ISO New England Transmission Equipment Outage Coordination 2018

System Operations

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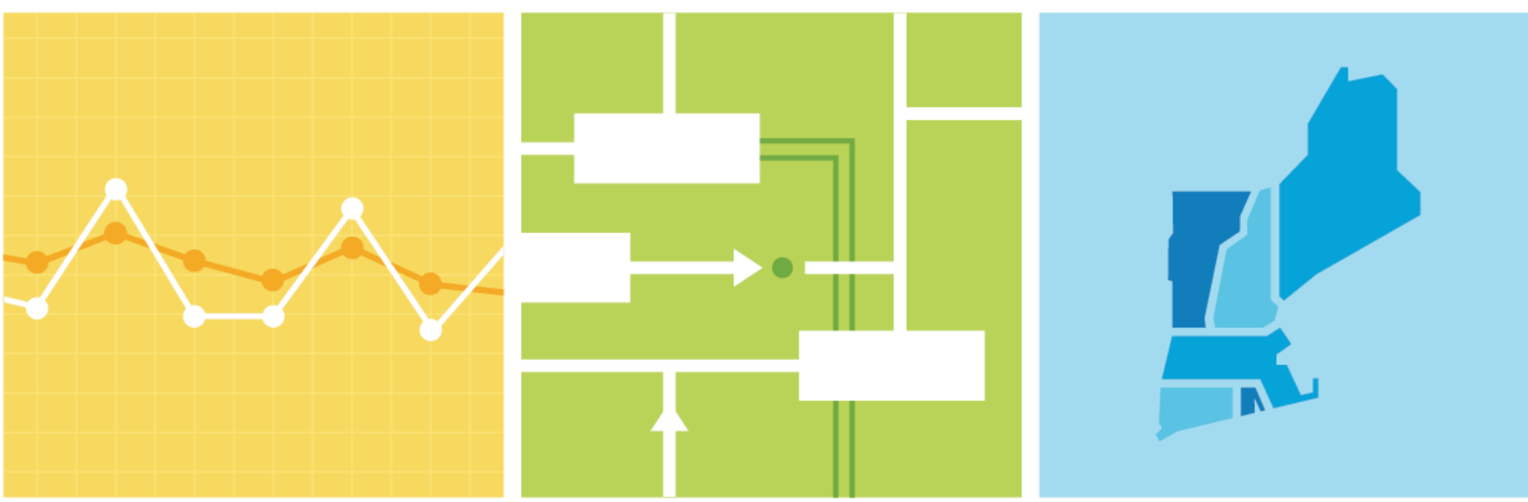

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Section 1
Introduction

Created in 1997, ISO New England Inc. (ISO) is the not-for-profit organization responsible for the day-to-day reliable operation of the bulk electric power generation and transmission system in New England. As New England's Regional Transmission Organization (RTO), the ISO has broad authority for operating the region's bulk power and transmission system, conducting the regional system planning process, and independently and effectively managing the region's competitive wholesale electricity markets.

Among the ISO's responsibilities are scheduling and coordinating transmission equipment outages (i.e., when equipment is removed from service). ISO Operating Procedure No. 3, *Transmission Outage Scheduling* (OP 3), classifies transmission equipment outages into one of four general categories—*planned*, *unplanned*, *opportunity* or *cancelled*.[1] A *planned outage* is taking equipment out of service to conduct routine maintenance or to accommodate new construction, and the request for the outage is submitted within the planned timeframes established by OP 3. An *unplanned outage* occurs when equipment is forced out of service because a problem was discovered and the request for the outage did not meet the minimum notification requirements of the planned outage identified in OP 3.[2] An *opportunity outage* is when unanticipated changes on the power system allow transmission work to take place that otherwise would have required outage scheduling at a less opportune time. A *cancelled outage* is one that was requested but ultimately not taken.

The duration of an outage can vary from a few minutes to several weeks or months, and it can be continuous or noncontinuous. Because of the urgency of forced and emergency transmission-outage requests, they receive a higher scheduling priority than those for planned equipment outages.

The ISO coordinates outages in accordance with several governing documents. It follows the Transmission Operating Agreements (TOAs), which define the ISO's authority to direct the operation of transmission facilities in the region. It also complies with the rules and requirements established in the ISO's *Market Rule 1*, which sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England markets within the New England Balancing Authority Area.[3] The ISO entered into the TOAs and coordinates the outages with New England participating transmission owners (PTOs) and local control centers (LCCs).[4] The ISO also operates in accordance with

[1] For information on OP 3 (February 1, 2019), see http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op3/op3_rto_final.pdf.

[2] OP 3 categorizes unplanned outages into two categories; emergency and forced outages. An *emergency outage* is the obvious failure of a piece of transmission equipment that comes out of service on its own or requires immediate operator intervention to remove it from service. A *forced outage* is the discovery of a problem that needs to be repaired as soon as any combination of crews, equipment, or corrective dispatch actions can be put in place to allow the work to be performed. By definition, a forced outage cannot be scheduled.

[3] The TOAs are available at https://www.iso-ne.com/participate/governing-agreements/transmission-operating-agreements. *Market Rule 1* is available at http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1. For compliance with North American Electric Reliability Corporation (NERC) reliability standards, a *balancing authority area* is the bulk electric power system (BEPS) within metered boundaries under a balancing authority and a reliability coordinator (RC).

[4] The LCCs are located throughout New England and include 1) Connecticut Valley Electric Exchange (CONVEX), 2) National Grid LCC (NGRID), 3) Central Maine Power Company (CMP), 4) New Hampshire Electric System Control Center, 5) Vermont Electric Company (VELCO) Control Center, and 6) NSTAR. The LCCs are separate from the ISO Control Center and perform certain functions in accordance with the ISO tariff (see Appendix A), the Transmission Operating Agreements, and other operating procedures.

other governing documents, including Federal Energy Regulatory Commission (FERC) Order No. 2000, regional and national reliability standards, and ISO operating documents.[5] Appendix A contains more information regarding the TOAs. Appendix B includes more details about the outage-coordination processes.

This report documents the ISO's compliance with certain provisions of the TOAs that require the ISO to conduct an annual assessment of its coordination of transmission equipment outages. For example, Section 3.08(c) of the ISO's TOA with the New England PTOs states that the ISO must prepare and issue annual public reports on the scheduling and coordination of transmission outages.[6] This TOA section also states that the ISO's annual outage-coordination report must accomplish the following:

- Assess the accuracy of the ISO's estimation of congestion cost impacts and the inputs used in such estimation
- Assess any long-term impacts of the ISO's rescheduling of transmission-outage requests
- Provide information to the New England PTOs that will allow them to identify opportunities for improving outage coordination, reducing congestion costs, or increasing operational flexibility

[5] In FERC Order No. 2000, Section III.D.4, *Short-Term Reliability (Characteristic 4)*, FERC concluded that the RTO must have the authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages are accommodated within established reliability standards.

[6] The Section 3.08(c) references in this document refer to the TOA the ISO entered into with the New England participating transmission owners, which is posted at https://www.iso-ne.com/static-assets/documents/regulatory/toa/v1_er07_1289_000_toa_composite.pdf. Comparable provisions are contained in the other TOAs the ISO has entered into with other transmission owners in New England.

Section 2
Overview of Transmission Equipment Outage Coordination

Formed in 2005, the Transmission Outage Coordination Working Group (TOCWG) is made up of participating transmission owners (PTOs) and ISO staff. The TOCWG charter (see Appendix C) requires its members to monitor and identify areas to further improve the coordination and scheduling of transmission equipment outages. In addition to highlighting the goals and accomplishments of 2018, this report discusses some of the applied improvements and objectives the ISO and the TOCWG have achieved through the years. Cooperatively, the ISO and the TOCWG have accomplished the following:

- Increased the percentage of New England transmission equipment outages submitted into the long-term process (at least 21 days in advance) from 10.3% in 2005 to 81.2% in 2018
- Increased the percentage of major transmission element (MTE) equipment outages, as defined by OP 3, submitted at least 90 days in advance from 24.4% in 2009 to 75.6% in 2018[7]
- Increased the quantity of all transmission equipment outages submitted ≥90 days in advance from 23% in 2010 to 46% in 2018
- Repositioned a total of 107 transmission-outage requests that had an estimated $211 million in congestions savings since 2005

The improvements and achievements made throughout the years have directly contributed to the safe and reliable operation of the bulk electric system. The greater number of outages submitted in the long-term process facilitated earlier communications between the ISO, LCC, and TO, creating sufficient time for all parties to assess reliability and promoting market efficiency.

During 2018, the ISO and the PTOs continued to support the TOCWG, which participates in the overall process for scheduling transmission equipment outages and strives for continued coordination and communication improvements each year. The group adhered to a number of accepted principles:

- Comprehensive coordination of transmission equipment outages in accordance with OP 3, which encompasses the outage-coordination processes
- Continued focus on ensuring all contributors to the process (project management, engineering, field, and operation personnel) are aware of the benefits of broad coordination and further improving the planning and scheduling of generation and transmission equipment outages with an emphasis on minimizing reliability and economic impacts

[7] As defined in OP 3, a *major transmission element* is a subset of a "Category A" or "Category B" transmission facility that affects generators or dispatchable asset-related demand (DARD) resources and has one or more of the following characteristics: 1) is identified as an Northeast Power Coordinating Council (NPCC) "critical facility for notification," 2) is recognized within a defined external interface, 3) is recognized within a defined internal interface, 4) places restrictions on the operation of generators or DARDs, or 5) can be referenced in a ISO transmission operating guide, and that may have a significant impact on the reliable or economic operation of the New England transmission system and thus may have greater exposure than other transmission facilities to being cancelled or denied because of economic impacts.

- Encouragement of notifying New England stakeholders in advance of planned transmission outages by encouraging that more and higher quality outage requests are submitted into the long-term process when possible
- Promotion of operational efficiency of the entire New England transmission system through monthly metrics that help increase the awareness of outage-coordination performance
- Emphasis on MTE outage planning through a metric measuring the percentage of MTE outage requests submitted to the ISO at least 90 days before the planned outage date, as defined in OP 3

In addition to the efforts of the TOCWG, senior executives from the ISO and PTOs frequently review the metrics for coordinating transmission equipment outages and provide direction and feedback to their organizations, including TOCWG members.

During 2018, the ISO processed and managed 4,329 planned and unplanned transmission equipment outages submitted by transmission owners within ISO New England, a 3.9% decrease from 2017. Overall, the ISO processed and managed 5,711 planned and unplanned transmission equipment outages submitted by internal and neighboring transmission owners to New England, a 2.8% decrease from 2017. The ISO and PTO's anticipate sustained activity in scheduling transmission equipment outage requests to accommodate the integration of new facilities currently under construction or in the planning stages and to support the scheduled maintenance of existing transmission system equipment.

The ISO and PTOs remain committed to improving and implementing outage-scheduling tools and processes for coordinating transmission equipment outages more efficiently. Since 2005, the percentage of outage requests submitted into the long-term process has increased from 10.3% to 81.2% in 2018. For an equipment outage to be considered for the long-term process, a PTO must submit the request to the ISO from 21 days to 24 months in advance (see Appendix B for additional details). The increase of MTE outages submitted greater than 90 days in advance of the planned outage start date has risen from approximately 24.4% in 2009 to 75.6% in 2018. These long-term metrics continue to highlight the PTO's focus on submitting outage requests with longer lead times.

Through the outage-coordination process with the PTOs, local control centers, and adjacent reliability coordinators (RCs), the ISO will continue to reposition transmission equipment and generator outages as necessary to ensure the continued reliable operation of the New England transmission system and minimize economic impact. The PTOs and LCCs are required to initially coordinate outages within their purview. With its wide-area view and expanded situational awareness of all outage requests and forecasted system conditions, the ISO further refines and coordinates transmission equipment outages with generator outages to achieve the following objectives:

- Maintain overall system reliability
- Minimize congestion and thereby reduce overall costs to New England consumers
- Provide timely and accurate information for the Financial Transmission Rights (FTR) market[8]
- Minimize conditions that would impede the ability of generators to participate in the wholesale electricity markets

[8] A Financial Transmission Right is a financial instrument that market participants use to hedge congestion between pricing locations in the New England wholesale energy markets. For further details, see the ISO's "Financial Transmission Right," webpage (2019) at http://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/ftr.

- Coordinate outage scheduling with adjacent RCs and PTOs

As stated, the ISO identifies transmission equipment outages that, if repositioned, could reduce congestion during the outage-coordination process.

Since 2008, the ISO has been performing economic evaluations of these scheduled transmission equipment outages from two years in advance up to a few days before an outage start date. The purpose is to review the economic impact of equipment outages as study variables stabilize (i.e., improved load forecast, recent topology changes, anticipated generation dispatch, and other factors). If planned transmission outages were not evaluated and coordinated through the long-term economic evaluation process but were found, as part of the short-term economic evaluation process, to have a significant economic impact, sufficient time is expected for considering other options to reduce congestion costs. The ISO cooperates with the appropriate RC, LCC, and PTO to consider such options, which could include the repositioning or cancellation of the outage.

In 2018, the ISO did not reposition any transmission outages through the outage-coordination process. The overall improved communications between the ISO and LCCs before the LCCs submit outages has eliminated the need to reposition many outages that would have created reliability issues or excessive congestion as submitted in the past. These discussions allow for identifying problems earlier so that the requested bulk electric system work can be repositioned before the LCCs submit outage requests to the ISO. Over the past 20 years, the ISO's continuous study and analysis of the bulk transmission system has helped maintain reliability and guide cooperative regional investments to address weak spots and bottlenecks on the system. After years of strong investment, New England now has a more reliable and flexible power system, which has led to less congestion and thus lower costs.

2.1 Goals and Results of 2018

At a minimum, the TOCWG will meet six times per year to discuss and review the trends, performance, and challenges of the outage-coordination process. When the TOCWG meets, the group reviews the actual outage-coordination performance since the last meeting and discusses identified issues to determine actions to correct and further improve the outage-coordination process. At the last TOCWG meeting of the year, the group reviews and proposes new goals for transmission outage-coordination metrics for the upcoming year, which continues to challenge all participants to improve outage coordination and, ultimately, performance. The 2018 TOCWG goals and results are as follows:

Goal: The long-term scheduling of transmission outages improves forecasted system topology that will assist in anticipating economic and reliability impacts to the electric power system. A clearer expectation of system topology will ultimately result in more accurate analyses and better coordination. This "long-term planning" metric will measure transmission outages with one of the following characteristics:

- Equipment identified as MTE
- An outage period duration of at least 24 hours
- An outage with a recall time of at least 12 hours
- An outage that requires a generator to be on line or available

The purpose of this type of scheduling is to reinforce long-term coordination with the PTOs and LCCs and improve the ISO's ability to coordinate all requests for planned transmission equipment outages that could have an impact on economic dispatch and system reliability. The

ISO's target for 2018 was for the PTOs and LCCs to submit a minimum of 80% of all transmission-outage requests via the long-term process.

Year Result: The result for this goal was that 88.5% of the New England transmission equipment outages were submitted into the long-term process. The performance measures the successful submittal of outages into the long-term process that could have an impact and demonstrates a continued improvement, indicating a more efficient scheduling of transmission outages. Figure 2-1 shows the percentages of the total transmission equipment outage requests scheduled in 2018 using the long-term process.

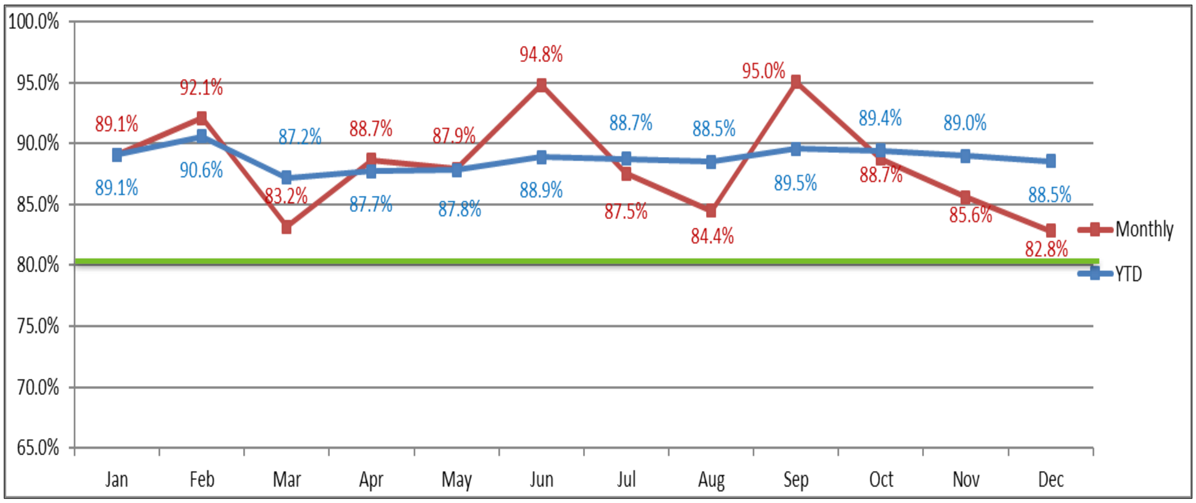

Figure 2-1: Percentages of total transmission equipment outage requests scheduled using the long-term process in 2018.

Note: The green line represents to 80% target for this metric.

Goal: To improve long-term coordination, the scheduling of projects and transmission equipment maintenance that could have an impact on economic dispatch and reliability continually challenges PTOs to plan and manage outage schedules further into the future. This "90-day metric" will measure transmission outages with one of the following characteristics:

- Equipment identified as MTE with a recall time of at least 30 minutes
- An outage duration of at least 120 hours
- A non-MTE element outage with a recall time of at least 48 hours
- An outage that contains an element identified to be critical as part of the ISO's transmission system restoration plan in the event of a system blackout[9]
- An outage that requires a generator to be restricted

Periodically, generation and transmission outages may need to be repositioned because of the priority held by unplanned outages, schedule conflicts, or anticipated adverse impacts. Submitting transmission outages in advance, however, makes outage management more

[9] For more information on system restoration, see the ISO's *System Restoration Plan*, Master/Local Control Center Procedure No. 18 (M/LCC 18) (July 31, 2018), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc18.pdf.

efficient. This goal is to improve the planning and coordination of the transmission equipment outages identified to potentially have an impact on economic dispatch or reliability. The ISO's target was for increasing the percentage of total requests submitted more than 90 days before the planned outage date to a minimum of 60%.

Result: This result for this goal was that 66.5% of all the requests for outages that could have an impact were submitted to the ISO more than 90 days before the planned outage date. Transmission owners continue to work with ISO to prioritize transmission project schedules and coordinate the timely submittal of requests for outages that could have an impact. Figure 2-2 shows the percentages of the total transmission equipment outage requests scheduled in 2018 more than 90 days before the planned outage date.

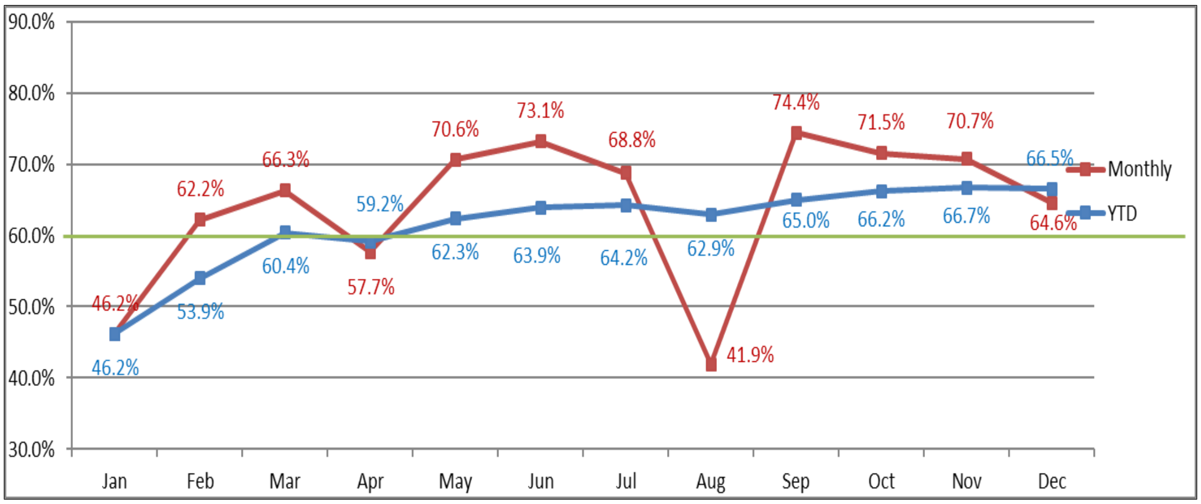

Figure 2-2: Percentages of the total transmission equipment outage requests scheduled more than 90 days before the planned outage date in 2018.

Note: The green line represents to 60% target for this metric.

Goal: The timely scheduling of planned transmission outages helps effectively analyze the impacts of recognized transmission equipment outages, improve the coordination and analysis of other planned transmission and generator outages, communicate the impact of such outages to the day-ahead market, and disseminate timely information to market participants on outages that could have an impact on economic dispatch or reliability. This "planned outage" goal was to improve the coordination of all planned transmission outages, with a target of coordinating at least 85% of all planned outages through transmission equipment outage requests.

Result: For 2018, 82.9% of all planned transmission-outage requests were coordinated. Figure 2-3 shows the percentages of the total planned transmission equipment outages coordinated in 2018—monthly and year to date.

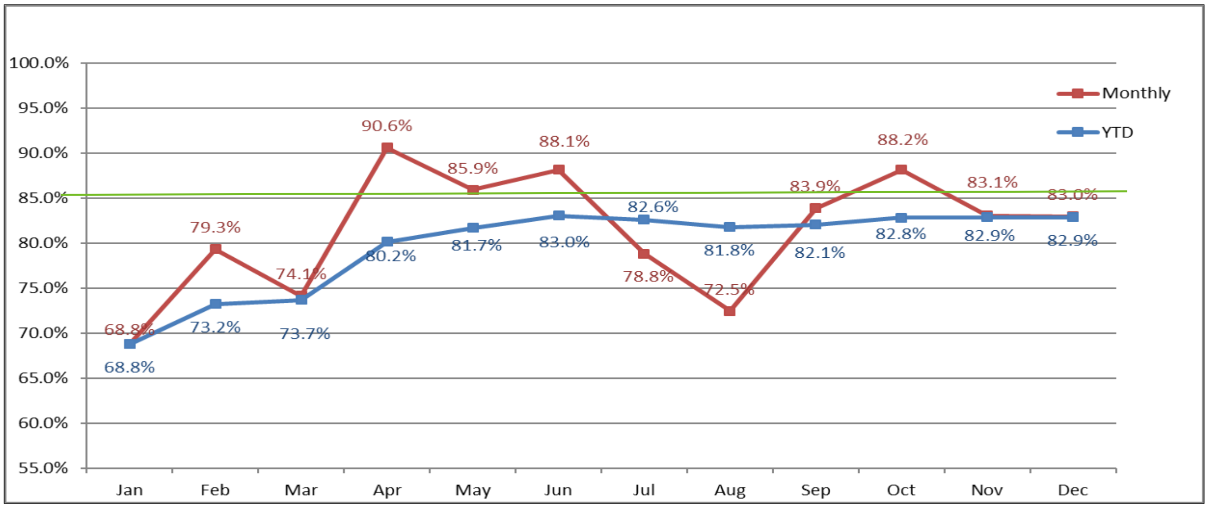

Figure 2-3: Percentages of the total planned transmission equipment outages coordinated in 2018.

Note: The green line represents to 85% target for this metric.

Goal: The energy markets operate more efficiently and effectively when the Day-Ahead Energy Market receives accurate information on transmission system topology and capability. Timely notifications of outage cancellations to the ISO before running the Day-Ahead Energy Market, especially those received before 10:00 a.m., enable the analysis of transmission limits to align with the expected conditions for the next operating day. Notifications of outage cancellations to the ISO after running the Day-Ahead Energy Market could result in adjustments to generation commitment and overall production costs. This "outage cancellation" goal is to improve timely notifications to the ISO for cancelling transmission equipment outages and increasing the percentage of outages cancelled before 10:00 a.m. the day before the scheduled outage. The target for 2018 was for the ISO to receive cancellation notifications before 10:00 a.m. the day before a scheduled outage for at least 65% of the total planned transmission equipment outages submitted.

Result: The result for this goal in 2018 was that 66% of the transmission equipment outages that were cancelled had occurred before the Day-Ahead Energy Market closed for bids and offers. The performance demonstrates an improved outcome from the 2017 result of 60%. The ISO, PTOs, and LCCs continue to evaluate best business practices and use the outage data to gauge performance. They also educate groups involved in planning, scheduling, and physically working on transmission equipment about the importance of notifying the ISO about outage cancellations and the impact these cancellations can have on the wholesale power markets. Section 4 further discusses surrounding outage cancellations and improved metrics. Figure 2-4 shows the percentages of cancelled outages cancelled before the 10 a.m. goal.

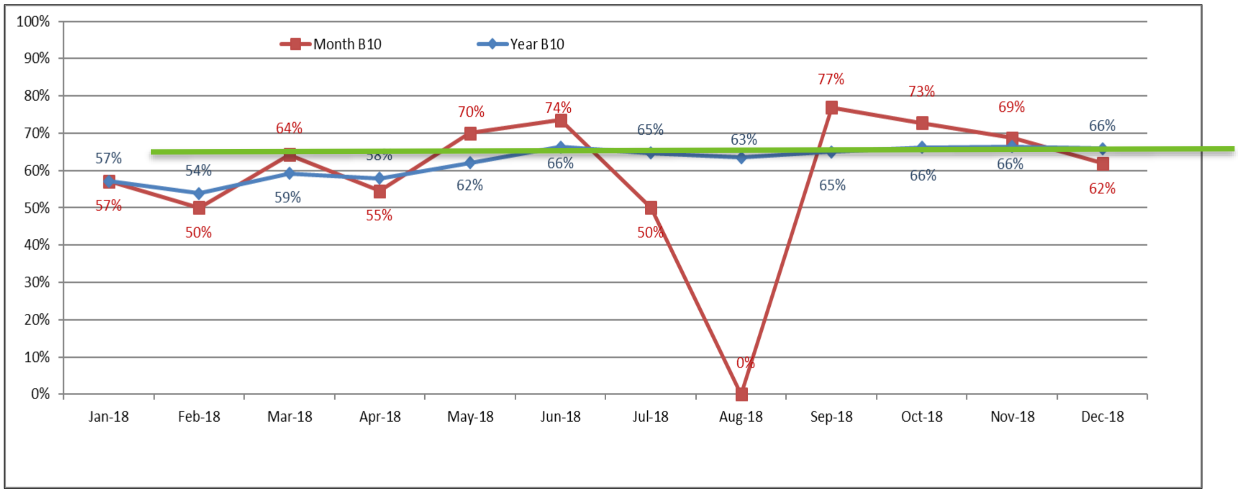

Figure 2-4: Percentage of cancelled outages in 2018 cancelled before the 10 a.m. goal.

Note: The green line represents to 65% target for this metric.

Goal: Understanding the impact of lengthy transmission outages and how they can affect economic dispatch and system reliability requires sufficient notification for reviewing multiple potential outage periods. The judicious scheduling of these outages provides the outage-coordination process with ample time to analyze overall system impacts. This "FERC metric" goal focuses on outages for transmission lines ≥200 kV, for a duration at least five days. The target was that at least 98% of the planned outages were submitted at least 30 days before the scheduled outage date.

Result: The result for this goal in 2018 was that 100% of all planned outage requests for lines ≥200 kV, for a duration of at least five days, were submitted 30 days or more before the scheduled outage date. Figure 2-55 shows these results with a comparison to the total percentage for 2017.

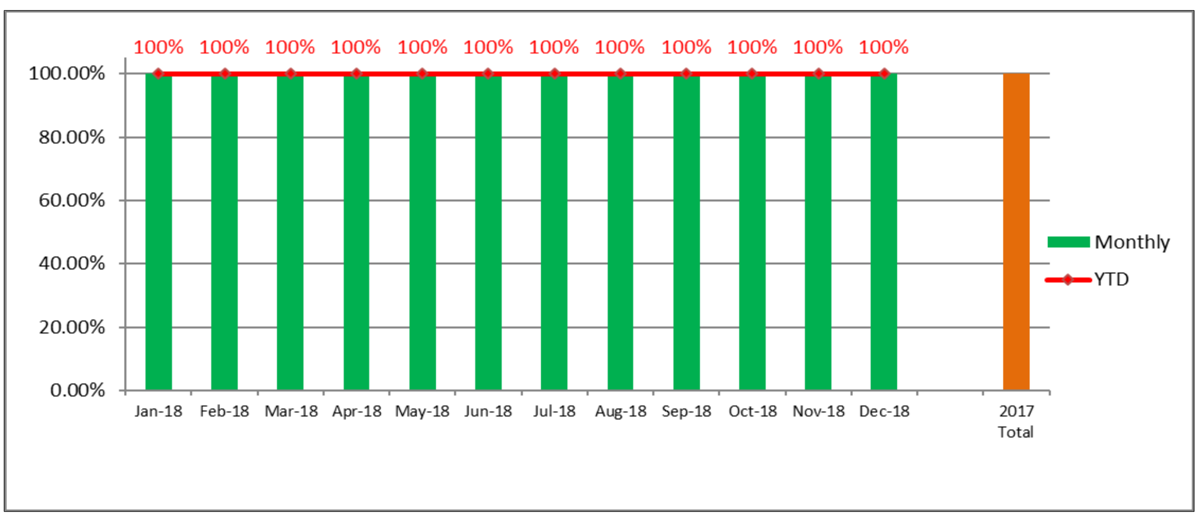

Figure 2-5: Total outage requests for ≥200 kV lines for at least five days, excluding all forced and emergency outage requests, submitted 30 days or more before the scheduled outage date in 2018.

2.2 Additional Achievements in 2018

The ISO studied and ultimately approved or disapproved 99.88% of all transmission-outage requests 48 hours before the planned start date for the outage, which is 24 hours more than the time requirement identified in OP 3.[10] This goal was established to encourage sending the results back to the PTOs or LCCs expeditiously, which helps them improve planning and offer assurance that the outage will occur. The ISO also incorporates three long-term metric goals internally, as follows, to ensure that outage requests are evaluated in a timely manner:

- For all MTE outages submitted greater than or equal to 90 days before the planned start, the ISO must approve, deny, or cancel the outage more than 45 days before the start month.
- For all MTE outages submitted less than 90 days before to the planned start, the ISO must approve, deny, or cancel the outage within 21 days after submittal of the outage.
- For all outages that take equipment out of service where the requests are submitted more than 21 days before the planned start, the ISO must approve, deny, or cancel the outage more than 14 days before to the start of the outage.

The ISO continues its membership in the North American Outage Coordination Working Group (NAOCWG) and encourages PTO participation from its TOCWG representatives. The NAOCWG is composed of a broad representation of North American bulk transmission system operators and outage coordinators, which includes Independent System Operators, transmission owners and operators, Regional Transmission Organizations, and other entities active or interested in the reliable operation and outage coordination of the bulk transmission system. The NAOCWG was established in 2007; it is supported by individual participants, and has no direct affiliation with any recognized group.

The ISO reviewed its processes in ISO Operating Procedure No. 3 and continues to allow the use of opportunity outages when reliability permits. This enables transmission owners to perform work when forecasted operating conditions are favorable and would eliminate the potential for congestion. To illustrate, in 2010, approximately 22 transmission outages were submitted as opportunity outages, while in 2018, this increased to 90 outage requests. The increase in opportunity outage requests submitted in the short-term outage planning process has helped avoid economic impact to the transmission system and afford transmission owners the opportunity to perform work under favorable operating conditions.

[10] OP 3, Section VI, A 1, directs ISO New England to approve or disapprove transmission-outage requests at least 24 hours before 00:01 a.m. of the day the work is to begin.

Section 3
Coordination Results and Discussion

This section provides an overview of the impacts that transmission equipment outages can have on congestion and a summary of how the ISO has met its obligations under Section 3.08(c) of the TOA. It also contains summary statistics on requests for transmission equipment outages from 2018.

3.1 Impacts of Transmission Equipment Outages on Congestion

During 2018, the ISO continued to work with the PTOs to review outage-coordination practices for more effective scheduling and coordination of transmission equipment outages. To benchmark the efforts, the ISO and PTOs reviewed detailed transmission equipment outage data. These data established a baseline set of metrics that allows the ISO to assess and further enhance the overall effectiveness of the process to coordinate transmission equipment outages with the PTOs and LCCs as required by Section 3.08(c) of the TOA. The results of the ISO's analysis are assessed on the basis of three criteria:

Assess the accuracy of the ISO's estimation of the cost impacts of congestion and the inputs used in such estimation

The ISO did not need to reposition any major transmission equipment outages to reduce congestion in 2018. As mentioned, this can be directly attributed to the continued progress in the coordination and communication of transmission outages along with the numerous transmission project components placed in service that helped fortify the transmission system.

Assess any long-term impacts of the ISO's rescheduling of transmission maintenance outages

The assessments conducted by the ISO in 2018 indicated that its efforts to coordinate and reposition requests for transmission equipment outages were warranted and reduced the forecasted congestion and reliability costs.[11] They also did not identify any undue financial constraints on the PTOs. The repositioning of some outages did affect the original schedule to complete the work and required the PTOs and generators to modify their schedule or work methods to minimize the impacts to the schedule.

Provide information to the New England PTOs that will allow them to identify opportunities for improving outage coordination, reducing congestion costs, or increasing operational flexibility

In 2018, the ISO continued to provide detailed performance metrics to the PTOs on a monthly and annual basis. This report along with the TOCWG meetings and continued communication

[11] Reliability costs arise when, depending on system conditions, the ISO needs to make supplemental commitments of generation resources to supply local second-contingency reserves. A resource committed for this type of local second-contingency coverage is described as a local second-contingency-protection resource (LSCPR). These supplemental commitments are of resources that do not receive sufficient revenues through the market-pricing mechanisms to remain profitable but are needed to maintain the reliability of the system. Second-contingency commitments are a function of local reserve requirements and the availability of fast-start units (i.e., those that can start up and be at full load in less than 30 minutes) to meet these requirements. Limited transmission capacity into an area reduces the amount of reserves that resources outside the area can supply, and this lack of supply increases local reserve requirements. For more information on reliability cost provisions, see the ISO's *Annual Markets Report* at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

practices highlights such findings and data-collection efforts. The tracking and communicating of these performance metrics will continue during 2019 and beyond (see Section 4, Conclusions).

3.2 Overview and Statistics of Transmission Equipment Outage Requests

Metrics tracked over the past few years have indicated process improvements as well as areas where performance has remained consistent and areas requiring additional consideration. These metrics also indicate the awareness and continuous efforts of the PTOs, LCCs, and the ISO to improve outage-coordination practices. As in previous years, the TOCWG analyzed monthly outage-coordination data to identify trends and define benchmarks of outage-coordination practices across New England. Such data included summaries of equipment outage types and revalidated causes of emergency and forced outages; the frequency of various planned, unplanned, and cancelled equipment outages; and other relevant statistical information on equipment outages. The identified metrics are measured and monitored for improvements, including the lead time for submitting outage requests to the ISO for prompt coordination with affected generators and neighboring balancing authority areas.

Table 3-1 and Table 3-2 provide summary statistics pertaining to New England PTOs and their submitted transmission equipment outage requests for outages with a start date during 2018. Data for 2015 through 2017 are also provided for comparison. Of all transmission equipment outage requests the ISO processed in 2018, 80.8% were scheduled and taken as planned outages and 19.2% were taken as unplanned outages, which is a decline of approximately 2.5% from 2017. The remainder of the table shows equipment-outage requests ultimately cancelled or had profiles that were cancelled—16.1% in 2018, which is a 0.1% increase from the performance in 2017. Extraneous outages represent the remaining 39.5% in 2018.[12] Of the profiled requests for transmission equipment outages cancelled, 66% were cancelled before the close of the Day-Ahead Energy Market.[13] Timely communication of the transmission-outage cancellations allow the ISO to factor the anticipated status of the facilities into the forecasts of transmission interface limits used in the Day-Ahead Energy Market.

[12] An *extraneous outage request* is a transmission-outage request submitted by an adjacent reliability coordinator and ultimately considered to be invalid for reasons such as data-entry errors or being a duplicate request or informational outage.

[13] A *profile* is a subset of an outage request. If the planned start and planned end dates are the same day, the outage request is continuous and has one profile. If an outage request has multiple planned start and planned end dates (e.g., return evenings, return weekends, or return evenings and weekends), each planned start and planned end-date pair defines a profile.

Table 3-1
Requests for Transmission Equipment Outages in New England that Began in 2015, 2016, 2017, and 2018

Type of Request (excluding Extraneous)	2018			2017		2016		2015	
	Total	%	% Change over previous year	Total	%	Total	%	Total	%
Submitted for long-term process (≥21 days in advance)	2,840	81.2%	−0.9%	3,142	82.1%	3,066	79.2%	3,621	83.3%
Submitted for short-term process (<21 days in advance)	656	18.8%	0.9%	685	17.9%	807	20.8%	725	16.7%
Total number of requests submitted	3,496		−9.5%	3827		3,873		4,346	
	2018			**2017**		**2016**		**2015**	
Planned	3,496	80.8%	−2.5%	3827	83.2%	3,873	82.5%	4,346	84.4%
Unplanned	833	19.2%	2.5%	770	16.8%	824	17.5%	806	15.6%
Subset of unplanned									
Emergency (immediately)	447	53.7%	7.6%	355	46.1%	365	44.3%	388	48.1%
Forced (ASAP)	386	46.3%	−7.6%	415	53.9%	459	55.7%	418	51.9%
	2018			**2017**		**2016**		**2015**	
Cancelled outages	562	16.1%	0.1%	613	16.0%	551	14.2%	726	16.7%
	2018			**2017**		**2016**		**2015**	
Extraneous outage requests	1,382	39.5%	10.2%	1,123	29.3%	890	23.0%	861	19.8%

Table 3-2
Transmission Owner Requests for Transmission Equipment Outages in New England that Began in 2015, 2016, 2017, and 2018

	2018			2017		2016		2015	
Cancelled before day-ahead market closes	425	59.7%	1.9%	484	57.8%	382	60.0%	427	67.8%
Cancelled after day-ahead market closes	287	40.3%	−1.9%	354	42.2%	255	40.0%	203	32.2%
	2018			**2017**		**2016**		**2015**	
MTE outages submitted; Percentage based on total number of requests submitted	254	6.7%	−1.0%	309	7.8%	317	8.4%	332	8.2%
MTE submitted >90 days in advance	192	75.6%	0.8%	231	74.8%	237	74.8%	236	71.1%
MTE submitted <90 days in advance	62	24.4%	−0.8%	78	25.2%	80	25.2%	96	28.9%
All planned outages submitted >90 days in advance	1,737	46.0%	−1.0%	1,869	47.0%	1,608	42.6%	1,979	49.1%

Figure 3-1 illustrates the percentage of transmission equipment outage requests in various categories for outages desired to begin in 2018. These charts show the relationship between planned, unplanned, and cancelled outages. Figure 3-2 depicts transmission equipment outages planned to start in each month in 2018 compared with the monthly peak demand. The TOCWG continues to analyze the data to identify trends, develop plans to improve transmission equipment outage scheduling, and improve the process to coordinate and schedule long-term transmission equipment outages.

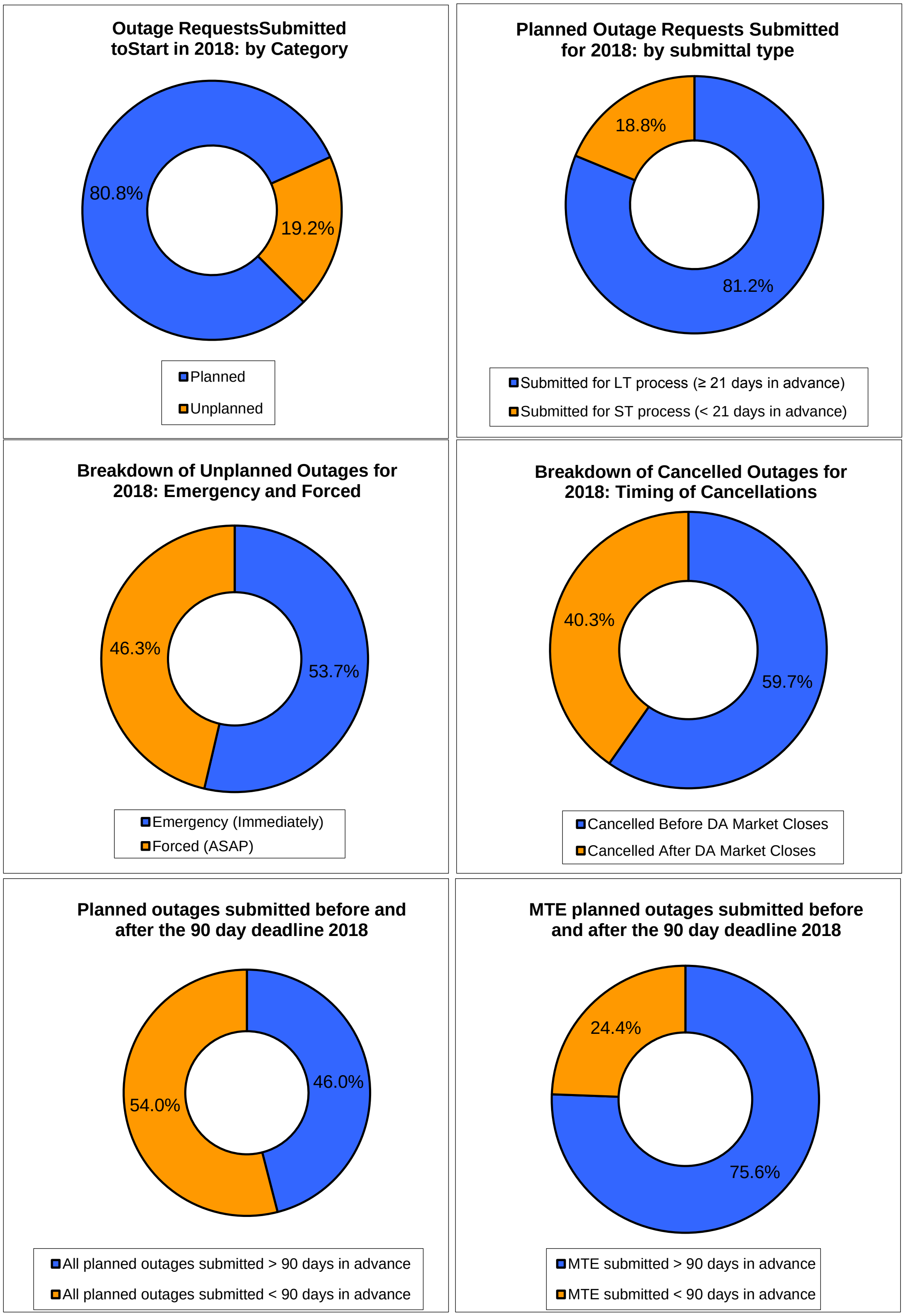

Figure 3-1: Requests submitted for transmission equipment outages beginning in 2018, by category.

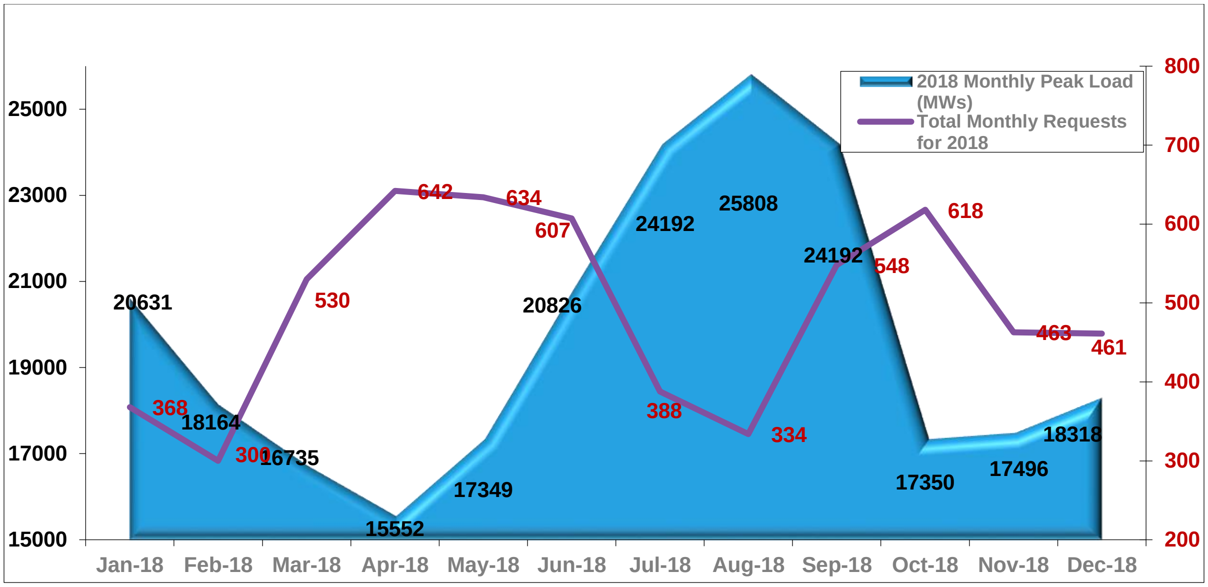

Figure 3-2: Transmission equipment outages planned to start in each month in 2018 compared with monthly peak demand.

Figure 3-3 illustrates and compares the causes for the various types of unplanned transmission equipment outages in 2018 (emergency and forced). The relatively high percentages for the equipment category shows that transmission system elements and supporting equipment were the leading drivers of both emergency and forced outages.

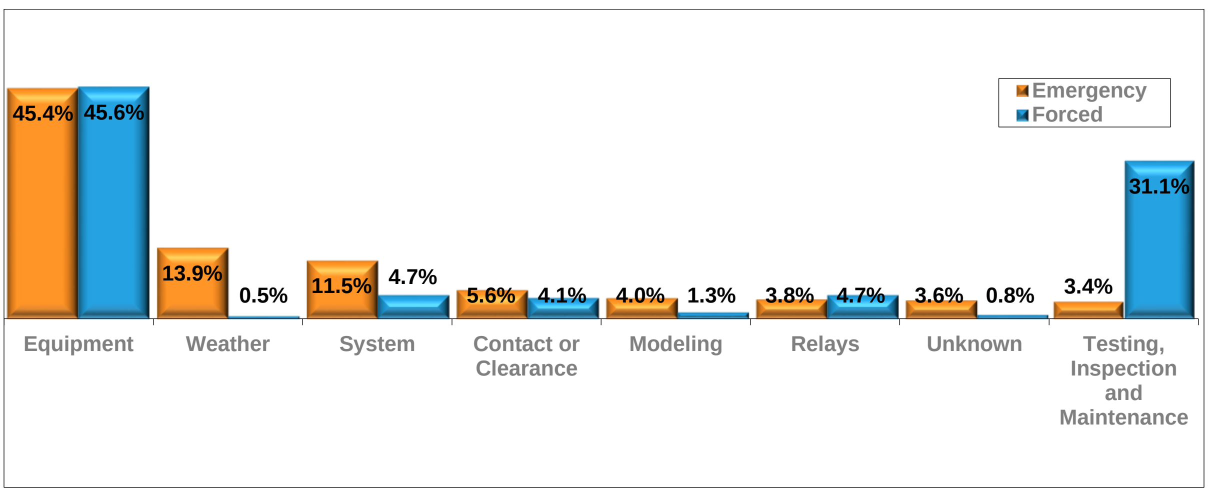

Figure 3-3: Reasons for unplanned transmission equipment outages in 2018.

Figure 3-4 illustrates the top reasons for cancelled outage requests in 2018. Despite the best planning practices in use to schedule transmission equipment outages well in advance, a certain degree of variation is always present, and the cancellation of outages is an unavoidable part of the coordination process. In 2018, a total of 562 outage applications were cancelled due to various reasons, as depicted in the table below. Divergence between forecasted and actual operating conditions sometimes necessitates the cancellation of planned transmission work. Weather, load variability, equipment accessibility, workforce changes, and many other factors all have a direct impact on the schedule, and the ultimate equipment outage.

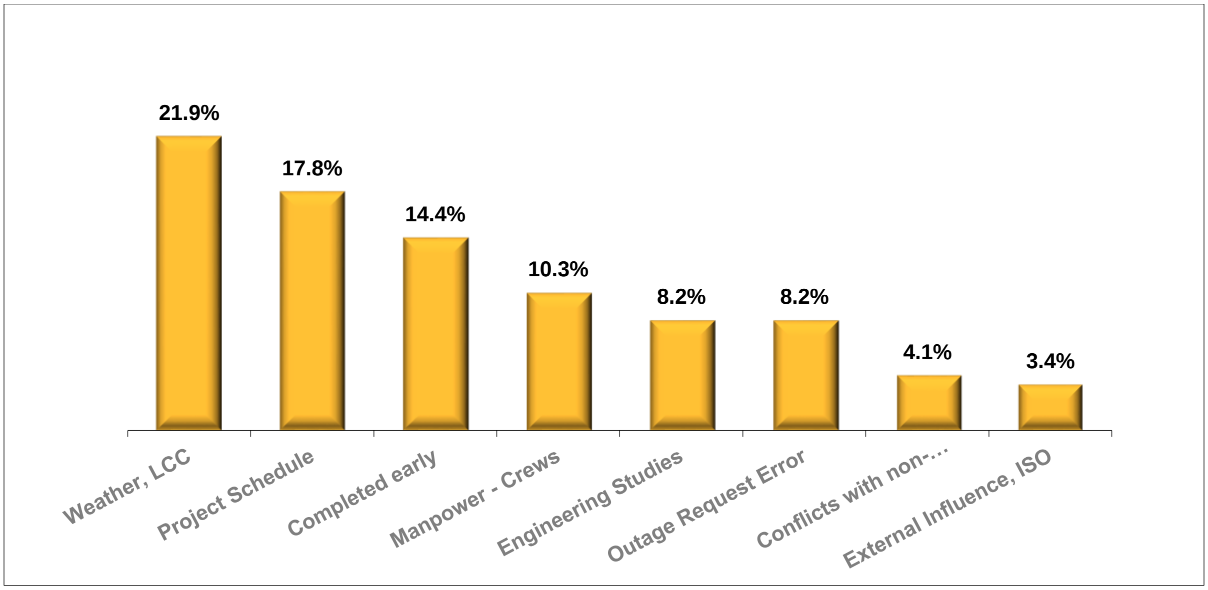

Figure 3-4: Reasons for cancelled transmission equipment outages in 2018.

For 2018, the TOCWG evaluated the outage-coordination process for reporting transmission-outage cancellations and examined the cancellations to determine more precise reasons for their occurrence. The reasons for the outage cancellations are summarized below:

- **Weather conditions and forecasts:** outages submitted through the outage-coordination process that had been cancelled due to forecast weather conditions or if crews had been reprioritized to address weather-related transmission outages, as mentioned above
- **Project schedule changes:** outages submitted through the outage-coordination process but subsequently cancelled due to specific project needs and schedule changes
- **Early completion:** outages finished before the expected end date, allowing unnecessary work days to be cancelled as a result
- **Worker shortage:** outages submitted through the outage-coordination process but cancelled due to the unavailability of contractors or crews
- **Results of engineering studies:** outages cancelled due to reliability studies that recognized system reliability could be jeopardized if the work were to proceed as scheduled. These cancellations could have occurred due to unexpected topology changes in the transmission system unforeseen when the applications were originally submitted.
- **Outage request error:** outages cancelled due to duplicate outage submittals, unnecessary work submission, or other administrative errors identified on the outage application itself
- **Conflicts with nonemergency work:** outages submitted through the outage-coordination process but cancelled predominantly due to outage prioritization with transmission projects or postponement when more favorable system conditions were forecasted
- **External influence:** outages submitted through the outage-coordination process but could not be supported by the adjacent transmission or generation owner due to reliability or economic impact concerns

The ISO added a variety of subcause codes to better capture and understand the reason for the outage cancellations late in 2018. This was recognized as an area for improvement in 2017, and as such, the subcause codes were added for clarity moving forward. The ISO will look to further build on the subcause codes moving into 2019 as well.

Section 4
2018 Conclusions and 2019 Action Plan

The process to coordinate transmission equipment outages and the metrics that track performance continue to identify areas of continued success and areas that may require improvement. The noteworthy progress made with the judicious scheduling of transmission-outage requests in 2018 can be attributed to the increased use of historical and forward-looking metrics, as well as better-defined metrics. These metrics have increased the quality of outage submissions and have increased the timeliness of submissions, which supports planning processes for all entities involved. The historical results, represented as lag indicators, helped identify past outage-coordination behaviors that appear cyclical in nature, and the forward-looking metrics, represented as lead indicators, helped identify opportunities for additional coordination and scheduling improvements. The lead and lag indicators helped improve submittal behaviors for long-term outages and expand awareness of the long-term outage-coordination process by those coordinating the work, PTOs, LCCs, generator owners, and the ISO. The better-defined metrics increase outage-scheduling flexibility throughout the full outage-coordination process, and they have expanded expectations for the PTO and LCCs. An evaluation of the metrics and indicators used to measure performance indicates the continued need for and promotes further improvements in the outage-coordination process. Specific metrics incrementally improved, are as follows:

- Communication of total transmission-outage cancellations before 10:00 a.m. increased to 66%; this is a 6% improvement from 2017.
- The quantity of MTE equipment outages to be submitted more than 90 days before the scheduled start date improved by 0.8% (from 74.8% to 75.6%)
- The ISO improved the cause codes used in reflecting the cancellation of transmission-outage requests.

Recognizing these improvements, the TOCWG identified room for further progress in the following activities:

- The quantity of planned outages for transmission lines submitted at least 21 days before the scheduled outage date decreased by 0.9% (from 82.1% to 81.2%).
- The quantity of unplanned outages increased by 2.5% in 2018 (from 16.8% to 19.2%), which as annotated, was largely due to generalized equipment problems.

The energy markets operate more efficiently and effectively when the Day-Ahead Energy Market receives accurate information on transmission system topology and capability. Not all transmission outages have an impact to the Day Ahead Energy Market, but timely notifications of all transmission-outage cancellations to the ISO, enables the analysis of transmission limits to align with the expected conditions for the next operating day. For 2019, the TOCWG will identify and review factors that inhibit the timely notification of all impactful transmission outage cancellations, and evaluate ways to improve performance moving forward.

The timely submittal of planned transmission-outage requests continues to be a prime objective. This affords ample time to review the impacts of transmission equipment outages and improve coordination with other planned transmission and generator outages. It also allows for the timely dissemination of outage information to market participants. Because out-of-service MTE facilities typically have a greater impact on operations than other equipment, resulting in differences in commitments and congestion, the early notification of MTE outages allows for improved coordination and advanced publishing of outage intentions and provides greater benefit to all entities involved. Through outage coordination, participating factors (e.g., forecasted system load, generation dispatch, transmission topology, and others) become apparent, and favorable opportunities submitting transmission outages in the short-term can become evident. Proposed metrics in 2019 and 2020 will incentivize transmission owners to schedule transmission maintenance activities when favorable conditions exist.

Early notification of transmission outages provides greater transparency to all entities and will have a positive impact on the ISO New England markets because all affected parties will be able to identify any resulting reliability and financial impacts sooner. The ISO, LCCs, and PTOs are mindful that outages associated with the significant transmission construction, maintenance, and obsolescence work expected to continue must be planned and coordinated well in advance whenever possible.

Continued cooperative efforts by the ISO, PTOs, and LCCs are expected to benefit system operations and the New England markets. The ISO plans to accomplish the following goals in 2019:

Goal: To continue to build on the benefits of long-term coordination, PTOs must face the challenge of planning, scheduling, and managing outage schedules further ahead of when the outages must take place for projects and transmission equipment maintenance determined to have impacts. This “90-day metric” goal will measure transmission outages identified as containing one of the following:

- An MTE element
- An outage period of at least 120 hours in duration
- An outage with a recall time of 48 hours or more
- An outage that contains an element identified to the ISO system restoration plan

An outage that requires a generator to be restricted

Periodically, repositioning generation and transmission outages may be necessary because of the priority held by unplanned outages, schedule conflicts, or anticipated adverse impacts; however, submitting transmission outages in advance is more efficient. This goal is to improve the planning and coordination of the transmission equipment outages identified to have an impact. The ISO’s target for 2019 is to maintain the percentage of total requests submitted more than 90 days before the planned outage date to 60% or higher.

Goal: The long-term scheduling of transmission outages improves forecasted system topology that can help anticipate economic and reliability impacts to the electric power system. A clearer expectation of system topology will ultimately result in more accurate analyses and better coordination. This “long-term planning” goal will measure transmission outages identified as containing one of the following:

- An outage period of at least 24 hours in duration
- An outage with a recall time of 12 hours or more

An outage that requires a generator to be on line or available

This goal is to reinforce the importance of long-term coordination and therefore improve the ISO’s ability to coordinate all planned transmission equipment outage requests by working with the PTOs and LCCs. The ISO will maintain the 2019 target at a minimum of 80% of the total transmission-outage requests to be submitted via the long-term process.

Goal: Scheduling planned transmission outages in a timely manner provides the opportunity to effectively analyze the impacts of recognized transmission equipment outages, coordinate with other planned transmission and generator outages, communicate about the impact of such outages to the day-ahead market, and disseminate timely outage information to market participants. This "planned outage" goal is to improve the coordination of all planned transmission outages. The ISO will maintain the 2019 target of at least 85% of all outages to be planned outages.

Goal: Providing the Day-Ahead Energy Market with accurate information on transmission system topology and capability helps the energy markets operate efficiently and effectively. Timely notifications to the ISO of outage cancellations, before running the Day-Ahead Energy Market, enable the analysis to align with the expected conditions for the next operating day. Cancellation notices received before 10:00 a.m. on the day before the scheduled outage lead to more accurate transmission system topology information used to calculate the Day-Ahead Energy Market transmission limit. Notifications to the ISO of outage cancellations after running the Day-Ahead Energy Market could result in adjustments to generation commitment and overall production costs. This "outage cancellation" goal is to improve timely notifications to the ISO for cancelling MTE outages and increase the percentage of outages cancelled before 10:00 a.m. the day before the scheduled outage. The ISO will maintain that the 2019 target for the annual average of total cancellations submitted before 10:00 a.m. the day before a scheduled outage will be at least 65% in 2019.

- **Goal:** Understanding the impact of lengthy transmission outages and how they can affect economic dispatch and system reliability necessitate sufficient notification for reviewing multiple outage periods. The judicious scheduling of these outages provides the outage-coordination process with ample time to analyze overall system impacts. This "FERC metric" goal focuses on outages for transmission lines >200 kV, for a duration more than five days. The target is to submit at least 98% of these outages at least 30 days before the scheduled outage date, excluding all unplanned outage requests.

The frequent review of the statistics regarding outage coordination helps maintain awareness of anomalies, performance, and desired behaviors to improve strategies in planning equipment outages. The prompt review of behaviors observed throughout the process helps recognize areas for improvement. The ISO will use its stated goals, provided to the PTOs and LCCs, to cooperatively develop action plans to improve transmission-outage coordination and communications and reduce the number of unplanned transmission equipment outages by the end of 2019.

Appendix A
ISO's Transmission Operating Agreements

The ISO operates the New England transmission system pursuant to, among other things, various Transmission Operating Agreements with transmission owners in New England. The ISO is a party to the following TOAs:

- The Transmission Operating Agreement that governs the transmission facilities owned by New England participating transmission owners. ISO New England, et al., 106 FERC ¶ 61,280 (2004), accepted by FERC by letter order dated March 28, 2005, in Docket No. ER05-527-000.[14]

- The high-voltage direct current (HVDC) Transmission Operating Agreement (HVDC TOA) that governs the 450 kV Phase I/II HVDC transmission facilities (HVDC-TF). These facilities, owned by certain New England asset owners, interconnect New England with Québec. Certain holders of long-term rights offer transmission service over the HVDC-TF (Schedule 20A service providers), whose rates are recovered under the Schedule 20A of the ISO's *Open Access Transmission Tariff* (OATT), which is part of the ISO New England Inc. *Transmission, Markets, and Services Tariff*. ISO New England, et al., 111 FERC ¶ 61,244 (2005), accepted by FERC by letter order dated May 25, 2005, in Docket No. ER05-754-000.

- The MEPCO Transmission Operating Agreement (MEPCO TOA), which governs the 345 kV transmission facilities that interconnect with New Brunswick. MEPCO owns these facilities and offers transmission service over them pursuant to Schedule 20B of the ISO OATT. ISO New England, et al., 111 FERC ¶ 61,277 (2005), accepted by FERC by letter order dated May 27, 2005, in Docket No. ER05-730-000.[15]

Also, Section II.47.7(c) of the ISO OATT indicates that a merchant transmission facility (MTF), such as the Cross-Sound Cable, shall be subject to the ISO's operational control, scheduling, and maintenance coordination. FERC approved this provision via a letter order dated October 26, 2005, in Docket No. ER06-69-000. Section II.47.7(c), along with Schedule 18 of the ISO OATT, set forth the full measure of the ISO's oversight authority regarding MTFs.

[14] Note that on December 1, 2008, the classification of the MEPCO 345 kV transmission facilities under the ISO OATT changed from "other transmission facilities" to "pool transmission facilities," pursuant to a settlement agreement approved by FERC on September 29, 2008, in *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008), Docket No. ER07-1289, *et al*. ("Settlement Agreement"). In accordance with the Settlement Agreement, the MEPCO 345 kV transmission facilities are currently governed by the Transmission Operating Agreement.

[15] The MEPCO TOA was terminated on December 1, 2008, as a result of the Settlement Agreement providing for the treatment of the MEPCO 345 kV transmission facilities as pool transmission facilities (see previous footnote).

Appendix B
Transmission Outage Coordination Process

This appendix provides an overview of the outage-coordination process and describes the long-term and short-term processes for coordinating transmission equipment outages.

B.1 Overview of the Outage-Coordination Process

Regular maintenance of existing transmission facilities and the construction of new facilities are essential for assuring that the transmission system is able to meet the demands of customer load while maintaining reliability at the lowest cost. To accomplish this, equipment must be taken out of service, which has an impact on the normal configuration and operation of the transmission system. ISO New England carefully reviews and coordinates both planned transmission and generation outage requests to minimize the overall impact and ensure that load will be served reliably under expected and contingent conditions while striving to minimize economic impact.

The planning of transmission equipment outages must be carefully coordinated to ensure that load will be reliably served if the most limiting generator or transmission facility contingency (i.e., N-1 criteria) were to occur while the maintenance, construction, or both is in progress. In defined areas of New England, because of the potential impact on the interconnection and to meet NERC standards, coordinating transmission equipment outages requires assurance that loads can continue to be served during the maintenance and construction activities while the system suffers the most-limiting first and second contingencies (N-1-1 criteria).

Advanced planning of transmission equipment outages allows the ISO to conduct studies and computer simulations to project system conditions, as well as potential congestion costs under a given set of assumptions. If the results are unacceptable, scheduled outages are repositioned to a more suitable period. In addition to the obvious benefits of effective communication with the TOs, LCCs, and the ISO, publishing accurate information regarding transmission outages assists market participants in effectively hedging potential congestion costs. Working closely with the LCCs and TOs, the ISO gathers and analyzes data to better understand current outage-planning practices and identify areas for improvement.

The coordination of bulk transmission equipment outages begins with the TOs identifying work to be performed (e.g., either routine preventative maintenance or outages needed to accommodate new construction projects). Each TO will then establish a desired outage schedule in coordination within its own company project timeline and with due consideration for the reliability of its local area. The TOs then convey their desired transmission equipment outage requests to their LCCs who will evaluate the initial impacts of the requests on intra-area reliability. This initial planning by each of the TOs in coordination with their respective LCCs results in an outage plan designed to maintain reliability during the outage. Requests that receive LCC approval are submitted to the ISO for a final reliability study and congestion analysis. These ISO studies are intended to ensure that regional and interarea reliability is maintained, as well as identify and work toward minimizing congestion cost and impacts to generation during the outage. The ISO, the New England TOs, and the LCCs work cooperatively to minimize the impacts of these necessary transmission equipment outages, aiming to avoid scheduling equipment outages during periods of high load and to avoid conflicts with generator and other transmission equipment outage requests.

B.2 Long-Term Coordination of Transmission Equipment Outages

The ISO evaluates planned transmission equipment outages through either the long-term or short-term process, depending on when the outage request is submitted. To be considered as part of the long-term process, an equipment outage request can be submitted to the ISO from 24 months to 21 days in advance of the requested outage start date.[16]

The long-term process is the more desirable option because it allows sufficient time to conduct both the mandatory reliability studies as well as a congestion analysis. Early and effective long-term outage coordination has the added benefit of providing increased assurance to the TO seeking the equipment outage. Essentially the ISO will have more opportunity to arrange the outage to meet the TO's desired scheduling timeframe while minimizing the reliability and economic impacts to the system. A transmission-outage request submitted as part of the long-term process is given a higher priority than one submitted as part of the planned short-term process. Additionally, transmission equipment outage requests in the long-term process may also be considered in the Financial Transmission Right auction assumptions.[17]

Working with the LCCs, TOs, and generator owners, the ISO assembles the submitted equipment outage requests associated with both transmission and generation facilities. The schedules are then reviewed to determine whether any submitted equipment outages can potentially have a negative impact on system reliability or cause excessive congestion. When the reliability studies conducted identify an undesirable condition, the ISO and the LCCs work as needed with the select TOs and generator owners to minimize the impacts to the extent possible. The ISO publishes on its website long-term transmission equipment outage information from 24 months to 21 days in advance, updated on a daily basis, in conformance with the *ISO New England Information Policy*.[18]

Incentives designed into the long-term outage-coordination process encourage the submittal of requests for equipment outage at least 90 days in advance. If a submitted outage request meeting the 90-day criteria is for an MTE, and it receives an interim approval, the outage may also be given an economic approval to provide a higher level of priority and incentive to stay on schedule. It is understood that some equipment outages routinely create significant congestion regardless of when they are scheduled; therefore, these types of outages would benefit by following this advanced approval process. Likewise, market participants benefit from this advanced coordination and timely notification because this allows participants to account for the effects of the congestion and take appropriate steps to employ applicable hedging. Outages that do not receive this economic approval will be considered at risk for economics and subject to repositioning or cancellation through the short-term economic evaluation process.

[16] This timing is in accordance with OP 3, which requires submittal to the ISO; the LCCs may require earlier submittal.

[17] The FTR auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of *Market Rule 1*. This auction allows market participants to acquire or sell FTRs for hedging congestion between pricing locations in the New England wholesale energy markets. For more information, see *Market Rule 1* at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html and the ISO's webpage on FTRs at https://www.iso-ne.com/markets-operations/settlements/understand-bill.

[18] The *ISO New England Information Policy* provides the rules and procedures the ISO follows to disclose information collected and created while administering New England's wholesale electricity markets and operating the region's transmission grid. It is posted at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/attach_d/attachment_d.pdf.

B.3 Short-Term Coordination of Transmission Equipment Outages

The ISO short-term process evaluates equipment outage requests received from 20 days in advance to the day before the outage is scheduled to occur, respecting current implemented outages and forecasted system conditions. The ISO conducts system studies of these equipment outages and renders approval or denial for planned outages up to the day before the equipment outage is to begin. The approved daily transmission equipment outage data, including actual equipment-outage detail, associated power-flow cases, and hourly interface limits are input into the models and tools for the Day-Ahead Energy Market as well as real-time control room operations. Outage requests received in real time are managed by the ISO control room. The ISO publishes on its website, in 15-minute intervals, a comprehensive listing of information on transmission equipment outages, from 21 days in advance up to and including sustained outages in real time, in conformance with the *ISO New England Information Policy*. The ISO short-term group creates the next-day report detailing transmission and generation outages for communicating to adjacent RCs.

The short-term economic evaluation process is intended to forecast the affect that equipment outages have on the Day-Ahead Energy Market. The ISO will conduct an economic evaluation of all outages three to four days before the outages are scheduled to take place. Outages that create significant congestion and *have not* been given an economic approval through the long-term process will be more likely to be considered for repositioning or possible cancellation than those that have been given an economic approval through the long-term process. This consideration is conducted in consultation with the appropriate LCC and TO, such that additional factors can be understood and taken into consideration.

At any time up to and including the actual scheduled outage time, the ISO, LCCs, and TOs each have the independent authority to deny or cancel an equipment outage that could have an impact on their jurisdictional area. Additionally, at any time during the actual outage and within safety parameters, the equipment can be recalled to address unforeseen system reliability needs.

Appendix C
Scope of New England Transmission Owner/ ISO New England Transmission Outage Coordination Working Group

This appendix provides an overview of the Transmission Outage Coordination Working Group (TOCWG).

Purpose

The purpose of the TOCWG is as follows:

- Review and introduce improvements to the transmission outage coordination process
- Discuss improvements to existing processes and information flows, including the improvement and replacement of current tools, as needed
- Assess the compilation, content, and statistical presentation (definitions, content, format, and the like) of certain data associated with transmission outages
- Identify the effectiveness of the data and data presentations in bringing about meaningful communication to improve the transmission outage coordination process
- Evaluate the data to gain a better understanding and awareness of trends and the overall impacts associated with maintaining and improving the performance of the New England transmission grid

Deliverables

- Develop and monitor proposed changes to the rules and governing documentation for coordinating transmission outages
- Develop and enhance monthly outage coordination reports
- Develop and enhance yearly outage coordination plans

Structure

Membership

- ISO New England to appoint a chair
- New England transmission owners to appoint representatives
- Working group to appoint a vice chair and secretary

Meeting Frequency

- Bimonthly or as required

Meeting Conduct

- Generally informal; however, minutes will be taken and approved by the TOCWG

Reporting

- Reports to the transmission owners/ISO New England Executive Committee

Influence

- Advisory