in DEEP initiatives, is the ability of market participants to reflect negative offers for energy. Negative offers will allow units with high start-up and shut down expenses to make the economic decision to keep running. It will also

⁷⁰ While FERC approved the proposal in interim, it noted that the changes "may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful." See 141 FERC ¶ 61,196, p.11.

⁷¹ See ISO-NE's Settlements Issues Forum, Q2 2013 Meeting, Rachel Likover, June 28, 2013, slides 14-15, available at http://www.iso-ne.com/stlmnts/qrtly_stlmnts_mtrls/settlement_quarterly_webex_06_12_2013.pdf.

⁷² See 145 FERC ¶ 61,014.

allow resources such as wind power to run at times when demand is low or when the system is becoming physically constrained.

- **Proactive Commitment of Non-Gas Resources:** During periods of gas supply and deliverability constraints, ISO-NE proactively commits long lead-time oil-fired generators out-of-economic-merit so that they are available for dispatch when needed.
- **Allowing Generators to Reflect Real Time Price of Fuel:** ISO-NE implemented changes that allow generators to more accurately reflect the real time price of fuel in their offers. The above improvements to communications, scheduling, and operation of the gas and electric markets are helping to optimize the use of available non-firm gas supply, but have not resolved the underlying gas capacity limitations in the New England region that affect liquidity and the physical ability to respond to electric generator needs. Still, underlying issues of reliability and high costs remain due to the reliance of generators on non-firm gas purchases.

IMPACT OF GAS SUPPLY CONSTRAINTS ON SYSTEM RELIABILITY AND ELECTRICITY PRICES IN NEW ENGLAND

The limited availability of non-firm gas supply during periods of peak winter demand is driving significant increases in spot natural gas prices in New England. Spot market natural gas prices have historically been priced at a premium, but this premium has increased in recent years. This premium, or difference, between the price in New England and the Henry Hub, a location in Louisiana considered representative of the general U.S. market, is referred to as the “basis differential.”

The number of days in which the New England natural gas price differential to the Henry Hub was greater than \$2/MMBtu increased from 51 days in the winter of 2010/11 to 65 days in winter 2012/13 and to 77 days in winter 2013/14.⁷³ The rising frequency of days with basis differentials exceeding \$10/MMBtu is even more impressive. Whereas basis differentials rarely exceeded \$10/MMBtu before 2012, the basis differential exceeded \$10/MMBtu on 25 days in 2012/13 and 28 days in 2013/14.⁷⁴ This considerably raised average delivered gas prices in New England, affecting generators and wholesale electricity prices.

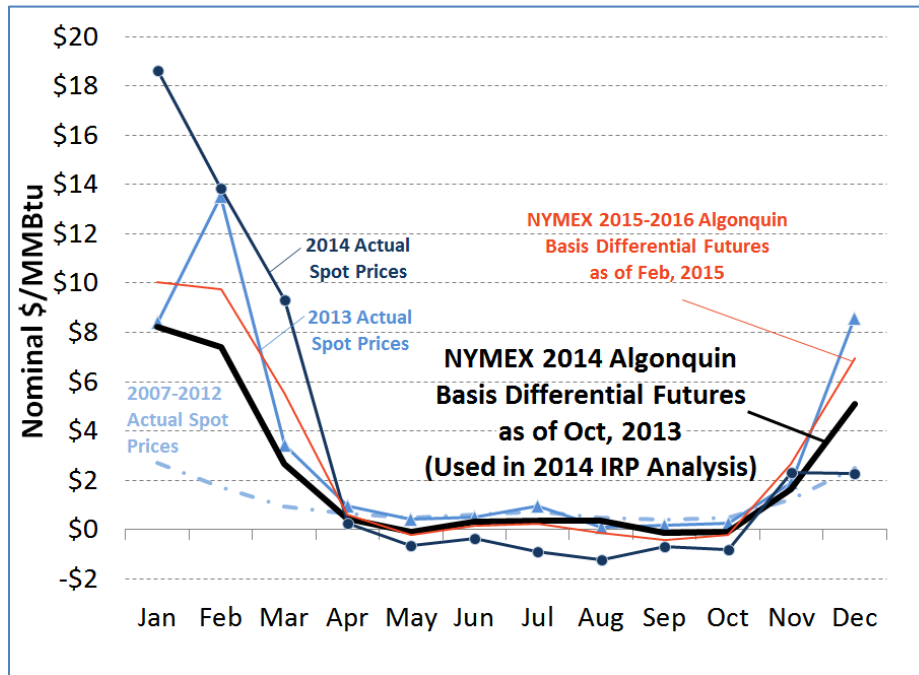
Figure 8 shows how monthly average basis differentials have increased over time, particularly in the winter: from only about \$1-3/MMBtu in winters prior to 2012/13, to about \$8/MMBtu in 2012/13, and to almost \$14/MMBtu in 2013/14; this also lifted annual average basis differentials from about \$1/MMBtu before 2013 to about \$3/MMBtu in 2013. Futures prices for the next year (March 2015 through February 2016) are similarly around \$3/MMBtu on average.⁷⁵

⁷³ Based on daily spot natural gas data compiled by SNL Financial LC.

⁷⁴ Sussex Economic Advisors, LLC. *Maine Public Utilities Commission, Review of Natural Gas Capacity Options*. Framingham, MA: Sussex Economic Advisors, LLC., 2014, available at <http://www.sussex-advisors.com/wp-content/uploads/2014/03/Maine-PUC-Final-Report-February-26-2014.pdf>.

⁷⁵ This IRP projects basis differentials using basis swaps futures as of October, 2013.

Figure 8
Algonquin Citygate Monthly Basis Differentials⁷⁶

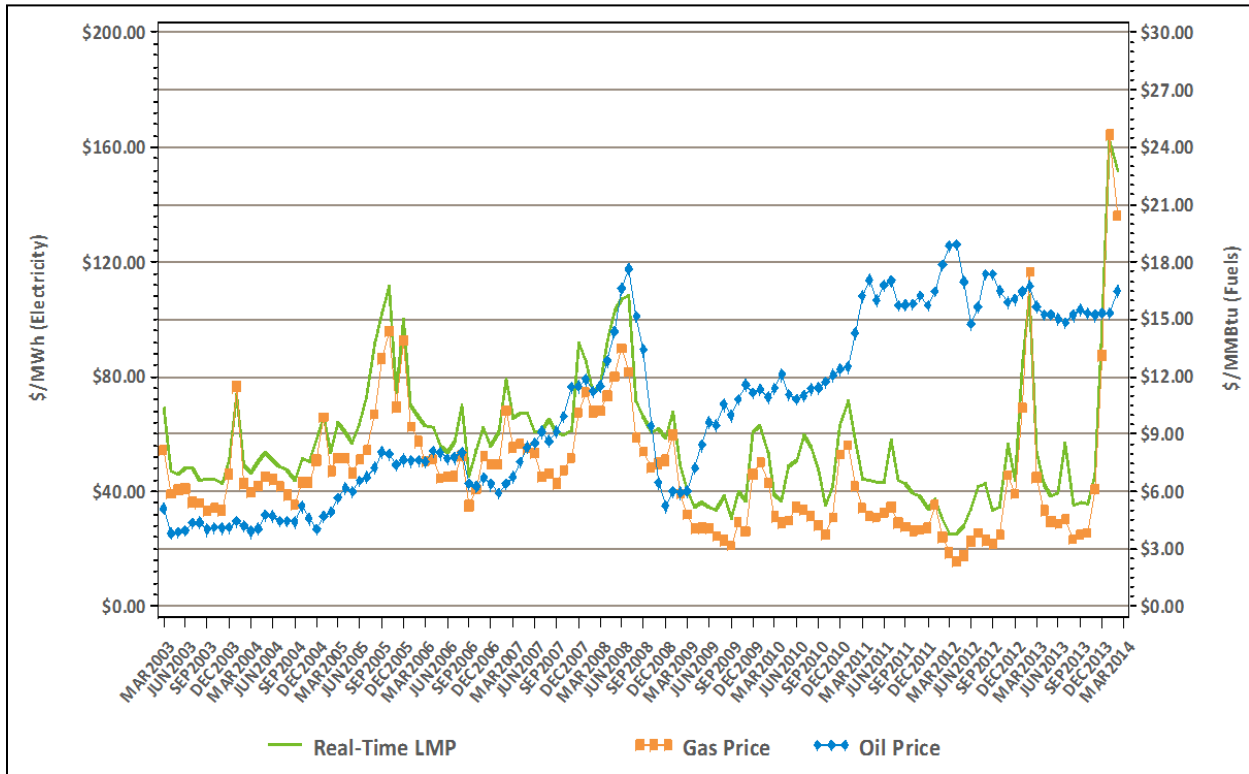


The real-time “locational marginal price” (LMP) indicates the cost of buying electricity in a certain area of New England at any given time. In New England, all generators are paid the price of the marginal generator needed to supply load. Natural gas is the primary fuel on the margin in New England when gas is available. As a result, day-ahead and real-time LMPs typically follow the price of gas. When gas pipelines are not constrained, the price of oil is significantly higher than the price of gas. Due to pipeline constraints in the winter of 2013/14, however, the price of gas was often double the price of oil or even higher, as shown in **Figure 9**.⁷⁷ This resulted in oil units running more this past winter than in the past, setting the locational marginal price for all generators in more hours. In the winter of 2013/14 there was approximately 11,000 MW of gas fired generation in New England with capacity supply obligations. But on the coldest days, only about 3,000 MW of gas fired generators operated during the peak hours.

⁷⁶ Actuals are based on daily spot Algonquin Gates and Henry Hub natural gas data compiled by SNL Financial LC. The 2014 NYMEX basis differentials are based on an average of 30 trading days (9/16/2013-10/15/2013) for the 2014 delivery year. The 2015-2016 NYMEX basis differentials are based on an average of February, 2015 trading days for delivery periods March through December of 2015 and January through February of 2016.

⁷⁷ Ibid.

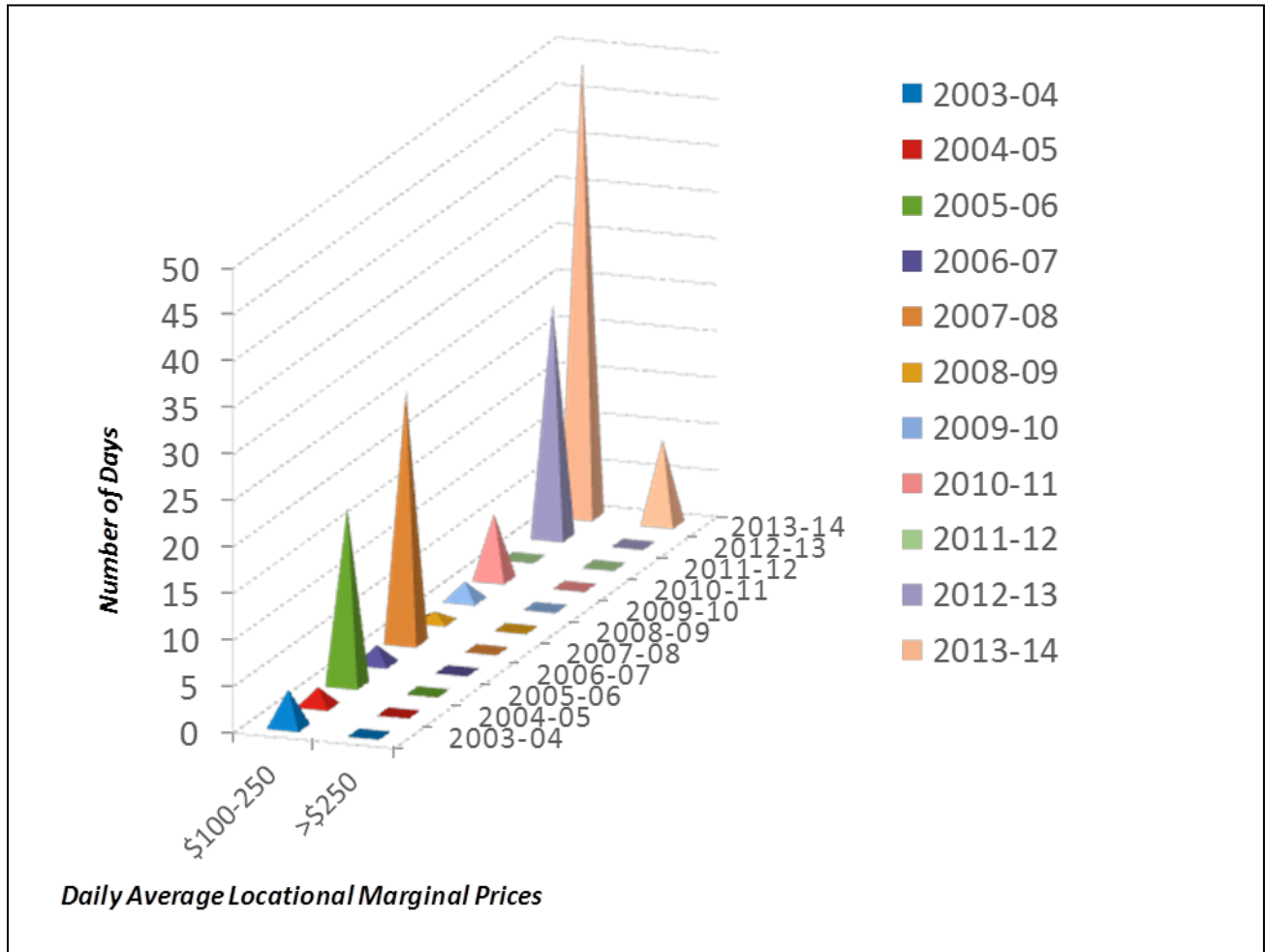
Figure 9
Real-Time LMP, Gas Prices, and Oil Prices in 3-month Intervals
(March 2003 – March 2014)



Wholesale electric prices were high and stayed high throughout the 2013/14 winter. During the winter of 2013/14, 64% of the average daily real-time prices were above \$100, in contrast to 28% in the winter of 2012/13, which was also higher than preceding years. For the first time in ten years, average daily real time electric prices exceeded \$250 (25 ¢/kWh). This occurred nine times this past winter. **Figure 10** shows how in the winter months of January and February the average real-time LMP in the region has risen 100% since January 2011.⁷⁸

⁷⁸ Brandien, Peter. *Cold Weather Operations: Federal Energy Regulatory Commission*. ISO New England's Winter Operations Technical Conference. April 1, 2014.

Figure 10
Daily Average Locational Marginal Prices (January – February) from 2003 to 2014



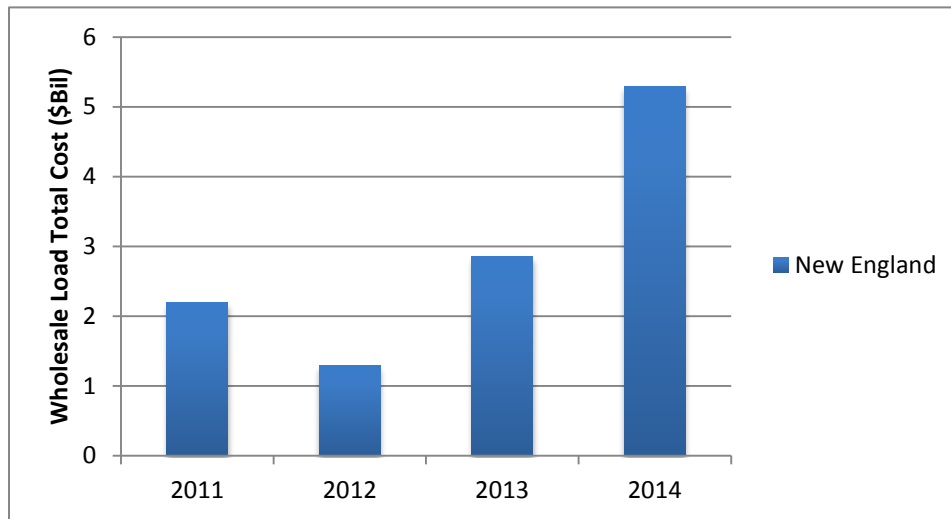
The winter of 2013/14 was one of the coldest winters in recent history. The ISO-NE Winter Reliability Program was critical in maintaining reliability during that winter, but electric prices still rose and resulted in a dramatic increase in rates to electric customers. The Winter Reliability Program was intended to improve reliability but not suppress electric prices, though it did have some impact. Prices still rose to record levels and operational challenges led to significant uplift payments. As generation units were needed and ran out of merit, they received these uplift payments to compensate them for their higher costs. Uplift payments increased from \$20.4 million in December 2013 to \$73.3 million in January 2014.

The total wholesale generation cost of serving electric load in New England for the winter of 2013/14 was over \$5 billion, compared to \$5.2 billion for all of 2012. The winter of 2012/13 also saw days with high gas prices due to constrained pipes, which caused a higher-than-normal cost in that year of \$2.9 billion. Because there is a time lag between wholesale cost and the prices retail customers pay in rates, many consumers in New England did not see the bill impact of these wholesale costs until late 2014. The rate increases are staggering: Eversource’s residential Rate 1 increased from 9.99 ¢/kWh in the fall of 2014 to 12.63 ¢/kWh in January 2015 through

June 2015. UI's residential rate increased from 8.67 ¢/kWh to 13.31 ¢/kWh for the first six months of 2015. This represents a 26% increase for Eversource and approximately 54% increase for UI. Some of the other New England states have seen even more dramatic increases to the generation charge, largely attributable to the infrastructure constraints in the natural gas system.

Chart 1: Wholesale Load Total Cost All-hours Dec-Feb 2011-2014

This chart shows total wholesale cost of serving load for the months of December through February in 2010-2011, 2011-2012, 2012-2013, and 2013-2014.



The 2013/14 Winter Reliability program was intended to provide a short-term solution to mitigate the regions reliance on natural gas and other concerns about fuel availability. As part of the program, oil and dual fuel units were compensated for securing fuel inventory and fuel switching capability. In total, ISO-NE accepted bids for oil inventory and demand resources equivalent to 1,950,600 MWh, or 3,057,554 barrels of oil. The total program costs were estimated to be about \$75 million, but will be about \$9 million less given unit unavailability and failure to procure oil. Additionally, the program allowed dual fuel units to recover the costs of a successful test demonstrating the ability to switch fuels.

ISO-NE implemented another winter reliability program for 2014/15 to address the same concerns as the winter 2013/14 winter reliability program, however, the details of the program differ. The long-term sustainability of a winter reliability program focused on back-up oil has serious reliability and cost implications. The winter 2013/14 winter reliability program had a potential cost of \$75 million and did not alleviate the price spikes that added billions of dollars to ratepayer bills. As gas dependence grows and environmental regulations put added pressures on oil fired generators, the consequences of reliance on oil generators will increase the likelihood of reliability issues, as oil generators retire or face restricted operating hours, and negative economic pressures. Lastly, the potential of PFP to put added pressure on the economic viability of oil fired units could radically alter the market. Therefore, the long-term reliability of the

electric system will depend on access to firm gas supplies and alternative resources connected by an expanded transmission system.

Despite ISO New England's efforts to reduce winter peak demand, acutely constrained pipelines have continued to threaten New England's reliability and increase customer costs. These trends are likely to continue and become exacerbated in the future – as the following modeling scenarios will demonstrate. This necessitates further action to avert these challenges and affordably meet demand.

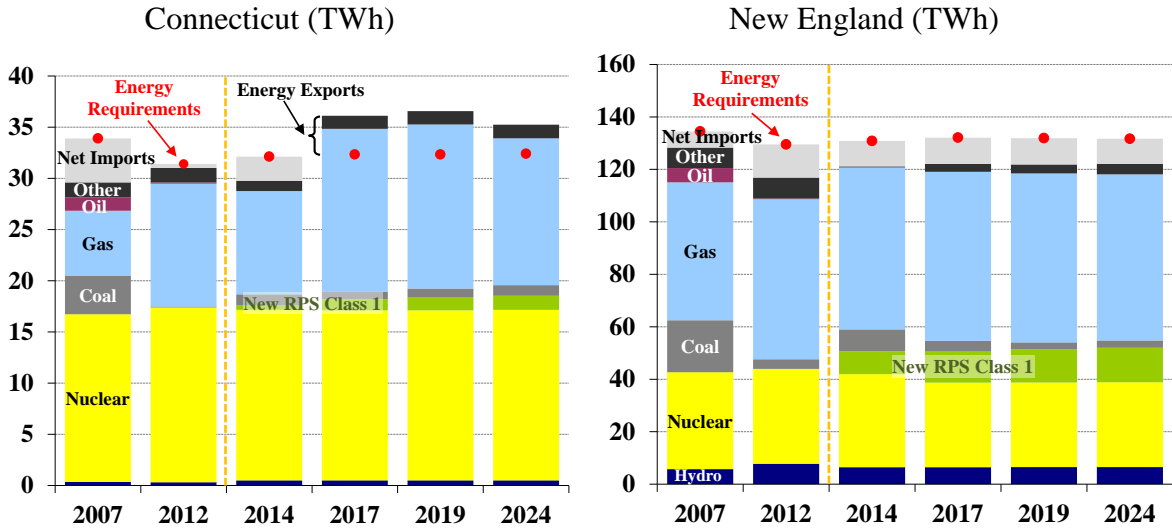
FORECAST: FUEL USAGE FOR ELECTRIC GENERATION, 2014-2024

DEEP expects the region's generation fleet to become even more dependent on natural gas over the next ten years. Nuclear power will remain the second largest source of generation even with the loss of Vermont Yankee at the end of 2014. Coal-fired generation will remain very low due to coal retirements and low utilization of the small remaining plants in a low gas-priced environment. Significant development of new renewable generation, particularly new wind developed through 2017 and new solar PV developed through 2020, is expected to increase the share of renewable generation to increase from 6% in 2007 to 13% in 2024.

The combined effect of these changes on total generation by fuel type is shown in **Figure 11**, which includes data for historical years 2007 and 2012, and projections for 2014, 2017, 2019, and 2024 for Connecticut and New England.⁷⁹ This shows a steep decline in coal and oil generation and an increase in gas. Total generation in Connecticut has increased since 2007, mostly because of two factors: (1) the 2011 addition of the Kleen generating station (an efficient 620 MW natural gas-fired combined-cycle plant); and (2) starting in 2017, the inclusion of the existing 745 MW Lake Road electric generating station in Connecticut with completion of components of the Interstate Reliability Project.

⁷⁹ Regional natural gas and oil generation for historical years are estimated by The Brattle Group. For forecast years, generation is simulated in the DAYZER model.

Figure 11
Base Case Projection of Annual Generation by Fuel Type



On the demand side, changes in the electric sector point to growing reliance on non-firm gas. New England is losing a substantial amount of non-gas generation and could lose more. Vermont Yankee nuclear (600 MW), Salem Harbor coal/oil (600 MW), and Norwalk Harbor oil (300 MW) will retire by 2014; and Brayton Point coal/oil (1,500 MW) will retire by 2017. These plants would generally have been generating on cold winter days and would now be replaced by 3,200 MW of gas-fired generation when gas is available. That would require approximately 530 MMcf/d of gas, assuming a 7,000 Btu/kWh heat rate for marginal gas-fired combined-cycle generation (or less if the non-gas generation would have been operating less than 24 hours per day) to maintain the system at the current level of gas constraint.

New renewable generation will help relieve the region's reliance on gas to some extent. The 2014 IRP projects cumulative renewable additions of about 1,800 MW of (nameplate) renewable capacity by 2017.⁸⁰ Assuming an average capacity factor of 25% and a 7,000 Btu/kWh heat rate for marginal gas-fired combined-cycle generation, the renewable additions would displace roughly 76 MMcf/d of natural gas consumption after adjusting for gas usage by fuel cell awards under Project 150 and LREC.

⁸⁰ This reflects all planned and contracted renewable resources, including resources contracted under Connecticut's Section 106, LREC/ZREC, Section 127, Project 150, and Section 6.

FORECAST: SUPPLY AND DEMAND FOR NATURAL GAS

New England’s total winter gas supply capability is roughly 5.9 billion cubic feet per day (Bcf/d), consisting of 3.7 Bcf/d of interstate pipeline capacity,⁸¹ 1.5 Bcf/d of peak shaving,⁸² and 0.7 Bcf/d of LNG import capacity,⁸³ as shown in **Figure 12** below.⁸⁴ However, not all of this supply is available for all uses. Peak-shaving capacity is owned or contracted for by LDCs for service to retail gas customers during the coldest days of the year, and is generally not available to other customers such as electric generators. Most of the non-peak-shaving LNG import capacity is currently underutilized due to natural gas prices in the region remaining below higher international prices.

Figure 12
Existing Interstate Natural Gas Pipelines Serving New England

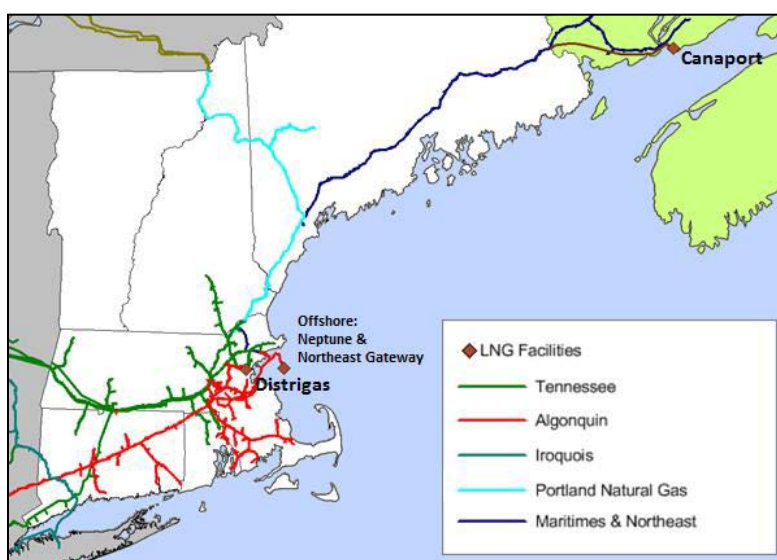


Figure 12 Sources and Notes: ISO-NE Phase II study, p.10.

Regional natural gas demand is only 2.5 Bcf/d on an annual average basis, but the winter peak is much higher due to heating demand from the natural gas LDCs’ residential and commercial

⁸¹ The 3.7 Bcf/d includes 0.8 Bcf/d of Maritimes and Northeast (M&E) pipeline capacity that is dependent on LNG imports into eastern Canada. Excluding M&E, the interstate pipeline capacity would be about 2.9 Bcf/d.

⁸² These peak-shaving facilities are small satellite LNG storage tanks strategically located to provide service during peak consumption periods.

⁸³ This excludes the LNG import capacity of Northeast Gateway and Neptune Deepwater, which is equal to 1.2 Bcf/d. These two import terminals have not received any LNG shipments since September 2010, and Neptune has suspended operations.

⁸⁴ “Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II,” (Draft Report) ICF International LLC., December 16, 2013, p.12. The study assumes that two projects, AIM and Tennessee Gas Pipeline’s Connecticut Expansion (TGP CT Expansion) project, will add 0.38 Bcf/d and 0.7 Bcf/d, respectively, of incremental pipeline capacity during 2016/2017. This study is referred to as the *ISO-NE Phase II study* in the remainder of this document.

customers. The LDC “design day” demand is currently estimated at 4.5 Bcf/d.⁸⁵ The design day demand is generally calculated based on extremely cold weather, such as during 1-in-30 year event. Therefore, the actual LDC demand during a normal weather winter peak day would likely be lower than 4.5 Bcf/d.

Projected LNG Supply

Between 2009 and 2014, LNG imports into New England declined as a result of relatively low New England natural gas prices compared to higher international LNG prices. For example, estimated landed prices for LNG in Asia during November 2013 were around \$14-\$16/MMBtu⁸⁶ while New England natural gas prices for that month averaged only around \$6/MMBtu. This has led to low utilization of LNG import capacity in New England. In fact, the Northeast Gateway and Neptune Deepwater import terminals did not receive any LNG shipments from September 2010 through the winter of 2013/14, and Neptune suspended operations for 5-years starting 2013. The Everett LNG terminal is still importing but the imports have been declining. In 2013, the Everett terminal imported roughly 175 MMcf/d (or 64 Bcf) compared to 370 MMcf/d (or 135 Bcf) in 2011.

New England natural gas prices have been increasing and prices exceeded \$14-\$16/MMBtu during several days in recent winters. Continued high prices and higher frequency of days with high prices may incentivize additional LNG imports in the future, especially during peak winter periods. Nevertheless, New England will still need to compete in the international market for spot LNG supplies and will incur the international prices for LNG imports.

In large part due to lower global oil prices there was significant increase in LNG imports into New England in the winter of 2014/15 over the last winter. Low oil prices reduce LNG prices due to the price in Asia is being indexed to the price of oil. Accordingly, when LNG prices decline in the world market shipping LNG to New England becomes more attractive due to shipping costs to Asia. Increased LNG imports relieve pipeline constraints coming from the West and help maintain proper pipeline pressures throughout the New England pipeline system. Energy prices in the New England market for the first part of the 2014/15 winter were lower than the previous winter, in part, because of this phenomenon.

Shale gas production from the Marcellus shale is increasing, creating prices in Pennsylvania below Henry Hub.⁸⁷ In neighboring regions, gas producers have invested in pipelines to get the

⁸⁵ *ISO-NE Phase II Study*, p.14.

⁸⁶ See <http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf>.⁸⁷ “Henry Hub” is a natural gas distribution hub in Erath, Louisiana that is commonly used as a reference point for natural gas prices. “MMBtu” is one million British Thermal Units. Unless otherwise noted, prices shown are annual averages, expressed in constant 2014 dollars.

⁸⁷ “Henry Hub” is a natural gas distribution hub in Erath, Louisiana that is commonly used as a reference point for natural gas prices. “MMBtu” is one million British Thermal Units. Unless otherwise noted, prices shown are annual averages, expressed in constant 2014 dollars.

gas out of Marcellus, but most of their projects (approx. 3.5 Bcf/d) have extended capacity into the New York/New Jersey and Mid-Atlantic regions as opposed to New England.⁸⁸

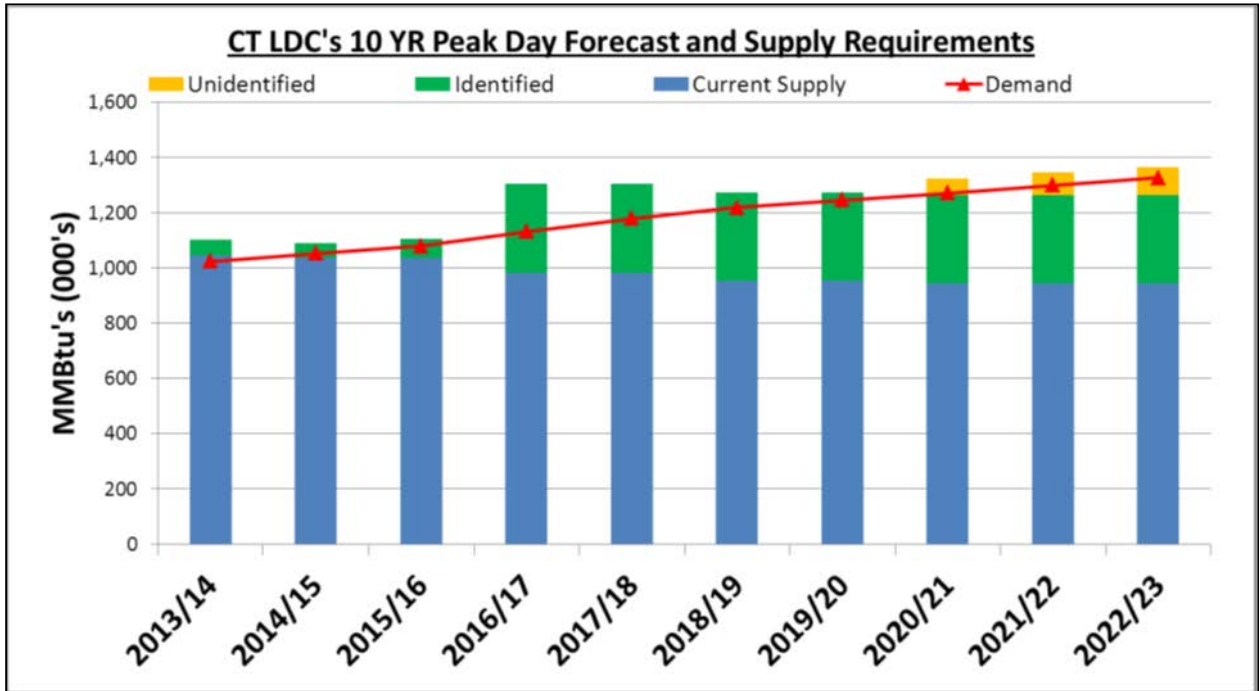
Recognition of the gas capacity constraints and related high basis differentials in New England have not resulted in new market participants – such as gas producers or generators – investing in new gas delivery infrastructure. While there is some gas pipeline capacity expansion planned into New England, this expansion is not sized to meet gas generators’ fuel needs, as it is driven primarily by regional LDCs for the purposes of serving firm demand growth from homes and businesses in their franchise areas. The Connecticut LDCs have contracted for most of the new capacity committed to go forward in New England, to satisfy capacity needs for on-system gas customer growth from the state’s Natural Gas Expansion Plan. The Connecticut LDCs have procured enough capacity to meet demand growth through the 2019/20 timeframe, when demand is projected to exceed supply. As shown in **Figure 13** below, there is little excess gas pipeline capacity for electric generators to purchase non-firm gas before 2016 or after 2019.^{89, 90}

⁸⁸ “Marcellus natural gas pipeline projects to primarily benefit New York and New Jersey,” EIA, October 30, 2013.

⁸⁹ Connecticut Natural Gas (CNG), Southern Connecticut Gas (SCG), and Yankee Gas Services Company (Yankee). *Connecticut’s Gas LDCs Joint Natural Gas Infrastructure Expansion Plan*. Hartford, CT: CNG, SCG, and Yankee, 2013.

⁹⁰ The procured capacity in the shortfall timeframes (2020/2021, 2021/2022, and 2022/2023) average out to 1.298 million Dth/day each year, but the demand requirements will potentially be 1.344 million Dth/day each year. The difference between both figures is the capacity shortage.

Figure 13
CT LDCs' 10 Year Peak Day Forecast and Supply Requirements⁹¹



The Algonquin pipeline, already a major natural gas conduit for New England, is expected to expand its capacity from its current 1.12 Bcf/d⁹² to roughly 1.46 Bcf/d by 2016/17. This expansion, called the Algonquin Incremental Market (AIM) project, is supported by 340 MMcf/d of firm commitments primarily from Connecticut LDCs to serve their ten-year natural gas expansion plan. The Algonquin pipeline's owner, Spectra, conducted an open season in 2013 in an effort to solicit additional commitments, but firm commitments were limited to the LDCs' 340 MMcf/d as opposed to 440 MMcf/d, the original proposed scope of the project. No electric generators in New England — nor other parties — bid for the remaining 100 MMcf/d offered. As a result, that incremental 100 MMcf/d capacity will not be developed as part of the AIM project.

⁹¹ Connecticut Natural Gas (CNG), Southern Connecticut Gas (SCG), and Yankee Gas Services Company (Yankee). *Connecticut's Gas LDCs Joint Natural Gas Infrastructure Expansion Plan*. Hartford, CT: CNG, SCG, and Yankee, 2013.

⁹² *ISO-NE Phase II Study*, p.12.

The Tennessee Gas Pipeline, another large pipeline serving the region, is proposing a much smaller expansion of roughly 70 MMcf/d into Connecticut, also driven primarily by the Connecticut LDCs' natural gas expansion plan.⁹³

When these two pipeline expansion projects come in service, they are expected to temporarily provide service to generators through gas sales or capacity release for the period of 2017-2020 until sufficient new firm gas customers are added to the LDCs customer base to utilize the new supply. This excess capacity, therefore, is not expected to provide a long-term solution for the problems inherent with an electric system that relies on non-firm gas purchases to supply the fuel for a large portion of its generation fleet.

Several projects have been proposed to add incremental gas pipeline capacity in New England, including the Spectra Energy–AIM project, Spectra Energy and M&NP–Atlantic Bridge project, Kinder Morgan–Northeast Expansion project, TransCanada PipeLines – Mainline System project, and the Portland Natural Gas Transmission System – C2C Expansion Project. In September 2014, Spectra and Northeast Utilities announced a partnership to expand pipeline capacity along existing right-of-way as part of a 1 Bcf/d project named “Access Northeast.” The Spectra Energy – AIM project alone will provide incremental pipeline capacity to ten LDCs throughout Connecticut, Massachusetts, and Rhode Island. In addition, the Kinder Morgan — TGP project could potentially add 179 miles of incremental pipeline capacity that will serve five different states in the Northeast.⁹⁴ Overall, the proposed projects have the potential to be operational by November 2018. These projects are currently in their open seasons. DEEP believes that producers and generators are unlikely to invest in these proposed incremental pipeline capacity expansion projects, and that the demand for these types of expansion will be driven by LDC demand. Lack of participation by producers and generators could potentially put the market at risk, causing volatile natural gas prices and a diminished supply of natural gas for electric generation in New England.

A report from Maine Public Utilities Commission's (Maine PUC) consultant, Sussex Economic Advisors (Sussex), concluded that the incremental pipeline sponsored by Maine acting independently would not produce sufficient cost savings from reduced prices to offset the cost of the pipeline expansion. However, the study showed benefits from regionally-sponsored pipeline expansion. Pursuant to the Maine Energy Reduction Act (35-A M.R.S. § 1901 *et seq*), Maine PUC is evaluating whether it would be cost beneficial for the Maine to act alone and enter into firm contracts for incremental pipeline expansion of up to 200 MMcf/d in a contested proceeding

⁹³ Note also the Constitution pipeline project (650 MMcf/d) that Cabot, a natural gas producer, and others propose to build from Pennsylvania to the Iroquois and Tennessee Gas Pipelines in Upstate New York would provide additional Marcellus shale gas directly into the pipes that serve New England, with an in-service date some time in 2015. None of this capacity was contracted by electric generators. While Constitution will not add pipeline capacity in New England, it will directly displace more expensive Canadian supplies into New England and in so doing may provide further commercial impetus to expand the existing pipelines into the region.

⁹⁴ Sussex Economic Advisors, LLC. *Maine Public Utilities Commission, Review of Natural Gas Capacity Options*. Framingham, MA: Sussex Economic Advisors, LLC., 2014, available at <http://www.sussex-advisors.com/wp-content/uploads/2014/03/Maine-PUC-Final-Report-February-26-2014.pdf>.

(Docket No. 2014-00071).⁹⁵ The Act allows Maine PUC to enter into firm pipeline contracts up to 200 MMcf/d or for a total amount not exceeding \$70 million annually.

Projected Electric Sector Demand for Natural Gas

The electric system does have alternatives to natural gas under most circumstances – including non-gas generation (i.e., nuclear, coal, oil), gas-fired generation that has firm natural gas supply, power imports, and demand response – but these resources are already deployed on the coldest days. Many gas generators can also use oil, although the current market rules do not provide much incentive for them to hold oil in inventory. Without special incentives provided by the ISO-NE’s Winter Reliability programs, many dual fuel units would not otherwise have been available.

Planned retirements will reduce the supply of alternatives, and their effects will be only partially offset by new renewable additions and lower expected winter peak loads. By 2017, winter non-gas-fired generation is expected to decline to 18.3 GW (from the current 21.6 GW), but 4.5 GW of dual-fueled generation and 3.3 GW of gas generation with firm fuel should also be available (assuming the status of the plants has not changed since the 2012 IRP). If outage rates reach 10% on a particular day, the combined generation capability, excluding plants with non-firm fuel supply, is 23.5 GW. Meanwhile, the 90/10 winter net peak load forecast is 22 GW (21 GW under 50/50 weather conditions), plus 2 GW of operating reserves. Comparison of total supply and demand indicates the likely need to rely at least on some gas-only generation that lacks firm fuel. If no non-firm gas is available to any of these plants on the coldest days, there is a risk of depleting operating reserves and possibly not meeting reliability criteria.

Moreover, reliability would worsen if more non-gas capacity retires or if firm fuel arrangements or dual-fuel capabilities are not maintained. However, widespread retirements are unlikely because they would trigger capacity shortages and very high capacity prices that would incent retention.

As noted above, the high and volatile gas prices experienced in recent winters are exposing customers to high and volatile electric prices across the New England region. In Connecticut, standard service generation rates will rise effective January 2015 by 26%-59%, largely due to higher gas prices in the winter. DEEP expects the situation to become more acute over the next few years before new pipeline capacity is added, as firm customer demand grows and non-gas generation retires (especially Vermont Yankee, Salem Harbor, and Brayton Point). The impact on prices could be even dramatic if more non-gas generation retires, forcing high-cost oil-fired generation to set prices more often. Every \$1/MMBtu increase in annual average prices could

⁹⁵ Prior to initiating the proceeding, Maine PUC’s consultant, Sussex Economic Advisors (“Sussex”) concluded that incremental pipeline would not likely be cost beneficial if Maine acted alone unless the cost of expansion was very low. Despite the Sussex recommendation, Maine PUC staff has recommended that Maine PUC entertain proposals for incremental pipeline due to the importance of the issue and potential changing circumstances (Examiners’ Report, October 1, 2014 available at <https://mpuc.cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7BFF433329-B390-4899-B295-36990DDB664B%7D&DocExt=pdf>). The Examiners’ report, however, that regional support of incremental gas pipeline expansion would be cost beneficial

add approximately \$250 million to Connecticut customer bills. Meanwhile, market rules have not changed to encourage generators to contract for firm gas.

In 2014, ISO-NE implemented rule changes that will allow generators to more accurately reflect the real time price of fuel in their offers. The proposed change is intended to provide a financial incentive for generators to follow dispatch and to have market prices more accurately reflect the costs to produce energy. Among the changes, which were considered in DEEP initiatives, is the ability of market participants to reflect negative offers for energy. Negative offers will allow units with high start-up and shut down expenses to make the economic decision to keep running. It will also allow resources such as wind power to run at times when demand is low or when the system is becoming physically constrained.

ISO-NE's planned pay-for-performance ("PFP") mechanism was proposed to deal with reliability objectives identified by ISO-NE. Although PFP should address reliability including the winter reliability problem, DEEP is concerned that the PFP has the potential to have significant costs to ratepayers and it will not encourage contracting by electric generators for firm gas service. PFP will likely encourage electric generators to use oil for backup and will result in higher emissions from these sources. DEEP believes that modifications to the Winter Reliability Program for 2014-15, which includes cost recovery for LNG and other modifications, could help reliability but there are no incentives for firm gas purchases and, like PFP, will increase reliance on oil, exacerbate costs for consumers and negatively impact air quality.

DEEP believes that the current market structure and recent changes are not adequate to provide a cost-effective long-term solution to the winter reliability problem at a reasonable cost to New England ratepayers. New England has some of the highest electric rates in the country and will only go higher unless this issue is addressed. This is a burden on residential customers and makes businesses less competitive with those in other regions, discouraging economic development. Action is needed to provide a long term solution winter reliability problem at a reasonable cost to consumers. Specific recommendations to address this winter reliability issue are examined in Resource Strategy 4 in Section IX.

IV. MEETING CONNECTICUT'S COMMITMENT TO RENEWABLE GENERATION

Connecticut and most other states in New England have enacted statutory requirements on a state-by-state basis to support the deployment of more renewable generation in the region. Connecticut's RPS, enacted in 1998, requires the state's electricity providers to obtain certain minimum percentages of the electricity they sell to Connecticut customers from different categories, or classes, of renewable generation located within the region. The current (2015) Connecticut Class I target is 12.5% and will increase up to 20% by 2020. Connecticut's targets

for Class II and Class III resources remain constant at 3% and 4%, respectively, bringing the total percentage of renewables from all three classes required by 2020 to 27%.

This Section analyzes the impact of the procurements conducted in 2013 in Connecticut and Massachusetts on the availability of Class I supply over the 2014-2024 planning timeframe. These procurements will help meet the regional Class I requirements, but this IRP still projects a regional shortage of Class I resources to occur by 2017. These findings underscore the importance of the state's opportunity to secure additional long-term contracts for new, cost-effective Class I renewables through a forthcoming solicitation for Class I or large-scale hydropower projects under Section 7 of Public Act 13-303. Assuming the prices offered in a Section 7 solicitation are similar to those offered in the recent Section 6 solicitation, procurement of an incremental 1,620 GWh of new renewables by 2024 (5% of Connecticut's Base Case energy requirement) under Section 7 can attract resources at a cost significantly below the state's Alternative Compliance Payment level. These savings could help offset the additional cost of regional transmission upgrades that will be needed to integrate additional renewable resources.

This Section also addresses the requirement in Public Act 13-303 to include a proposed schedule for phasing down REC credits for Class I biomass and landfill gas facilities in the 2014. For the 2014 IRP, DEEP conducted an analysis of the role of biomass in meeting RPS requirements, particularly in light of the recently announced retirements of other major non-gas generation resources. As discussed further below, DEEP proposes in the 2014 IRP a phase-down schedule for three years that would maintain eligibility for the full REC value for three years beginning in 2015, and would propose to have the REC value phase down beginning in 2018 at a percentage to be established in the 2016 IRP.

In proposing this schedule, DEEP considered the implications of a phasedown on the Class I market and capacity and energy markets to Connecticut ratepayers as well as market participants. A rapid phase down could result in accelerated retirements of biomass or landfill methane gas plants further threatening reliability and driving up costs at a time when capacity is needed in the region, Class I facilities are needed to meet growing RPS requirements and gas availability is strained during peak winter months.

A schedule that begins the phase-down in 2018 would allow time for contracted Class I projects to come online, thereby avoiding, or at least reducing the impact of a possible shortage in the Class I REC market over the next few years. This schedule will also allow time for new electric resource capacity to be added to meet regional resource needs providing greater reliability and lower costs to ratepayers than might be expected under a faster phase-out schedule. Finally, a phase down that begins in 2018 would be better timed to minimize possible impacts on the reliability of the electric system in winter periods by providing the time necessary to add incremental gas pipeline capacity which is expected to be in service by 2018.

SUPPLY AND DEMAND FOR CLASS I RESOURCES

CONNECTICUT'S LONG-TERM CONTRACTING PROGRAMS FOR CLASS I RESOURCES

Load-serving entities in New England have historically relied on a regional spot market for Class I RECs to comply with RPS requirements. Since 2011, Connecticut has put new programs in place to make it easier for developers to secure funding for new facilities — both in Connecticut and around the region — while keeping the state on course to meet its RPS goals at a lower cost to electric ratepayers. These programs initially focused on development of in-state Class I facilities. As a result of Connecticut clean energy programs put in place in 2011, the amount of clean energy annually added to the Connecticut electric grid has increased by more than ten-fold. For example, in 2010 there were 5 MW of clean electricity added to the Connecticut grid. In 2013, there were 59 MW of clean electricity added to the grid. Connecticut's in-state programs include:

- **Project 150** is currently anticipated to lead to the development of 30 MW of contracted biomass capacity and 33 MW of fuel cell projects.
- **ZREC/LREC** programs provide EDCs with 15-year contracts for “zero-emission”⁹⁶ and “low-emission” generation projects.⁹⁷ The ZREC program allows for \$720 million to be spent over six years and the LREC program allows for \$300 million over five years. Initial procurements resulted in 38 MW of solar and 7 MW of fuel cell resources all scheduled to come on line by the end of 2015.
- **Section 127** program authorizes each EDC to build or contract with 30 MW of renewable capacity in Connecticut⁹⁸: including approximately 15 MW of solar, 5 MW of wind, and 10 MW of fuel cells; approximately 10 MW has been installed to date.
- **Section 106 Residential Solar:** The Green Bank's Residential Solar Incentive Program (RSIP) was established under Public Act 11-80 to support the installation of at least 30 MW of residential rooftop solar PV by 2020. As of January 6, 2015, the Green Bank has approved the installation of nearly 60 MW of residential rooftop solar PV – delivering the legislative target of 30 MW eight years ahead of schedule. Since 2011, installed costs have reduced by nearly 20 percent (\$5.35 to \$4.45 per watt), incentives have reduced by nearly 60 percent (\$1.70 to \$0.75 per watt), and investment has increased by nearly 2000 percent (\$8.3 million to \$160.8 million), creating jobs across Connecticut.

⁹⁶ Conn. Gen. Stat. §§ 16-244r and 16-244s.

⁹⁷ Conn. Gen. Stat. § 16-244t.

⁹⁸ Conn. Gen. Stat. § 16-244v.

In the 2012 IRP, DEEP evaluated the available supply of Class I renewables and concluded that by 2017, the region would likely fall short of satisfying the regional Class I renewable requirements, or earlier than 2017 if renewable projects in the ISO-NE interconnection queue are not developed as expected. Further, the 2012 IRP stated that if the region's renewable energy development does not keep pace with the region's demand for Class I renewable resources, Connecticut could pay a significant amount of Alternative Compliance Payments, increasing the cost associated with complying with the state's RPS.

In April 2013, DEEP issued a study of the state's RPS.⁹⁹ The study, entitled "Restructuring Connecticut's Renewable Portfolio Standard," confirmed that regional Class I renewable generation would likely be inadequate to meet RPS targets, but projected the shortage would occur in the 2019-2022 timeframe (later than the 2012 IRP had estimated). The study also identified that the vast majority of Connecticut's Class I target is currently met by power from existing biomass and landfill gas facilities, as opposed to newer, cleaner wind and solar facilities. The RPS Study recommended the use of long-term contracting to help meet RPS requirements by facilitating more secure financing of new renewable projects at a reasonable price. The Study also called for allowing large-scale hydropower to compete with Class I renewable supply for a portion of long-term contracting authority as a means to provide greater diversity in energy supply, help achieve the requirements of the Connecticut Global Warming Solutions Act, and help meet a limited portion of the Class I RPS requirements in the event of a shortage.

Public Act 13-303, enacted in June 2013, implemented many of the recommendations of the 2013 RPS Study. The Act authorized the Department to direct the EDCs to enter into long-term contracts for energy and/or renewable energy credits from Class I renewable resources selected through a competitive processes. Specifically, the Act authorized up to 20-year contracts for up to 4% of the EDCs' load from new Class I resources (Section 6); up to 10-year contracts for up to 4% of EDC load from Class I biomass, landfill gas, or small-scale hydropower facilities (Section 8); and maximum 15- to 20-year contracts for up to 5% of EDC load from Class I resources or large-scale hydropower (Section 7). The Act allowed any large-scale hydropower procured under Section 7 of the Act to satisfy up to one percentage point per year of the state's Class I target in the event of a sustained, material shortage of Class I renewables that is verified through a multi-step "trigger" mechanism. It also allowed for any Alternative Compliance Payments made in the event of a shortage of renewable supply to be refunded to Connecticut ratepayers. And it directed DEEP, in this IRP, to establish a schedule for assigning a gradually reduced REC value for biomass facilities, as a means to transition the state away dependence on legacy biomass and landfill methane gas resources to fill its Class I goal.

Immediately after Public Act 13-303 became effective, the Department initiated a competitive solicitation for long-term contracts with new Class I renewables under Section 6. That process concluded in September 2013, when, under DEEP's direction, the EDCs signed 20-year contracts with a 250 MW wind farm in Aroostook County, Maine and a 20 MW solar facility in

⁹⁹ DEEP, Restructuring Connecticut's Renewable Portfolio Standard (April 26, 2013), available at http://www.ct.gov/deep/lib/deep/energy/rps/rps_final.pdf. DEEP conducted this study in accordance with Section 129 of Public Act 11-80.

Lisbon, Connecticut, for energy and RECs sufficient to fill approximately 3.7% of EDC load. DEEP estimated that those contracts would save ratepayers \$219 million on the cost of RPS compliance over the life of the contracts.¹⁰⁰

In October 2013, DEEP issued a competitive solicitation for long-term contracts with new or existing Class I landfill gas, biomass, or small-scale hydro facilities under Section 8 of Public Act 13-303. The selection process concluded in January 2013, with the EDCs signing contracts for RECs from three proposals from two existing biomass facilities totaling 29 MW or less than 1% of load. The estimated cost savings for Class I compliance are approximately \$15 million over the life of the contracts signed under Section 8.

In February 2015, pursuant to Section 7 authority as well as the remaining authority under Section 6, DEEP in coordination with Massachusetts and Rhode Island, released Draft New England Clean Energy RFP.¹⁰¹ The RFP will seek bids on incremental Class I Renewable Energy projects – which include wind, solar, small hydro, biomass, and fuel cells – of at least 20 MW and large scale hydro power projects that were constructed after January 1, 2003. The draft RFP seeks to allow the three states to consider projects for the delivery of clean energy through any combination of: 1) traditional power purchase agreements that do not require transmission upgrades; 2) traditional power purchase agreements that require transmission upgrades; and/or 3) transmission projects containing clean energy delivery commitments, but without any associated power purchase agreements. Connecticut is seeking purchase power agreements for projects of up to 1,500 GWh/yr (the equivalent of 500 MW of wind) as its share of the procurement. Transmission costs would be allocated to the states on the basis of each state's load share. The three states are taking comment on the Draft RFP and will make appropriate changes in response to public input with the goal of issueing the Final RFP in the spring of 2015. Review of bids will take between three and six months, depending on the complexity of the modeling and bids received. The three states hope that the winning bidders will get through the regulatory process by the end of 2016.

A summary of all of the projects currently supported through Connecticut's in-state and regional Class I procurement programs are listed in **Figure 14**.

¹⁰⁰ Massachusetts has also solicited and executed long-term contracts that will support deployment of new renewable generation in the region. In 2012, Massachusetts EDCs executed power purchase agreements in 2012 for the development of 150 MW of new renewable generation in the region and, in 2013, for an additional 565 MW of new renewables pursuant to Sections 83 and 83A of the state's Green Communities Act, respectively. See An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, §§ 35 & 36 (Section 83A); Green Communities Act, St. 2008, c. 169, § 83 (Section 83).

¹⁰¹ Available at www.cleanenergyRFP.com

Figure 14
Summary of Current Class I Programs in Connecticut¹⁰²

Program	Technology	Capacity (MW)	Plant	Location	Status	Online Date
Project 150						
	Biomass	30	Plainfield Renewable Energy	Plainfield, CT	Operating	Dec-13
	Fuel Cell	15	Bridgeport Fuel Cell Park	Bridgeport, CT	Operating	Dec-13
	Fuel Cell	18	---	CT	Approved	2015
Section 127						
Eversource/UI	Solar	5	East Lyme Solar Park	East Lyme, CT	Operating	2014
Eversource/UI	Solar	5	Somers Solar Center	Somers, CT	Operating	2013
Eversource	Wind	5	Wind Colebrook South	Colebrook, CT	Approved	2015
Eversource	Fuel Cell	5	CTS Energy	South Windsor, CT	Approved	2015
UI	Solar	2.2	Bridgeport Green Energy Park	Bridgeport, CT	Approved	2015
UI	Solar	2.2	---	CT	Approved	2015
UI	Fuel Cell	2.8	Bridgeport Green Energy Park	Bridgeport, CT	Approved	2015
UI	Fuel Cell	2.8	East Shore	New Haven, CT	Approved	2015
ZREC/LREC						
Eversource	Solar (Large)	10	---	CT	Approved	2014
Eversource	Solar (Med)	13.8	---	CT	Approved	2014
Eversource	Solar (Small)	6.5	---	CT	Approved	2014
Eversource	Fuel Cell	5.9	---	CT	Approved	2014
<i>Eversource</i>	<i>Solar (Large)</i>	<i>27.6</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>Eversource</i>	<i>Solar (Med)</i>	<i>17.8</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>Eversource</i>	<i>Solar (Small)</i>	<i>11.6</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>Eversource</i>	<i>Fuel Cell</i>	<i>5.3</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
UI	Solar (Large)	2.6	---	CT	Approved	2014
UI	Solar (Med)	2.5	---	CT	Approved	2014
UI	Solar (Small)	2.4	---	CT	Approved	2014
UI	Fuel Cell	1.2	---	CT	Approved	2014
<i>UI</i>	<i>Solar (Large)</i>	<i>2.4</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>UI</i>	<i>Solar (Med)</i>	<i>4.4</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>UI</i>	<i>Solar (Small)</i>	<i>2.5</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
<i>UI</i>	<i>Fuel Cell</i>	<i>8.0</i>	<i>---</i>	<i>CT</i>	<i>Approved</i>	<i>2015</i>
Section 106						
<i>CEFIA</i>	<i>Solar</i>	<i>55</i>	<i>---</i>	<i>CT</i>	<i>Operating</i>	<i>2015</i>
Section 103						
<i>CEFIA</i>	<i>Anaerobic Digester</i>	<i>1.6</i>	<i>City of Ansonia</i>	<i>Ansonia, CT</i>	<i>Approved</i>	
<i>CEFIA</i>	<i>Anaerobic Digester</i>	<i>1.0</i>	<i>Southington AD Facility</i>	<i>Southington, CT</i>	<i>Approved</i>	
<i>CEFIA</i>	<i>Anaerobic Digester</i>	<i>1.6</i>	<i>Bridgeport BioEnergy Facility</i>	<i>Bridgeport, CT</i>	<i>Approved</i>	
<i>CEFIA</i>	<i>Anaerobic Digester</i>	<i>1.6</i>	<i>Central CT AD Facility</i>	<i>Southington, CT</i>	<i>Approved</i>	
Section 6						
	Wind	250	Number Nine Wind Farm	Aroostook County, ME	Approved	2016
	Solar	20	Fusion Solar Center	Lisbon, CT and Sprague, CT	Approved	2016
Section 8						
	Biomass	21.5	Schiller Station Unit 5	Portsmouth, NH	Existing	2016
	Biomass	5	McNeil Station (Burlington Electric)	Burlington, VT	Existing	2015
	Biomass	2.7	McNeil Station (Green Mountain Power)	Burlington, VT	Existing	2015

¹⁰² Capacity added through the 2015 ZREC/LREC program was estimated. The first two solar projects under Section 127 were procured by DEEP with contracts executed by the EDCs. All solar capacities are shown in terms of AC output. Plainfield is a 37.5 MW project, 30 MW of which is under contract. CEFIA is now known as the Connecticut Green Bank.

FORECAST: SUPPLY AND DEMAND FOR CLASS I RESOURCES, 2014-2024

The 2014 IRP projects that demand for Class I renewable energy resources in New England will double over the next decade to meet current state RPS rules and regulations. Because regional energy needs are projected to be virtually flat over the study period, growth in demand for Class I renewable energy resources will be entirely driven by the ramp-up of RPS requirements as a percentage of load. Since the 2012 IRP, the projection of New England's load growth subject to RPS requirements has decreased due to an increase in the expected impact from energy efficiency programs and the growth of distributed solar generation.

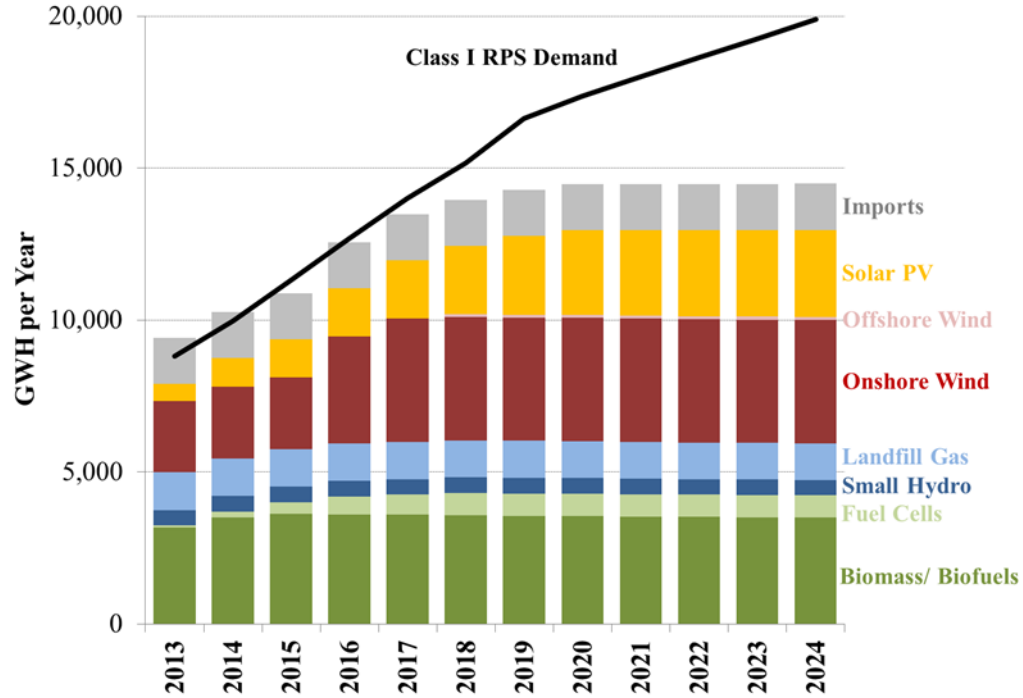
Among the New England states, Connecticut has the most ambitious Class I target as a percentage of load (11% in 2014, increasing up to 20% by 2020). The Connecticut RPS accounts for approximately one-third of the regional renewable energy demand in 2020 (second only to Massachusetts). Connecticut's RPS has unique eligibility characteristics, with some resources qualifying for Class I status only in Connecticut.¹⁰³ In estimating the supply and demand balance of the regional Class I Renewable Energy Credit (REC) market, the analysis has taken into account resources that are specific to certain states, including Connecticut. DEEP also has considered the long-term contracts executed in Connecticut and Massachusetts in the Base Case, along with Class I renewable resources already built, under construction, or qualified across the New England states.

With these assumptions, the 2014 IRP projects that the renewable supply in New England will hover around the region's Class I RPS target levels through 2016, with some years slightly below the target. After 2017, the region will not have sufficient Class I supply to meet the states' RPS commitments without additional procurement or merchant build-out. See **Figure 15** below.

¹⁰³ DEEP, Restructuring Connecticut's Renewable Portfolio Standard 55 (April 26, 2013), available at http://www.ct.gov/deep/lib/deep/energy/rps/rps_final.pdf.

Figure 15
New England Class I Renewable Resource Supply and Demand Balance
(Cumulative GWh)

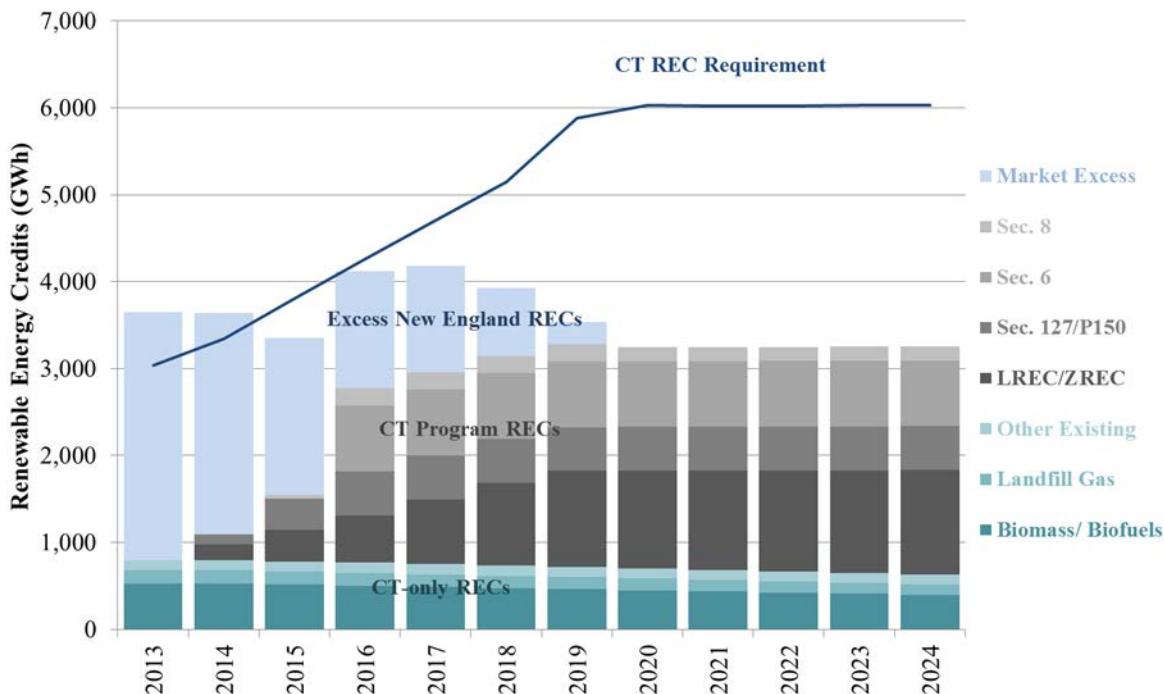
Starting in 2017, regional Class I supply will not be sufficient to meet the region's RPS targets.



Connecticut also expects to have insufficient RECs to meet state RPS targets starting in 2015. The shortage is currently projected to be roughly 450 GWh in 2015, growing to 2,800 GWh in 2020 and beyond.¹⁰⁴

¹⁰⁴ See Appendix D (Renewable Energy) for more details on the expected supply and demand balance for Connecticut to meet its RPS goals.

Figure 16
Connecticut Class I Renewable Resource Supply and Demand Balance in the Base Case



Note that the Base Case assumption in the 2014 IRP is significantly different from the Base Case assumption in the 2012 IRP in several respects. The amount of renewable resource supply assumed in the 2014 Base Case is *not* based on a forecast of planned projects that are likely to occur. Instead, it only assumes that resources that are known to be built, procured, or contracted through existing renewable procurement programs will be developed.¹⁰⁵ As such, for the Base Case in the 2014 IRP, the Department assumed future LREC/ZREC growth based on the established program and projected solar costs; the Department did not assume any incremental Class I renewables due to procurements allowed under Section 7 or Section 9 of Public Act 13-303.

Section 7 of Public Act 13-303 allows DEEP to solicit an incremental 1,375 GWh (5% of Connecticut’s Base Case energy requirement) of new Class I renewables or large-scale hydropower. Section 9 of Public Act 13-303 allows DEEP to solicit additional proposals for Class I renewables if the Commissioner determines that there is a material and sustained Class I REC shortage. The magnitude of additional procurements of Class I resources under Section 7 and Section 9 of Public Act 13-303 would help Connecticut meet its RPS goals, but may not be sufficient to completely satisfy the 20% Class I requirements with contracted resources by 2020. For instance, if DEEP assumes that additional procurement under Section 7 would yield approximately 535 MW of onshore wind and 56 MW of solar (similar to mix of resources recently procured through PA 13-303 Section 6), the result would still leave Connecticut to be

¹⁰⁵ As described in more detail in Appendix D (Renewable Energy), we assume future procurement of renewable capacity through the ongoing LREC and ZREC programs based on the known funding levels and projections of future renewable costs.

approximately 1,200 GWh short of the state’s 2020 mandate.¹⁰⁶ However, excess resources from the rest of New England may help meet Connecticut’s requirements, and if so, Connecticut could be in a better situation — approximately 300 GWh short of the 2020 RPS mandate of roughly 6,000 GWh. Connecticut load-serving entities will continue to be exposed to some risks associated with purchasing from the spot market for RECs. Because Connecticut’s ACP is lower than the Massachusetts ACP in New England, whenever the region is short of Class I RECs, suppliers will prefer to sell RECs to the load-serving entities in Massachusetts before Connecticut. Thus, whenever the region is short of Class I RECs, Connecticut’s load-serving entities will likely pay the ACP for at least a portion of the Class I requirements.

The annual cost of complying with Class I requirements in the Base Case is estimated to be approximately \$229 million in 2014 and \$249 million in 2024.¹⁰⁷ In comparison, the 2012 IRP estimated that it would cost about \$460 million to comply with Class I RPS requirements by 2022.

The RPS costs estimated in this IRP assumes that the portion of RECs purchased under long-term contracts or state programs will reflect long-term costs needed to provide suppliers with an adequate return on their investments, while another portion will be based on paying a spot REC price close to Connecticut’s ACP. It is assumed that the REC spot price will reflect the condition that the region falls short of the target levels, and thus prices are assumed to approach the ACPs. Even in years when the supply is slightly above the demand (in 2014, and 2016-2018), the 2014 IRP assumes that the excess margin is small enough that REC prices remain close to the ACP.

REQUIREMENTS UNDER SECTION 9 OF PUBLIC ACT 13-303

Section 9 of Public Act 13-303 authorizes the Commissioner of DEEP to initiate a sequence of actions in the event of a material and sustained shortage of Class I RECs. These actions are predicated on a finding that “alternative compliance payments . . . [have been] made for failure to meet the renewable portfolio standards,” creating a presumption that there is an insufficient supply of Class I renewable energy sources for the calendar year the alternative compliance payments are made.¹⁰⁸ In the event that an ACP triggers such a presumption, the Commissioner has discretion to determine “whether such payments resulted from a material shortage of Class I renewable energy sources,” including a consideration of whether the payment of ACP resulted from “intentional or negligent action by an electric supplier or [EDC]” not to purchase RECs that were available in the NEPOOL GIS market.¹⁰⁹ Further, if the Commissioner determines that the ACP payment was caused by a material shortage of Class I supply, then the Commissioner must determine whether there is adequate, or potentially adequate, supply of Class I resources available to meet succeeding years’ RPS demand.

¹⁰⁶ The impact of Section 7 would be 1,375 GWh of RECs, which leaves Connecticut 300 GWh short in 2020 based on our Base Case assumptions (including Section 7).

¹⁰⁷ This includes an estimated \$139 million in ACP payments that would be credited back to ratepayers in 2024 under a provision enacted in Public Act 13-303.

¹⁰⁸ See Public Act 13-303 § 9(a).

¹⁰⁹ *Id.* at § 9(b).

In 2014, PURA initiated RPS proceedings for compliance years 2011 and 2012. In the Final Decision in the 2011 proceeding, PURA determined that ACP in the amount of \$18,190,205 was paid by load-serving entities in order to comply with their obligations for Class I under the RPS. This amount of ACP reflects that approximately 14% of the Class I compliance obligation was satisfied by ACP. In the Final Decision of the 2012 proceeding, PURA determined that ACP in the amount of \$38,520,790 was paid for Class I compliance, representing approximately 27% of the Class I compliance obligation met by ACP.¹¹⁰ (Pursuant to Sections 10 and 11 of Public Act 13-303, all ACP for both 2011 and 2012 compliance years will be used to offset the cost of the LREC/ZREC program and \$16,740,231.29 will be refunded to Connecticut ratepayers.) These determinations by PURA create a statutory presumption that there was an insufficient supply of Class I renewables to meet the RPS obligations for calendar years 2011 and 2012.

As noted above, the Commissioner of DEEP may, at his discretion, determine whether the ACP made in calendar year 2014 for compliance years 2011 and 2012 resulted from a material shortage of Class I renewable supply. The Commissioner declines to determine whether there is a material shortage of Class I renewable sources for either compliance year 2011 or 2012. Even if the Commissioner were to exercise his discretion to determine whether there is a material shortage, this IRP projects that there is only a limited inadequacy forecast in 2015 and more than an adequate supply in 2016-2018 (*see* **Figure 15** and **Figure 16**). As described above, these are conservative forecasts; further, DEEP has not exhausted its renewable energy procurement authority under Section 7 of Public Act 13-303. For these reasons, it is unnecessary to determine whether a material shortage occurred in 2011 or 2012, nor whether there is sufficient evidence of a material shortage of Class I renewable sources sufficient to warrant action under subsections (c) and (d) of section 9 of Public Act 13-303.

SUPPLY AND DEMAND FOR CLASS II & CLASS III RESOURCES

In addition to forecasting the availability of Class I renewables, for the 2014 IRP DEEP also evaluated the supply and demand for Class II and Class III resources, summarized in Appendix D. Class II requirements are initially set at 3% and remain constant at that level. The current supply of Class II resources significantly exceeds the existing RPS requirements. This drives the Class II REC prices down to less than \$1/MWh. Class II REC prices and costs are expected to remain low in the future unless some of the existing resource recovery facilities retire, or there are legislative changes to the eligibility requirements. Currently, Class II RECs trade in the \$0.50/MWh range. DEEP estimates the total cost of Class II RPS compliance was approximately \$500,000 in 2014 and should continue at this level in the future.

The Class III eligibility criteria have changed since the 2012 IRP. Pursuant to changes in Public Act 13-303, energy efficiency resources procured through state programs will no longer qualify as Class III resources starting in 2014. Class III prices have consequently increased from the floor of \$10.00 per REC to the mid-twenties for each REC purchased for compliance. While CHP generation has grown significantly from 2009 to 2012, it is unknown how much new CHP

¹¹⁰ *See* PURA Docket Nos. 12-09-02 & 13-06-11

generation will enter the market in future years and at what costs. DEEP will continue to evaluate the Class II market to track supply, demand, and the outlook for REC prices. Assuming that future Class III REC prices will be \$25/MWh, DEEP estimates the total cost of Class III RPS compliance to be \$32 million.

V. FORECAST FOR WHOLESALE GENERATION PRICES & RETAIL CUSTOMER RATES

By far the largest component of electric rates is the generation charge, which primarily consists of the wholesale market price of energy and the wholesale market price of capacity. Both are expected to increase over the study period, causing customer rates to rise. The next two sections present the 2014 IRP's wholesale energy and price forecasts, followed by the implications for customer bills.

FORECAST: WHOLESALE ENERGY PRICES

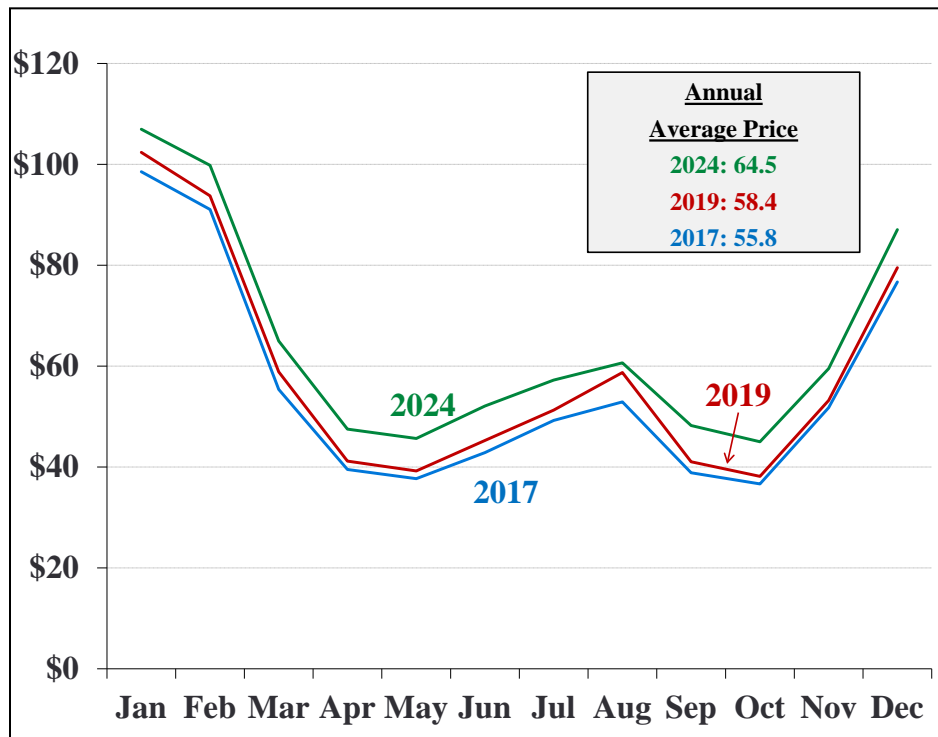
Between 2014 and 2024, wholesale energy prices are expected to rise. As shown in **Figure 17**, the expected annual average load-weighted wholesale energy prices in Connecticut are \$58.7/MWh in 2017, \$61.6/MWh in 2019 and \$67.5/MWh in 2024, or \$55.8/MWh, \$58.4/MWh, and \$64.5/MWh respectively in constant 2014 dollars.^{111,112} These prices, when multiplied against total expected electricity consumption in Connecticut, translate to about \$2.1-2.4 billion in energy costs per year. The expected increase in energy prices over the 2014–2024 timeframe is mostly due to a moderate increase in natural gas prices. The increase is tempered over time by Connecticut's (and the region's) investments in energy efficiency, which are expected to keep energy demand flat. These prices reflect expectations for weather conditions and other supply/demand factors; actual prices are likely to vary due to fluctuations in gas and electricity demands during unusually hot or cold periods of time. For example, average real-time LMPs during the first quarter of 2014 were \$144/MWh,¹¹³ driven in part by unusually cold weather.

¹¹¹ These values were calculated based on the assumptions discussed in this section, using the DAYZER model, which simulates ISO-NE's operation of the electrical system and its administration of the energy market. The outputs of the model include hourly locational marginal prices (LMPs), dispatch costs, generation and emissions for every generating unit in New England, transmission flows, and congestion costs.

¹¹² Load-weighted average prices tend to be higher than simple average prices, due to relatively high prices during high-load hours.

¹¹³ ISO New England Internal Market Monitor, *2014 First Quarter: Quarterly Markets Report*, May 9, 2014.

Figure 17¹¹⁴
Base Case Projection of Monthly Simple Average Energy Prices in Connecticut
(2014 \$/MWh)



NATURAL GAS CAPACITY CONSTRAINTS WILL DRIVE SIGNIFICANT INCREASES IN WHOLESALE ELECTRICITY PRICES

Natural gas prices are the biggest driver of generation prices in New England. Over the study period, gas prices are expected to increase, reflecting an expected modest increase in the price of the gas commodity itself, and a sharp increase in the cost of delivering gas into New England over the region’s constrained natural gas pipeline system. In the 2014 IRP, natural gas prices are projected based on NYMEX Henry Hub futures, plus the premium paid to transport natural gas into New England over constrained infrastructure (i.e., basis differentials), plus a local distribution adder.

Between 2014 and 2024, the 2014 IRP projects that the price of the natural gas commodity will increase from \$3.94/MMBtu to \$6.22/MMBtu (nominal dollars), based on NYMEX Henry Hub futures as of fall 2013.¹¹⁵ More recent Henry Hub futures have flattened in the later years, and are

¹¹⁴ This figure reflects analyses conducted in 2013.

¹¹⁵ Henry Hub prices are given by futures traded from September 16, 2013 through October 15, 2013, for monthly deliveries through 2024. Nominal traded annual average prices during this period were \$3.94/MMBtu for 2014 delivery, rising to \$4.32/MMBtu for 2017, \$4.69/MMBtu for 2019, and \$6.22 for 2024. This is a 58% increase in nominal dollars. In real terms (constant 2014 dollars), this represents a smaller “real” increase in price of about \$1.35/MMBtu from 2014 to 2024.

about \$0.8/MMBtu lower by 2024 (nominal dollars, or about \$0.7/MMBtu in 2014 dollars). Updating the gas price based on current commodity futures prices would reduce expected annual average 2024 prices shown in **Figure 17** by up to \$5.6/MWh.¹¹⁶

Basis differentials were estimated using 2014 NYMEX basis differentials from Henry Hub to the Algonquin City-Gates, traded in late 2013.¹¹⁷ These average basis differentials add approximately \$4.6/MMBtu during October through February and \$2/MMBtu annually (2014 dollars), and are assumed to persist at that level in real terms (rising at the rate of inflation). Compared to historical prices before 2012, this level of basis differential adds up to \$8/MWh to wholesale electricity prices, 0.8¢/kWh to customer rates, and approximately \$250 million per year to Connecticut customer bills.¹¹⁸ Note that the 2014 IRP estimates of delivered gas prices also include a \$0.30/MMBtu charge for generators served by local gas distribution companies instead of directly by a pipeline.

Since the IRP modeling analysis was conducted, futures prices for basis differentials have been volatile. December 2014 trades saw natural gas basis differentials rise by about \$1.50/MMBtu annually and by about \$2.50/MMBtu October through February. February 2015 trades saw prices then drop back down to levels slightly below the late 2013 trades. In all forward strips, prices in 2017 indicate some decline, possibly reflecting relief due to the AIM and TGP pipeline expansion projects scheduled to enter service by November 2016. If annual average prices turn out to be closer to \$3/MMBtu than the \$2/MMBtu assumed in this IRP, then customer rates could be up to another 0.8¢/kWh higher and Connecticut customers' annual bills could increase by another \$250 million per year higher than reported in this IRP, all else being equal.

PRICES OF COAL, OIL, AND EMISSIONS ALLOWANCES WILL HAVE A LESSER IMPACT

By comparison to natural gas prices, the prices of coal, oil, and emissions allowances will influence wholesale market outcomes to a much lesser extent. Future oil prices are projected to remain much higher than natural gas prices using current forward prices. Delivered coal prices, affecting only about 1,000 MW of capacity in New England after the planned retirements of Brayton Point and Salem Harbor 3, are projected at just over \$4/MMBtu in each study year.¹¹⁹

With respect to emissions allowances, prices for CO₂ allowances under the Regional Greenhouse Gas Initiative (RGGI) are assumed to increase to moderate levels, from current levels of about \$5 per short ton, to \$8.00/ton by 2017, \$9.23/ton by 2019, and \$10.63/ton by 2024 in nominal dollars.¹²⁰ Prices for NO_x and SO₂ are both projected to be zero over the study horizon: New

¹¹⁶ Assuming 8,000 Btu/kWh market heat rate and natural gas as the marginal fuel.

¹¹⁷ Based on September 16, 2013 through October 15, 2013 trade dates.

¹¹⁸ Assuming 8,000 Btu/kWh market heat rate and natural gas as the marginal fuel.

¹¹⁹ Coal prices are based on NYMEX Central Appalachian futures, plus transportation costs.

¹²⁰ These projections are based on the Regional Greenhouse Gas Initiative Integrated Planning Model projections for the Updated Model Rule. The analysis also does not presume implementation of a Federal climate policy implementing a carbon price within the 10-year study horizon. RGGI expires in 2020. This analysis assumes CO₂ prices increase at a similar rate thereafter.

England is exempt from EPA's proposed Cross-State Air Pollution Rule, and ozone season NO_x emissions from electric generating units in Connecticut remain below the Clean Air Interstate Rule allowance budget. Clean Air Act Title IV allowances are assumed to have near-zero cost due to emission reductions associated with other programs. SO₂ allowance prices are assumed to be negligible for all electric generating units.¹²¹

FORECAST: WHOLESALE CAPACITY PRICES

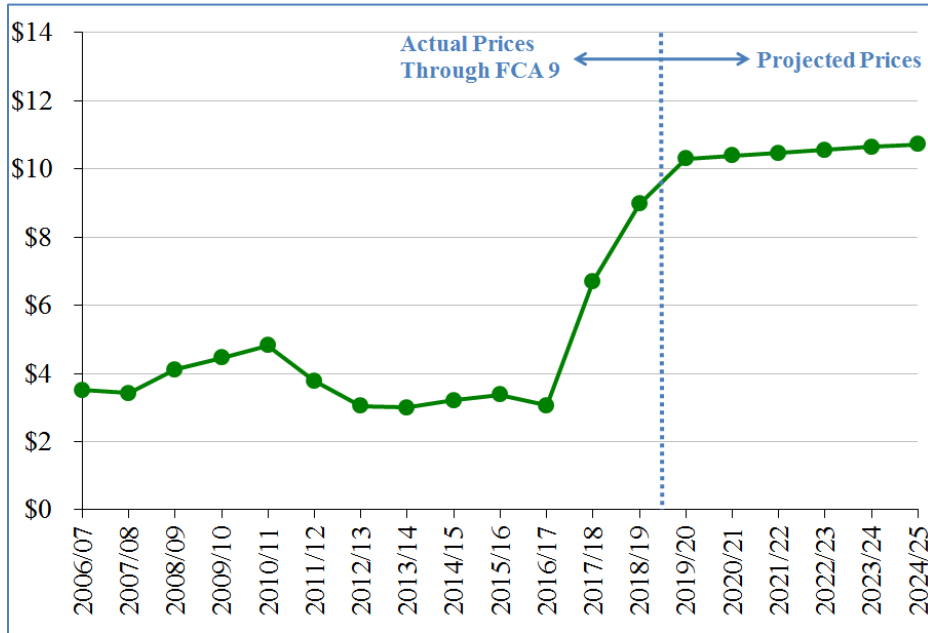
Capacity prices in New England are determined primarily through ISO-NE's 3-year forward capacity auctions (FCA). The three most recent auctions have shown a dramatic shift in fundamentals: The auction from the 2016/17 delivery cleared with excess capacity at the administratively-determined price floor of about \$3/kW-month, similar to the prior several auctions. The following auction, for the 2017/18 delivery year, eliminated the price floor and might have cleared at a lower price had fundamentals stayed the same. Instead, unanticipated resource retirements and a reduction in capacity imports created a slight shortage and drove the price up to \$7/kW-month (\$15 in the NEMA/Boston zone). Capacity prices would have been even higher had it not been for an administrative pricing rule that was triggered. The latest auction, for the 2018/19 delivery year, cleared about \$1.5/kW-month below Net CONE at \$9.55/kW-month, as new supply entered the market, including a new combined-cycle plant in Connecticut.

Going forward, fundamentals are projected to remain tight as peak load grows, and even higher prices can be expected.¹²² Rising capacity prices will likely first attract low-cost supply to meet growing load. New contracted renewables may also help to meet regional capacity requirements to some degree, although the contribution will be limited by relatively low capacity values of wind and solar during peak hours compared to other types of resources. Ultimately, as low-cost supply is exhausted, the capacity market will need to attract new conventional gas-fired resources to meet capacity requirements.

¹²¹ Both ozone season NO_x and annual NO_x allowance prices were assumed to be negligible for all electric generating units. Therefore, the 2014 IRP modeling does not include any policy mechanisms for additional NO_x controls, and electric generating units are assumed to emit NO_x at their current rates. Additionally, Connecticut's fuel sulfur content regulations are not expected to significantly impact electric generating unit operations. Therefore, the 2014 IRP modeling does not include any policy mechanisms for additional SO₂ controls, and electric generating units are assumed to emit SO₂ at their current rates.

¹²² FCA 9 incorporated two major new market design elements that FERC approved in May of 2014: a sloped demand curve and performance incentives. Even with the rule changes, the fundamentals were about the same as in the IRP modeling analysis, which was conducted before the rule changes were approved. Prices will have to be high enough on average to attract new supply.

Figure 18
Projected Capacity Prices (2014\$/kW-month)



The 2014 IRP projected capacity prices are shown in **Figure 18**.¹²³ These prices reflect the most recent 2018/19 capacity auction results, as well as recent estimates of the gross Cost of New Entry.¹²⁴ As the figure shows, prices in the Base Case increase to almost \$10.3/kW-month (2014 dollars) in the 2019/20 auction, then remain approximately at that level in real terms (rising with inflation). Prices could temporarily decrease after 2019/20, due to the large amount of capacity cleared for 2018/19. However, this IRP projects prices rising to \$11/kW-mo (in 2014 dollars) in the long-term, corresponding to the Net Cost of New Entry when new generation is needed again. This price level equates to about \$1.1-1.2 billion (2014 dollars) in annual capacity payments by Connecticut customers, and on average is what would be expected of a functioning capacity market in order to attract new gas-fired combined cycle generators to meet the system’s capacity needs through 2024.¹²⁵

Actual prices will undoubtedly differ as market conditions change, but this price projection is a reasonable estimate of expected average prices given currently available information. For example, a large amount of new low-cost supply from increased demand response, generator uprates, or imports could lead to lower prices. Conversely, prices could be higher if, for example, new market rules increase the risk of participation and drive out some less reliable resources and

¹²³ Prices are shown by capacity delivery year. For example, the 2017/18 price is for capacity deliveries from June 1, 2017 through May 31, 2018.

¹²⁴ These parameters are described in more detail in Appendix B (Resource Adequacy).

¹²⁵ This long-run equilibrium price is about \$10-11/kW-month (2014 dollars), based on an analysis conducted for ISO-NE, and explained in more detail in Appendix B (Resource Adequacy). This price assumes that a generic new natural gas combined cycle powerplant would earn enough from capacity plus energy margins to cover fixed costs and earn a competitive return on capital.

if new generation requires higher prices or longer lead-times to enter. Section VI will explore the potential price impacts of these types of uncertainties through scenario analysis.

FORECAST: CONNECTICUT CUSTOMER GENERATION RATES

The Generation Service Charge currently makes up approximately half of the total customer bill, with the rest coming from transmission and distribution charges, systems benefits charge, and other special charges that the 2014 IRP does not project.

For comparison purposes, **Figure 19** shows estimated historical and current Generation Service Charge rates for Standard Service for residential and small commercial and industrial customers in 2007 and 2014.^{126,127} As the chart shows, rates declined substantially from 2007 through 2014. The 2014 IRP analysis projects the Generation Service Charge for Connecticut customers to increase over the next ten years.

Based on the capacity prices,¹²⁸ energy prices,¹²⁹ and estimated payments for renewables described above, DEEP projects that the average Generation Service Charge will increase from 9.2¢/kWh in 2014 to 10.8¢/kWh in 2017, 13.5¢/kWh in 2019, and 15.9¢/kWh in 2024 in nominal dollars. This equates to approximately 9.2¢/kWh in 2014, 10.2 ¢/kWh by 2017, 12.2 ¢/kWh in 2019, and 13.1 ¢/kWh in 2024 (in constant 2014 dollars), as shown in **Figure 19**.^{130,131}

¹²⁶ Estimated Standard Service rates shown in **Figure 19** are based on a weighted average of filed rates for Eversource (80%) and UI (20%), converted to 2014 dollars. These rates apply only to residential and small commercial and industrial customers that choose to take retail service from the Electric Distribution Companies. Hence, these rates are not strictly comparable to the projected future rates shown in **Figure 19**, which represent an average across all customers in the state.

¹²⁷ The numbers in **Figure 19** show an average for all customers and do not include the costs for special contracts.

¹²⁸ See **Figure 18** above, which includes actual prices from FCA8 and FCA9.

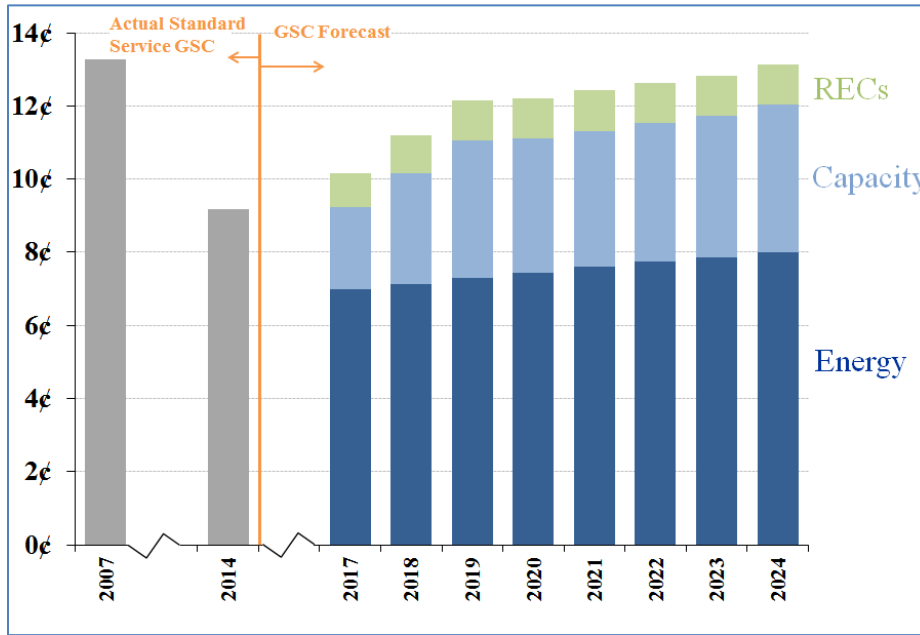
¹²⁹ In **Figure 19**, “energy” costs include the costs of electrical loss net of loss refunds, congestion costs net of financial transmission rights (FTR) revenues, costs of generator uplift, operating reserve costs, and an estimated 15 percent adder to account for other ISO-NE charges and a risk premium.

¹³⁰ DEEP recognizes that the generation service charge increased in January 2015 to levels above those forecasted for 2017. There are two reasons for this: One, the average annual basis differentials was assumed to be about \$2/MMBtu when the generation rate forecast was developed. Current natural gas basis futures are closer to \$2.9/MMBtu, or \$0.9/MMBtu higher than what was assumed. This would increase rates about 1¢/kWh higher than projected each year. In **Figure 19**, the projected dark blue bars would all increase by about 1¢/kWh. This would yield projected generation rates in 2017 of about 11¢/kWh. The second issue is that comparing the 2017 projections to the first half of 2015 is not quite apples-to-apples. The first half of 2015 likely reflects expectations for very high prices in January and February. This shows up in current natural gas futures for 2015 deliveries. Current natural gas basis futures are \$2.934/MMBtu on average for the year, but \$4.3/MMBtu for January – June and \$1.5/MMBtu for July – December. Only looking at January – June, our updated 2017 projected rates would be about 12.6¢/kWh. This is similar to the standard service rates for first half of 2015.

¹³¹ The Generation Service Charge costs shown in **Figure 19** do not include other components of customer bills, such as transmission and distribution (T&D) costs, the net costs of mandated renewable investments (ZREC/LREC or Project 150 programs), or the cost of long-term contracts with the Kleen Generation, AMERESCO energy efficiency, Waterbury Generation or Waterside Generation, and Devon, Middletown, and New Haven peaking generation facilities. Nominal rate projections must be interpreted in light of inflation, i.e., if inflation is 2%, a 1% increase in nominal rates means rates have decreased by 1% in real terms.

Rates are not expected to regain pre-recession levels in real terms during the study period, primarily because Henry Hub natural gas commodity prices are expected to remain below \$6/MMBtu (in nominal terms) through 2024.

Figure 19
Annual Average Generation Service Charge for Connecticut Customers
Base Case Projection ($\text{¢}/\text{kWh}$)



The projected 3.0 $\text{¢}/\text{kWh}$ increase¹³² from 2017 to 2024 in real terms is due to several factors affecting the New England region:

- An increase of 1.8 $\text{¢}/\text{kWh}$ ¹³³ is expected due to regional capacity prices rising to the level needed to attract new generation and maintain resource adequacy as retirements and load growth erode the capacity surplus that kept prices low in the past. Such price increases are to be expected given the fundamentals and a well-functioning market.
- An increase of 1.0 $\text{¢}/\text{kWh}$ is expected due to rising energy prices in the region, caused primarily by natural gas commodity prices rising over time.
- An increase of 0.2 $\text{¢}/\text{kWh}$ is expected due to rising costs of new renewable generation. This is due to the higher volume of renewable energy that will be purchased as the Class I requirement increases, and to a higher price paid as the scarcity of regional supply causes the Class I REC prices paid outside of the contracted or procured resources to be set by the Connecticut ACP.

Projected rate increases will affect customers, although energy efficiency programs will help keep total consumption approximately flat and consumption per capita slightly negative, thus moderating the effect on customers' monthly bills. Resource strategies that may further lower

¹³² Small difference due to rounding.

¹³³ Note that this is the difference from 2017 levels. The difference from current capacity prices would be higher.

customer costs are discussed in Section VII (Resource Strategies), with special focus on gas pipelines and renewable procurements.

VI. MANAGING ELECTRIC SECTOR EMISSIONS TO ACHIEVE CLIMATE & AIR QUALITY GOALS

The “cleaner” component of Governor Malloy’s vision for a “cheaper, cleaner, and more reliable energy future” strives to reduce Connecticut’s emissions of climate-altering greenhouse gases and other health-related air pollutants like ozone, nitrous oxides, and volatile organic compounds. Over the past decade, Connecticut has committed itself to reducing these public health and climate hazards through a variety of legislative and regulatory efforts at the state and federal level. Connecticut has committed itself to reducing these public health and climate hazards through a variety of legislative and regulatory efforts at the state, regional, and federal level. For instance, in 2005 Connecticut signed a regional Memorandum of Understanding to join RGGI – the nation’s first market-based cap-and-trade scheme for greenhouse gases (GHGs).

The state succeeded in returning overall GHG emissions to 1990 levels by 2010, a goal set by the New England Governors and Eastern Canadian Premiers as part of the first multi-national, multi-jurisdictional framework for climate change action. Connecticut’s Global Warming Solutions Act (GWSA) of 2008 set a goal of reducing greenhouse gas emissions 10% from 1990 levels by 2020 — a goal that almost certainly has already been met. Connecticut also has responded favorably to federal efforts to reduce air pollution, such as EPA’s updates to the National Ambient Air Quality Standards (NAAQS) for criteria air pollutants (e.g., NO_x, SO_x, particulates and toxics), and EPA’s recently released Clean Power Plan under Clean Air Act section 111(d) for existing power plant emissions of greenhouse gases. This section will discuss how Connecticut has reduced its air pollution in the electric sector through these initiatives, and how the future may appear given today’s trends

STATE, REGIONAL, AND FEDERAL COMMITMENTS TO REDUCING CRITERIA POLLUTANTS AND GREENHOUSE GAS EMISSIONS

CONNECTICUT GLOBAL WARMING SOLUTIONS ACT (GWSA)

Connecticut’s total emissions of carbon dioxide and other greenhouse gases (GHGs) peaked in 2004 and declined more than 20 percent by 2011, the most recent year for which full data are available. Over the two-decade period for which the state has tracked GHGs (1990 to 2011),

emissions declined 9.5 percent overall. Connecticut is achieving significant progress toward meeting a key target established in the GWSA: 10 percent reduction in GHG emissions between 1990 and 2020. The 9.5 percent reduction achieved by 2011 indicates the state is likely to reach this goal well ahead of schedule, and preliminary indications are that it probably was achieved by 2012. Planning is underway to extend these reductions to meet the long-term goal the GWSA imposes: 80 percent reduction by 2050 (relative to 2001).¹³⁴

Most of the statewide GHG emissions reduction to date has occurred in the electric power sector, whose emissions fell 40% between 1990 and 2011. Here, as in other sectors, the trajectory of Connecticut's emissions is moving in the direction of the goals set in the GWSA. However, factors such as the recent winter-time natural gas constraints present challenges for which the state must develop smart solutions.

REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

Connecticut, the other New England States, New York, Delaware and Maryland continue to implement the RGGI, the first multi-state cap-and-trade program where CO₂ allowances are auctioned to an open market, rather than allocated to regulated sources at no cost. The auction proceeds are invested in deployment of renewable energy and energy efficiency measures designed to reduce carbon emissions and energy consumption across all classes of electricity rate payers. The states adopted rules to implement RGGI in 2008.

Under the RGGI Memorandum of Understanding (MOU), in 2012-2013 the RGGI program underwent an extensive review to evaluate its effectiveness. The states observed that a significant surplus of allowances existed due to the fact that recent CO₂ emissions were significantly lower than promulgated allowance budgets. In order to preserve the reduction in current emissions and reduce future CO₂ emissions, the RGGI states committed to lowering the regional CO₂ allowance cap and reducing states' individual CO₂ allowance budgets to align with recent actual emissions and adjust for the surplus of CO₂ allowances in the marketplace. The new regional cap of 91 million CO₂ allowances is just slightly less than 2012 and projected 2013 emissions. Each year, that regional cap declines by 2.5%. States also committed to retire any surplus allowances that were not sold in prior auctions to protect the integrity of the new regional cap. Finally, states included cost containment mechanisms to mitigate CO₂ allowance price spikes from abhorrent circumstances (e.g., an unforeseen, drastic decrease in the supply of pipeline natural gas).

All nine RGGI states have implemented the necessary statutory and regulatory changes to satisfy the commitments made during the 2012 program review, the most significant of which is the reduction of the regional cap from 181 million metric tons down to 91 million metric tons region-wide. All of the changes were effective as of January 1, 2014.

¹³⁴ "Connecticut continues to achieve substantial reductions in climate pollution" (2014), <http://www.ct.gov/deep/lib/deep/climatechange/2011progressreport-2014-10-27/2011climatechangeupdate-2014-10-27.pdf>.

NATIONAL AMBIENT AIR QUALITY STANDARD (NAAQS)

One of the steps Connecticut is required to take under the 2008 8-hour National Ambient Air Quality Standard for ozone is a review of major sources of oxides of nitrogen (NO_x) and volatile organic compound (VOC) emissions to determine if the sources are subject to an appropriate level of control. The required level of control is the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. This level of control is called reasonably available control technology, or RACT. DEEP is currently evaluating the NO_x emissions limitations in RCSA section 22a-174-22 for boilers, turbines and engines. DEEP is currently revising its NO_x emissions limits for fuel burning sources to satisfy RACT under the 2008 ozone NAAQS. The revised RACT rules would likely require EGUs to meet more stringent, federally enforceable NO_x limits and will include provisions to ensure that Connecticut continues to meet its High Electric Demand Day or HEDD targets. The new emissions limits would first apply in 2017 with full implementation required in 2021 or 2022. In addition, DEEP will be required to perform a new RACT analysis under the 2015 ozone NAAQS, likely in or near 2022.

REGULATION OF EMISSIONS FROM EXISTING POWER PLANTS UNDER CAA 111(D)

The objective of EPA's proposed rule under Clean Air Act section 111(d) is to exert sustained pressure to reduce CO₂ emissions from the electric power sector, the nation's largest sources of climate pollution. The rule would do so by requiring each state to meet tailored targets for the amount of carbon pollution emitted per unit of energy the power sector produces, while encouraging implementation of energy efficiency and renewable energy. The rule calls for state plans to be completed by 2016 or 2017 if submitting a multi-state plan. Emission reductions are set to begin occurring in 2020 with a final target emission rate for 2029. States will be required to meet an average emission rate for the years 2020 through 2029. The rule also allows states to convert their target emission rate into a mass based cap, such as the RGGI cap.

DEEP has submitted comments to EPA that generally support the proposed rule, while also offering suggestions on where the rule could be strengthened and improved.¹³⁵ DEEP's

¹³⁵ DEEP's comments are available at http://www.ct.gov/deep/lib/deep/energy/111d/connecticut_comments_on_epa_clean_power_plan_proposal_-_final-11-28-2014.pdf. Connecticut also supports comments from RGGI, available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf and http://www.rggi.org/docs/PressReleases/PR120114_RGGI_SupplementalComments_CPP.pdf; Northeast States for Coordinated Air Use Management (NESCAUM), available at <http://www.ct.gov/deep/lib/deep/energy/111d/nescaum-comments-111d-cpp-esps-20141126-final.pdf>; 13 States' Attorney Generals, available at http://www.ct.gov/deep/lib/deep/energy/111d/2014.12.01.final_111d_state_&_ag_comments.pdf; National Association of Clean Air Agencies (NACAA), available at http://www.4cleanair.org/sites/default/files/Documents/111d-NACAACCommentsFinal-12-1-14_LETTERHEAD.pdf; Environmental Council of the States (ECOS), available at http://www.ct.gov/deep/lib/deep/energy/111d/ecos_111d_comment_letter_final_12_1_14.pdf; Northeast Energy Efficiency Partnership (NEEP), available at

expectation is that the state is well situated to meet EPA's proposed 111(d) requirements, in part due to the emission reduction initiatives already in place. Carbon emissions from the state's electric power sector fell almost 31 percent between 1990 and 2010 as the state shifted to low-carbon fuels and began taking aggressive steps to reduce demand for power from conventional fuels by focusing on energy efficiency and deployment of renewable energy projects. In recent years, Connecticut has doubled funding for popular and cost effective energy savings programs and increased by ten-fold the in-state generation of power from renewable sources.

Commissioner Klee signed onto joint comments of the RGGI states submitted on November 5, 2014 supporting the general framework of the proposed rule. Connecticut's participation in the RGGI serves as a flexible, market-based solution that the proposed rule recognizes other states can replicate or adopt as a compliance mechanism under the rule. The RGGI program dramatically cuts carbon pollution from power plants in a manner that recognizes the costs of such pollution while protecting ratepayers and building a new economy by generating funds for energy efficiency and renewable energy programs.

As proposed, EPA projects that nationwide the rule would yield a 30 percent reduction in CO₂ emissions from the electric power sector below the 2005 level by 2030. Connecticut's power sector achieved a reduction of nearly 30 percent between 2005 and 2011.

FORECAST: EMISSIONS TRENDS IN THE ELECTRIC SECTOR, 2014-2024

DEEP projects that displacement of coal and oil generation by gas and renewable generation will continue to produce a dramatic reduction in regional NO_x, SO₂, and CO₂ emissions relative to historical levels.

CO₂ EMISSIONS OUTLOOK

As shown in **Figure 20**, Connecticut CO₂ emissions from the electric sector that are counted under RGGI have decreased from 9.5 million tons in 2007 to a projected 7.8 million tons by 2014 and remain close to that level through 2019. In 2024, Connecticut's CO₂ emissions are expected to decrease to 7.1 million tons, due to assumed capacity developments outside of Connecticut to meet regional capacity needs. Connecticut's emissions in all simulated years are projected to be well below the state's 2020 target under the GWSA. New England as a whole is expected to have declining CO₂ emissions through 2024.

Under the recently developed RGGI Updated Model Rule, state CO₂ budgets for the period 2014 through 2020 have been tightened considerably. Relative to the prior Model Rule, the nine-state RGGI emissions cap has been lowered by 45%, in order to better align state CO₂ budgets with

http://www.ct.gov/deep/lib/deep/energy/111d/joint_neep_ee_stakeholder_comments_111d.pdf; and the Georgetown Climate Center, available at http://www.georgetownclimate.org/files/GCC-States_CPP_Support_and_Comments-Dec%202014.pdf.

current emissions levels. **Figure 20** shows that, by 2019, the six-state New England budget is 27.1 million tons (relative to projected emissions of 29.7 tons), and the Connecticut budget is 5.2 tons (relative to projected emissions of 7.7 tons).

In early 2013, the RGGI assessed the Updated Model Rule using the Integrated Planning Model (IPM) that, in part, projected state-by-state fuel use, generation, and emissions for each program year through 2020. The IPM results for projected emissions under the Updated Model rule are also shown in **Figure 20**. For New England, the 2014 IRP results are very close to the IPM results. For Connecticut, the 2014 IRP results are higher than the IPM results, primarily because IPM assumes Connecticut's only coal-fired electric generating unit, Bridgeport Harbor 3, retires (whereas the 2014 IRP modeling assumes this unit remains in operation).

It is important to note that, although projected emissions exceed individual state budgets under the Updated Model Rule, the Department expects that RGGI overall will meet its targets. The Department's projected New England emissions levels are roughly in alignment with IPM results. New England's emissions in excess of the New England states' budget are expected to be offset by emissions under individual state budgets in other (non-New England) states.

SO₂ AND NO_x EMISSIONS OUTLOOK

SO₂ AND NO_x EMISSIONS OUTLOOK

Because Connecticut's electric power sector relies on low/no sulfur fuels (i.e., natural gas and nuclear), its power sector SO₂ emissions are expected to remain far below 2007 levels, as shown in **Figure 21**. For example, 2012 emissions were 95% lower than in 2007 and 2014 emissions are projected to be 77% lower. By 2024, Connecticut's SO₂ emissions are projected to remain low at 1.3 thousand tons.

NO_x emissions are also likely to remain far below 2007 levels and well below target levels for annual NO_x, Seasonal NO_x, and High Electric Demand Day NO_x alike. **Figure 22** shows a substantial reduction in Connecticut's annual power sector NO_x emissions, with only modest increases after 2014 as coal-fired generation capacity factors increase slightly. For example, 2012 emissions were 71% lower than 2007 emissions; future years are projected to remain at about 68% below 2007 emissions levels. In New England, the planned retirement of a significant amount of coal capacity is expected to drive annual NO_x emissions down to below 2012 levels.

As **Figure 23** shows, Connecticut's NO_x emissions during the May through October ozone season are projected to remain well below the Clean Air Interstate Rule allowance budget over the entire 2014 IRP timeframe. Similarly, High Electric Demand Day (HEDD) NO_x is projected to remain at acceptable levels through 2024. **Figure 24** shows NO_x emissions on Connecticut's top four HEDDs. These projections compare favorably to an average of 27 tons per day experienced on the 4 hottest days in the period 2007 through 2012, and the target level of 42.7 tons per day that Connecticut has committed to the Ozone Transport Commission in 2007. However, in 2014 Connecticut measured ozone levels exceeding the 2008 as well as the 1997 8-hour ozone standards. Ozone standard exceedances were recorded on High Electric Demand Days (HEDD) when peaking units (HEDD units) are relied upon to meet electrical demand. HEDD units accounted for at least 57% of the NO_x

emissions while supplying only 17% of the MWHs. To address these exceedances and plan for a new tighter ozone standard a renewed focus and control strategy is necessary for HEDD units.

Figure 20

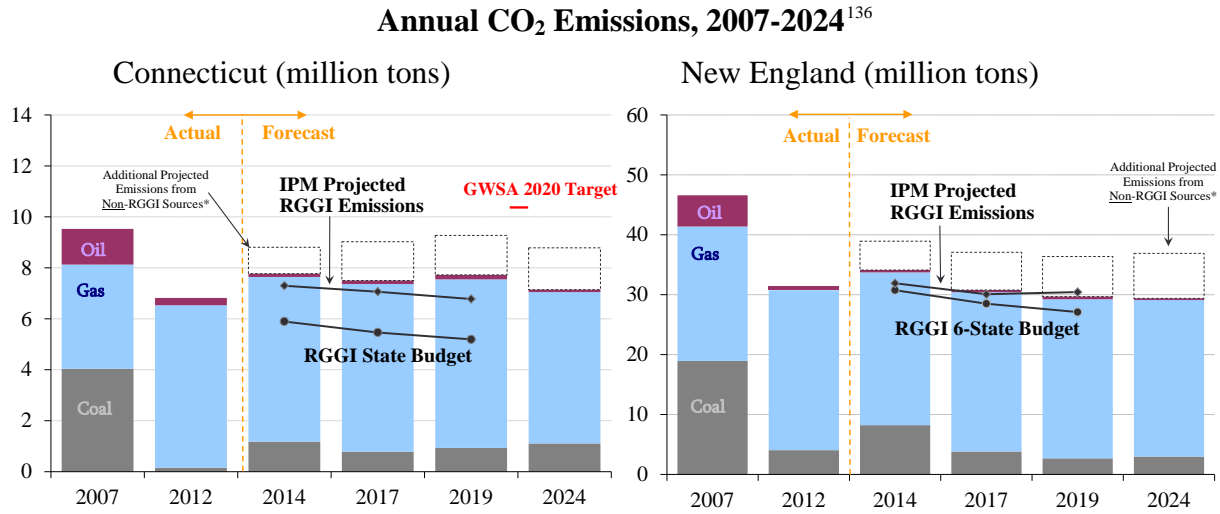
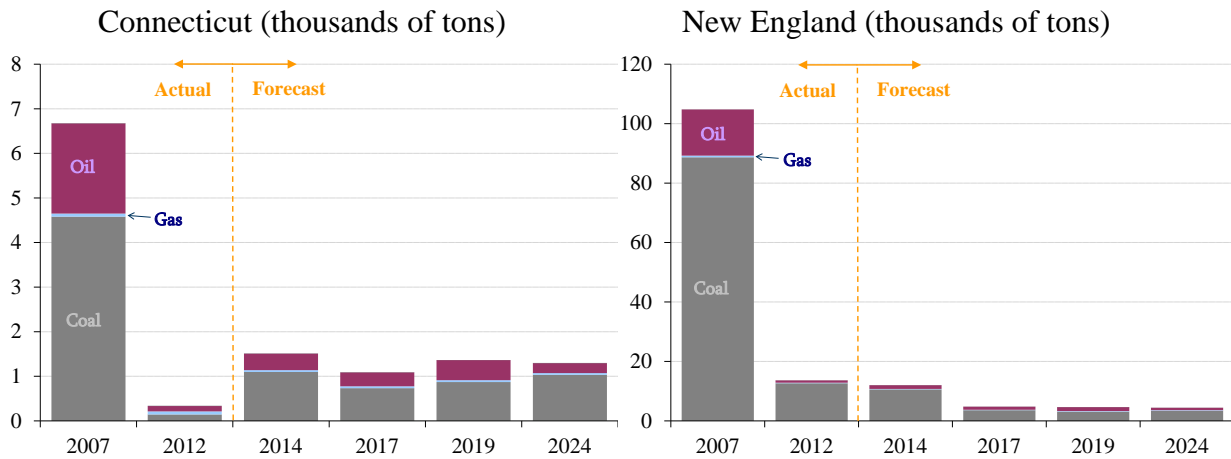
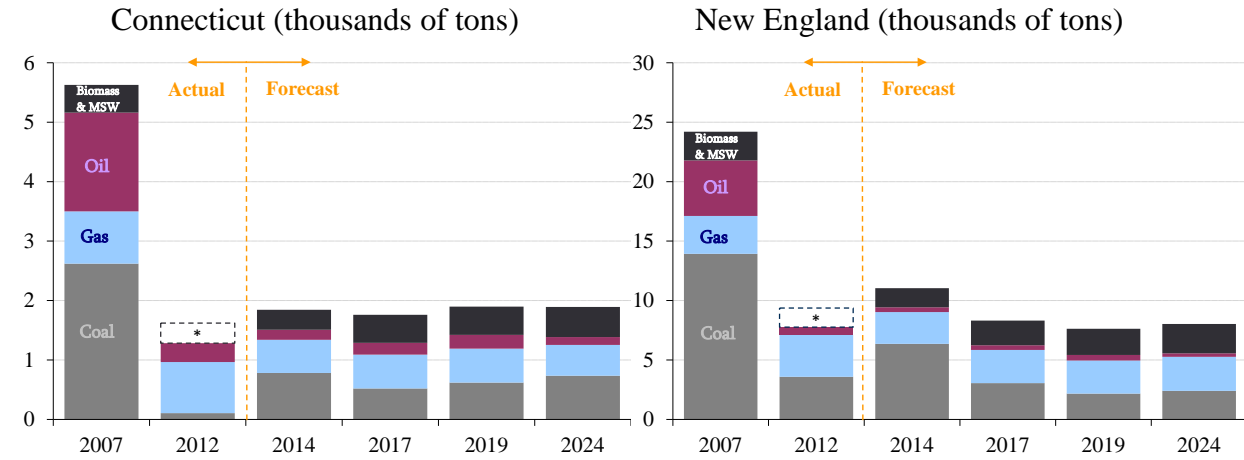


Figure 21 Annual SO₂ Emissions, 2007-2024



¹³⁶ Dotted area indicates emissions from non-RGGI sources, including generators under 25 MW, biomass and municipal solid waste plants, and fuel cells.

Figure 22
Annual NO_x Emissions, 2007-2024



* 2012 data on biomass and municipal solid waste facilities not available.

Figure 23
Seasonal NO_x Emissions in Connecticut (tons), 2014-2024

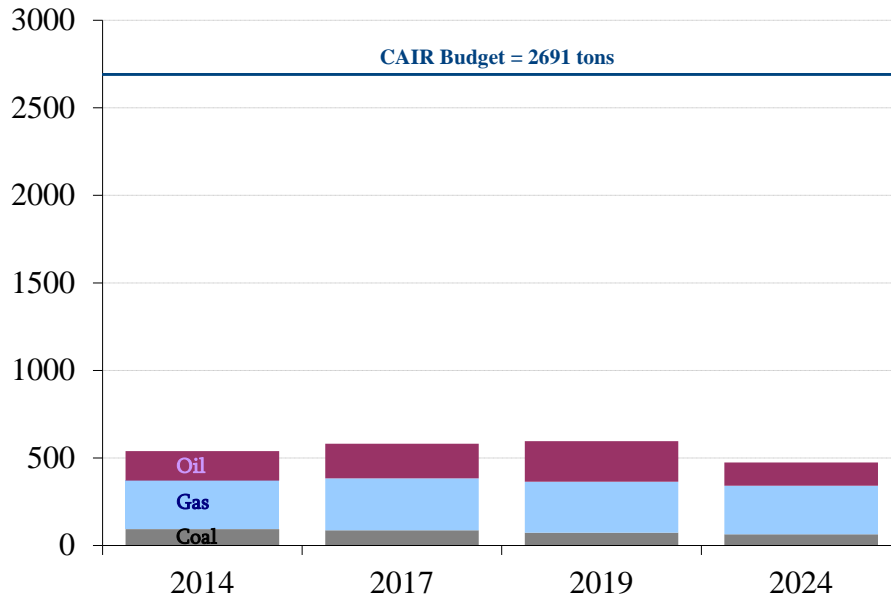
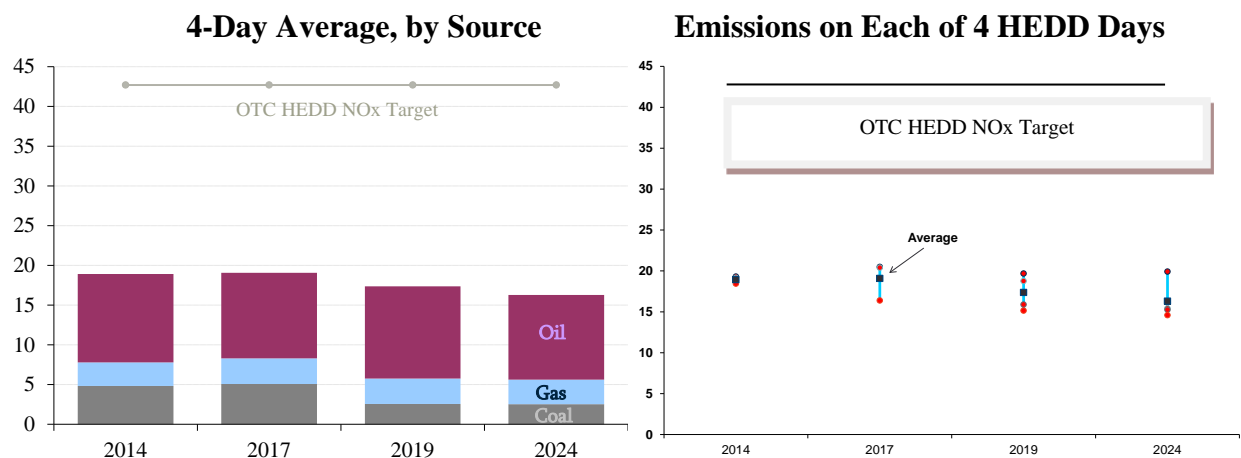


Figure 24
High Electric Demand Day (HEDD) NOx Emissions in Connecticut (tons per day)



VII. IMPROVING THE SECURITY AND RESILIENCY OF CONNECTICUT'S ELECTRIC DISTRIBUTION SYSTEM

Major storms in recent years have highlighted the need to improve emergency preparedness and electric reliability in the state. In 2012, the Two-Storm Panel issued a report with broad-ranging recommendations to improve emergency preparedness, communication protocols, and post-storm recovery and restoration efforts within the state. These recommendations provided a basis for subsequent initiatives, including the enactment of Public Act 12-148, which authorized a grant program to support the deployment of microgrids at critical facilities around the state. DEEP completed further assessments in the 2012 Energy Assurance Plan, which provided a comprehensive overview of efforts within the state to enhance energy system reliability, resiliency, and emergency response. DEEP also reaffirmed the need to improve grid resiliency, promoted distributed generation and new technologies, and recommended development of a cybersecurity strategy in the 2013 CES. PURA established emergency performance standards in Docket No. 12-06-09. Utilities developed plans for enhancing vegetation management, equipment reinforcement, and communications.

STORM PREPAREDNESS AND RESPONSE

Connecticut suffered three major storms in the past few years: Tropical Storm Irene, the October Nor'easter in 2011, and Superstorm Sandy in 2012. These storms demonstrated Connecticut's

need to continually improve critical energy infrastructure and enhance energy system resiliency to prevent or mitigate future energy supply disruptions. PURA's subsequent array of investigations and proceedings have resulted in decisions, recommendations, and policy changes to greatly improve the state's emergency responsiveness and storm restoration capabilities. While no energy system is 100% damage-proof, continually making improvements on storm response will better prepare the state for future storms and increase the systems' reliability.

Due to the progression and dynamic nature of storm-related threats, and given the state's recent experiences with major storms, energy security and resiliency to extreme events is an ongoing concern. The Department is encouraged by the EDCs' investment in tree-trimming, hardening of infrastructure, and use of GIS as tools effective in mitigating the effects of severe weather and power disruptions and supports the continued development of such programs and the continued coordination with state agencies charged with emergency planning and response.

The Department reaffirms that regulators, policymakers, and the utilities must continually assess how adaptive is their framework to the changing nature of the risks Connecticut faces. It is easier to prepare for those natural disasters we have already experienced because those types of threats are better known and often well understood. Innovative techniques, use of new technology, better training and preparation, as well as recovery techniques need to be continually tested and assessed to ensure the reliability of the electric system and to protect the health and welfare of Connecticut's residents and businesses. Connecticut is doing its due diligence in this respect but should not rest on its laurels. Through PURA, DEEP will monitor the EDCs' response to storms after every major event with significant power outages to review utility performance and ensure that it continues to meet the standards established in Connecticut and best practices.

MICROGRIDS AND NEW TECHNOLOGY

DEEP conducted its first Microgrid Grant and Loan Pilot Program in 2013. DEEP reviewed 36 proposals for potential microgrid projects. Nine microgrid projects were awarded a total of \$18 million in funding primarily through the DEEP Microgrid Pilot Program.

DEEP conducted the second round of Microgrid Program in 2014. The second round incorporates many lessons learned from round one, including new criteria around financial viability of proposed microgrids. Five proposals were received in the second round and two proposals met all the Stage One Threshold Review Criteria and moved to the Stage Two review. Both projects were ultimately award grants for a total of \$5.1 million.¹³⁷

Microgrids are a rather new technology being implemented across the world. As the projects are being installed and operated, there will be challenges encountered and lessons learned. The Department understands the need to develop microgrid standards and guidelines with the help of the EDCs. There are many technical, operational, and economic challenges with implementing

¹³⁷ Awarded projects can be found under "Public Act 12-148 – Section 7 – Microgrid Grant Program – Round 2" on the Department's website at <http://www.ct.gov/deep/energyfilings>.

microgrids. Regarding the technical and operational challenges, a “microgrid” requires “micro-operators” — persons responsible for ensuring overall power quality to customers while the microgrid is islanded from the rest of the distribution system.

The model for financing and developing Microgrids continues to evolve. DEEP's microgrid program is focused on developing models for financing microgrids that can be scalable and replicable, from a ratepayer, developer, and private investment perspective. New onsite generation, new grid infrastructure, and improvements to existing grid infrastructure to accommodate microgrids can require substantial investment. While recent changes – such as the expansion of a virtual net metering tariff to microgrid-interconnected facilities – will drive new revenues to microgrids, additional sources of revenue will be needed, for example through participation in demand response or ancillary services markets, or through new forms of payment for capacity and energy reliability services. DEEP’s goal is to leverage as much of private funding as possible to build microgrid projects so the cost burden is not entirely on ratepayers.

Optimization of new technologies such as smart grid, alternative fuel vehicles, and battery storage can improve the State’s energy future. It is vital that the state partner with its utilities, universities, and other organizations, to develop and realize the benefits of new technologies. DEEP is also committed to developing policies to overcome barriers to the adoption of these emerging technologies. If we fully take advantage of these opportunities, the State will be much closer to its goals regarding climate change, ensuring an adequate and diverse energy supply system in the future, and remaining competitive in a global economy.

CYBERSECURITY THREATS

In the utility industry, “cybersecurity” refers to measures taken to protect power system infrastructure from threats of deliberate, internet-based attacks on critical facilities, including components of the electric system. Potential perpetrators include organized crime (largely overseas) engaging in extortion, and terrorists or foreign governments engaging in warfare. By planting malware programs on critical facilities such as transformers and power plants, they can threaten to disable or damage the facilities. Recent attacks from Iran, for example, have allowed hackers to gain access to control-system software that they could use to manipulate oil or gas pipelines.¹³⁸ The effects of a widespread or well-targeted attack could be devastating as the national power supply supports every other sector from transportation to emergency services.

In general, cyber-attacks are trending upward but it is still unclear as to the full extent and nature of our vulnerabilities. The U.S. Department of Homeland Security (DHS) reported in 2012 that it saw an increase of 68% in cyber-incidents involving Federal agencies, critical infrastructure, and other select industrial entities.¹³⁹ Reported cyber-attacks on utility sector control systems

¹³⁸ Siobhan Gorman and Danny Yadron, “Iran Hacks Energy Firms, U.S. Says,” *The Wall Street Journal*, May 23, 2013

¹³⁹ Edward Markey and Henry Waxman, “Electric Grid Vulnerability: Industry Responses Reveal Security Gaps,” May 21, 2013.

increased more than 50% over 2012.¹⁴⁰ Unfortunately, there is some evidence that many attacks still go unreported by utilities nation-wide. Depending on the level of underreporting, vulnerability across the grid could be far greater than current data shows.

Recognizing these threats, the North American Electric Reliability Corporation (NERC) has taken the lead in establishing for utilities both mandatory and voluntary security standards called Critical Infrastructure Protection Standards (CIPs). Systems requiring enhanced cybersecurity include information technology (IT) systems, supervisory control and data acquisition (SCADA) systems, and smart grid systems. FERC and various electric industry groups have also issued recommendations and tools aimed at establishing technically feasible and cost-effective defense. Examples include reports such as “Cryptographic Protection of SCADA Communications” by the American Gas Association or the cybersecurity failure scenarios published by the National Electric Sector Cybersecurity Organization Resource (NESCOR).

NERC, DHS, and DOE are leading the development of guidance and models for implementing security, but many industry stakeholders are also contributing to the cybersecurity conversation. Great gains have been made in enhancing security. However, the technologies used are rapidly evolving and the types and targets of threats to infrastructure are changing. In this environment, the development and assessment of cybersecurity needs to be continuous and involve as many stakeholders as possible. There have been many calls for greater information sharing and collaboration across sectors.

PURA has taken an active role in cybersecurity by reporting on the security of EDCs and LDCs in its former Docket No. 10-11-08. The 2013 CES required PURA to further investigate this issue. Consequently, PURA issued a report entitled “Cybersecurity and Connecticut’s Public Utilities,” on April 14, 2014. In the April 14, 2014 report, PURA identified a number of questions that still need to be addressed. PURA is ready to face the challenge presented to Connecticut utilities and the State that cybersecurity presents. PURA has recently established Docket No. 14-05-12: PURA Cybersecurity Compliance Standards and Oversight Procedures, to begin breaking down these challenges. This docket is intended to address the questions left unanswered through discovery and technical sessions, and to produce a set of compliance standards and oversight procedures to strengthen the State’s cybersecurity defense capabilities. DEEP will continue working collaboratively with PURA, the utilities, regional, and federal agencies to continue to assess cybersecurity threats and defenses, to better understand how vulnerable utilities are, and what kinds of defenses are technically feasible. Such an assessment is very important given the potential size of the threat, the incomplete state of knowledge of the threat, and the likelihood that sufficient defenses are not currently in place.

¹⁴⁰ Ahren Tryon, Cozen O'Connor, “Industry Wide Cybersecurity Standards Emerging Through Voluntary Framework,” *Electric Light and Power*, June 12, 2012.

VIII. ALTERNATIVE MARKET SCENARIOS

Connecticut customers purchase generation service through their electric distribution companies or retail electric suppliers, who procure electricity on a wholesale market at prices reflecting supply-demand fundamentals. If the fundamentals change, wholesale prices can change, and so can access to adequate supply.

The IRP Base Case Ten-Year Outlook reflects the most likely market conditions based on currently-available information. However, substantial uncertainty surrounds this and any ten-year forecast. Uncertainties that most affect supply adequacy include load growth and suppliers' resource investment or retirement decisions. The uncertainty that most influences New England electricity prices (and, in turn, some supplier decisions to invest or retire) is the market price of natural gas. To examine a plausible range of potential effects that uncertainties can have on the 2014 IRP's outlook on resource adequacy, customer costs, and emissions, the Department defined the following four Market Scenarios:

- *Low Gas Price Scenario:* Based on the “high oil and gas resource” case presented in the U.S. Energy Information Administration’s Annual Energy Outlook 2013,¹⁴¹ natural gas prices at Henry Hub are assumed to be 37% lower than in the Base Case by 2024.
- *High Gas Price Scenario:* Based on the “low oil and gas resource” case presented in the U.S. Energy Information Administration’s Annual Energy Outlook 2013,¹⁴² natural gas prices at Henry Hub are assumed to be 30% higher than in the Base Case by 2024.
- *Tight Supply Scenario:* Based on the high economic growth load forecast presented in ISO-NE’s 2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT),¹⁴³ by 2022 region-wide peak load is assumed to be 1,310 MW higher, and the total energy requirement is assumed to be 12 TWh higher, than in the Base Case. The gross Cost of New Entry for a new gas-fired combined-cycle unit is assumed to be 15% higher than in the Base Case, representing more overall risk perceived by potential developers and/or higher capital costs. Due to potential unexpected technical issues, more stringent ISO-NE performance requirements, or other unknowable external factors, 800 MW of existing capacity is assumed to become unavailable region-wide starting in the summer of 2018.

¹⁴¹ U.S. Energy Information Administration, Annual Energy Outlook 2013 with Projections to 2040, released April 15 - May 2, 2013, available at <http://www.eia.gov/forecasts/aeo/>

¹⁴² *Ibid.*

¹⁴³ ISO New England, Inc., 2013-2022 Forecast Report of Capacity, Energy, Loads, and Transmission, May 1, 2013, available at <http://www.iso-ne.com/trans/ceft/index.html>.

- *Abundant Supply Scenario:* Based on the low economic growth load forecast presented in ISO-NE’s 2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission,¹⁴⁴ by 2022 the region-wide peak load is assumed to be 1,305 MW lower, and the total energy requirement is assumed to be 12 TWh lower, than in the Base Case. The lower peak and energy levels in this Market Scenario could also represent the unexpected entry of low-cost supply.

DISCUSSION OF ALTERNATIVE MARKET SCENARIOS

The Department analyzed these four Market Scenarios in the 2014 IRP modeling system to assess impacts on resource adequacy, costs, and emissions. The modeling system incorporates likely market responses to higher or lower prices, such as changes in economic retirements or new generic builds. Regarding customer responses to higher or lower prices, customer price elasticity of demand was not modeled, because it is only a second order effect that becomes more important with very large shifts extending over long time periods. Resource adequacy, cost, and environmental implications of each of the Market Scenarios are summarized below.

During final production of this IRP, new data on capacity market supply and demand became available. Most notably, ISO-NE reduced its system-wide gross peak load forecast by about 200 MW by 2022; ISO-NE increased its assumed energy efficiency savings in other states by about 300 MW by 2022; and about 500 MW in firm imports exited the capacity market in the 2017/18 capacity auction. The net effect is not expected to change capacity supply and demand fundamentals in these scenarios significantly. Re-entry of firm imports could potentially be a source of unexpected low-cost supply, but that remains to be seen. ISO-NE also updated its projections of energy efficiency (EE) in Connecticut, as previously discussed, and the new projections are more consistent with what is assumed in this IRP.

Impact of Alternative Scenarios on Resource Adequacy

In all market scenarios, Connecticut is projected to have sufficient capacity to meet its local resource adequacy requirement through the end of the study period, with a surplus of at least 1,375 to 2,097 MW persisting through 2024, or even more if new resources are developed in Connecticut in response to system-wide needs. Region-wide, the resource adequacy need becomes large in the Tight Supply Market Scenario, rising to 4,000 MW by 2024 (about a third of which is projected to come from new demand response in all years). This possibility sharpens the need to monitor the market’s success in meeting the needs and developing contingency plans, as discussed in Section IX below.

In the Low Gas Price and High Gas Price Market Scenarios, regional resource adequacy is not materially different from the Base Case. Almost no new generation is needed over the study horizon in the Abundant Supply Market Scenario. Resource adequacy for all Market Scenarios is discussed in more detail in Appendix B (Resource Adequacy).

¹⁴⁴ *Ibid.*

Impact of Alternative Scenarios on Market Prices

Projected capacity prices are shown in **Figure 25**. Compared to the Base Case, near-term 2019/20 projected capacity prices range from \$2.3/kW-month higher in the Tight Supply Market Scenario to \$7.3/kW-month lower in the Abundant Supply Market Scenario (in constant 2014 dollars). In the longer term, price differences reflect differences in the average capacity prices needed to attract new gas-fired combined cycle generators to the market to meet the region's resource adequacy requirements. It is important to note that these average price trajectories can have a wide uncertainty band depending on the performance of the market and year-to-year changes in market conditions. In the Tight Supply Market Scenario, a higher gross Cost of New Entry means that long-run average capacity prices need to be higher in order to attract new entry. In the Low Gas Price and High Gas Price Market Scenarios, capacity prices are not materially different from the Base Case due to similar capacity supply conditions. In the Abundant Supply Market Scenario a capacity surplus of about 1,000 MW in 2018/19 delays the need for new resources in the region until 2024, and correspondingly depresses capacity prices during that timeframe. The capacity market model and projected prices for all Market Scenarios are discussed in more detail in Appendix B (Resource Adequacy).

Compared to the Base Case, average energy prices in Connecticut are about \$13/MWh higher in the High Gas Price Market Scenario, and about \$15/MWh lower in the Low Gas Price Market Scenario, as shown in **Figure 26**. Energy prices in the Tight Supply and Abundant Supply Market Scenarios are similar to the Base Case. The energy market model and the projected prices for all Market Scenarios are discussed in more detail in Appendix B (Resource Adequacy).

Impact of Alternative Scenarios on Costs and Rates

Given the plausible range of market uncertainties identified, impacts on Connecticut customers' power supply-related costs under each Market Scenario are shown in **Figure 27**. Base Case power supply-related costs are about 13.6¢/kWh by 2024,¹⁴⁵ as low as about 12.0¢/kWh in the Low Gas Price Market Scenario, and are as high as about 15.0¢/kWh in the High Gas Price Market Scenario. Differences in capacity prices by scenario have the greatest impact on customer costs in the study years 2019 and 2024, followed by differences in energy prices. In the Tight Supply and Abundant Supply Market Scenarios, impacts on total customer costs are partially offset by higher and lower volumes of customer sales (kWh), as shown by comparing the two panels in **Figure 27**.

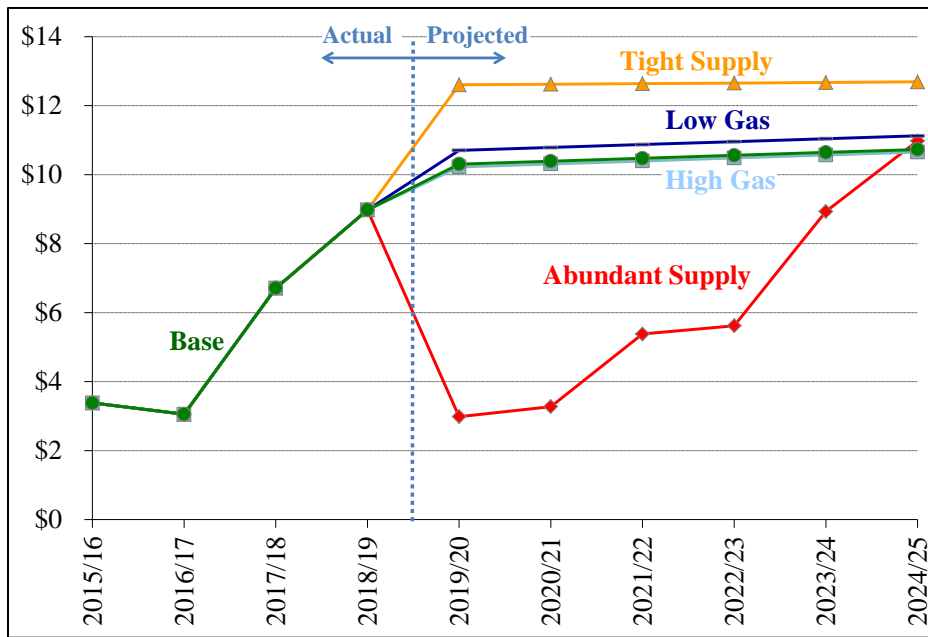
Impact of Alternative Scenarios on Generation and Emissions

Emissions are most sensitive to the capacity factors of coal- and oil-fired generation, which vary as load levels change and as efficient new gas-fired combined-cycles enter. For example, in the High Gas Price Market Scenario, coal-fired generation is more economic and runs at a higher capacity factor relative to the Base Case (higher emissions), and vice versa in the Low Gas Price Market Scenario (lower emissions). In the Tight Supply Market Scenario, higher energy

¹⁴⁵ This includes a 13.1¢/kWh Generation Service Charge as shown in **Figure 19**, plus 0.5¢/kWh in charges for energy efficiency and transmission associated with remote renewable generation. Please see Appendix A (Detailed Tables) for more detail on customer cost estimates.

requirements require more fossil fuel to be burned (higher emissions), which is partially offset by generation from new combined-cycles displacing output from old oil-fired generation. Similarly, in the Abundant Supply Market Scenario, lower energy requirements require more fossil fuel to be burned (lower emissions). These patterns are illustrated in **Figure 28**. Connecticut, for example, is projected to emit about 8.8 million tons of CO₂ in 2024 in the Base Case, as low as about 8 million tons CO₂ in the Abundant Supply Market Scenario, and as high as about 9.2 million tons CO₂ in the High Gas Price Market Scenario.

Figure 25
Capacity Prices in New England¹⁴⁶
 (\$/kW-Mo, in constant 2014 dollars)



¹⁴⁶ Prices are shown by capacity delivery year. For example, the 2017/18 price is for capacity deliveries from June 1, 2017 through May 31, 2018.

Figure 26¹⁴⁷
Annual Average Energy Prices in Connecticut (2014 \$/MWh)

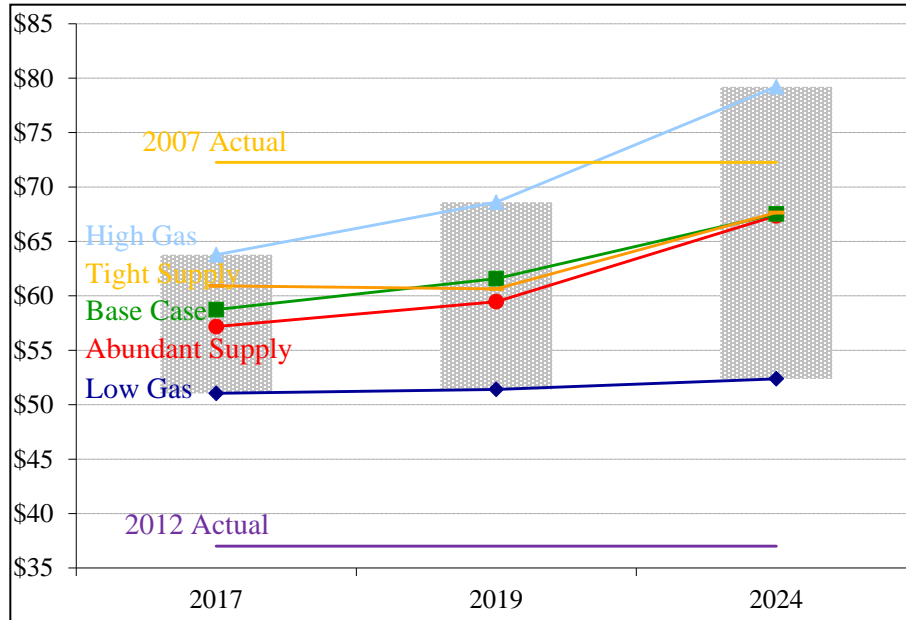
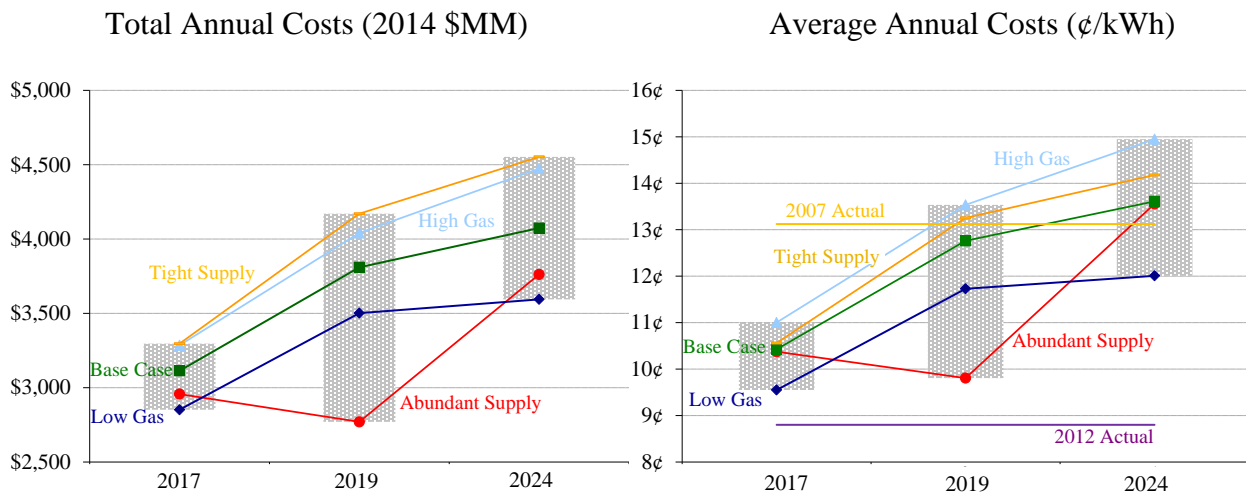


Figure 27^{148,149}
Connecticut Customers' Power Supply-Related Costs



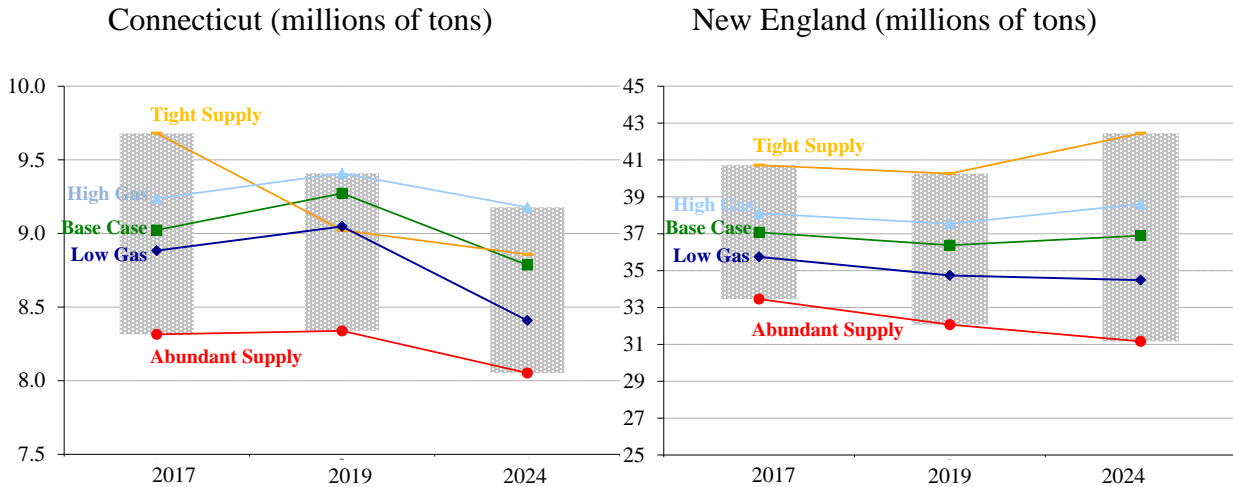
¹⁴⁷ The energy prices in this figure reflect analyses done in late 2013 and prompt year gas futures traded in January 2015 are slightly lower than in late 2013, which would result in slightly lower projected energy prices.

¹⁴⁸ The energy prices in this figure reflect analyses done in late 2013 and prompt year gas futures traded in January 2015 are slightly lower than in late 2013, which would result in slightly lower projected energy prices.

¹⁴⁹ This figure reflects updated capacity prices shown in **Figure 25**. Detailed components are in **Figure 3** on p. A-3 of Appendix A (Detailed Tables).

Power Supply-Related Costs includes Generation Service Charge (GSC), EE charges, and transmission charges associated with remote renewable generation. Average annual costs shown in the right panel are calculated as total annual cost (shown in left panel) divided by total projected kWh retail sales.

Figure 28
Annual CO₂ Emissions¹⁵⁰



In summary, these Market Scenarios highlight the following salient risks or notable differences from the Base Case:

- Future customer costs, shown in **Figure 27**, could vary substantially, being higher in the High Gas and Tight Supply Market Scenarios, and lower in the Low Gas and Abundant Supply Market Scenarios. Within a plausible range of uncertainty, total Connecticut customers' power supply-related costs could vary by +/-12%, or +/- \$500MM per year, by 2024.
- The Tight Supply Market Scenario is resource-adequate only if suppliers bring approximately 2,000 MW in new capacity resources to the market by 2018. This is indicated in **Figure 25** by strong capacity price signals, but the depth of the capacity need is explained in more detail in Appendix B (Resource Adequacy). This larger reliance on market entry compounds the market failure risks. Nevertheless, the signposts and contingency plans recommended for the Base Case should still apply in the Tight Supply Market Scenario, although they would occur sooner.

¹⁵⁰ Values include emissions from RGGI and non-RGGI sources, including estimated emissions for generators under 25 MW, biomass and municipal solid waste plants, and fuel cells.

IX. RECOMMENDED RESOURCE STRATEGIES

As detailed in the prior sections of this IRP, Connecticut families and businesses are facing several critical developments in New England's wholesale electricity markets that are challenging the affordability, reliability, and environmental impacts of the region's electric system. As described below, proactive policies are needed to achieve three major policy objectives identified in the 2014 IRP: (1) to ensure that Connecticut and the New England region retain adequate capacity resources to meet summer peak electric demand; (2) to resolve the region's natural gas infrastructure constraints; and (3) to secure additional Class I renewable generation to meet RPS requirements in Connecticut and the New England region.

In this section, the Department recommends eight strategies to achieve these objectives and secure a cheaper, cleaner, more reliable energy future for Connecticut. Each of these strategies involve different types of resources, with different profiles of location, capacity value, risks, costs, and benefits. Some of these strategies would require new legislative authorization, and some may depend on regional coordination to ensure cost-effectiveness. It is important to emphasize that many of these strategies serve multiple policy goals at once. A matrix is provided at the conclusion of this section to illustrate the various policy objectives that are served by each of the recommended strategies.

OVERVIEW OF POLICY OBJECTIVES

ENSURE RESOURCE ADEQUACY

As discussed in Section II, above, the forward capacity auction conducted in 2014 (FCA8) indicated that the New England region will experience a shortfall in generation capacity beginning in 2017. New resources that cleared in FCA9, including a 725 MW combined-cycle plant located in Connecticut, will help the region to meet its reliability needs for 2018. The 2014 IRP projects that resources within Connecticut are expected to be sufficient to meet Connecticut's Local Sourcing Requirement through 2024, although Connecticut generation prices will be affected by regional supply/demand conditions. If the resources cleared in FCA 9 do not come online by the 2018 timeframe, the region will experience a capacity shortfall, which will increase prices for all ratepayers in the region, including Connecticut.

The 2014 IRP concludes that Connecticut's increased investment in conservation and load management (C&LM) programs has succeeded in halting any growth in the state's annual average electricity demand between 2014-2024, and has reduced growth in the state's summer peak electricity demand to 0.5% per year. Achieving this limit on demand growth will help Connecticut and the New England region avoid the cost of any increased capacity need due to growing electricity usage. By continuing to strengthen the state's efficiency investments, as

highlighted in Resource Strategy #1, below, Connecticut can continue on this trajectory to avoid capacity costs by maximizing cost-effective energy demand reduction.

Barring any market failures, the ISO-NE regional capacity market should continue to attract new capacity to supply the existing regional need, which could include generation facilities constructed in Connecticut. However, recent changes in market rules may affect participation in the capacity market among both new and existing generators, and pending litigation is creating significant uncertainty about the ability of demand response resources (DR) to participate in the market as well. For these reasons, the 2014 IRP recommends, in Resource Strategy #2, that DEEP monitor litigation affecting DR, and utilize existing state authority to support DR as a contingency in the event that DR is not able to participate in the wholesale markets. Further, in Resource Strategy #3, the 2014 IRP recommends that DEEP continually monitor the markets and participate in ISO-NE and FERC proceedings and be prepared to utilize state authority if needed to ensure that resources are adequate to meet Connecticut's electric needs.

RESOLVE NATURAL GAS INFRASTRUCTURE CONSTRAINTS

The 2014 IRP identifies inadequate infrastructure to supply the region's increasingly gas-dependent generation fleet as the most pressing problem facing the electricity system in Connecticut and New England at this time. This infrastructure challenge threatens winter reliability and has resulted in billions of dollars in higher generation costs over the past few years. As described in Section III, above, no market solution appears to be forthcoming and all analysis concludes that this problem will persist in the years ahead. DEEP does not believe that this issue has been adequately addressed by ISO-NE and FERC and that regional market intervention is needed at this time. This problem is too big for any one state to solve alone, and all New England states should contribute to a solution. Since 2013, Governor Malloy has been actively leading the six New England Governors in a regional energy infrastructure initiative to address this problem.

Resource Strategy #4 evaluates recent studies to determine the scale of resource investment that could cost-effectively resolve the region's winter peak reliability problem, and the potential cost-benefit of different types of resources that could help to alleviate the region's gas infrastructure constraints. Strategy #4 recommends that DEEP secure long-term contracts with cost-effective resources by coordinating with other New England states to utilize a competitive procurement for Class I renewables and/or large-scale hydropower. In addition, Strategy #4 recommends that DEEP seek legislative authorization for an additional procurement, open to a broad range of resources including: natural gas infrastructure, LNG, non-gas generation and associated transmission (if needed), and measures that reduce demand for natural gas and/or electricity. DEEP would solicit bids from all of the above resource types, and select cost-effective resources that can contribute to Connecticut's reasonable share of the needed regional solution. Finally, Resource Strategy #5, which recommends revitalizing the state's incentive programs for combined heat and power facilities under 20 MW (which would likely be too small to compete in the procurements discussed and proposed in Resource Strategy #4), has the potential to contribute an incremental amount of gas and electricity demand reduction while securing energy savings for participating Connecticut customers.

ADDRESS CLASS I RPS SHORTAGE

Connecticut's commitment to procuring an increasing portion of its electricity from renewable resources is a critical component of the state's ability to reduce greenhouse gas emissions from its electricity sector. Renewable generation resources also provide an alternative to natural gas generation, which is of renewed importance in light of the region's increasing dependence on natural gas and its associated winter reliability challenge.

The 2014 IRP identifies a potential regional shortage in Class I renewable resources later in the decade, which could raise costs to customers and limit Connecticut's ability to secure the benefits of its RPS commitment. To the extent that Class I resources are successful in the two procurements described in Resource Strategy #4, those procurements could result in a significant amount of new Class I resources coming online to mitigate the projected shortage. While the outcome of those procurements would be pending, in Resource Strategy #6 the 2014 IRP recommends continued investment in the deployment of in-state renewable generation, through modifications to existing programs to reach more in-state potential with the lowest possible subsidy. Resource Strategy #7 further calls for a re-evaluation of incentives and regulatory policies for distributed energy resources to ensure they are fully integrated into distribution system planning and operation. Finally, in Resource Strategy #8, this IRP also recommends deferring until 2018 the requirement to establish a schedule for the phase-down of the value of renewable energy credits for Class I biomass and landfill gas facilities. The delay in retirement of such facilities will avoid exacerbating the region's capacity need and increasing reliance on natural gas generation while other resource solutions are forthcoming.

Having summarized the main policy objectives underlying the recommendations proposed in this IRP, we now turn to describe each of the Resource Strategies in detail in the remainder of this Section.

RESOURCE STRATEGY #1: CONTINUE TO IMPROVE COST-EFFECTIVENESS AND INCREASE ENERGY SAVINGS FROM CONSERVATION & LOAD MANAGEMENT PROGRAMS AND STATE BUILDINGS

Investment in electric efficiency measures contributes to reduced electric capacity needs for Connecticut and the New England region. Investments in both electric and natural gas efficiency measures can help to alleviate the impact of the region's gas infrastructure constraints on system reliability and electricity market prices, to the extent that these measures reduce demand for electricity or natural gas during winter peak periods. For these reasons, the Department continues to prioritize investment in energy efficiency as a "first fuel" to resolve the capacity and electricity market needs, to the extent technically available and cost-effective.

As noted in Section II, in 2013, DEEP approved a three-year (2013-2015) budget for investment in utility-administered C&LM Plans at the maximum level authorized by the legislature in Public Act 13-298 – approximately \$180 million for electric efficiency and an average of \$42 million

for gas efficiency (funded at a rate equivalent to 0.6¢/kWh and 0.046¢/ccf for electricity and gas, respectively).¹⁵¹ These statutorily authorized budget levels fell short of the estimated budget needed to achieve all cost-effective electric savings in the state — identified in the 2012 IRP at \$206 million per year¹⁵² — but have allowed for a gradual ramp-up of program activity to maintain program quality and ensure that demand for the programs kept pace with the expansion of budgets.¹⁵³ At this budget level, Connecticut’s electric C&LM programs are expected to reduce energy consumption by an incremental 290 GWh per year, on average.¹⁵⁴ C&LM programs are assumed to experience diminishing returns, however, with costs per unit saved increasing at 5.3% (nominal) per year according to the assumed schedule described in Appendix C. As a result of continuous implementation of energy efficiency programs over the study period, the 2014 IRP forecasts cumulative annual energy savings (starting in 2014) reaching 3,194 GWh in 2024. These programs are also expected to yield 38 MW of annual capacity savings on average, in the 2014 through 2024 timeframe. Cumulative annual capacity savings are expected to reach between 309 to 413 MW in 2024.

As detailed in Resource Strategy #4, below, the Department proposes to include energy efficiency as a resource eligible in a multi-resource procurement to help address the gas infrastructure constraints that are affecting electricity prices and system reliability. In addition to that procurement opportunity, the Department proposes the following actions to maximize deployment of cost-effective efficiency in Connecticut.

Continue to Improve Cost-Effectiveness of and Increase Energy Savings from Ratepayer-Supported Efficiency Programs

Connecticut General Statutes Section 16-245m requires that the C&LM plan for utility based energy efficiency and demand reduction programs shall include a detailed budget sufficient to fund all energy efficiency that is cost-effective or lower cost than acquisition of equivalent supply. In the near-term the Department will focus on ensuring that all utility-based energy efficiency achievements are cost effective within the scope allowed by Connecticut General Statutes Section 16-245m. Ratepayer-funded programs are continuously being improved through the numerous program evaluations conducted to ensure program effectiveness and cost effectiveness.

¹⁵¹ Connecticut General Statutes Section 16-245m(d)(1).

¹⁵² In 2014, Forward Capacity Market and RGGI revenues contributed approximately \$23 million to the C&LM budget. In 2015, \$11 million was allocated.

¹⁵³ KEMA, *Connecticut Electric Residential, Commercial, and Industrial Energy Efficiency Potential Study*, April 2010, prepared for the Connecticut Energy Conservation Management Board

¹⁵⁴ IRP assumptions differ slightly from the actual C&LM decision because the IRP analysis was completed before the C&LM decision and its implications were finalized. The budget and savings reflect an approximation of the C&LM budget approved by DEEP for 2014 and 2015, as at the time of the construction of the Base Case EE model, the C&LM Plan was not final and approved by DEEP. For that reason, the cost rates assumed to derive the Base Case EE program savings also slightly differ from those assumed in the final C&LM Plan for 2014 and 2015

Commercial

For example, additional financing tools have become available, catalyzing investments in deeper measures in the commercial and industrial sector. Commercial Property Assessed Clean Energy (C-PACE) enables commercial, industrial, and commercial multi-family building owners to access affordable, long-term financing. This enables building owners to go deeper into their facilities and invest in long-payback measures with significant long-term energy savings, such as building envelope improvements. Since its launch in January 2013, C-PACE provided financing for nearly \$65 million for more than 90 clean energy projects, which will result in the deployment of over 12 MW of solar energy, CHP, and energy efficiency improvements across over 4 million square feet of buildings.

Industrial

In the 2013 CES, DEEP identified significant potential for efficiency savings in industrial processes. Program costs for industrial efficiency tend to run approximately 40% below the costs of traditional programs. The Department expanded funding in the 2013-2015 C&LM Plan for the PRIME (Process Re-engineering for Increased Manufacturing Efficiency) program concentrates on energy savings through “lean” manufacturing productivity improvements. This approach, combined with using a business sustainability approach and strategic energy management approach, is expected to prompt additional efficiency gains in the industrial sector.

Residential

- HES Follow-On Measures to Increase Savings Per Home. The utilities’ performance incentives have been tied to the implementation of performance standards for vendors. HES has increased the uptake and adoption of follow-on measures, and the savings per home (thereby leveraging the value of the HES assessment and its cost), through such performance standards for HES vendors (MMBtu savings/home) and the incentive to receive more leads with better performance, combined with an emphasis on effective sales of follow-on measures supported with sales training.
- Incentives for Retailers and Manufacturers. The residential efficiency programs are moving towards providing financial incentives almost entirely upstream for Heating Ventilation and Air Conditioning equipment (HVAC) and domestic hot water systems in 2015. This approach has the potential to achieve lower cost energy savings as unit volumes increase and per unit redemption and administrative costs decrease. Lighting incentives applied at the manufacturer and retail levels dramatically reduce costs As prices for LEDs decline, incentives can be adjusted accordingly.
- Appliances and Equipment. As the market for efficient appliances and HVAC equipment transforms and the average baseline efficiencies increase, the programs have responded by setting higher eligibility criteria. This raises gross savings and tends to reduce free ridership.

While this is good progress, the Department believes there is more to be done to increase the cost-effectiveness of the C&LM programs. For example, the HES copay was increased to \$99 in

2014. Since participation in HES was up to the C&LM budget in 2014, the Department believes the HES copay should be increased again in 2015.

The Department will continue to monitor the performance and cost-effectiveness of new utility ratepayer-funded efficiency measures through the multi-year C&LM Plan review and approval processes and through reviews of annual C&LM Plan updates based upon the three-year cycle approved in Public Act 13-298. The Companies will jointly submit the next three-year C&LM plan by November 2015 for 2016–2018. The Department will continue to tie increased savings goals and specific program improvements to the performance management fee paid to utilities, in order to continue the focus on continuous improvement and increased efficiency.

Evaluation studies perform a critical function in determining whether C&LM programs are cost-effective and are implemented to achieve maximum savings. Evaluation studies also perform an especially important strategic function to assure that ramped up residential and commercial and industrial sector programs are successfully implemented, programs achieve their savings goals, and new savings opportunities are revealed. As part of its role in developing energy efficiency programs, the Department, in collaboration with the Connecticut Energy Efficiency Board (EEB), ensures that an objective third-party evaluation administrator evaluates the programs funded by the Connecticut Energy Efficiency Fund.

While the Connecticut Green Bank also evaluates the cost effectiveness of its programs, the method is different than that used for measuring and verifying the C&LM programs. In order to have a full understanding of all energy savings programs, evaluation, measurement, and verification efforts for all energy efficiency programs should be aligned so that common assumptions and protocols are used.

Government: Continue Investment in Efficiency in State Buildings through Lead By Example (LBE)

The energy savings potential of all state buildings and facilities likely exceeds 1,023,297 MMBtu annually. Achieving this level of energy savings, which represents about 25% of the state's current energy expenditures, would result in a savings for Connecticut taxpayers of more than \$51 million annually. The scale of comprehensive energy efficiency opportunities that exist in this sector means that a combination of funding, including a significant investment in the capitalization of energy savings performance contracting, will be necessary to allow state buildings and facilities to implement upgrades and lead by example.

In September 2011, the State Bond Commission authorized \$15 million to finance energy efficiency projects in state facilities. These funds have been fully utilized for the approval of 55 efficiency projects with an estimated annual energy cost reduction of \$2.2 million. Approval in January, 2015 of \$10.0 million of additional bond funds to continue this progress will enable the Department to fund additional high-payback energy reduction projects, and to put in place the necessary infrastructure to implement energy savings performance contracting as a financing mechanism. These funds have been and will be used in conjunction with other funding mechanisms for clean energy projects such as lease or revenue bond financing, utility administered C&LM and renewable energy incentive programs, and the PURA Rate Buydown Program, to maximize potential energy reductions. Together, these funding mechanisms will assist the Department in realizing a whole-building approach to energy efficiency, ensuring that

all energy using systems (building envelope, heating, cooling, ventilation, lighting, etc.) are integrated to maximize and maintain energy reductions.

The Department will continue to work with the Connecticut Green Bank, the Office of the Treasurer, the Office of Policy and Management, the Department of Administrative Services, and other stakeholders to secure financing for energy savings performance contracting, reducing the need for capital outlays for energy-related equipment in future years. In addition, the Department will continue to work with and educate state facility managers and agency financial staff on the available resources to lead by example. Utilization of all of these available funding mechanisms will serve to maximize the efficiency potential across state agencies.

Assess Potential for Additional Cost-Effective Energy Savings in Connecticut

The Department plans to shift to a more dynamic, data-driven system of assessing potential opportunities to achieve future savings from C&LM, using information gleaned from the utilities' data management system and through ongoing studies focused on key opportunities in specific sectors. While Public Act 13-298 amended the statutes at section 16-245m by identifying the maximum amount that may be collected through a CAM to ensure that the state's C&LM Plan budget is sufficient "to fund all energy efficiency that is cost-effective or lower cost than acquisition of equivalent supply," it did not alter the statutory mandate in Connecticut General Statutes Section 16a-3a that "resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."

To accurately identify the "all cost-effective" efficiency level, the Department and the utilities need to move toward a dynamic, readily updated accounting system to identify all the potential opportunities to achieve cost-effective energy efficiency in the state. This will need to take into account efficiency savings that can be achieved through ratepayer-subsidized C&LM programs, as well as financing programs administered by Connecticut's Green Bank that are supported largely by private capital. Such an accounting system or study could not be completed in time for the preparation of this IRP, but will be developed as soon as practicable, potentially for consideration in the next IRP prepared in 2016. DEEP is committed to working on improved analytics, including such an updated and dynamic assessment of the statewide opportunities for energy efficiency, to better inform future IRPs and other state plans. This improved data is expected to more precisely guide the implementation of the diverse array of state policy actions targeted at reducing wasted energy and ensuring the achievement of energy efficiency and controlled load growth.

While a new assessment of efficiency potential is forthcoming, data from existing C&LM program implementation suggests that there is significant demand, and cost-effective savings, available, especially among oil heated homes. Between January and October 31, 2014, residential home energy audits were completed at 8,396 oil-heated homes,¹⁵⁵ representing 62% of all residential home energy audits, compared with natural gas (25%), electric (7%), and propane (4%). This demonstrates significant demand for energy savings on the part of residents who heat with oil. Furthermore, in a baseline assessment of the number of homes considered weatherized,

¹⁵⁵ Connecticut Statewide Energy Efficiency Dashboard, available at <http://www.ctenergydashboard.com>.

50% of electrically heated homes are considered weatherized, while only 25% of homes heated with oil and other delivered fuel – and only 22% of homes heated with natural gas – had achieved the same level of weatherization.¹⁵⁶ This demonstrates that significant potential generally exists to improve the efficiency of oil and gas heated homes.

While this data indicates a general potential for increased efficiency in gas and oil heated residences, Connecticut’s 2013 Comprehensive Strategy noted that a lack of data makes it difficult to identify the precise amount of potential gas or oil savings for Connecticut. With respect to natural gas, a study was prepared in 2009 of the natural gas energy efficiency potential in Connecticut’s commercial and industrial sectors, but no similar study has been completed recently for the state’s residential sector. Similarly, there are no current oil efficiency potential studies for Connecticut. In light of these data limitations, the savings potential for natural gas and fuel oil in Connecticut can be approximated by referencing gas and oil efficiency potential studies from Massachusetts and Vermont — states whose building stock is similar in type and vintage to Connecticut’s. Based on the Massachusetts and Vermont studies, the comparable level of investment needed to place natural gas and fuel oil efficiency programs on a par with all cost-effective electric programs is estimated to be about \$120 million annually.

Focus Conservation Programs on Reducing Peak Demand

Electric use exhibits a dual peak in which the system peaks during the summer months and also during the winter. The 2014 IRP projects, in Section II, that while total annual consumption will remain essentially flat out to 2024, summer peak electricity consumption will likely grow at a rate of 0.5% both in Connecticut and across the region. And as discussed in Section III, above, winter electric energy prices have increased to record levels due to high spot market prices for natural gas. Natural gas demand by residential and commercial customers is driven by space heating which is very weather-dependent, therefore winter gas demand peaks during specific periods on the coldest days (winter peak days). For these reasons, the 2014 IRP recommends refocusing efficiency efforts on peak opportunities, including both summer and winter peak demand reduction. Peak shaving initiatives could include:

- Offering targeted/higher incentives to encourage timely installation of winter peak measures.
- Offering higher incentives or a “comprehensive bonus” for adoption of HES add-on measures (focused on electric and gas savings during winter peak periods, with less emphasis on oil savings at this time), to encourage timely action, increase comprehensiveness, and achieve winter peak electric and gas savings.
- Targeting sales and project management efforts to attract and prioritize electric and gas EE Commercial and Industrial projects to achieve winter peak savings (e.g., prioritize the potential projects in the queue).

¹⁵⁶ NMR Group, Inc., “Single-Family Weatherization Baseline Assessment (R5),” (June 3, 2014): <http://www.energizect.com/sites/default/files/R5-Connecticut%20Weatherization%20Baseline%20Assessment-FINAL%2006-04-14.pdf>

- Targeting outreach/sales efforts to and prioritization of large gas boiler projects.

The objective behind these examples is to focus a larger portion of C&LM program funding for electric and gas conservation programs on winter peak end uses and opportunities. Reallocation could mean reallocating funding across efficiency programs, reallocating funding within a program, reallocating program efforts and staff assignments, reallocating or prioritizing sales/outreach efforts, or prioritizing potential projects in the queue.

Summary

In addition to the steps identified above, the Department will continue to work with other state and federal agencies on diverse efforts outside of C&LM programs to achieve energy efficiency and reduce energy waste. DEEP notes that energy efficiency can be also be expanded by complementary measures such as updating building codes and standards, requiring more efficient consumer products, offering additional financing mechanisms, achieving broader participation in energy efficiency opportunities, strengthening the capacity of the workforce to install energy efficiency measures and equipment, and other innovative initiatives.

RESOURCE STRATEGY #2: PURSUE OPTIONS TO RETAIN DEMAND RESOURCES

Demand Resources (DR) takes two principle forms. Passive DR includes measures designed to save electricity use at all times, such as energy efficiency measures like high-efficiency lighting and appliances, and the use of smart appliances to automatically regulate energy use. Passive DR is not dispatchable. A second form of DR, called active DR, refers to energy reduction that can be activated when needed. For example, a large energy user may power down machinery or switch to backup generation when called on to reduce consumption from the electric grid.

DEEP strongly believes that DR can be a cost-effective option to ensure reliability and minimize price increases, especially during peak hours when active DR can be dispatched. The IRP 2014 has identified the need to reduce summer peak demand (still projected to grow at 0.5% annually) and to provide for reliable, affordable electricity during winter periods when natural gas delivery infrastructure is constrained. DR can be an important resource to cost-effectively address both of those peak demand needs.

Connecticut has long been a leader in promoting both types of DR. Connecticut has worked with NEPOOL and ISO-NE to develop DR programs and incorporate DR into the regional electricity markets. In the Forward Capacity Markets, active DR can receive capacity revenues for commitments to reduce load or shift to backup generation during emergency events (i.e., OP4 events). Passive DR can receive capacity revenues based on reduced electricity consumption during peak hours or peak months. Passive DR cannot receive energy market revenues because it is non-dispatchable. Active DR have been allowed to bid into the hourly energy markets, however that may change as a result of recent litigation, discussed below. Connecticut has encouraged DR by supplementing ISO payments, providing capital grants for emergency generators, and providing technical assistance to DR developers through the state's electric C&LM programs. Connecticut had approximately 800 MW of various types of DR that cleared

in the 2017/18 capacity auction. The loss of these resources could dramatically impact the state's resource adequacy position going forward.

Over the past few years, DR participating in the ISO-NE program has increased to over 3600 MW in 2015/16 capacity commitment period but declined to 3040 MW in 2017/18, even though capacity prices doubled from \$3.43/kW to \$7.02/kW. This likely occurred due to market rule changes (such as ISO-NE's Pay for Performance regime) that have driven up the cost of participation for DR. Even though DEEP expects capacity prices to increase in future capacity auctions, this IRP does not expect DR to return to historical levels during the study period.

In Order 719, issued in 2008, FERC ordered ISO-NE and other regional grid operators to allow active DR to bid in to the hourly energy markets, similar to wholesale generators. Subsequently, in Order 745, FERC set the compensation for active DR at the locational marginal price (LMP) for the place and time the active DR is offered. In May 2014, a three-judge panel of the D.C. Circuit invalidated Order 745 on grounds that FERC had exceeded its jurisdiction and interfered with states' rights to regulate retail rates when it required compensation for active DR from retail customers; and that FERC's decision to set the level of compensation at LMP was inadequately explained and therefore arbitrary and capricious.¹⁵⁷ The D.C. Circuit has agreed to stay its decision while FERC decides whether to petition the U.S. Supreme Court to review the issue.

The Department is very concerned that the uncertainties raised by the D.C Circuit and other recent judicial actions have the potential to undermine resource adequacy and drive up energy prices in the near term, at a time when the region is also facing retirements of substantial amounts of non-gas resources. Although Order 745 specifically addressed active DR in the wholesale energy markets, the appellate decision vacating Order 745 is creating uncertainty around the participation of both active and passive DR in the wholesale capacity market, including the capacity auction planned for February 2015. The Department believes that if DR were unable to participate in the forward capacity auction, capacity costs could potentially increase by hundreds of millions of dollars for Connecticut ratepayers.

To avoid such an outcome, DEEP is monitoring the relevant court proceedings and preparing to take action if needed. Specifically, in coordination with PURA, the OCC, and other affected state parties, DEEP is examining ways that Connecticut, ideally in coordination with New England states, can utilize state authority to ensure that DR remains a competitive resource. Such state action could include:

- Extending the state's authority to direct the electric distribution companies to implement cost-effective active DR programs within their service area and permitting the EDCs to recover the cost of such programs through retail rates.
- Requiring each EDC to submit to PURA an application to implement time-of-use rates for customers that have a maximum demand of not less than 100 kilowatts. Additionally, the EDCs should offer optional interruptible or load response rates and time-of-use rates

¹⁵⁷ *EPSA v. FERC* (D.C. Cir. 2014) 11-1486.

for all customers. The Department notes that some limited legislative clarifications may be needed to reinforce authority to implement such a program, including adequate enforcement authority to ensure that DR can perform as needed to be taken into account in calculating the capacity requirements and to ensure that the state's EDCs are appropriately motivated to procure demand resources.

Any such state program will help to improve reliability by reducing demand in the event of an outage. To ensure that the program will also achieve economic benefits for ratepayers by avoiding the cost of generation capacity and electric demand, it will be necessary to ensure that ISO-NE reduces the Installed Capacity Requirement for Connecticut and the region by the amount any DR procured through a state program. In fact, the existing New England wholesale market rules provide a pathway to capture demand side resources in the calculation of installed capacity requirements.

RESOURCE STRATEGY #3: MONITOR CAPACITY MARKET AND PLAN FOR CONTINGENCIES

According to the resource adequacy outlook detailed in Section II, under the Base Case scenario, New England will need 1,500 MW of new capacity by 2024; under the Tight Supply scenario, the region could need 4,000 MW of new capacity by 2024. Connecticut will not need new in-state capacity through 2024 to meet ISO-NE's Local Sourcing Requirement, unless the Millstone nuclear plant somehow became inoperable. However, system reliability and generation rates for Connecticut ratepayers will be affected by the higher regional capacity prices, driven by the regional capacity need.

Under our deregulated market system, new generation capacity is procured through a regional capacity auction, administered annually by ISO-NE to procure capacity to meet projected regional electricity demand three years in the future. The eighth Forward Capacity Auction (FCA 8), conducted in February 2014 for supply commitments beginning in 2017, was the first to result in a capacity shortage. The ninth auction (FCA 9) attracted capacity commitments from new resources, testing the ability of the capacity market construct to attract power plant investments in the region for the first time. Although the capacity market did attract capacity there remains some uncertainty whether it will continue to do so in the future. Adding to the uncertainty is the fact that the ISO-NE has recently instituted major changes in the capacity market rules, including the adoption of a complicated new Pay-for-Performance incentive program.

For these reasons, Connecticut needs to be prepared for the possibility that regional capacity auctions do not deliver new generation resources when called upon to meet capacity needs. If this possibility were to occur, Connecticut's rates and reliability would be significantly impacted. This IRP recommends monitoring for market failures and developing contingency plans so that actions under state authority can be taken to avoid capacity shortages if necessary. For example, as described in Resource Strategy #2, recent court decisions regarding the participation of active DR in the energy markets, if upheld, would necessitate action by the state to insure that active DR can impact energy markets.

Beginning with the next capacity auction (for delivery years 2018/19), DEEP will look for the following signs that the market is not working to gauge if, when, and/or how much market intervention is needed:

- Large amounts of non-price retirements for reasons other than plant failures or major capital expenditure needs comparable to the cost of new generation.
- Very limited new entry of low-cost resources such as DR and generation uprates as prices rise to \$5, \$8, or even \$10/kW-mo. If DR is allowed to participate but is not entering, it will be important to determine whether the cause is the lack of market participants' faith in the capacity market or narrow barriers posed by ISO-NE's participation rules for DR.
- The DR is not allowed to participate in wholesale markets.
- The forward auction fails to clear enough capacity on a three-year forward basis.
- Insufficient competition in the forward capacity auction.
- A lack of fuel source diversity in the generation capacity jeopardizing the reliability of the electricity grid in the event of a disruption to fuel supply

If any of these signs appear and DEEP projects a shortfall expected each year, assuming no competitive market-based entry, and given updated market conditions (for example, if the market is closer to the 2014 IRP Base Case, or the Tight or Abundant Supply scenarios), DEEP will recommend intervention. The Department will then consider options to fill gaps where shortfalls are projected to not be filled by the market. Such intervention could be conducted pursuant to existing state laws, including Section 16a-3b of the general statutes. Any intervention would consider the realities of resource development lead times:

- Small, short-term gaps may be best filled by short-term contracts for short lead-time, less capital-intensive projects; the best candidate resource type would be new DR, which would require as little as months to develop.
- Other short- and medium-term options may include generation uprate projects that typically require closer to a year or two (or more) to develop.
- Meeting larger, long-term gaps may require long-term contracting with larger new generation resources, such as combined-cycle gas-fired generation, or possible other resources, such as imported large-scale hydropower. Solicitations would have to occur as soon as large gaps of at least several hundred MW are within three years of occurring (and are unlikely to be filled by market response). Considering likely lead times, new simple-cycle gas-fired generation may require 2–3 years to develop depending on whether it has already begun permitting, and new efficient combined-cycle generation may

require 3–4 years to develop depending on whether it has already begun permitting.¹⁵⁸

- Meeting larger, long-term risk to fuel source diversity necessary for grid security and reliability may require acquisition or long-term contracting with existing generation facilities such as nuclear, coal, or oil fired units. Consideration will be given to the impacts to reliability of announced and anticipated non-price retirements.

The Department does not plan to intervene solely for resource adequacy purposes unless necessary, so as to avoid the perception of undue interference in a functioning market, and to minimize the risk that contracted resources would fail to receive capacity credit under ISO-NE's Minimum Offer Price Rule. If intervention becomes necessary, the Department would seek to work with other New England states to ensure fair allocation of costs to procure solutions that would necessarily have regional benefits. Special consideration may be given to resource types that also meet complementary policy objectives, such as gas-electric reliability and environmental goals.

RESOURCE STRATEGY #4: PROCURE RESOURCES TO ADDRESS WINTER PEAK DEMAND

The 2014 IRP identifies inadequate infrastructure to supply the region's increasingly gas-dependent generation fleet as the most pressing problem facing the electricity system in Connecticut and New England at this time. This infrastructure challenge threatens winter reliability and has resulted in billions of dollars in higher generation costs over the past few years. As described in Section III, no market solution to the infrastructure inadequacy problem appears to be forthcoming and all analysis concludes that this problem will persist in the years ahead. DEEP does not believe that this issue has been commensurately addressed by ISO-NE and FERC. For all these reasons, and due to a well-documented host of cross industry regulatory issues, DEEP believes regional market intervention is needed at this time.

In this section, DEEP examines the winter peak reliability problem in three steps, beginning with an assessment of the magnitude of the problem, and then proceeding to discuss the cost-effectiveness and scalability of a range of potential resources that could be utilized to address this problem, including both demand-side and supply-side resources. DEEP then recommends a strategy to procure cost-effective resources.

¹⁵⁸ Several projects are already in development, including the Advanced Power of North America's Brockton Energy Center in Massachusetts. Public power entities have also proposed and permitted potential combined-cycle projects, including MMWEC's 293 MW Stoney Brook project and the 400 MW Pioneer Valley project. Other potential projects not yet permitted could take longer to develop.

MAGNITUDE OF SOLUTIONS NEEDED TO ADDRESS WINTER PEAK RELIABILITY PROBLEM

To determine the scale of resource investment that could cost-effectively resolve the region's winter peak reliability problem, DEEP relies in this IRP on several studies, including the Gas Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Power Generation Needs, prepared for ISO-NE in three phases by ICF International, as well as the NESCOE Phase I & II Gas Study (Black and Veatch, 2013).

ISO-NE Gas Assessment Phases I-III (ICF International, 2012, 2013, 2014)

Since it identified natural gas inadequacy as a key strategic risk, ISO-NE commissioned ICF International (ICF) to evaluate the ability of the gas pipelines to serve the needs of electric generation in New England through 2020.¹⁵⁹ Phase I of the study evaluated gas adequacy during winter design days¹⁶⁰ when total gas demand is the highest and during summer peak days when the electricity demand is the highest. ICF compared the electric sector gas demand¹⁶¹ to the total amount of natural gas delivery capacity¹⁶² remaining after serving the firm LDC demand. ICF concluded that the gas pipeline capacity is inadequate to satisfy regional gas demands on a winter design day over the next decade under all cases and scenarios evaluated.^{163,164} **Figure 28** shows the level of gas infrastructure deficiency identified by the Phase I Study which generally ranges from approximately 500 Dth/day to 1,100 Dth/day or more.

¹⁵⁹ See "Gas Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs." ICF, June 21, 2012 (Public Version). This study is referred to in this document as the "ISO-NE Phase I Gas Study."

¹⁶⁰ Winter design day refers to gas demand based on temperatures corresponding to a particularly cold winter such as 1 in 30 year event.

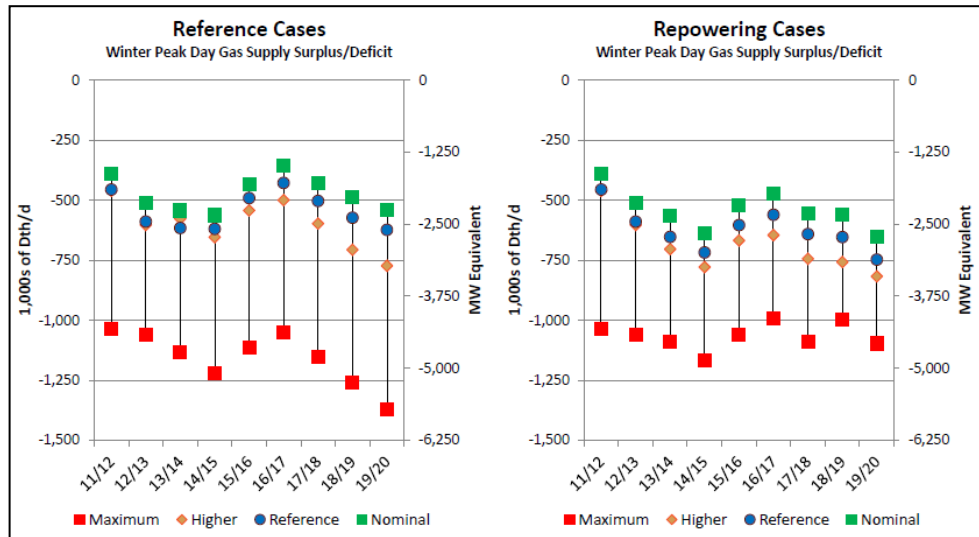
¹⁶¹ The electric gas demand includes the fuel reserve margin, which is defined as "the amount of additional gas required to be continuously delivered (over a 24 hour period) from the triggering of operating reserves in order to replenish the hypothetical loss (N-1) of a 1,200 MW class nuclear unit within the regional fleet." (ISO-NE Phase I Gas Study, p.30).

¹⁶² Natural gas delivery capacity included existing interstate pipeline capacity, LNG imports, LNG peak-shaving, and projected 350 MMcf/d expansion of the Algonquin system (Algonquin AIM project) by November 2016.

¹⁶³ ICF evaluated a Reference Case assuming that existing fleet continues to operate and a Repowering Case assuming some of the non-gas capacity is replaced with gas-fired capacity over time. For each of these cases, ICF evaluated 4 gas demand scenarios: (1) Nominal Gas Demand with 50/50 electric demand; (2) Reference Gas Demand with 90/10 electric demand; (3) Higher Gas Demand assuming additional gas demand to cover a disruption to non-gas-fired capacity, but higher gas prices moderates gas demand; and (4) Maximum Gas Demand assuming additional gas demand to cover a disruption to non-gas-fired capacity and low gas prices drives more gas demand.

¹⁶⁴ The study also found that under the Maximum Gas Demand Scenario the natural gas supply capability during the summer peaks might be inadequate until the natural gas pipeline capacity expansion (Algonquin AIM project) is built in 2015/2016.

Figure 28
New England Gas Supply Surplus/Deficit
As per ISO-NE Phase I Gas Study



Source: ISO-NE Phase I Gas Study, p.32.

In 2013, at ISO-NE’s request ICF International revisited its earlier assessment of New England’s natural gas infrastructure.¹⁶⁵ While the Phase II study demonstrated that gas generators lack adequate supplies of gas on peak winter demand days, it was published before the current pipeline expansion projects were announced that could potentially alleviate today’s supply constraints. However, these marginal capacity increases should be considered within the context of foreseeable further supply deficiencies on near-peak demand days that ICF’s earlier analysis did not investigate. On these days, New England’s thermal gas loads are still relatively high, but LDCs are not compelled to bring additional supplies from LNG terminals and regional peak shaving facilities online once their firm-gas commitments are satisfied. The LDCs optimize their systems to reserve these relatively expensive and limited-in-size emergency resources for heating use, and therefore, New England’s electric generation facilities are still left with gas deficiencies that resemble peak-winter demand days. ICF suspected that these conditions develop frequently throughout the peak winter demand period from December 1 to February 28, so their prior analysis in Phase I would have substantially underestimated the limitations of New England’s gas supply infrastructure available to generators.

ICF subsequently investigated these near-peak demand days in the Phase II study to capture a more accurate picture of New England’s gas supply limitations.¹⁶⁶ Phase II also included the approximately 450 MMcf/d of additional pipeline capacity that the Algonquin and Tennessee expansion projects will jointly deliver in 2016. Partnering the same methodology as Phase I with

¹⁶⁵ ISO-NE Phase II Gas Study (ICF International, December 16, 2013).

¹⁶⁶ ICF International. “Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II.” December 16, 2013. Available online: http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2013/dec182013/a3_draft_icf_phase_2_gas_study_report_without_appendices.pdf.

a new experimental design for simulating winter near-peak demand days, Phase II yielded 49 distinct, possible outcomes through 2020. ICF developed 40 of these projections by matching three potential supply forecasts with four possible demand futures in various permutations. Specifically, ISO-NE's "At-Risk" retirement list, its 2015-2021 gas efficiency forecast, and ICF's custom decreased LNG forecast served as the supply scenarios, while four separate gas demand forecasts entitled Nominal,¹⁶⁷ Reference,¹⁶⁸ Higher,¹⁶⁹ and Maximum¹⁷⁰ rounded-out the demand scenarios. For Phase II's winter near-peak scenario, ISO-NE created three, separate power sector gas demand cases, and ICF developed supply and temperature-derived load duration curves to estimate the gas supply available for the electric sector.

Despite new pipeline capacity, the Phase II analysis still illustrated significant gas supply deficits on peak winter demand days from 2014 to 2020. With ISO-NE's expected power plant retirements, winter peak day supply deficits ranged from approximately 400,000 Dth (400 MMcf/d) in the Nominal scenario to 1 million Dth (1Bcf/d) in the Maximum scenario. Even though energy efficiency measures reduced the electric sector's gas consumption in the modeling by 550,000 Dth (550 MMcf/d) by the winter of 2019/20, these measures did not eliminate the power sector's gas supply deficit on winter peak demand days. Over the course of that same winter, New England's power sector could face median deficits of approximately 6 million Dth (6 Bcf) to about 10.7 million Dth (10.7 Bcf). Given these projected gas supplies and future demands, New England's natural gas electric generation fleet faces a high probability of experiencing critical gas shortages on 24 to 34 days every winter by 2020. The coldest scenario in this analysis, which was conducted before the severe winter of 2013/14 could be included in the twenty-year reference baseline, left power generators without 21.9 million Dth (21.9 Bcf) of gas for 51 days in the winter of 2019/20.

The winter of 2013/14 provided ICF with an opportunity to test their Phase II conclusions. In April 2014, ICF benchmarked their models by pairing winter 2013/14 New England gas system performance data with ISO-NE's new peak day winter and summer electric generation gas demand projections through 2020.¹⁷¹ ICF found that their earlier assumptions for LDC firm demand,¹⁷² pipeline capacity, pipeline flows,¹⁷³ and peak shaving facilities¹⁷⁴ were largely

¹⁶⁷ This forecast is based on a 50/50 electric demand forecast where the probability of electric load (and gas demand by extension) exceeding the forecast is 50%.

¹⁶⁸ Comparable to a peak demand design day, this forecast is based on a 90/10 electric demand forecast where the probability of electric load (and gas demand by extension) exceeding the forecast is only 10%.

¹⁶⁹ This is the reference gas demand forecast modeled with a large nuclear or coal-fired power plant outage and high regional gas prices.

¹⁷⁰ This is the higher gas demand forecast but with low rather than higher regional gas prices.

¹⁷¹ Petak, Kevin. "Winter 2013/14 Benchmark and Revised Projections for New England Natural Gas Supplies and Demand." ICF International. April 29, 2014, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a3_icf_benchmarking_study.pdf.

¹⁷² Based on the new LDC send-out data, ICF lowered its design day demand by about 3% from its original estimate at the peak. However, the revised projections for demands between 63 and 45 HDDs (2 to 20 degrees F) are higher than ICF's original projection.

¹⁷³ Even though ICF reduced its pipeline expansion projections from 450 MMcf/d to 414 MMcf/d in this new analysis, conflicting data from nomination data on peak demand days did not compel ICF to change its estimate of current pipeline capacity in New England.

confirmed by this new information and required only minor adjustments. However, LNG facilities¹⁷⁵ and the M&N pipeline both supplied less LNG than ICF had anticipated for a winter as cold as 2013/14.¹⁷⁶ As a result, ICF's revised model projects reduced LNG send-out by about 50 MMcf/d on peak days and 150 MMcf/d less, on average, throughout the study period's winters. In total, the revised projections for gas supplies available to electric generation throughout a winter like 2013/14 are about 500 MMcf/d lower, on average, than Phase II's projections.

ICF's latest analysis found that if winter 2014/15 follows the winter 2013/14 temperature profile (the third coldest winter in 20 years), New England's electric generators would, in their estimation, make available to generators less than 1,000 MMcf/d (1Bcf/d) on 45 winter days and less than 500 MMcf/d on 20 days.¹⁷⁷ Further, this means that any major supply disruption would almost completely eliminate the gas supply for electric generators with implications for electric reliability. Based on data from the latest forward capacity market auction (FCA 8), ISO-NE's "extreme" fuel price projections for natural gas (\$22.98/MMBtu) would dwarf competing fuel types (coal: \$3.34/MMBtu, oil: \$12.72/MMBtu) under these weather conditions. Given these prices and weather conditions, ICF found that winter peak day gas supplies would "be barely adequate or slightly in deficit through 2020," even without any unforeseen supply interruptions. It should also be noted that despite how the winter 2013/14 severity has been perceived, as previously mentioned, it was only New England's third coldest winter in the past two decades. Colder winters and unexpected weather patterns commonly occur across New England, which puts the region's gas and electric reliability into even riskier territory.

NESCOE Phase I & II Gas Study (Black and Veatch, 2013)

In 2013, NESCOE retained Black and Veatch to assess the adequacy of the natural gas infrastructure to support power generation and to evaluate potential solutions. The study was conducted in three phases, with Phases I and II focusing specifically on the adequacy of New England's gas infrastructure to meet electric demand. Phase I, completed in December 2012, reviewed existing studies and literature on this topic and concluded that "New England's natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows

¹⁷⁴ ICF's revised model of peak shaving send-out showed higher utilization on "near-peak" winter days when temperatures are below 10 degrees Fahrenheit.

¹⁷⁵ During the winter of 2012-2013, Distrigas sent out an average of 280 MMcf/d. This figure was used in the Phase II Distrigas model. However, Distrigas only distributed approximately 100 MMcf/d during the winter of 2013-2014. Similarly, the new Deep Panuke offshore platform has yielded less than its projected maximum capacity of 300 MMcf/d that ICF used in Phase II.

¹⁷⁶ The M&N pipeline is still expected to flow at full capacity on peak days, but ICF now projects that flows on off-peak days will be approximately 300 MMcf/d lower than previously modeled, on average. Distrigas released 64% less LNG (100 MMcf/d) this winter than it did in 2012-2013 (280 MMcf/d) despite this winter's harsher conditions.

¹⁷⁷ For comparison, the 2014/15 winter peak gas demand day projections for electric generation gas demand ranged from 1,500 MMcf/d (1.5 Bcf/d) to 2,250 MMcf/d (2.25 Bcf/d) for less than extreme gas prices in 2014/15.

due to coal plant retirements and summer peak growth (albeit reduced), leading to infrastructure inadequacy at key locations.”¹⁷⁸

Phase II, completed in April 2013, analyzed the extent and duration of historical and forecasted natural gas congestion. Black and Veatch evaluated the adequacy of New England’s gas-electric infrastructure and projected constraints lasting more than 30 days across several sub-regions in the near future. They identified constraints by using daily load duration curves for the 14 sub-regions in New England and counting the number of days when the demand is higher than 75% of the current pipeline capacity serving the sub-region, a threshold established through statistical analysis of high prices and throughput.

The NESCOE Phase II study tried to address several shortcomings in the 2011 ISO-NE Phase I Study. In order to account for intra-regional constraints, the study separately analyzed 14 different sub-regions within New England. The NESCOE study also evaluated gas infrastructure adequacy accounting for the hourly variations in gas demand by electric generators.¹⁷⁹ Black and Veatch concluded that with existing natural gas infrastructure, significant portions of New England would experience infrastructure constraints lasting for more than 30 days in the relatively near future.

In Phase III of the NESCOE study, Black and Veatch analyzed the relative cost-effectiveness of various infrastructure solutions under three different levels of natural gas demand: a Base Case scenario modeled as the most likely level of gas demand based on the outlook at the time the study was created, a High Demand scenario modeled on assumptions of increased gas demand, and a Low Demand scenario that assumed regional demand for natural gas would remain flat or decline.¹⁸⁰ Importantly, changed market circumstances announced shortly after the release of the Phase III study in September 2013 indicate that the region’s natural gas demand will be greater than assumed by Black and Veatch when the three demand scenarios were designed:

- **Vermont Yankee:** The Black and Veatch study assumed the Vermont Yankee nuclear station would operate to the end of its current license in 2032. On August 27, 2013, Vermont Yankee announced that it is retiring in 2014. The power plant’s approximately 600 MWs of no-carbon, non-gas-fired energy is likely to be replaced by gas-fired resources. This has the potential to increase regional gas demand by 100 MMcf/d above that contemplated by the study.

¹⁷⁸ See “Natural Gas Infrastructure & Electric Generation: A review of issues facing New England,” Black and Veatch, April 16, 2013, p.2.

¹⁷⁹ Black and Veatch concluded that their hourly models do not yield results that were materially different from their daily models. See “Natural Gas Infrastructure and Electric Generation: Constraints and Solutions,” Black and Veatch, April 16, 2013, p.20.

¹⁸⁰ In the Low Demand scenario, Black and Veatch assumed that natural gas and electricity demands will not grow any further. This could be attributable to higher deployment rates of renewable energy, substantial energy efficiency gains. As a result, New England’s natural gas demand is lower than the Base Scenario by 100 MMcf/d in 2014, and 400 MMcf/d [by the end of the modeling period in 2029. Monthly average electricity prices were significantly depressed from the Base Scenario by \$15-20/MWh. Black and Veatch observed no constraints in the low demand scenario.

- **Brayton Point:** The Black and Veatch study assumed that the Brayton Point coal-and oil-fired generation station would continue to operate through the study period. On January 27, 2014, Brayton Point announced that it will retire in 2017. A portion of the power plant’s approximately 1500 MW of non-gas-fired energy is likely to be replaced by gas-fired resources, increasing regional gas demand beyond that assumed in the study.
- **The AIM Project:** The Black and Veatch study assumed that Spectra’s Algonquin Incremental Market (“AIM”) project would be built at 500 MMcf/day. Since the study concluded, Spectra has announced that the project will increase natural gas import capability into New England by 342 MMcf/day in 2016. This smaller project size will provide less infrastructure congestion relief, approximately 150 MMcf/day less than assumed in the study.
- **Eastern Canadian Production and Imported LNG:** The Black and Veatch study assumed significant supply contributions from eastern Canadian production and LNG imports. Eastern Canadian production was assumed to range from 350 MMcf/d to 200 MMcf/d over the course of the study period. LNG imports were assumed to provide approximately 350-400 MMcf/d during winter peak months. Recent announcements by Spectra Energy regarding the bi-directional flow capability of the Maritimes & Northeast Pipeline (M&NP), declining maritime off-shore production and growing demand in the eastern Canadian provinces raise questions regarding the Black and Veatch study’s assumed supply contributions from the Canaport facility and the M&NP generally. Winter 2013/14 imports to the Everett LNG terminal also averaged about 110 MMcf/d, significantly less than the Black and Veatch study’s 200-250 MMcf/d assumption.

The combined effect of these changed circumstances means that: (i) it is extremely unlikely that the region’s demand for natural gas will remain flat or decrease, and therefore the sustained level of demand in the Low Demand scenario appears increasingly unattainable; and (ii) the extent and duration of infrastructure congestion likely exceeds the results of the Phase II analysis. Further, these changed circumstances indicate that the assumptions in the Base Case scenario are conservative. The Department believes that Black and Veatch’s analysis is still directionally correct, but understates the benefits associated with the various solutions in the Base Case and Low Demand scenarios and the severity of future prices associated with infrastructure inadequacy.¹⁸¹

Accordingly, DEEP believes that the High Demand scenario provides a better approximation of the gas demand and a better indication of the relative cost-effectiveness of infrastructure solutions going forward. In the High Demand Scenario, Black and Veatch made six alterations

¹⁸¹ For example, natural gas daily prices in New England in January and February 2014 exceeded \$80/MMBtu, and the average monthly price in January was \$22.34/MMBtu. In contrast, the Black and Veatch study forecasted daily prices to be *at worst* on the order of \$10/MMBtu in the short-term and \$10-\$20/MMBtu in the long-term under High Demand conditions and monthly average prices to be *at worst* on the order of \$5-8/MMBtu.

from the Base Scenario that would reduce the supply and increase demand for natural gas.¹⁸² These six assumption alterations increased New England's Base Case scenario aggregate gas demand from 2,900 MMcf/d in the Base Case to 3,200 MMcf/d in the High Demand Scenario; an additional 300 MMcf/d (approximately 10% more total gas demand than the Base Case), while the average monthly basis prices would be higher, by \$2-\$4/MMBtu, during the winter peak months. While the actual changed market circumstances are different than those assumed by Black and Veatch, the overall impact of these events could be greater than 300 MMcf/d and will occur much sooner than forecast. DEEP therefore believes that the High Demand scenario better indicates the cost-effectiveness of potential resource solutions than the Base Case or Low Demand scenarios.

Discussion

The studies underscore DEEP's finding that current gas pipeline capacity is inadequate to satisfy regional gas demands on a winter peak design day over the next decade under all cases and scenarios evaluated. While ICF's Phase II report provides the most comprehensive view of New England's wintertime gas shortages, even this analysis likely underestimates the potential number of peak and near-peak winter demand days, given the subsequent benchmarking study. Moreover, ICF's study period only focuses on the typical winter weather period of December 1 to February 28, but as winter 2013/14 demonstrated, peak and near-peak demand days occur in March and other adjacent months. The ICF study clearly shows the magnitude and the duration of the problem facing New England.

The Black and Veatch study provides an illustrative analysis of the cost-effectiveness of gas infrastructure going forward. The cost-effectiveness of any firm proposal would be subject to further evaluation and regulatory review to validate the cost-effectiveness of the project.

In summary, on the basis of these two studies, DEEP believes that at least 1.0 Bcf/d of natural gas transportation capacity or equivalent gas storage and supply, or the equivalent of approximately 5,000 MW of winter peak electric demand reduction or 5,000 MW of non-gas fired generation will be needed for 30 days or more to adequately address the region's winter reliability problem.¹⁸³

¹⁸² Black and Veatch reduced its supply by assuming that 1) consumer penetration growth rates would slow down in states with high degrees of penetration; 2) international LNG exports would siphon an additional 4 Bcf of gas per day away from the New England market; and 3) M&NP is allowed to redirect gas flows to Canada when price arbitrage opportunities arise. To increase demand, the High Demand scenario assumed that states would only achieve 75% of their RPS goals, rather than 100% in the Base Scenario, thereby increasing gas-fired electricity demand. It also assumed that energy efficiency measures would be less prevalent or effective, resulting in a 0.2% annual electricity demand growth rate rather than 0.18% in the Base Case. Finally, nuclear plants retire five years earlier in this High Demand scenario than in the Base Case.

¹⁸³ Gas Quantity (MMBtu) = MW x hrs x 1,000 kWh/MWh x heat rate (Btu/kWh) x MMBtu/1,000,000 Btu. Implied marginal heat rate 8,400 based on 2013 Assessment of the ISO New England Electricity Markets. Potomac Economics. June 2014. p.44.

EVALUATION OF POTENTIAL RESOURCES TO ADDRESS WINTER PEAK RELIABILITY PROBLEM

Having reviewed the magnitude of resource solutions needed, in this section DEEP examines the role that different resource solutions can play in addressing the region's winter peak reliability problem. These solutions include supply-side resources — such as incremental gas pipeline capacity, LNG, dual-fuel generation capability, transmission to facilitate imports of large-scale hydropower and Class I renewable resources — as well as demand-side resources such as conservation and load management (both gas and electric), active demand response, and distributed generation resources such as combined heat and power (CHP).

The resources analyzed have very different characteristics. Some, like natural gas pipeline capacity or transmission for large-scale hydropower or Class I resources, require significant lead time for project development; once in place, they can provide large amounts of natural gas demand reduction at once, and remain in service for decades. Other resources, such as LNG and active demand response, can be readily procured without long development lead times through contracts of short- to medium-term duration. Such features allow for contracted amounts to be calibrated to resource need over time, reducing the possibility of stranded costs. To the extent that resource need proves to be large and persistent, the costs of these so-called short term resources may be greater than the costs of long-lived infrastructure in the long-term.

This interplay of resource characteristics and cost-effectiveness is shown in Phase III of the NESCOE Gas Study, discussed above. In Phase III, Black and Veatch evaluated a combination of two short-term solutions and three long-term solutions that could alleviate constraints on the natural gas pipeline system, to compare potential cost-effectiveness. The two short-term solutions modeled the addition 2.3 TWh of dual-fuel generation with demand response, and an additional 300 MMcf/d of winter season LNG purchases. The three long-term solutions included: a 1.2 Bcf/d cross-regional natural gas pipeline; imports of 1,200 MW of firm-priced Canadian hydropower; and imports of 1,200 MW of economic-priced (non-firm) Canadian hydropower.

Natural Gas Pipeline Capacity

The Black and Veatch study concluded that a hypothetical 1.2 Bcf/d pipeline from Wright, New York to Dracut, Massachusetts, estimated to cost \$1.2 billion to construct, provides the highest net economic benefits to New England customers compared to other long-term options over a study period of 2017 to 2029. The total cost of the gas pipeline over the thirteen years from 2017 through 2029 is estimated to be approximately \$2.3 billion or \$176 million annually.¹⁸⁴ In the Base Case, the estimated benefits are \$3.87 billion or \$294 million annually for a benefit to cost ratio of 1.67.¹⁸⁵ Black and Veatch estimated that this pipeline could yield \$118 million of annually averaged net benefits when compared to estimated net benefits from economic

¹⁸⁴ These amounts are expressed in future dollar values and have not been discounted to the present value.

¹⁸⁵ Capacity market impacts were beyond the scope of the Black and Veatch analysis.

hydropower imports (\$37 million), firm hydropower imports (\$61 million), LNG imports (\$96 million),¹⁸⁶ and dual fuel with demand response (\$101 million).¹⁸⁷

The savings and therefore benefit/cost ratio of each of the long-term solutions increased significantly in the High Demand Scenario compared to those in the Base Case. Savings for the gas pipeline increased from \$294 million annually to \$516 million annually, increasing net benefits to \$340 million annually and the benefit cost ratio to 2.93. According to Black and Veatch, the gas pipeline would break even in year 8 in the High Demand Scenario (see **Figure 29**). The benefits also increased for the Firm Hydro import option, from \$450 million annually to \$512 million annually. This increased the benefit cost ratio to approximately 1.32, compared to approximately 1.16 for this option in the Base Case.

Figure 29
Net Benefits for Infrastructure Solutions, Phase III High Demand Case, 2017-2029
(in Million Dollars)

Option	Total	Average Annual
Cross-Regional Pipeline	\$4,424	\$340
Firm Contract-Based Canadian Imports	\$1,471	\$123
LNG and Demand Response	\$3,093	\$236

Source: Black and Veatch

The findings of the Black and Veatch study with respect to natural gas pipeline capacity are generally consistent with a February 2014 study prepared by Sussex Economic Advisors, LLC for the Maine PUC.¹⁸⁸ The Sussex study reviewed, among other things, the potential costs and benefits of incremental natural gas deliverability into New England. Similar to other reports, Sussex analysis shows that current prices in New England are high and forward prices are expected to continue to be at a premium to Henry Hub and Mid-Atlantic natural gas prices in the future. Based on the relationship between natural gas and electric locational marginal prices in ISO-NE, Sussex calculated the potential reduction in LMPs as a result of a reduction in wholesale natural gas prices to estimate the potential energy cost savings to electric customers for the year November 2012 through October 2013. The report concludes that savings associated with a reduction of 40% in New England natural gas basis would offset the cost of a 1,000,000 Dth/day of incremental pipeline capacity, assuming a daily pipeline charge as high as \$2.00/Dth.

¹⁸⁶ The LNG Import and Dual Fuel & Demand Response options would be forgone in years of negative net benefits. Therefore, the average net benefit of LNG jumps to \$138 million when these years are omitted from the calculations.

¹⁸⁷ As described in the Phase III report, the costs and benefits for the pipeline and imported large-scale hydropower solutions reflect assumed in-service dates and payback periods that extend beyond the study horizon. In contrast, the LNG imports and dual-fuel and demand response solutions were only pursued for portions of the study period, reflecting the shorter-term commitments associated with these solutions. Average annual net benefits for each of the solutions were calculated based on these temporal assumptions, cost-of-service cost estimates, and the analysis of economic benefits.

¹⁸⁸ Sussex Economic Advisors, Maine Public Utilities Commission Review of Natural Gas Capacity Options (Feb. 26, 2014), available at <http://www.maine.gov/tools/whatsnew/attach.php?id=615609&an=1>. See also Maine Energy Cost Reduction Act, P.L. 2013, c.369, codified at 35-A M.R.S. §1901 *et seq.*

Similar to the Black and Veatch and Sussex findings, a more simplified analysis conducted for this IRP also suggests that new pipeline capacity could provide net economic benefits. In a hypothetical example, DEEP assumed a range of costs for new pipeline capacity based on the costs of the Algonquin AIM project that Connecticut's gas LDCs are sponsoring and a hypothetical project assessed in the NESCOE study.¹⁸⁹ The result is a levelized cost of \$0.38 to \$1.07/MMBtu in constant 2014 dollars.¹⁹⁰ When compared to 2014 spot market basis swaps of \$3.5/MMBtu, this cost range may be attractive and suggests that new pipeline capacity could provide net economic benefits. However, if the costs are closer to the \$1 to \$2 per MMBtu suggested by Sussex, the net savings would be more marginal; net savings would clearly depend on actual costs being lower than but-for basis differentials.

If signing up for new pipeline capacity allowed for lower fixed pipeline charges in place of paying for higher and more volatile basis differentials and saved, say, \$1/MMBtu, each 100 MMcf/d of new pipeline capacity would save customers \$37 million per year net of the fixed pipeline costs (owning 100 MMcf/d would provide a hedge on approximately of 4,600 GWh of customer electric load, or 520 MW on average, assuming an average market heat rate of 8 MMBtu/MWh). DEEP estimates that this amount of pipeline capacity could also add \$10 million in annual reliability value, considering that ISO-NE has just committed to paying roughly \$75 million as part of the 2014/15 Winter Reliability Program to ensure approximately 1.95 GWh of dual-fuel inventory that corresponds to approximately 4,000 MW of dual-fuel capability assuming that they were operated over the course of 20 winter days.

Large-Scale Hydropower

Incremental pipeline capacity and transmission to enable large-scale hydropower imports can both improve winter reliability and lower electric costs but do so in different ways. The incremental pipeline option makes gas more available so that existing gas generators can operate during peak periods. This improves the reliability of gas generators and consequently the reliability of the electric system. Adding gas supply will also drive down delivered gas prices; with lower gas costs, generators can reduce their bids in the wholesale energy market and thereby lower wholesale electric prices.

Importing power can also improve reliability and lower cost but does so by displacing gas or other fossil generation with large-scale hydropower generation. Large-scale hydropower has no

¹⁸⁹ This range can be translated into a revenue requirement (to be paid to the pipeline owner) by assuming a 15-year cost recovery and an assumed after-tax weighted average cost of capital of 8.7%. The revenue requirement declines with depreciation, and it accounts for income taxes the pipeline owner would have to pay net of depreciation deductions. For presentation purposes, we translate the revenue requirement into a level-real equivalent using the same cost of capital.

¹⁹⁰ AIM is projected to cost about \$1 billion for 340 MMcf/d of new capacity into New England, for an average cost of \$2.9 million per MMcf/d of expansion capacity. (For comparison, the project assessed in the NESCOE study was estimated to cost \$1.2 billion for 1,200 MMcf/d of capacity, for an average cost of \$1 million per MMcf/d.)

fuel costs and therefore can bid zero or close to it in the energy market.¹⁹¹ This compares to gas and oil generators that must recover their fuel costs in the energy market bids. Due to its lower variable cost, large-scale hydropower is typically dispatched ahead of gas and oil generation, thereby lowering wholesale energy prices.¹⁹²

Requiring firm delivery in the large-scale hydropower contract during winter peak periods when gas may not be available for gas fired generators is essential to ensure reliability benefits as well as to maximize cost-benefit, considering that Canada's winter-peaking market may otherwise limit imports into New England during winter peak periods. The Black and Veatch study evaluated the costs and benefits of importing large-scale hydropower under two scenarios: (1) firm-based imports, and (2) economic-based imports. Under both electric import scenarios, Black and Veatch assumed the cost of constructing a 180-mile transmission line originating at the Canadian border and terminating in New England, at a cost of approximately \$1.1 billion. Levelized over twenty years, the annual cost of service for the transmission project was estimated to range from \$180 million to \$219 million.¹⁹³

Firm Canadian electric imports were more cost effective than market based imports. Importing large-scale hydropower from Canada was not as cost effective as the pipeline option, but was still cost effective and a viable long-term solution for the winter reliability crisis. For the economic-based imports scenario, Black and Veatch assumed no firm contract for generation would be in place, and that hydropower would flow over the transmission line only when the wholesale electricity price in New England exceeds the prices in other available markets. Imports for economic based power were expected to be limited due to Canada's winter peaking market, never exceeding 700 MWh in the winter throughout the analysis period. This assumption limited the benefits of non-firm imports to \$256 million annually, resulting in \$37 million in net benefits over the study period under the Base Case.

For the Firm import analysis, Black and Veatch assumed the cost of transmission construction as well as the cost of expansion and/or construction of generating facilities and a firm contract for 1200 MW every hour. This added \$170 million in costs annually but also increased price suppression savings by \$194 million to \$450 million annually resulting in a net benefit of \$61 million in the Base Case.¹⁹⁴ The benefits increased for the Firm Hydro import option in the High Demand Scenario compared to those in the Base Case, doubling from \$61 million in the Base

¹⁹¹ An economically rational imported large-scale hydropower resource would likely offer its supply for the opportunity cost of selling the power to other regional markets or storing the power for another higher priced time.

¹⁹² In the wholesale market the last generator selected to meet demand in each hour sets the clearing price for all generation in that hour. If something can be done to reduce the clearing price in a particular hour such as by adding pipeline capacity or adding lower cost large-scale hydropower generation, the cost of all generation is reduced and therefore can provide significant benefits. This is referred to as "energy price suppression" and is the primary benefit analyzed in the Black and Veatch studies.

¹⁹³ These cost estimates are based on regulatory filings of a proposed project.

¹⁹⁴ If the cost of the generation is removed, the net benefits of the firm transmission line increase significantly to \$231 million annually, for a benefit to cost ratio of 2.05 in the Base Case. The net benefits increase to \$293 million annually and the benefit to cost ratio increases to 2.34 for Firm Hydro under the High Demand Scenario.

Case to \$123 million annually in the High Demand Scenario. This increased the benefit cost ratio to approximately 1.32 compared to approximately 1.16 for this option in the Base Case.

It is important to point out that the Black and Veatch study compared all resource solutions solely based on the savings associated with their wholesale energy price suppression benefits. The Firm Import option included generation costs but only price suppression benefits. No other benefits associated with a firm fixed price large-scale hydropower contract were included. This approach is internally consistent for comparing the gas pipeline, LNG, and dual fuel with demand response solutions, since price suppression was the primary benefit associated with those winter reliability solutions. However, imported large-scale hydropower offers other benefits not addressed in the Black and Veatch analysis:

- Large-scale hydropower offers an opportunity to add non-emission generation which would help to diversify the fuel mix and reduce electric costs. Increased large-scale hydropower generation would reduce the use of natural gas and other fossil fuels reducing energy prices and providing environmental benefits to Connecticut citizens and to those throughout New England. When new large-scale hydropower resources replace a portion of the baseload resources added in the 2014 IRP Base Case, New England's CO₂ emissions drop by about 2% (0.6–0.7 million short tons), and New England natural gas use drops by about 2–3% (10–13 million MMBtu).
- Large-scale hydropower could also serve as a hedge against fuel price volatility similar to Class I if contracted on a fixed price basis. Connecticut and other states could consider contracting for large-scale hydropower at fixed or indexed prices. Such arrangements would delink the price of the power from natural gas prices and provide a hedge against higher than expected energy price increases in the future.¹⁹⁵
- Other benefits may include capacity value, capacity price suppression, and energy savings if the contract price is below the long-term market rates.
- Large-scale hydropower might also be coupled with Class I resources in a single transmission project under certain configurations to help meet RPS goals and reduce REC prices. Large-scale hydropower is available more often and could be dispatched compared to wind and solar that produces electricity more intermittently. This provides greater certainty and flexibility to grid operators and also allows power to flow over the transmission lines at a higher capacity factor spreading transmission costs over more kilowatt hours. Because it is more flexible, large-scale hydropower could also be used in certain configurations to operationally complement and balance Class I resources increasing the utilization of transmission lines. Large-scale hydropower resources can

¹⁹⁵ It might also be possible for large-scale hydropower power to be delivered to New England at market prices. The price of the power would fluctuate with the market price of electricity which would still be driven by the cost of the marginal generation unit, often gas. However, increased base load power would reduce the need to operate less efficient generators thereby reducing energy prices for all kilowatt hours produced in New England sold through the ISO-NE energy market.

provide greater reliability benefits and/or reduce the need for additional operating reserves to integrate intermittent resources.

Today, there are transmission lines amounting to 2,200 MW of transfer capability linking New England to Eastern Canada. These lines are currently utilized most hours of the year so there is not much excess capacity that could be utilized to import additional large-scale hydropower power to New England. In order for large-scale hydropower to have a significant impact, new transmission facilities are needed in Canada and New England.

Class I Renewable Resources

Class I resources by themselves are not likely to offer a viable alternative to gas infrastructure or firm large-scale hydropower to improve winter reliability and lower costs. The cleanest Class I options, such as wind and solar, are intermittent resources and therefore they may not be available when needed.¹⁹⁶ These resources produce at relatively low capacity factors so that the cost of transmission would be considerably higher than large-scale hydropower on a ¢/kWh basis. Other Class I resources such as biomass, landfill methane gas and fuel cells can operate at high capacity factors.

Solar or wind could provide a viable cost-effective means of addressing the winter reliability problem if it is combined with large-scale hydropower or other Class I resources to ensure deliverability during peak periods when desired. Wind could conceivably replace some of the large-scale hydropower in the Black and Veatch Firm Hydro solution analysis. Assuming the resources and transmission were configured accordingly, the combination of large-scale hydropower and wind would have the same reliability impact and price suppression benefits as the Firm Hydro option. The Class I resources and associated transmission may cost more than large-scale hydropower, but the purchasing entity would receive Class I RECs to offset RPS compliance costs. Procuring renewables to address the gas infrastructure constraint would have the added benefit of helping to remedy the shortage of Class I supply that is projected as RPS targets increase in Connecticut and across the New England region.

Liquefied Natural Gas (LNG)

In the High Demand Scenario, Black and Veatch estimated the benefits for Liquefied Natural Gas (LNG) imports to be \$433 million annually and the cost to be \$196 million annually resulting in a benefit to cost ratio of 2.24. This is lower than the benefit to cost ratio of 2.93 for the gas pipeline. By itself, LNG is not likely to be the best long-term solution to the winter reliability problem. But LNG (and demand response) may be quite cost-beneficial in meeting the demands in the highest peak days when it may not be economic to secure firm pipeline capacity. Short-term purchases of LNG could offer benefits in the near term as LNG relieves system constraints, putting what amounts to an upper limit on gas prices. LNG imports have the potential to offer significant savings in the near term, but these savings would be expected to

¹⁹⁶ For example, solar resources are generally unavailable during the winter peak demand, which is typically in the evening.

decrease in later years as demand growth causes total gas demand to reach levels too great for LNG imports to significantly impact price spikes caused by seasonal constraints.

This conclusion is also supported by analysis performed by ICF International at the request of GDF Suez, the owner of the Everett LNG import terminal in 2014.¹⁹⁷ ICF utilized an analytical approach that examines the relative unit costs of dual fuel, LNG, and pipeline as a function of time. The so-called cost-duration curve analysis finds that for congestion that occurs less than 30 days per year, LNG has lower unit costs than pipeline. However, for congestion that exceeds approximately 30 days per year, pipeline solutions have lower unit costs than LNG investments. Thus, as the region's gas demand is expected to grow over time with anticipated non-gas-fired retirements, the currently expected duration of constraints of approximately 24-34 days per year by 2020 would be likely to grow. The cost duration analysis therefore supports the conclusion that over time, as the extent and duration of constraints grow, pipeline investments are likely to have lower per unit costs than LNG as a strategy to alleviate infrastructure constraints.

In the shorter term, before long-term solutions can be built, DEEP recommends that dual-fuel generation, demand response measures and the seasonal purchase of LNG cargoes be deployed by ISO-NE through the Winter Reliability program.

Passive DR

As noted above, solving the New England region's winter reliability problem will require up to 1.0 Bcf/day of new gas pipeline capacity available to natural gas generators in the winter, or the equivalent of replacing approximately 5,000 MW electricity generation capacity with non-gas alternatives, which could include energy efficiency measures to reduce demand for either electricity or natural gas.

Connecticut's gas and electric energy efficiency programs are playing an important role in helping Connecticut families and businesses lower their energy costs during this period of volatile, increasing electricity rates. The 2014 IRP estimates that all of the passive DR (conservation) in New England will achieve approximately 230 MW of summer peak demand reduction in 2017 at the current expanded spending levels. Yet summer peak demand is expected to continue to grow by 440 MW in 2017, and 365 MW in 2018.¹⁹⁸ Just reducing peak demand growth to zero would require an increase in conservation spending of approximately 175% across all New England states.

In the 2013-2015 Electric and Natural Gas C&LM Plan, the EDCs estimated that their proposed expanded electric conservation program would cost \$242.6 million in 2014, and yield total

¹⁹⁷ ICF International, *New England Natural Gas Supply and Demand: Post-Winter Review* (May 29, 2014), Addendum to May 30, 2014 comments of GDF Suez on the Incremental Gas for Electric Reliability approach to increasing natural gas infrastructure, at 14-15, available at http://www.nescoe.com/uploads/GDF-SUEZ_CommenstonIGER_30May2014.pdf.

¹⁹⁸ See Figure 16 in Appendix B (Resource Adequacy).

capacity savings of approximately 74.7 MW.¹⁹⁹ If winter peak demand reductions are assumed to cost the same as summer capacity savings, at this cost level of \$3,248/kW it would cost \$16.2 billion to provide 5,000 MW of peak capacity savings. This far exceeds the estimated expected cost of a gas pipeline.. Similarly, the total peak day savings from gas conservation programs in Connecticut for 2015 are estimated to be 6.6 MMcf/day at a utility cost of \$45 million.²⁰⁰ This is only 6% of the capacity needed to address the winter reliability problem. At this cost rate, it would cost \$6.8 billion to obtain 1 Bcf/day, far exceeding the cost of the gas pipeline.

Given the cost per unit savings of these programs, and the scale of the resource solution needed, conservation programs in Connecticut and across the New England region are best deployed as a supplement to, but not a substitute for, other resource solutions for the winter reliability problem.

Conservation alone cannot provide enough capacity quickly enough or economically to effectively meet the shortfall from non-firm gas generators, but investments in these resources will help to keep demand for natural gas from increasing, so as to avoid any need for the states to invest in additional transmission or pipeline infrastructure in the future. C&LM programs also provide non-electric benefits not considered here, including fossil fuel avoided costs, water savings, reduced maintenance costs to the participant, environmental benefits, infrastructure benefits, and achievement of state sustainability goals. C&LM cost effectiveness tests consider some of these benefits, which are roughly half of the electric system benefits reported in the EDCs' final C&LM filings. Also, efficiency has other non-monetized benefits that are important to consider, including creating localized energy savings for families and businesses within Connecticut, as well as economic benefits associated with program installation and implementation.

Combined Heat & Power

Combined heat and power (CHP) systems have the potential to help alleviate the region's winter reliability problem by reducing demand for electricity through on-site, simultaneous production of electricity and heat from a single fuel source, typically natural gas. To effectively contribute to relieving the region's gas infrastructure constraints, CHP facilities would need to displace existing separate heating and electricity demands, and have the associated distribution infrastructure and firm natural gas supply in place.

As with conservation and load management, DEEP believes that the amount of cost-effective and technically feasible CHP potential is too small to entirely avoid the need for new infrastructure to resolve the winter reliability problem, but cost-effective CHP should be deployed to the extent possible to right-size the infrastructure build-out (*see* Resource Strategy #5). A 2004 study of statewide CHP potential concluded that there is nearly 700 MW of technical potential in Connecticut, meaning that even after counting all CHP systems currently in operation, only 400 MW of technical potential remain in the industrial sector today. In the 2013 CES for

¹⁹⁹ Eversource's proposed budget and savings were adjusted to eliminate ISO Load Response Program. This budget level was not ultimately approved for 2014 but provides a reasonable estimate of the costs and savings that can be expected from electric efficiency. C&LM Plan, *supra* note 24.

²⁰⁰ C&LM Plan, *supra* note 27, at 100.

Connecticut, DEEP estimated that a reasonable estimate for actual development would be closer to 170 MW in Connecticut over the next five years.²⁰¹

Active Demand Resources

As described in more detail in Resource Strategy #2, active DR is an important “peaking” resource that can help to reduce electricity demand and thereby alleviate dependence on constrained natural gas infrastructure during periods of high winter demand, improving reliability and reducing electricity prices. Active DR can meet the highest peaks for short periods cost effectively. However, active DR is not suited to solve the winter capacity need over many days. Over prolonged periods, it is likely more cost effective to procure pipeline capacity and/or non-gas generation resources.

CONCLUSION & MECHANISMS FOR PROCUREMENT

DEEP concludes that a combination of cost-effective solutions should be considered to improve winter reliability, and lower generation costs. The analysis presented in this IRP indicates that a variety of resources could help to relieve the region’s gas infrastructure constraints. Studies suggest that supply-side incremental gas pipeline capacity and electric transmission facilities can provide some of the most durable and cost-effective solutions in the long run. Class I resources — particularly if balanced by hydropower — can provide an attractive alternative to natural gas generation, increasing the diversity and therefore reliability of the region’s electric supply while also helping Connecticut and the region meet increasing RPS targets. Contracts for LNG and active DR are not likely to be more cost-effective as a substitute for gas or transmission infrastructure, but may be very cost-effective as “peaking” resources to “right-size” infrastructure build-out and avoid stranded costs. Similarly, resources that reduce demand for electricity or natural gas — such as conservation, combined heat and power — are not available in sufficient quantity to entirely avoid the need for new infrastructure, but these passive DR may help to “right-size” gas and transmission infrastructure, and provide additional benefits by supporting Connecticut’s clean energy economy and lowering energy bills for those Connecticut families and businesses who deploy these technologies.

New England Regional Coordination: Progress to Date

The winter peak reliability problem is regional in scope. The lack of gas infrastructure has driven up prices and compromised the reliability of the New England wholesale electricity market, and the effects are felt by ratepayers across the region. As noted above, the magnitude of the solutions needed is very large — on the order of 1 Bcf/day of natural gas, or 5,000 MW of non-gas generation or demand reduction — too big for any one state to secure on its own. Even though the potential solutions are much cheaper in the long run than the high electricity costs ratepayers are currently paying because of the lack of infrastructure, the solutions are cost-prohibitive for one state to bear alone, since the benefits are dispersed across the region in terms

²⁰¹ DEEP, 2013 Comprehensive Energy Strategy for Connecticut (February 19, 2013), p. 57, available at <http://www.ct.gov/energystrategy>.

of lower wholesale market costs and improved system reliability. Coordinated investment by multiple states, representing a critical mass of ratepayers, is necessary.

For these reasons, the New England Governors are pursuing a regional energy infrastructure solution to the winter reliability problem. In December 2013, the six New England Governors issued a joint statement committing to regional cooperation on strategic investments in low- and no-emission resources and energy infrastructure to improve New England's energy reliability and resiliency, diversify the region's energy portfolio, increase its economic competitiveness by reducing energy costs, and protect New England's environment and quality of life.²⁰²

The six states, working through NESCOE, have proposed various ways to meet these goals. In addition to commissioning the Black and Veatch analysis of infrastructure solutions, discussed above, NESCOE met with each sector of the New England Power Pool, including, for example, representatives of end users, generators, alternative resources, environmental advocates, transmission owners and municipal utilities. NESCOE invited, through the NEPOOL and the New England Gas-Electric Focus Groups, stakeholder comment on the level of natural gas capacity needed to address the region's energy challenges, the appropriate structure for backstopping natural gas capacity contracts, the appropriate structure for managing the release of procured gas capacity into the market, and any other concepts that could achieve the six states' objectives.²⁰³ NESCOE also presented monthly status updates to NEPOOL, and brought specific proposals to the appropriate NEPOOL committee for discussion and feedback. NESCOE received input from a wide variety of stakeholders including regulated utilities, infrastructure developers, representatives of end users, environmental advocates, and trade associations, among others. These comments were valuable in focusing and refining the states' efforts and, as described in a January 2014 letter to ISO-NE, the New England states focused on FERC-jurisdictional ISO-NE tariffs as the preferred proposal to fund incremental natural gas pipeline capacity and transmission to deliver low- or no-emission electricity,²⁰⁴ since such tariffs provide an effective mechanism for recovering costs fairly from all New England electric ratepayers who would receive the economic benefits from the infrastructure expansion. Accordingly, NESCOE engaged with stakeholders about the proposal in the NEPOOL process, through which ISO-NE tariffs are proposed and considered, but before proposals are submitted to FERC for consideration.

While this regional coordination on proposed tariffs for FERC consideration has been ongoing, states have also advanced solutions utilizing their existing state authority:

- In 2013, legislation was enacted in Maine that authorized the Maine PUC to pursue regional and federal efforts to improve the transmission of natural gas into the region; encourage private efforts to build additional pipeline capacity; and to enter into contracts

²⁰² See New England Governors' Commitment to Regional Cooperation on Energy Infrastructure Issues, available at http://www.nescoc.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf.

²⁰³ See NESCOE, Regional Infrastructure, available at http://www.nescoc.com/Regional_Infrastructure.html (providing all letters and public comments on the six state energy initiative).

²⁰⁴ Letter from NESCOE to Gordon van Welie, President and CEO, ISO New England (January 21, 2014), available at http://www.nescoc.com/uploads/ISO_assistance_Trans_Gas_1_21_14_final.pdf.

for up to an additional 200,000 MMcf on Maine PUC's own behalf or direct state gas distribution companies, electric distribution companies, or natural gas pipeline companies.²⁰⁵

- In 2014, legislation was enacted in Rhode Island that allows the Rhode Island Office of Energy Resources to work with energy officials throughout New England and use a competitive energy procurement process to implement cost-effective energy infrastructure that lower energy costs, improve grid reliability, advance clean energy goals, and protect the quality of life and the environment. The Rhode Island legislation specifies that investments made resulting from the competitive procurement process must share the costs and benefits appropriately among all New England states and the benefits to Rhode Island and its ratepayers must exceed the costs.²⁰⁶
- A bill was introduced into the Massachusetts General Court in March 2014 that would have required all distribution companies to solicit contracts for no less than 18,900,000 MWh of electricity annually from clean energy generators. Any long-term contracts entered into as a result of the solicitation would have been coordinated with the Massachusetts Department of Energy Resources and subject to approval by the Department of Public Utilities. That bill was not approved before the Massachusetts legislature adjourned in July 2014.²⁰⁷

Securing authority for large-scale procurement of low- or no-emission resources was critical to Massachusetts' participation in the procurement of resources described in the January 2014 letter to ISO-NE, and therefore NESCOE requested an extension of the NEPOOL schedule for consideration of proposed tariff mechanisms for FERC's consideration associated with the Governors' Infrastructure Initiative.²⁰⁸

In the meantime, the need for solutions to the regional gas infrastructure constraint has become even more apparent. In the fall of 2014, new standard service rates were announced for several utilities across New England, yielding significant increases in retail generation rates that were expected to follow the spike in wholesale electricity prices over the previous winter. In Massachusetts, generation rates increased for National Grid customers by 96%, from 8.3 ¢/kWh to 16.2 ¢/kWh, and by 58%, from 8.8 ¢/kWh to 14.0 ¢/kWh for residential customers of Western Mass. Electric Company. More recently, in Connecticut, PURA approved new generation rates for Connecticut customers on standard service: For residential customers of Eversource, the rate increased by 26% from 9.99 ¢/kWh to 12.63 ¢/kWh in January 1, 2015, meaning that the average bill for a customer using 700 kWh per month increased by \$18.48 per month. For residential customers of the United Illuminating Company, the standard service generation rate increased by 54% from 8.67 ¢/kWh to 13.31 ¢/kWh. These increases in retail rates reflect the market's

²⁰⁵ Maine Energy Cost Reduction Act, P.L. 2013, c.369, codified at 35-A M.R.S. §1901 *et seq.*

²⁰⁶ Rhode Island Affordable Clean Energy Security Act, H 7991 Substitute A (2014), available at <http://webserver.rilin.state.ri.us/BillText/BillText14/HouseText14/H7991A.pdf>.

²⁰⁷ 2014 Proposed Bill H.3968, 188th General Court of the Commonwealth of Massachusetts.

²⁰⁸ New England States Committee on Electricity, Statement on Extension of Schedule, available at http://www.nescoe.com/uploads/ScheduleExtensionStatement_1Aug2014.pdf.

expectation that gas basis differentials, and therefore wholesale electric prices, will continue to remain high in New England. For these reasons, as described below, DEEP plans to (1) utilize existing state authority under Public Act 13-303 to procure Class I and/or large-scale hydropower that can offset some increment of natural gas demand, and (2) seek new authority from the legislature to solicit proposals from demand-side or supply-side resources that can cost-effectively resolve the gas infrastructure constraint, up to an amount that is proportional to Connecticut's share of regional electric demand.

Utilize Existing Authority to Procure Delivery of Class I and/or Large Scale Hydropower Through Coordinated Regional RFP

As noted above, both Class I renewables and large-scale hydropower have the potential to provide a cost-effective solution to the region's natural gas infrastructure constraints, while diversifying the fuel mix and lowering emissions. The Department has existing statutory authority to issue a solicitation for long-term power purchase agreements (PPAs) for up to 5% of the state's electricity demand under Section 7 of Public Act 13-303. This Section 7 solicitation must be open to bids from both large-scale hydropower and Class I resources as prescribed by statute. This equates to approximately 175 MW of large-scale hydropower at a 90% capacity factor, or 450 MW of wind at a 35% capacity factor. In addition, the Department has authority remaining under Section 6 of Public Act 13-303 to solicit long-term PPAs for up to approximately 125 GWh/year of Class I renewables.²⁰⁹ In total, the amounts DEEP can solicit utilizing existing statutory authority represents about 1,500 GWh/year of clean energy. This amount is insufficient to fully resolve the region's gas infrastructure constraints, but could incrementally reduce the high winter energy prices caused by the constraints on gas fired generation during the winter peak hours; reduce greenhouse gas emissions; and provide a hedge against fuel price fluctuations in the energy markets. To the extent any projects selected are located in Connecticut, they could provide economic development and reliability benefits the state. In addition, any Class I resources contracted for under this solicitation will also help Connecticut meet its Class I RPS requirements, which are projected to be short by 2015.

DEEP is coordinating this solicitation as part of a regional procurement for Class I, large-scale hydropower, and associated transmission with Rhode Island and Massachusetts. Rhode Island has authority to procure hydropower and renewable energy resources pursuant to state statute; Massachusetts EDCs have authority to procure Class I renewables under Section 83A of the Green Communities Act.

A complication of accessing grid-scale renewables or large-scale hydropower is that both resources likely need new transmission lines to move the power generated in remote areas to uncongested portions of the New England transmission grid so that all customers can benefit from these resources. Coordinating this procurement with other New England states offers the potential to attract bids from large-scale projects — including those requiring significant transmission investments — that would otherwise be too large or costly for one state to support

²⁰⁹ Under Section 6 of Public Act 13-303, the Department was authorized to procure contracts for up to 4% of the state's electricity demand from Class I resources. The Department's 2013 solicitation under Section 6 resulted in contracts filling 3.5% of load.

alone. It also raises the possibility of procuring transmission without an associated PPA, but rather, a commitment from the transmission developer to arrange with a supplier or suppliers for firm delivery of clean energy over the line. The advantage of transmission without an associated PPA is that it provides the benefit of addressing the region's natural gas infrastructure constraints, diversifies the fuel mix, lowers emissions, but does not require a long-term commitment to any given price for the generation.

To the extent that DEEP may select a project through the coordinated procurement that requires transmission, recovery of costs associated with that transmission would be subject to FERC jurisdiction and approval. Regardless of whether bids are exclusively PPAs for clean energy, a combination of PPAs for clean energy and associated transmission, or transmission without a PPA but with an obligation to deliver clean energy, DEEP will independently evaluate the bids that are eligible for selection under Connecticut's authority.

Secure Authority for Procurement to Meet Connecticut's Share of a Regional Infrastructure Solution

As noted above, DEEP believes that at least 1.0 Bcf/day of natural gas transportation capacity or equivalent gas storage and supply, or the equivalent of approximately 5,000 MW of non-gas fired generation will be needed for 30 days or more to address the region's winter reliability problem. While the procurement of Class I or large-scale hydropower under existing authority described above will help incrementally to alleviate regional gas infrastructure constraints, more action will be needed to fully and cost-effectively address the problem. Therefore, DEEP recommends seeking new authority from the legislature to run a competitive procurement open to a broad range of resources (including LNG and gas pipeline capacity; transmission for large-scale hydropower or Class I renewables; and demand response, energy efficiency, and combined heat and power) that can cost-effectively resolve or reduce the gas infrastructure constraint, up to an amount that is proportional to Connecticut's share of regional electric demand.

For illustrative purposes, under the most recent load forecast issued by ISO-NE, Connecticut accounts for approximately one quarter of regional electric usage; Massachusetts consumes about half of the region's electricity; Rhode Island, Maine, New Hampshire, and Vermont account for the remaining twenty five percent. Therefore, it may be reasonable for Connecticut to seek legislative authorization to procure resources, alone or in combination, equivalent to up to roughly 250 million cubic feet of natural gas capacity, or 1,250 megawatts of non-gas generation or its energy efficiency equivalent, or any combination thereof.

Any calculation of Connecticut's "share" of a regional solution should be offset by incremental resources brought forth outside of this procurement, such as: any new or incremental Class I or firm large-scale hydropower supply contracted for by Connecticut EDCs pursuant to the coordinated regional procurement under existing authority, described above; any energy efficiency savings (described in Resource Strategy #1) that are not counted in the ISO-NE load forecast; new combined heat and power facilities developed through a revitalized CHP program as recommended in Resource Strategy #5; incremental distributed generation supported through Connecticut's LREC/ZREC program or the next iteration of the Connecticut Green Bank's Residential Solar Incentive Program (RSIP), as described in Resource Strategy #6; and any demand response or conventional non-gas generation or gas generation with firm fuel supply that

the state may procure in the event of a capacity market failure, as detailed in Resource Strategies #2 and #3.

To the extent that Connecticut utilizes state authority to invest in resources, all of the costs of those resources would be recovered from Connecticut electric ratepayers. The benefits provided by the contracted resources would include increased reliability and reduced wholesale energy prices. The benefits may also include lower capacity prices, lower greenhouse gas emissions, and increased regional renewable supply, depending on the type of resource that is procured. Because Connecticut receives its electric supply through a regional market, these benefits would necessarily flow to the ratepayers of all six states participating in that market. As such, any Connecticut investment under state authority to address the regional gas infrastructure constraint will be contingent on other New England states taking coordinated action to do their part and invest in similar resources.

While joint action among the New England states will require substantial coordination across jurisdictions, this approach provides individual states with flexibility to determine which resource or set of resources best fits their policy priorities. To allow for such flexibility without compromising a fair allocation of costs among the states, it may be important to ensure that the states reach mutual agreement about how to determine the equivalency of different resources procured by different states. For example, investments in pipeline or transmission infrastructure will require several years to come online and will last — and be paid for — over several decades, while “peaking” resources such as LNG or active DR may be procured right away but on shorter contract terms. These contrasting resource characteristics raise questions about how to account for the states that procure peaking resources and re-contract for those resources if needed when initial terms expire, and/or how to value longer-lived investments against short-term contracts. Other questions that will need to be resolved will be how to value non-gas generation that is intermittent (such as solar or wind), as compared to resources that are dispatchable or offset baseload gas demand.

These and other issues will need to be addressed in order to determine the extent to which Connecticut procurement is cost-effective for Connecticut ratepayers, in the context of other states’ actions. The level of cooperation among the New England states with respect to our shared natural gas infrastructure challenge has been positive and unprecedented, and DEEP believes that any procurement authority, if authorized by the Connecticut General Assembly, would be best implemented through regionally-coordinated procurements, as the Department is currently pursuing with Rhode Island and Massachusetts EDCs using existing authority. Moreover, to the extent multiple states may procure resources such as natural gas pipeline capacity, it will be important to establish a common structure or mechanism to manage and release such capacity to ensure maximum benefit to electric ratepayers. In this way, DEEP would hope to continue to build on the work the states have done, through NESCOE, to continue to obtain stakeholder input and refine proposals regarding the management and structure of electric ratepayer investment in natural gas resources.

RESOURCE STRATEGY #5: PROVIDE SUPPORT FOR INCREASED CHP DEPLOYMENT

Combined heat and power (CHP) systems improve the efficiency of conventional power generators by capturing heat lost in the combustion process that would otherwise be wasted. By using this heat for other energy services like drying paper or making chemicals, CHP systems can increase the combined efficiency of separate heat and power generation from approximately 45% to nearly 80%.²¹⁰ This saves fuel, reduces energy costs, and lowers emissions.

Despite the maturity and benefits of this technology, significant technical, administrative, and financial barriers have often restricted the widespread adoption of CHP system. The upfront cost of installing CHP systems – about \$1,314,000 per MW for a typical 5 MW, simple-cycle turbine – can be prohibitively expensive for many users. Along with additional insurance requirements, barriers like these often threaten or eliminate the viability of a CHP project.

In Connecticut, regulators and legislators recognized these challenges and responded to them over the past decade by unveiling a number of policies and incentives that improved CHP development. Beginning in 2005, the Connecticut General Assembly directed the former Department of Public Utility Control (DPUC) to establish a CHP grant program and low interest loans that significantly reduced the capital costs of CHP systems. The legislature also standardized grid interconnection processes, reduced stand-by rates, eliminated natural gas delivery charges, and created a new Class III renewable energy credit for CHP and efficiency measures to help fund CHP projects. In addition, these state actions were augmented by even more federal incentives designed to boost CHP development.²¹¹

As a result, 91 megawatts of new CHP capacity were added in Connecticut from 2005 to 2011, more than anywhere else in New England.²¹² The capital grant program has since expired, but the other state incentives continue to be available. In addition, Connecticut has passed more CHP-friendly policies like the long-term renewable energy credits for fuel cells within the LREC program. This program has advanced fuel cells development in recent years, but gas-fired CHP adoption rates have slowed without capital grants.

In 2011, the capital grant program was discontinued, and Public Act 11-80 created two new CHP incentive programs in its place. One program, administered by the Green Bank, offers up to \$450/kW in loans (or loan enhancements), grants, or power purchase agreements for CHP projects in development up to 5 MW in capacity.²¹³ The second program, administered by DEEP,

²¹⁰ American Council for an Energy Efficient Economy, “Topics: Combined Heat and Power (CHP),” available at <http://www.aceee.org/topics/chp>.

²¹¹ Numerous investment tax credits, loan guarantees, interconnection standards, bonds, and accelerated cost-recovery rules were available during the 2005-2011 period. *See* U.S. Environmental Protection Agency (EPA). “dCHPP (CHP Policies and Incentives Database).” EPA, July 2013: Washington, D.C, available at: <http://www.epa.gov/chp/policies/database.html>.

²¹² Combined Heat and Power Installation Database. Combined Heat and Power Units located in Connecticut. ICF International and U.S. Department of Energy, available at <http://www.eea-inc.com/chpdata/States/CT.html>.

²¹³ *See* Public Act 11-80 §103.

was established under Section 116(f) of Public Act 11-80. The DEEP program was designed to offer grants at a set incentive of \$200/kW for new or incremental CHP projects of 1 MW or less, to be funded through the Non-Bypassable Federally Mandated Congestion Charge (NBFMCC).

Progress under these two programs has been limited. The Green Bank program has been conducted in two solicitations, with the second and final solicitation at the end of February 2015 when the program expired. To date, the program has provided nearly \$1 million in incentives (mostly in grants, but also in interest rate buydowns on commercial PACE financing) for five projects totaling 3,820 kW installed CHP capacity. One 3,000 kW project was awarded an incentive of \$210/kW; the other four projects were much smaller and took higher incentives (\$450/kW on average). Meanwhile, implementation of the DEEP-administered Section 116(f) program never began and was suspended in March 2014, when PURA declined to create a cost recovery mechanism for the program in the absence of express statutory authorization to do so.²¹⁴ No grants have been provided under the 116(f) program, pending any legislative confirmation that the EDCs may recover costs associated with the program.

A 2004 study of statewide CHP potential cited in the 2013 CES concluded that there are over 400 MW of technical potential remaining in Connecticut's industrial sector today, with only about 40% or 170 MW of that technical potential cost-effective to develop.²¹⁵ Supporting deployment of this cost-effective CHP can provide multiple benefits to the electric system, in addition to lowering energy bills for the facilities where they are installed. First, as discussed above, CHP can help to reduce demand for natural gas and/or electricity, and therefore will contribute to alleviating the natural gas infrastructure constraints that are threatening the reliability and affordability of electricity in New England. CHP units can also provide onsite generation to power microgrids at critical facilities, helping to increase the reliability of the distribution system and maintain electric service during grid outages. And CHP units can also help to reduce electric demand in congested or overloaded circuits, thereby providing a more cost-effective alternative to traditional upgrades to the distribution grid.

The Department therefore recommends streamlining and revitalizing the state's CHP programs to support deployment of this cost-effective CHP potential. Specifically, DEEP proposes to amend its existing authority under P.A. 11-80 section 116 to create a new combined heat and power (CHP) program that would be open to businesses that are interested in developing CHP projects. The program would complement DEEP's Microgrid Grant and Loan Pilot program, and provides incentives to businesses that have an interest in developing a CHP project to boost their

²¹⁴ See PURA Final Decision in Docket No. 13-11-09 (March 5, 2014), available at <http://www.ct.gov/pura/docketsearch>. Authorization for cost recovery has also been a barrier to implementation of a pilot program established under Section 59 of Public Act 13-298, allowed for up to 20 MW of CHP systems (with nameplate capacity of 500 kw to 5 MW) placed in service between 2012 and 2015 to qualify for an exemption from demand ratchets during outages, and demand charges based on daily demand pricing prorated from standard monthly rates for outages of more than three hours (and no demand charges for outages of less than three hours). The Section 59 program was designed as a pilot, with requirements for data reporting to assess the viability of using daily demand charges for all CHP units.

²¹⁵ 2013 CES, *supra* note 201, at 57-9.

competitiveness, reduce their energy costs, and improve distribution system resilience and reliability.

Furthermore, in order to ensure an open and a competitive process, the new CHP program will contain a proposed schedule for offering the incentives over the duration of the program. The schedule would provide for “blocks” that result in a total of 170 MW of CHP capacity. The incentives would commence at four-hundred and fifty dollars per kilowatt are intended to be sufficient to meet the customer’s reasonable payback expectations, considering the estimated cost of installations, the value of the energy offset by the system, and the overall cost effectiveness of the system. Any attributes associated with such systems will be maintained for the benefit of all ratepayers. The incentives will decline over time and will automatically move to the next block once DEEP has committed the resources for a block. The Department can modify the approved schedule before it issues its next plan to account for changes in state or federal law or regulation or developments in the CHP market when these changes could affect the cost effectiveness of the program or are no longer in the interest of ratepayers. DEEP could consider premium incentives based on location, resiliency, or necessary upgrades to the distribution system.

RESOURCE STRATEGY #6: SUPPORT DEPLOYMENT OF ADDITIONAL CLASS I RENEWABLES

In 2013-2014, DEEP conducted two procurements under Sections 6 and 8 of Public Act 13-303, in consultation with the OCC, the Attorney General, and the state’s Procurement Manager. These procurements resulted in contracts for 299.2 MW, at an estimated savings of \$335 million in RPS compliance costs for ratepayers over the life of the contracts.

DEEP will continue to monitor the Class I market to determine if resources will be available for Connecticut to meet its RPS goals in the years ahead. To a great extent, this will depend on the renewable programs and procurement strategies of the other New England states, including the outcomes of the procurements described in Resource Strategy #4 to help resolve the region’s natural gas infrastructure constraints. In the coming months, DEEP will participate in a regional coordinated procurement of generation and associated transmission (if needed) that is open to Class I and large-scale hydropower, utilizing existing authority under Sections 6 and 7 of Public Act 13-303. In Resource Strategy #4, the Department further recommends seeking legislative authority to solicit bids for resources that can help to alleviate the region’s natural gas infrastructure constraints. As envisioned by DEEP, this solicitation would be open to a broad range of resources, including Class I facilities, and could result in long-term contracts for a significant amount of resources (equivalent to 5,000 MW of non-gas fired generation) if cost-effective.

Continue to Support Deployment of In-State Renewable Generation

As noted in the Department’s 2013 RPS Study, the amount of renewable generation built in the state increased tenfold between 2011 and 2013 with the support of programs such as Project 150, LREC/ZREC, the Section 127 program for utility-owned renewable generation, and the

Connecticut Green Bank's Residential Solar Incentive Program.²¹⁶ At the same time, the subsidies provided through several of these programs have been decreasing steadily.

- The LREC/ZREC program is now in its third of six years of implementation, pursuant to a process established by PURA in Docket No. 11-12-06. As of October 2014, the program is providing support to more than 800 active LREC and ZREC projects, with almost 21 MW of Class I capacity installed (approximately 17 MW of solar and 4 MW fuel cell) in the state and more than \$300 million in contract commitments executed. The program has seen average project pricing drop substantially in each subsequent solicitation for all size classes except the LREC.
- The Green Bank's Residential Solar Incentive Program (RSIP) was established under Public Act 11-80 to support the installation of at least 30 MW of residential rooftop solar PV by 2020. As of November 1, 2014, the Green Bank has approved the installation of 45 MW of residential rooftop solar PV – delivering the legislative target of 30 MW eight years ahead of schedule. Since 2011, installed costs have dropped by 20 percent (\$5.35 to \$4.30 per watt), incentives have dropped by 40 percent (\$1.70 to \$1.00 per watt), and investment has increased by more than 1,500 percent (\$8.3 million to \$126.1 million), creating jobs across Connecticut.

In the 2015 legislative session, the Connecticut Green Bank is proposing to evolve their Residential Solar Incentive Program to allow the Connecticut Green Bank to enter into 15-year contracts for the purchase of solar home renewable energy credits by the electric distribution companies (i.e., Eversource and UI) for solar power produced by eligible residential customer-sited generating projects. The purchase price of solar home renewable energy credits would be determined by the Connecticut Green Bank and would not exceed the lesser price of small zero-emission renewable energy credit projects for the preceding year or the alternative compliance payment pursuant to section 16-245(k) of the general statutes.

In the 2014 legislative session, Senate Bill 323 was proposed to establish a community solar program on a pilot basis. SB 323 contemplated a shared Class I renewable facility of up to 3 MW owned or leased by a for-profit or non-profit entity, with two or more subscribers (i.e., EDC customers located within the EDC's service territory) contracting for the "beneficial use" of the facility, including but not limited to a percentage interest or fixed amount of the electricity produced by the facility. SB 323 would have charged DEEP with establishing a billing credit and consumer protections for subscribers of the shared Class I facility. There may be other models that should be considered that would provide similar benefits to Connecticut residents. Regardless of the program design, DEEP recommends establishing a transparent, competitive request for proposals process to select projects that benefit all Connecticut ratepayers along with an implementation framework that includes all necessary consumer protections.

²¹⁶ As of 2011, Connecticut had only about 66 MW of renewable generation installed within the state. As of 2011, Project 150 had resulted in 47 MW of installed renewable capacity.

DEEP recommends continued deployment of cost-effective renewable generation within the state, at the lowest cost to ratepayers. Over the past several years, Connecticut has developed a myriad of renewable generation programs. It is essential to look at these programs holistically to balance the desire to increase in-state renewable generation with potentially lower cost out of state renewable resources. DEEP believes that the grid modernization process addressed in Resource Strategy #7 will help determine the cost and value of these programs and how they should be balanced in our state energy policy. Additionally, the method for procuring these resources should be considered and designed to be transparent and competitive.

Other Considerations

Under Public Act 13-303 and other renewable procurement programs, the EDCs act as buyers, signing long-term contracts for renewable energy and associated RECs on behalf of all customers. They pass on to all customers the financial equivalent of their contractual position by buying the energy and RECs at the contract prices, re-selling the RECs to load serving entities (LSEs) in the short-term REC market, then charging (or, more likely, *crediting*) customers for the net cost through a special line item on all customers' bills. This mechanism provides customers the benefits of long-term contracting without exposing the EDCs to the market risks. However, when implemented at the scale allowed by Public Act 13-303, the EDCs, along with those playing a similar role in Massachusetts, become the largest sellers of RECs into the short-term REC market. This could create an undesirable *perception* of seller's market power, even if no such power is exercised. Furthermore, this arrangement can create some administrative and transactional inefficiencies that adversely impact the value of the contracts for customers when the EDCs sell the RECs into the market only to have LSEs buy those RECs to serve the same EDC customers (in effect, customers lose the bid-ask spread on all transactions). The state could consider simplifying the arrangement through legislative change. For example, the EDCs could instead retire most or all the RECs they purchase, and the LSEs' RPS requirements could be reduced correspondingly.

RESOURCE STRATEGY #7: RE-EVALUATE REGULATORY POLICIES AND INCENTIVES FOR GRID MODERNIZATION

The structure of the electric system is evolving, and the roles of the distribution companies, generators, PURA, ISO-NE and customers are being restructured, refined, and modernized to capitalize on emerging technologies and shifting consumer demands. The traditional utility model – one in which electricity is centrally generated, transmitted over high voltage power lines, stepped down in voltage, and locally distributed to customers – is facing a new set of challenges and opportunities that could initiate a period of innovation that propels the electric industry forward. Aging transmission infrastructure, more weather disruptions, and grid insecurity have threatened this system's reliability and hampered its resiliency. The emergence of distributed energy resources (DER)—including energy efficiency; distributed generation; technologies such as storage and active demand response, that enable more flexible and efficient operation of the distribution system; and technologies such as microgrids and “smart” appliances that utilize information technology and control functions to manage localized loads—offer the promise of increasing customer control, enhancing the benefits of distributed generation, and allowing for cheaper, cleaner, more reliable operation of the distribution system.

Findings in the 2014 IRP illustrate the important benefits that DER can provide to the Connecticut and New England electric systems. The region's power generation mix has shifted to greater dependence on natural gas, with oil and coal increasingly providing critical power generation in winter months as a consequence of constraints on natural gas infrastructure and new market rules established by the ISO-NE. This trend underscores the need for more diverse generation, particularly from low- or no-emission resources.

Information technology improvements have given electric utilities more agility to reroute power loads and diagnose disruptions in real-time. These market trends allow utilities to supplement and diversify their generation options while building a more resilient and efficient distribution system. Next-generation smart appliances will have the capacity to communicate directly with utilities for greater efficiencies. A new industry is developing around these technologies to improve building system management and industrial system controls. These improvements provide an opportunity for customers to manage their electricity usage more effectively than ever before, reducing their electric costs and making their business more competitive.

The deployment of distributed generation has grown rapidly over the past few years as costs have declined. Distributed generation is now more competitive with larger central station power plants. This growth has been aided by innovative programs and policies to encourage clean efficient distributed generation development at the lowest cost to Connecticut ratepayers. The incentives and regulatory policies have been adopted over time to supplement the current electric industry model. As distributed generation grows and reaches critical mass it is important that it be fully integrated into the planning, operation and investment decisions of the electric distribution companies and ISO-NE.

DEEP believes that it is time to reevaluate the incentives, and regulatory policies that are related to distributed generation development. The investigation should also examine the equipment and investments and regulatory policies necessary for the distribution companies to fully integrate distributed generation into their system planning and operation. Evaluating and adopting a modernized approach to DER integration may revolutionize how utilities operate and deliver more value to their customers.

VALUING DISTRIBUTED ENERGY RESOURCES

More than a dozen cost-benefit analyses of distributed solar photovoltaic (PV) have been conducted around the country in the past few years.²¹⁷ Many of these studies are designed to determine what benefits and costs distributed PV creates, and to examine how those benefits and costs should be assessed, allocated, and priced. Some benefits may be more readily quantified than others. For example, the value of energy and capacity provided by distributed PV may be easily calculated, while the value of reliability, economic development, and environmental benefits may be more difficult to quantify. Other benefits may vary depending on locational characteristics (such as the orientation of a PV installation) or seasonal dynamics in the

²¹⁷ RMI, *A Review of Solar PV Benefit & Cost Studies*, 2d ed. (2013).

generation mix. Certain assumptions, such as fuel price forecasts, can also drive variations in PV valuation studies.

The Department proposes to undertake a study of the costs and benefits of DER—including solar PV, but also other types of distributed generation prevalent in Connecticut, such as CHP and fuel cells—to inform Connecticut policymakers, regulators, and stakeholders to understand the net value that DER provide to the electric system and to society generally, in order to ensure that the net benefits provided by DER technologies is commensurate with the cumulative incentives available to support deployment of those technologies. Further, as part of such a study, the Department proposes to examine existing and potential mechanisms for recovering the costs of DER integration and crediting participants for the benefits of DER. This review would include such issues as: net metering, virtual net metering, feed-in tariffs, interconnection process, and standby charges, including a review of the compatibility of various rate design options with other federal and state incentives. The proceeding should also include an investigation of technologies to aid customers such as smart meters and appliances, as well as time-of-use and dynamic pricing options.

INTEGRATING DISTRIBUTED ENERGY RESOURCES INTO THE DISTRIBUTION GRID

The electric distribution system of the future must be capable of supporting DER, meaning that it must be able to handle the two-way flow of electrons without compromising reliability, and it must be able to integrate “smart” technologies such as digital meters, smart inverters, smart appliances, and plug-in electric vehicles. At the same time, this future distribution system must be hardened to withstand 21st Century threats, including more frequent, intense storm events and cyberattacks. Exploring new approaches to integrate the operation of DER into the utilities’ management of the distribution system offers the possibility of not only enhancing system reliability, but also increasing the benefits to the electric system provided by DER. The transition to a “modernized” grid capable of full DER integration will be complex. The Department recommends an incremental approach, to ensure that the best policies and new technologies can be carefully evaluated and integrated into the regulatory structure and utility business model.

The Department proposes two important first steps in this transition. First, increased transparency is needed to identify those circuits in which there are opportunities to align existing DER deployment efforts, including the state’s LREC/ZREC program and the Green Bank’s Solarize campaigns and renewable incentive programs, to support and enhance the needs of the distribution system. Some reporting on distribution system needs already exists, such as in the annual reports Connecticut EDCs provide to the Connecticut Siting Council a ten-year forecast of expected electric demand and generation resources.²¹⁸ Making more detailed information available to the policymakers, program managers, and the public about areas of current or future congestion, or other load management issues, as well as areas of increased DER penetration, would provide important opportunities to maximize the benefits of DER on a locational basis.

²¹⁸ This forecast is required pursuant to Conn. Gen. Stat. §16-50r.

Second, the Department proposes to collaborate with the Connecticut Green Bank and the electric utilities, with input from interested stakeholders, on a pilot to deploy DER technologies in selected circuits to allow for a full examination of the costs and benefits of DER, the challenges of integrating DER, and the potential benefits of siting DER in locations. Such a pilot would be intended to explore and identify potential changes to incentive program design to allow for premium incentives in locations where deployment of DER can avoid distribution system costs, and/or provide enhanced benefits to the operation of the distribution system. Piloting DER solutions such as storage or information technology will also facilitate evaluation of the prudence and reasonableness of investments in new technologies and systems.

RESOURCE STRATEGY #8: GRADUALLY PHASE-DOWN REC VALUES FOR CLASS I BIOMASS AND LANDFILL METHANE GAS, BEGINNING IN 2018

In the Department's 2013 RPS Study, *Restructuring Connecticut's Renewable Portfolio Standard*, the Department identified that the bulk of ratepayer investment made through the state's RPS to support Class I renewable generation was spent on older, out-of-state, and not very clean biomass and landfill gas facilities, many of which existed before the RPS was first enacted. Accordingly, in the 2013 RPS Study, the Department recommended "gradually reducing the value of renewable energy credits awarded to [biomass and landfill gas facilities]" in order to "replace many of these resources with new, cleaner resources such as wind power, solar arrays, or other zero-emissions renewables."²¹⁹ The study also recommended that the state be authorized to enter into power purchase agreements with some of these facilities if it determines that retaining them provides economic benefits to the state, is in the interest of ratepayers and furthers the goals of the 2013 CES and the GWSA (i.e., because the withdrawal of RPS support for a biomass or landfill gas facility would otherwise cause it to exit the market and be replaced by fossil fuel generation).

Consistent with the Department's recommendation, Section 5 of Public Act 13-303, enacted in 2013, requires that the Department, in this 2014 IRP, "[establish] a schedule to commence on January 1, 2015, for assigning a gradually reduced renewable energy credit value to all biomass and landfill methane gas facilities that qualify as a Class I renewable energy source." Per the terms of the statute, biomass and landfill methane gas facilities that currently hold a contract with the EDCs or a contract resulting from the solicitations under Public Act 13-303 Sections 6 or 8 will not be subject to the REC value reductions.²²⁰ Further, through subsequent IRPs, the statute

²¹⁹ DEEP, *Restructuring Connecticut's Renewable Portfolio Standard* (April 26, 2013), p. 55, available at http://www.ct.gov/deep/lib/deep/energy/rps/rps_final.pdf.

²²⁰ As of the time of this report, the Project 150 Plainfield Biomass facility holds such a contract. The Section 6 solicitation for Class I renewable resources did not result in any contracts for biomass or landfill methane gas facilities. The Section 8 solicitation, which is specifically for biomass, landfill methane gas, and small run-of-the-river, has secured 3 contracts (for two facilities, Schiller Unit 5 and McNeil Generating Station) that will represent approximately 1% of the state's electricity demand or approximately 200,000MWhs. All procured contracts are for biomass facilities.

provides that DEEP may review the set schedule and make changes if deemed necessary given the availability of other Class I renewable energy sources.

In the time since the issuance of DEEP's RPS Study and the enactment of Public Act 13-303, several changes in the New England capacity market have occurred that raise new considerations for scheduling the phase-down. Biomass and landfill gas-based generation resources make up about two percent (roughly 700 MW) of New England's total capacity resources. With the expected retirements of non-gas fired plants such as Brayton Point, Salem Harbor, and Vermont Yankee, DEEP notes the importance of setting a schedule for biomass and landfill gas REC value reduction that would not cause a significant amount of these additional non-gas fired generation facilities to retire before newer, cleaner Class I resources can be attracted into the market. In addition, the potential for a region-wide shortage of Class I resources later in the decade suggests that it would be best to set a schedule for the phase-down to begin in 2018, to allow for the development of newer, cleaner Class I facilities procured through past or future procurements. Therefore, DEEP has determined to begin the phase-down in 2018. DEEP will monitor the Class I market and capacity market and DEEP will propose a schedule that reduces the REC value for Biomass facilities.

CONCLUSION

As detailed in the prior sections of this IRP, Connecticut families and businesses are facing several critical developments in New England's wholesale electricity markets that are challenging the affordability, reliability, and environmental impacts of the region's electric system. This section has identified eight Resource Strategies, proposed to address three critical policy objectives identified in the 2014 IRP: (1) to ensure that Connecticut and the New England region retain adequate capacity resources to meet summer peak electric demand; (2) to resolve the region's natural gas infrastructure constraints; and (3) to secure additional Class I renewable generation to meet RPS requirements in Connecticut and the New England region.

The eight Resource Strategies discussed above are designed to achieve these objectives and secure a cheaper, cleaner, more reliable energy future for Connecticut. Each of these strategies involve different types of resources, with different profile of location, capacity value, risks, costs, and benefits. Some of these strategies would require new legislative authorization, and some may depend on regional coordination to ensure cost-effectiveness. It is important to emphasize that many of these strategies serve multiple policy goals at once. The matrix below illustrates the various policy objectives that may be served by each of the recommended strategies.

**Figure 30
Summary of Resource Strategies**

Resource Strategies	Policy Goals							
	Resource Adequacy	Winter Reliability	Increase Class I Supply	Diversify Fuel Mix	Lower Utility Costs	Reduce Electric Rates	CT Economic Development	Reduce Emissions
1. Improve Cost Effectiveness and Focus C&LM on Peak Savings	Yellow	Yellow	Red	Red	Green	Yellow	Yellow	Yellow
2. Demand Response	Green	Yellow	Red	Red	Green	Green	Green	Yellow
3. Monitor Capacity Market	Green	Green						
4. Fund Gas Pipeline Capacity	Green	Green	Red	Red	Green	Green	Green	Yellow
4. Procure Large Hydro Power	Green	Green	Red	Green	Green	Green	Red	Green
5. Combined Heat and Power	Yellow	Yellow	Red	Red	Green	Red	Green	Yellow
6. Procure Class I (out-of-state wind)	Yellow	Yellow	Green	Green	Green	Green	Red	Green
7. Evaluate DG Policies	Yellow	Yellow						
8. Slow Biomass Phaseout	Yellow	Yellow	Green	Green	Green	Yellow	Yellow	Red

Neutral or Negative Impact

Small to Medium Positive Impact

High Positive Impact

DEEP believes that these are appropriate actions at this time to lower costs and meet our reliability and environmental objectives. DEEP believes that market intervention is necessary and that regional cooperation is imperative to resolve the region’s natural gas infrastructure constraints. While Connecticut does not have a need for additional capacity at this time, uncertain conditions in the region’s capacity market cause DEEP to recommend that the state be prepared to procure additional conventional generation resources or demand response in the event that the market fails to attract such resources as needed.