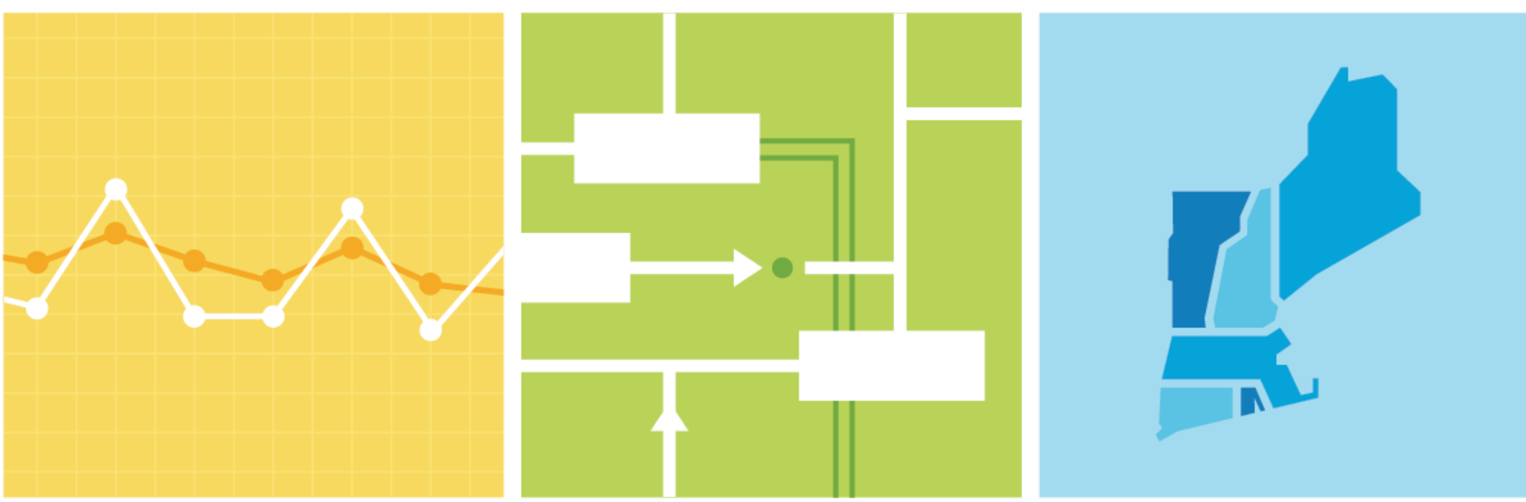
# NPCC 2016 New England Interim Review of Resource Adequacy



APPROVED BY THE RCC ON DECEMBER 6, 2016





# Section 1
# Executive Summary

This report is ISO New England's 2016 annual assessment (Interim Review) of its 2014 Comprehensive Review of Resource Adequacy, and covers the time period of 2017 through 2019. This Interim Review is conducted to comply with the Reliability Assessment Program (RAP) as established by the Northeast Power Coordinating Council (NPCC). It follows the resource adequacy review guidelines as outlined in the *NPCC Regional Reliability Directory #1 Appendix D, Basic Criteria for Design and Operation of Bulk Power System*.

To ensure the resource adequacy for the region, ISO New England identifies the amount and locations of resources the system needs and meets these needs in the short term through the Forward Capacity Market (FCM). Forward Capacity Auctions have been conducted to purchase needed resources for the years 2017/18[1] to 2019/20. The resources procured by ISO New England through FCM assume a capacity supply obligation (CSO), and must be available to offer energy and reserve to the New England energy markets. Resources that do not have a capacity supply obligation can participate in the energy markets to serve New England load and provide reserve. For this Interim Review, resource adequacy is assessed under two sets of resource assumptions: 1) using resources' seasonal claimed capabilities; 2) using capacity supply obligations of resources purchased in the Forward Capacity Market.

Table 1-1 and Table 1-2 summarize the Loss of Load Expectation (LOLE) for the study years for the two demand forecast scenarios simulated under two sets of capacity resource scenarios.

**Table 1-1**
**LOLE under Reference Demand Forecast**

| Year | 2014 Comprehensive Review (Days/Year) | 2016 Interim Review (Days/Year) | |
|---|---|---|---|
| | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Capacity Supply Obligations |
| **2017** | 0.060 | 0.056 | 0.069 |
| **2018** | 0.068 | 0.025 | 0.040 |
| **2019** | 0.074 | 0.027 | 0.028 |

[1] A capacity commitment period of 20xx/yy refers to a period from June 1, 20xx through May 31, 20yy.

**Table 1-2**
**LOLE under High Demand Forecast**

| Year | 2014 Comprehensive Review (Days/Year) | 2016 Interim Review (Days/Year) | |
|---|---|---|---|
| | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Capacity Supply Obligations |
| **2017** | 0.109 | 0.072 | 0.089 |
| **2018** | 0.130 | 0.036 | 0.056 |
| **2019** | 0.150 | 0.042 | 0.043 |

Results of this Interim Review show that New England has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under both the reference and high load forecast for the study period 2017 through 2019. Forward Capacity Market auctions have also procured an adequate amount of resources for these years.

# Section 2
# Introduction

This is the second update of New England's 2014 Comprehensive Review of Resource Adequacy, which was approved by NPCC in November 2014. Since the approval of the 2014 Comprehensive Review, ISO New England has conducted additional comprehensive resource adequacy assessments as part of its Regional System Plan (RSP) process. The major assumptions of this Interim Review are based on the planning assumptions developed in 2016 for the New England system[2]. ISO New England continues to use the General Electric Multi-Area Reliability Simulation (MARS) model to simulate New England system resource adequacy.

[2] https://www.iso-ne.com/committees/planning/planning-advisory

# Section 3
# Assumptions Changes

## 3.1 Resources

Table 3-1 compares resource assumptions between the two reviews. A total of approximately 2,900 MW of capacity are expected to be added to the New England system by 2019. This consists primarily of 2,700 MW of natural gas-fired generation, of which the largest projects are the Footprint Combined Cycle Plant (674 MW), which is projected to be in service by June 2017 and was already reflected in the 2014 Review, and the CPV Towantic Energy Center (725 MW) and PSEG's Bridgeport Harbor Expansion (484 MW), both of which are expected in service by June 2018. Over 2,200 MW of retirements are expected by June of 2019. The 1,535 MW Brayton Point Station, which consists of three coal-fired units and a dual-fuel (oil/gas) unit, will be retiring in 2017. The planned retirement of the 680 MW Pilgrim Nuclear Power Station, which was not included in the 2014 Review, is expected by June of 2019. As shown in the table, the amount of existing and planned generation resources assumed for this Interim Review have decreased by about 600 MW for 2017, while increasing by about 700 MW and 800 MW for the years 2018 and 2019, respectively. The decrease for 2017 is due to a delay of approximately 450 MW of planned resources from the original 2017 in-service year to 2019, and as well as rating changes in existing generation resources. The demand resources assumed in this review are approximately 150 MW to 600 MW lower than the values assumed in the 2014 Review. The amount of import capacity resources has increased by approximately 240 MW to 310 MW. The seasonal claimed capabilities of these resources are based on the ISO New England *2016–2025 Forecast Report of Capacity, Energy, Loads, and Transmission* (2016 CELT Report)[3]. The capacity supply obligation values assumed in the 2016 Interim Review are as of September 2016[4]. Recently, FERC accepted the ISO proposed market rule revisions[5] that will increase liquidity in the FCM by providing qualified resources additional opportunities to procure and exchange Capacity Supply Obligations. These revisions will create an increased pool of resources that are available to transact in the Annual Reconfiguration Auctions and bilateral windows, and thus provide greater competition within the FCM.

[3] https://www.iso-ne.com/system-planning/system-plans-studies/celt

[4] https://www.iso-ne.com/static-assets/documents/2016/09/september-2016-coo-report.pdf

[5] https://www.iso-ne.com/static-assets/documents/2016/10/er16-2451-000_10-18-16_order_accept_fcm_enhancements.pdf

**Table 3-1**

**Resource Assumptions Comparison[6] (Summer Ratings in MW[7])**

| Year | | Based on Resources' Seasonal Claimed Capabilities | | | Capacity Supply Obligations assumed in 2016 Review |
|---|---|---|---|---|---|
| | | 2014 Review | 2016 Review | Difference | |
| **2017** | Generations | 30,362 | 29,752 | -610 | 29,547 |
| | Demand Resources | 3,082 | 2,929 | -154 | 2,798 |
| | Import Resources | 1,167 | 1,405 | 239 | 1,406 |
| | **Total** | **34,611** | **34,086** | **-525** | **33,750** |
| **2018** | Generations | 30,362 | 31,073 | 711 | 30,626 |
| | Demand Resources | 3,322 | 2,903 | -419 | 2,704 |
| | Import Resources | 1,167 | 1,479 | 312 | 1,479 |
| | **Total** | **34,851** | **35,454** | **604** | **34,809** |
| **2019** | Generations | 30,362 | 31,165 | 803 | 31,341 |
| | Demand Resources | 3,546 | 2,940 | -606 | 2,746 |
| | Import Resources | 1,167 | 1,480 | 313 | 1,480 |
| | **Total** | **35,075** | **35,584** | **509** | **35,567** |

## 3.2 Load

This Interim Review uses the 2016 load forecast, which updates the data for the region's historical annual use of electric energy and peak loads by adding another year of historical data to the model, incorporating the most recent economic and demographic forecasts, and making adjustments for resettlement that include meter corrections. This year's forecast also reflects the impacts of behind-the-meter photovoltaics (PV) [8] load reductions. Demand response programs, which include both active and passive demand resources, are modeled and reported on the resource side. Table 3-2 compares the reference summer peak demand forecasts between the 2014 and the 2016 reviews. This year's forecast is lower by approximately 800 MW to 1,000 MW, which is mainly driven by the incorporation of the behind-the-meter PV and a projected slower growth in gross demand. Table 3-3 compares the high demand forecasts, which shows a similar trend.

**Table 3-2**

**Reference Demand Forecast Comparison**

| Year | 2014 Comprehensive Review (MW) | 2016 Interim Review (MW) | | | |
|---|---|---|---|---|---|
| | | Gross Forecast | Behind-the-Meter PV | Net Peak Forecast | Net Change |
| **2017** | 29,610 | 29,307 | 520 | 28,787 | -823 |
| **2018** | 30,005 | 29,652 | 583 | 29,069 | -936 |
| **2019** | 30,335 | 29,975 | 631 | 29,344 | -991 |

[6] The table only compares Seasonal Claimed Capabilities because the 2014 Comprehensive Review did not reflect Capacity Supply Obligations.

[7] Values may not add up to the total due to rounding.

[8] The PV values in this review are the expected PV output at the hour of peak demand.

**Table 3-3**
**High Demand Forecast Comparison**

| Year | 2014 Comprehensive Review (MW) | 2016 Interim Review (MW) | | | |
|---|---|---|---|---|---|
| | | Gross Forecast | Behind-the-Meter PV | Net Peak Forecast | Net Change |
| **2017** | 30,420 | 29,700 | 520 | 29,180 | -1,240 |
| **2018** | 30,915 | 30,130 | 583 | 29,547 | -1,368 |
| **2019** | 31,330 | 30,538 | 631 | 29,907 | -1,423 |

## 3.3 Interface Limits

The same sub-area configuration (bubble transportation model) is used in these two reviews. The transmission interfaces and their limits used in this Interim Review are based on the transfer capability analysis developed in 2016 for the New England system. Changes from the 2014 Comprehensive Review include: 1) the advancement of the expected in-service date of the interstate portions of the New England East-West solution transmission upgrade from 2018 to 2016; 2) the inclusion of the Greater Boston Project, which is certified to be in service in 2019; 3) an updated transfer capability for the North-South interface reflecting expected resource retirements; 4) a new defined Southeast New England interface to reflect expected system limitations in the NEMA/Boston and SEMA/RI areas in 2019; 5) an updated transfer analysis on the southwestern Connecticut. Table 3-4 shows the transmission transfer limits used for both reviews.

**Table 3-4**
**Major Transmission Interfaces and Limits Assumed in the 2014 & 2016 Reviews (MW)**

| Interface | Limit assumed in 2014 Comprehensive Review (MW) | Limit assumed in 2016 Interim Review (MW) |
|---|---|---|
| **New England Internal Interfaces** | | |
| Orrington South | 1,325 | 1,325 |
| Surowiec South | 1,500 | 1,500 |
| Maine – NH | 1,900 | 1,900 |
| North to South | 2,700 | 2,100<br>2,675[9] (year 2019) |
| Boston Import | 4,850 | 4,850<br>5,700[10] (year 2019) |
| SEMA / RI Export | 3,000<br>3,400 (year 2018) | 3,400[11] |
| SEMA / RI Import | 786 (year 2018) | 1,280[12] (year 2018) |
| East to West | 2,800<br>3,500 (year 2018) | 2,800<br>3,500[9] (year 2016) |
| West to East | 1,000<br>2,200 (year 2018) | 2,200[9] |
| Connecticut Import | 2,800 (year 2016)<br>2,950 (year 2018) | 2,950[9] |
| Southwestern CT Import | 3,200 | 2,500 |
| Norwalk / Stamford Import | 1,650 | No Limit |
| Southeast New England | Interface Not Defined | 5,700[8] (year 2019) |
| **New England External Interfaces** | | |
| New Brunswick to New England[13] | 700 | 700 |
| New York/New England (Summer/Winter)[14] | 1,400/1,875 | 1,400 |
| HQII Import[15] | 1,400 | 1,400 |
| Highgate Import[16] | 200 | 200 |
| Cross Sound Cable[17] | 0 | 0 |

[9] The North–South transfer capabilities reflect the retirements of Brayton Point and Vermont Yankee.

[10] These values reflect the Greater Boston upgrades project that is certified to be in service by June 2019.

[11] The New England East–West Solution (NEEWS) Interstate Reliability Program (IRP) has been placed in-service.

[12] In response to the Brayton Point retirement, the following Rhode Island area facilities are now planned to be upgraded and are certified to be in service by the start of the tenth capacity commitment period (i.e., by June 1, 2017): The V148N 115 kV line between Woonsocket and Washington, the West Farnum 345/115 kV autotransformer upgrade (already in service), and the Kent County 345/115 kV autotransformer.

[13] The electrical limit of the New Brunswick–New England (NB–NE) tie is 1,000 MW. When adjusted for the ability to deliver capacity to the ISO New England Area, the NB–NE transfer capability is 700 MW because of downstream constraints, in particular, Orrington South.

[14] The New York interface limits are without the CSC and with the Northport–Norwalk Cable at 0 MW flow. Simultaneously importing into New England and SWCT or CT can lower the NY–NE capability (very rough decrease = 200 MW). Conversely, simultaneously exporting to NY and importing to SWCT or CT can lower the NE–NY capability (very rough decrease = 700 MW).

[15] The HQ Phase II interconnection is a DC tie with equipment ratings of 2,000 MW. The PJM and NYISO systems may be constrained by the loss of this line. As a result, ISO New England has assumed that its transfer capability is 1,400 MW for capacity and reliability calculations. This assumption is based on the results of loss-of-source analyses conducted by PJM and NYISO.

[16] The capability for the Highgate facility is listed at the New England AC side of the Highgate terminal.

[17] The import capability on the CSC is dependent on the level of local generation.

## 3.4 Unit Availability

Table 3-5 compares the weighted average EFORd assumptions used in the 2014 Comprehensive Review and this Interim Review. Overall, the system weighted average EFORd for generating capacity assumed in this review has increased about 0.5% as compared to the 2014 review assumptions. The change is the result of the update of the rolling 5-year average of generator-submitted Generation Availability Data System (GADS) data.

**Table 3-5**
**Change In EFORd Assumptions – Weighted Averages**

| Unit Type | 2014 Comprehensive Review EFORd (%) | 2016 Interim Review EFORd (%) |
|---|---|---|
| Fossil | 14.9 | 17.6 |
| Combined Cycle | 3.6 | 3.8 |
| Diesel | 6.5 | 6.7 |
| Combustion Turbine | 9.5 | 10.8 |
| Nuclear | 3.1 | 2.5 |
| Hydro | 4.6 | 3.3 |
| Others | 14.2 | 17.6 |
| System | 6.7 | **7.2** |

## 3.5 Fuel Flexibility and Certainty

The regional reliance on natural-gas-fired generation, coupled with natural gas pipeline constraints, pose reliability issues and cause price spikes in the wholesale electric markets. Operating experience and studies, including the recently completed EIPC study of the interregional natural gas system highlight these issues. Environmental and economic considerations continue to influence the retirement of oil and coal-fired generating resources. This capacity is being partially replaced by gas-fired generation, which further exacerbates the reliance on a single fuel source.

For over a decade, the region has been working on gas-related challenges and will continue to do so. The ISO is addressing the gas-related challenges with market rule changes and operational enhancements. Recent market rules, such as those addressing energy market offer flexibility, allow resources to more accurately reflect their variable costs in their energy offers during the operating day, which improves incentives to perform. Another new market rule has changed the timing of the Day-Ahead Energy Market to align more closely with natural gas trading deadlines. In addition, the ISO has improved coordination and information-sharing with natural gas pipeline operators, such as working with the pipelines to coordinate generator and pipeline maintenance schedules. The ISO has also developed a gas usage tool which estimates the remaining gas pipeline capacity, by individual pipe, for use by ISO-NE system operators to determine whether the electric sector gas demand can be accommodated.

A winter fuel-reliability program has been acting as a bridge between now and 2018, when the longer-term Pay-for-Performance capacity market changes go into effect. The winter reliability program addresses regional winter reliability challenges created by New England's increased reliance on natural gas-fired generation and lack of adequate gas infrastructure. Resources participating in the program provide incremental energy inventory during the winter months to help ensure reliable system conditions. Components of the program include payment to generators for adding dual-fuel capability, securing fuel inventory, and testing fuel-switching capability; compensation for any unused fuel inventory; and non-performance charges.

Pay-for-Performance (PFP), which starts in June 2018, will help to improve reliability while ensuring resource adequacy. PFP is a two-part settlement in which a base payment is set in the Forward Capacity Auction, and a performance payment is determined during the delivery year. The performance payment may be positive or negative depending on resource performance during a shortage condition. Over-performing resources are paid a premium through revenue transfers from under-performing resources. PFP creates an incentive for investment in generators that are either: 1) low-cost and highly reliable (nearly always operating), or 2) highly flexible and highly reliable (goes online quickly and reliably). PFP will encourage generators to increase unit availability by implementing dual-fuel capability, entering into firm gas-supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site oil or LNG fuel storage, or expanded gas pipeline infrastructure.

### 3.6 Environmental Regulations and Initiatives

Compliance obligations for generators from existing and pending state, regional, and federal environmental requirements are not expected to pose reliability concerns during the study period, but are likely to impose operational limits on new and existing generators. These requirements pose less risk on unit retirements and system reliability compared with earlier assessments. Federal air, water, endangered species, and carbon standards could affect the economic performance of nuclear, renewable, and fossil-fired generators by imposing operational constraints and additional capital costs for pollution control retrofits. Other state and regional air, water, and carbon standards could require certain generators to further reduce emissions and other adverse environmental impacts through the extended operation of pollution control devices or curtailment in operation.

Clean Water Act final rules on cooling water 316(b) and waste water discharges from power plants may have impacts on the relicensing of some existing units during the study periods. The ISO is monitoring such proceedings to assess the impacts of operational restrictions, including the maintenance of minimum flows, on the ability of hydroelectric generators to offer regulation and reserve services.

The 2015 ozone standard, other existing National Ambient Air Quality Standards, Mercury and Air Toxics Standards, and the future Transported Air Pollution Rule may also affect some of the fossil-fueled power generators in New England. Most coal- and oil-fired fossil steam generators greater than 25 MW in capacity in New England are already complying with the standard's emissions limits for acid gases, toxic metals, and mercury based on maximum achievable control technologies (MACTs) or are exempted due to individual unit capacity factors.

On April 15, 2016, the U.S. Environmental Protection Agency (EPA) issued guidance regarding the vacatur of the EPA regulations that allowed Real-Time Emergency Generation (RTEG) resources to participate in the Forward Capacity Market.[18] This could impact as much as 248 MW of RTEG. The ISO is allowing these resources to participate in the FCM as Real-Time Demand Response (RTDR) if they are able to retrofit their generators to comply with EPA emissions regulations. To the extent that they are not able to, or do not wish to, continue participating in the FCM, they can sell their

[18] https://www3.epa.gov/ttn/atw/icengines/docs/RICEVacaturGuidance041516.pdf

obligation to another DR supplier. In any event, ISO-NE does not expect that the potential loss of these MW, which have decreased to 59 MW by 2019, will impact the reliability of the bulk power system since the region has an adequate amount of resources above the reference reserve margin.

## 3.7 Integration of Variable Energy Resources

The region has significant potential for developing renewable resources and energy efficiency, encouraged by Renewable Portfolio Standards, the Regional Greenhouse Gas Initiative, and other environmental regulations and public policy objectives. While variable energy resources can provide additional fuel diversity, integrating wind or solar resources could place additional stresses on the transmission system. Generators could be stressed as well if system operators call on them to change output on short notice to provide system balancing and reserves.

Wind resources have requested interconnection in remote portions of the system, which can require significant transmission upgrades. In response, the ISO improved the process for reviewing elective transmission upgrades in the interconnection queue. To further facilitate wind integration, the ISO has incorporated wind forecasting into ISO processes, scheduling, and dispatch services. The ISO has improved operating procedures and processes, participated in the development of industry standards, and conducted studies that inform developers and policymakers on how renewable resource development affects system performance. The ISO implemented a process for independently forecasting wind generation, which improves situational awareness and assists asset owners with bidding in the wholesale markets. As of May 25th, 2016, the ISO has finished implementing the full economic dispatch of wind resources, which improves economic efficiency and transparency, and uses ISO's dispatch software to automate congestion management for these resources. The ISO continues engaging stakeholders on the issues challenging the wind-interconnection process and the performance of the system with wind resources in locally constrained areas. The wind-integration component of the Strategic Transmission Analysis developed conceptual additions to the transmission system that would enable onshore wind resources to reliably serve load.

Photovoltaic resources are rapidly developing in New England and are predominately situated in southern New England. The large-scale development of photovoltaic and other distributed resources poses some potential issues that the ISO is beginning to address with stakeholders. Because the ISO cannot observe or dispatch most PV in the region, these projects act as a modifier of system load that must be accurately forecasted in the short-term to support the efficient administration of the day-ahead and real-time markets while ensuring the reliable operation of the system. As PV penetrations continue to grow and displace energy production from other resources, PV energy production will introduce increased variability and uncertainty to the system and eventually will have a greater impact on system operations (e.g., result in the need for increased reserve, regulation, and ramping capability). As such, new forecasting techniques will be required to properly account for PV power production. In early 2013, the ISO began participating in a three-year, DOE-funded project to improve the state of the science of operational solar forecasting. The results of this project now assist the ISO in developing ways of incorporating the load-reducing effects of PV into improved load-forecasting processes required to support the efficient and reliable integration of increasing amounts of PV. Additional improvements to the ISO's PV forecasting techniques are also underway. The ISO also is developing ways of improving the load-reducing effects of photovoltaics located behind the meter into the load-forecasting processes to support the efficient and reliable integration of increasing amounts of PV. The ISO and the states are addressing how to best maintain reliability with the growing penetrations of these PV installations, including implementing new rules for inverter-based resources that must meet revised interconnection requirements set by IEEE standards.[19] Additional work remains on incorporating the effects of PV in improved short-term load forecasting tools for use by system operators and fully addressing the potential reliability risks, which are not expected to be significant during the study period of this review.

## 3.8 Others

The interconnection benefits from neighboring Areas are considered in both assessments. Since the 2014 Comprehensive Review, ISO New England has conducted additional tie benefit studies to identify the amount of tie reliability assistance New England can rely on from its neighbors for resource adequacy studies. Table 3-6 summarizes the tie benefit assumptions for the 2014 and 2016 reviews.

**Table 3-6**
**Assumed Tie Benefits from Neighboring Areas (MW)**

| Year | 2014 Comprehensive Review | 2016 Interim Review |
|---|---|---|
| **2017** | 1,870 | 1,875[20] |
| **2018** | 1,970 | 1,970[21] |
| **2019** | 1,970 | 1,990[22] |

Other assumptions for these two reviews are consistent with each other.

[19] *DG interconnection Issues Update*, PAC presentation (July 7, 2015), http://www.iso-ne.com/static-assets/documents/2015/07/a2_dg_interconnection_issues_update.pdf.

[20] See presentation to Reliability Committee on 10/18/2016 https://www.iso-ne.com/committees/reliability/reliability-committee/?eventId=128742

[21] http://www.iso-ne.com/static-assets/documents/2014/09/a6_fca9_tie_benefits_study.pdf

[22] http://www.iso-ne.com/static-assets/documents/2015/09/a9_tie_benefits_results.pdf

# Section 4
# Results

Tables 4-1 and 4-2 summarize the New England system LOLE results for the scenarios investigated within this Interim Review and those from the 2014 Comprehensive Review. They show that New England has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under all scenarios for the study period 2017 through 2019.

**Table 4-1**
**LOLE under Reference Demand Forecast**

| Year | 2014 Comprehensive Review (Days/Year) | 2016 Interim Review (Days/Year) | |
|---|---|---|---|
| | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Capacity Supply Obligations |
| **2017** | 0.060 | 0.056 | 0.069 |
| **2018** | 0.068 | 0.025 | 0.040 |
| **2019** | 0.074 | 0.027 | 0.028 |

**Table 4-2**
**LOLE under High Demand Forecast**

| Year | 2014 Comprehensive Review (Days/Year) | 2016 Interim Review (Days/Year) | |
|---|---|---|---|
| | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Seasonal Claimed Capabilities | Based on Resources' Capacity Supply Obligations |
| **2017** | 0.109 | 0.072 | 0.089 |
| **2018** | 0.130 | 0.036 | 0.056 |
| **2019** | 0.150 | 0.042 | 0.043 |

# Section 5
# Conclusions

Results of this Interim Review show that New England's resource adequacy has improved since the 2014 Comprehensive Review. The region has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under both the reference demand forecast and high load forecast for the study period 2017 through 2019. ISO New England has procured an adequate amount of resources to meet system reliability through the Forward Capacity Market.

ISO New England does not expect that upcoming environmental regulations will impact resource adequacy during the period covered by this Interim Review.

Increased flexibility in scheduling natural gas, which allows generators to more reliably respond to system conditions, helps to alleviate the gas-related challenges during the winter. Recently implemented improvements to the day-ahead and real-time markets have helped achieve near-term system reliability, and they supplement improvement of the FCM that are part of a longer-term reliability solution. Winter reliability programs will continue to serve as a bridge between now and 2018, when FCM design changes to include resource performance incentives go into effect.