The Impact of Resource Inflexibility on Capacity Accreditation in New England

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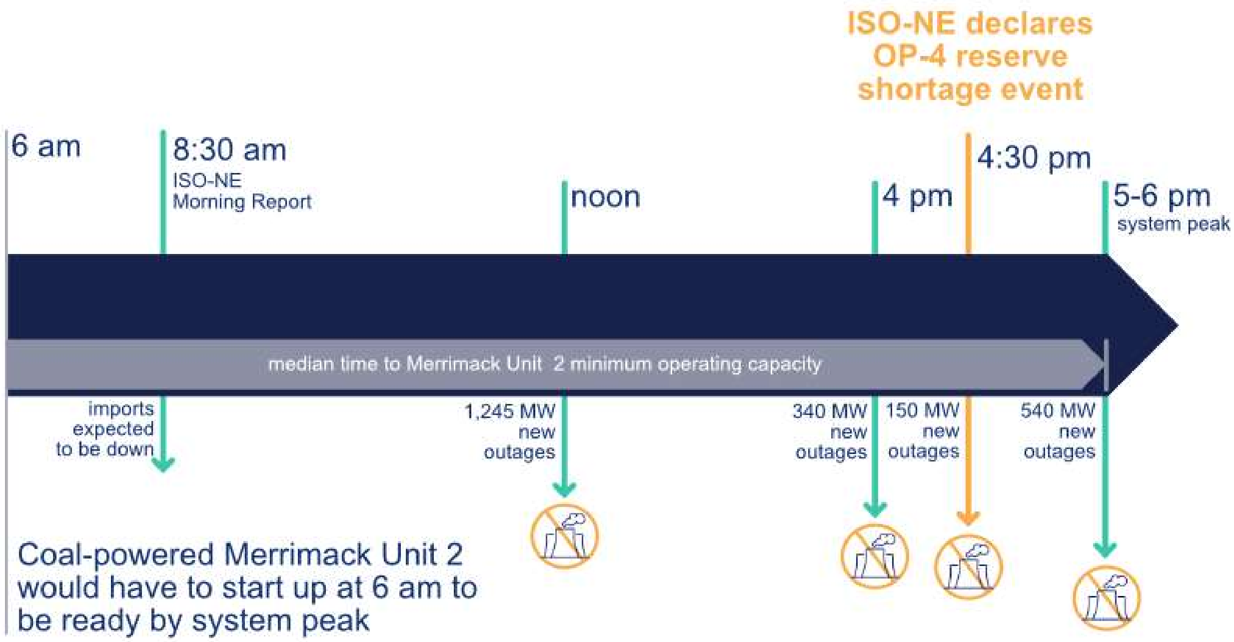
EXECUTIVE SUMMARY

On December 24, 2022, New England's electric grid operator, ISO New England, declared a reserve shortage event and the region got the closest it had been to rolling blackouts since 2018. While the weather was considerably colder than average, it was not so extreme that the grid should have run out of available capacity. Loads peaked at a little over 17,500 MW, far lower than the winter peak loads from ISO New England's long-term load forecast. The problem was that thousands of megawatts of generation (and imports) became unavailable during the day, and too many of the remaining resources that were theoretically available would have taken too long to start up to respond in time. Imports did not deliver the energy they had scheduled in the day ahead market. Then, by noon, 1,245 MW of outages and reductions had occurred within New England. By 6pm, an additional 1,030 MW became unavailable and ISO New England had fewer resources available for reserves than it is required to maintain by national and regional standards. As prices soared and the ISO began to call on its emergency Operating Procedure 4, more than 8,600 MW of capacity—which had been purchased by consumers to ensure resource adequacy—sat on the sidelines, unable to start up quickly enough to be helpful during the peak.[1]

One example of the kind of generation resource that is unable to start up quickly is Unit 2 of the Merrimack coal plant in New Hampshire, which typically takes close to 12 hours to start producing power from the time its operators switch it on. While this kind of resource may be useful when a high demand day is known well in advance, it provides near-zero resource adequacy value when it is offline and tight system conditions arise on short notice, as happened during Winter Storm Elliott. As shown in Figure 1, Merrimack Unit 2 would have needed to start up by 6am—well before the emergency was evident—to be ready by the system peak.

[1] Gravelin, J. 2022. "Implementation of ISO-NE Operating Procedure #4 on Saturday December 24, 2022." Available at: https://www.iso-ne.com/static-assets/documents/2022/12/op4-report-nepool-committees-12-24-22.pdf.

Figure 1. Timeline of December 24, 2022, scarcity event compared to a coal plant's start-up time



When ISO New England procures a set of resources to maintain resource adequacy throughout the year through its Forward Capacity Market, it does not consider the constraints of inflexible resources. And while the ISO is overhauling other aspects of how the capacity market accredits each resource as part of the ISO's Resource Capacity Accreditation project, the new framework would continue to ignore the limitations of inflexible resources.[2] Capacity accreditation, which values the reliability contribution of each generation resource, is a central component of the capacity market, and it is therefore essential for procuring a reliable set of resources each year. ISO New England's proposed accreditation methodology makes important improvements but fails to account for long start-up times and other key limitations of inflexible thermal power plants, even though these same limitations have been leading causes of the only two reserve shortages the region has experienced in the last five years. Most notably, long resource start-up times, which can be more than 12 hours, are not factored into accreditation at all.

This report describes our analysis of the operational limitations of several resources in New England. We also examined the risk of unpredicted scarcity events that could be impacted by unplanned outages and forecast error. We found that resources can take long amounts of time to start up in New England, and that within these long start-up periods there is considerable risk of forecast error or forced outages that push the system into shortage before long start-up time units can respond. While our analysis focused on several specific resources, the problems we identified are widespread. U.S. Energy Information

[2] ISO New England. 2023. "Resource Capacity Accreditation in the Forward Capacity Market Key Project." Available at: https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm/.

Administration data shows that 25.7 GW of the region's 38.3 GW of total operating nameplate capacity takes more than an hour to start up. Of that amount, 7.6 GW takes over 12 hours.[3] Given the widespread inflexibility of the generation fleet, it is important to consider resource operational constraints like start-up time in the capacity accreditation process to maintain system reliability and properly value the contributions of new, more flexible technologies.

[3] U.S. Energy Information Administration. 2022. "EIA-860, 2021." Available at: https://www.eia.gov/electricity/data/eia860/.

1. Introduction and Background

1.1. The grid's changing needs

New England's older energy generation resources are hindering the region's reliability and progress towards a clean energy system due, in part, to their inflexibility. However, as we show in this report, the region's primary resource adequacy mechanism—the capacity market—is not accounting for the substantial impacts their inflexibility could have on system reliability. New England states are working toward the important goal of decarbonizing the energy system while simultaneously maintaining a reliable electric grid in the face of increasingly severe and frequent extreme weather events. And grid operation is already changing accordingly. As New England's energy system enters new and uncharted territory, it becomes more essential than ever to accurately value the reliability contributions of all resources. In this report, Synapse examines the reliability impacts of the region's inflexible fossil fuel power plants and their treatment within the region's capacity accreditation framework.

Despite the grid transformation underway, many older generation resources remain. Many of these older fossil-fuel-powered resources have considerable limitations such as long start-up times that impede their ability to respond to events. The grid of the future, and even the grid of today, needs generation resources that can respond rapidly to unpredicted events and inevitable deviations from forecasted load and renewable generation. Notably, those unpredicted events include outages at some of these same old and unreliable fossil fuel power plants as well as other plants in the region. Inflexible resources are often unable to support the system during times of shortage when they are needed the most. But under today's market rules, these resources get a pass when it comes to measuring their contribution to system reliability.

1.2. Recent reliability challenges

Recent events have highlighted the need for changes. While the New England bulk power grid has operated reliably over the past few years, there have been periods where the system approached shortages.[4] It is these periods during which the system is most stressed that are most important to consider when evaluating capacity value, though flexibility can be valuable for other purposes throughout the year. Since 2018, the system has only twice been short of operating reserves required by the North American Electric Reliability Corporation (NERC), the national organization that sets standards for electric system reliability. This type of situation creates extremely high real-time energy prices and

[4] This is not to say that all electric customers in New England have received reliable delivery of electricity in recent years. Many customer outages are due to problems at the local distribution level, often as a result of storms that damage distribution lines and equipment. While the last few years have seen these types of local outages, there have been no system-wide outages resulting from a shortage of generation. It is these generation shortages that drive wholesale capacity accreditation market rules and ultimately procurement of generation resources through the Forward Capacity Market.

triggers special operating procedures by the region's independent system operator, ISO New England: Operating Procedure 4 (OP-4) allows the ISO to take emergency actions to prevent rolling blackouts. In both instances, the ultimate causes of the reserve shortage were unknown to system operators in advance, so operators were left with only hours to mitigate the problems. Over these short timeframes, resources with long start-up times were unable to support the grid unless they had already been dispatched before the event was known.

September 3, 2018, event

In September 2018, higher-than-forecast temperatures and humidity increased loads above ISO New England's expectations. In addition, about 1,600 MW of unanticipated outages occurred throughout the day, including a loss of approximately 1,000 MW that occurred between 3:00 PM and 3:30 PM. These factors combined to create a reserve shortage of approximately 700 MW. ISO New England implemented OP-4 between 3:30 PM and 8:00 PM to manage the shortage. Nearly 6,500 MW of capacity was offline and unavailable to respond to the event due to long start-up times.[5]

December 24, 2022, event (Winter Storm Elliott)

Most recently, on the evening of December 24, 2022, the New England grid fell short of needed operating reserves between 4:40 PM and 6:05 PM.[6] The shortage followed unexpected outages affecting 2,275 MW of generation resources throughout the day on December 24, in addition to lower-than-planned imports from adjacent regions, especially Quebec.[7] By the time it was clear the system was at risk of reserve shortage, there were only a few hours to prepare for the peak load hour, and more than 8,500 MW of available generation sat on the sidelines unable to start up in time to help.[8]

1.3. Gap in proposed ISO capacity accreditation methodology

ISO New England procures a set of resources to maintain system reliability through the Forward Capacity Market (FCM), held three years in advance of the year in which the system will need the resources. To procure capacity through the FCM, the ISO must determine each resource's potential contribution to reliability. The ISO quantifies this concept through the capacity accreditation process, which assigns a capacity value to each resource based on that resource's reliability contribution.

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[5] Gould, S. 2018. "Implementation of ISO New England Operating Procedure #4 on Monday September 3, 2018." Available at: https://www.iso-ne.com/static-assets/documents/2018/09/op4actionsseptember032018.pdf.

[6] Chadalavada, V. 2023. *December 24, 2022 OP-4 Event and Capacity Scarcity Condition*. Available at: https://www.iso-ne.com/static-assets/documents/2023/01/december-2022-op4-coo-report.pdf.

[7] Chadalavada, V. 2023. *NEPOOL Participants Committee Report: February 2023*. Available at: https://www.iso-ne.com/static-assets/documents/2023/01/february-2023-coo-report.pdf.

[8] Gravelin, J. 2022. "Implementation of ISO-NE Operating Procedure #4 on Saturday December 24, 2022." Available at: https://www.iso-ne.com/static-assets/documents/2022/12/op4-report-nepool-committees-12-24-22.pdf.

ISO New England is currently developing a new Resource Capacity Accreditation (RCA) methodology to better assess the contributions of resources as the region moves toward a more diverse resource mix and faces new and challenging weather events.[9] The RCA methodology proposed by ISO would accredit all resources through a Marginal Reliability Impact (MRI) framework, which determines each resource's accreditation based on its contribution to system reliability during the hours when the system would face the greatest risks of shortage. Critically, while the proposed framework includes some important improvements, it does not address a longstanding weakness of capacity accreditation in New England: the potential unavailability of inflexible resources during unpredicted reliability events. Historically, this weakness has resulted from the lack of operational limitations incorporated into the calculation of a resource's Qualified Capacity, which is primarily based on seasonal audits of a unit's maximum generation capability. In the proposed capacity accreditation framework, resource inflexibility will continue to be excluded. This is at least in part due to ISO New England's proposed use of a model that cannot simulate the impacts of key resource operating constraints, such as cold start-up times. In both cases, the result is that consumers do not get the level of reliability they pay for while inflexible resources get an unfair advantage over faster-performing resources such as battery storage.

2. Methodology and Analysis

Synapse's analysis included two primary areas of focus. First, we identified and studied some key operational limitations of generation resources in New England. Analyzing the performance of real-world generation resources is essential for understanding the scope of inflexibility in the generation fleet and how it can impact reliability. Second, we examined the factors that create the unpredicted circumstances in which inflexible resources struggle to perform. Two of these factors are forecast and outage uncertainty. We present a detailed analysis of forecast uncertainty, for both load and variable generation, because this uncertainty will increase as climate change causes more extreme and unpredictable weather events and as more variable generation resources connect to the grid. We also have high quality data available thanks to ISO New England's publication of its forecast data. Our higher-level treatment of unplanned outages (from both local generation resources and imports) is not to diminish their importance to the reliability challenges associated with inflexible resources. Rather, these outages are a clear and important risk factor that should be incorporated into resource adequacy structures. Given limited publicly available data about forced outages, we point to recent examples of the situations these outages can produce.

[9] ISO New England. 2023. "Resource Capacity Accreditation in the Forward Capacity Market Key Project." Available at: https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm/.

2.1. Resource limitations

Resource limitation overview and impact

Several factors impact whether a resource can be dispatched to meet sudden capacity or energy shortage events, including start-up time, ramp rate, and minimum down time. Start-up time is the amount of time it takes for a unit to go from fully offline to a certain level of generating output (such as minimum operating level or maximum capacity). Ramp rate is the rate at which a unit that is already operating at or above its minimum generation limit can increase its generation output. Minimum downtime is the length of time a resource must be fully offline before it can start up again.

Resources that have long start-up times, slow ramp rates, and/or long minimum down times are inflexible and are often unavailable during unforeseen grid events, such as capacity shortage events or energy supply issues. Units with long start-up times cannot begin generating fast enough to supply load during unexpected and near-term shortage events. For example, during the capacity shortage event on December 24, 2022, ISO New England had ample offline capacity to meet the reserve deficiencies, but these resources were not able to start up within the needed two-hour window to help during the peak load hour. Similarly, slow ramp rates can prevent resources from increasing generation within short windows to meet system capacity requirements during unpredicted events. Finally, resources with long minimum downtimes may still be in a cooldown period when an unexpected capacity shortage event occurs and may be unable to respond. Typically, coal units, as well as certain oil, biomass, and natural gas units, will exhibit at least a subset of these inflexible operating characteristics.

All three of these constraints are normally set to minimize the risk of damage to the unit during temperature and pressure changes, and to prevent other mechanical damage that could be caused by cycling a unit online too quickly. Other factors, such as constraints on the ability of the gas pipeline system to provide gas supply on short notice, could also result in these types of operational limitations. According to the International Renewable Energy Agency (IRENA), coal units can have start-up times anywhere from two to ten hours.[10] IRENA also notes that coal units typically have ramp rates of just 1.5 to 4 percent of operating capacity per minute, compared to 8 to 12 percent for gas turbines. This suggests that a coal unit can ramp from zero generation up to full capacity within 25 to 67 minutes, which means actual ramp times between minimum and maximum generation would be shorter. For units that can ramp within an hour, ramp rates have a more limited impact on reliability contribution than start-up times. While minimum downtimes are often more of an economic restriction than a physical limitation, ISO New England's energy market commitment software respects minimum downtimes requested by generators.[11] According to Gonzalez-Salazar et al., subcritical coal units have

[10] International Renewable Energy Agency. 2019. "Innovation landscape brief: Flexibility in conventional power plants." Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019.pdf?la=en&hash=AF60106EA083E492638D8FA9ADF7FD099259F5A1.

[11] ISO New England. 2023. "FAQs: Generator Operational Parameters." Available at: https://www.iso-ne.com/participate/support/faq/generator-operational-parameters.

an average minimum downtime of six hours.[12] We note that all three of these limitations can be partially or fully economic in nature. In emergencies it is possible that a unit could perform better than it does in typical operation, but at some cost of higher risk of mechanical failure or increased maintenance expenses.[13]

To better understand the impact of start-up time, ramp rates, and minimum downtimes in New England, we analyzed operating data from seven slow-start units, including four coal units, two oil units, and a biomass unit.

Methodology for resource limitation analysis

For our analysis, we relied on the U.S. Environmental Protection Agency's (EPA) Clean Air Markets Program Data (CAMPD), which includes hourly gross generation and heat input for emitting power plants across the country.[14] Using this data, we pulled out specific operating events from when a unit began operating to when a unit stopped operation. Within the dataset, our analysis focused on two variables: operating time and gross load. Operating time is a number between 0 and 1 which describes the proportion of the hour in which the unit was operating (consuming fuel). As such, if the value was greater than zero, we considered the unit to be operating at some level during the hour. If the value was zero, we considered the unit to not be operating during the hour. Gross load is the level (in MW) at which the unit was generating electricity. If the gross load was zero, the unit was not producing electricity. Notably, a unit could be operating (operating time is greater than zero) and have no gross load (gross load is zero) in a given hour. We used historical average net-to-gross ratios for each plant to convert the EPA CAMPD gross load values into net load values in our analysis.[15] For this analysis, we also used the U.S. Energy Information Administration's (EIA) Form 860 to determine each unit's minimum operating capacity (the minimum, stable generating output of a unit) and the seasonal capacity (the seasonal maximum operational capacity of the unit).[16]

Based on each unit's generating time, net generation, minimum operating capacity, and seasonal capacity, we categorized each hour of the unit's operation into five operating stages:

- Start-up, No Generation: The unit is operating and produces no net generation.

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[12] Gonzalez-Salazar, M.A., T. Kristen, and L. Prchlik. 2017. "Review of the operational flexibility and emissions of gas- and coal-fired power plants in future with growing renewables." *Renewable and Sustainable Energy Reviews* Vol. 82: 1497-1513. Available at: https://www.sciencedirect.com/science/article/pii/S1364032117309206.

[13] Ibid.

[14] U.S. Environmental Protection Agency. 2022. "Clean Air Markets Program Data." Available at: https://campd.epa.gov/.

[15] Net Load from: U.S. Energy Information Administration. 2022. "2021: EIA-923." Available at: https://www.eia.gov/electricity/data/eia923/; Gross Load from: Environmental Protection Agency. 2022. "Clean Air Markets Program Data." Available at: https://campd.epa.gov/.

[16] U.S. Energy Information Administration. 2022. "EIA-860, 2021." Available at: https://www.eia.gov/electricity/data/eia860/.

- Start-up, Low Generation: The unit is operating and produces non-zero net generation below the unit's minimum operating capacity.
- Operating, Below Maximum Operation: The unit is operating and produces net generation between the unit's minimum operating capacity and 90 percent of the unit's seasonal capacity.
- Operating, At Maximum Operation: The unit is operating at or above 90 percent of the unit's seasonal net capacity.
- Shutdown: The unit produces non-zero net generation below its minimum operating capacity immediately following an hour in an "operating" or "shutdown" stage.

There were some operating events that did not follow the typical operating pattern, as outlined above. For example, there were instances where the unit was generating, and net generation dropped below its minimum operating level for an hour or two before continuing to operate above its minimum operating capacity. These instances were reclassified as "operating, low generation" within the data and are considered periods of regular operation.[17]

Our analysis focused on start-up times, which quickly emerged as the most impactful limitation of the three considered in this report. We also evaluated ramp rates. We did not quantify minimum downtime in our analysis due to the difficulty in teasing out downtime restrictions from the available data. Many of the units we analyzed are often offline for periods longer than their minimum downtime restrictions for economic reasons. As a result, their minimum downtime requirements are hidden by other factors and cannot be extracted from the data. In addition, due to the low capacity factors of these units and their infrequent operation, minimum downtime is not typically a restriction to their operation. Instead, in most hours these units are offline, they have already been offline for longer than their minimum downtime requires. Minimum downtimes could have greater impacts on operations of units that are frequently cycled off and on and are more likely to have recently shutdown.

For our analysis of start-up times, we also used the length of the non-operating period (i.e., when the unit had no gross generation and no hours of operation) between operating events to classify start-up events as hot starts, warm starts, or cold starts. Per the EPA, hot starts occur when a unit has been offline for up to 24 hours, warm starts occur when a unit has been offline for 25 to 119 hours, and cold starts occur when a unit has been offline for 120 hours or more.[18]

We considered two metrics to describe the amount of time that a cold start-up takes, starting from the first hour of fuel consumption or unit operation. The first of these options is the time it takes for the unit to reach its minimum operating level and the second is the time it takes for the unit to reach 90 percent

[17] Additional outliers include instances where the unit cycled to "start-up, no generation" within a "start-up, low generation" period. These instances were categorized broadly as "start-up" periods. The units also sometimes cycle into "no generation" for an hour or two within a "start-up, no generation" or "start-up, low generation" period. These instances were also reclassified as "start-up" periods. Finally, units sometimes still operate (consume fuel) but have no net load at the end of a shutdown period for an additional hour. We classified these as "shutdown" periods rather than offline periods.

[18] Kokopeli, P., J. Schreifels, R. Forte. 2013. "Assessment of start-up period at coal-fired electric generating units." *US Environmental Protection Agency, Office of Air and Radiation.* Available at: https://www.epa.gov/sites/default/files/2015-11/documents/matsstartstsd.pdf.

of its maximum operating capacity. The first option is typically more consistent between operating events, as units tend to ramp up to at least their minimum operating level during each start-up event. Since units do not always ramp up directly to 90 percent of their operating capacity, the second value can be more variable depending on the unit's dispatch instructions. However, measuring the time to 90 percent of maximum operating capacity better reflects the time it takes for a unit to become fully available. For this analysis, we focused on the time it takes for a unit to reach its minimum operating level because we have more consistent data available for this metric. Our analysis did not include the notification time that a generation resource might require to begin the start-up process, as this time before fuel starts to be consumed does not appear in the data. Thus, the full time between the ISO's first dispatch instruction and the moment the plant reaches minimum operating capacity is likely slightly longer than we calculated.

In addition to analyzing start-up times, we identified the fastest observed ramp rates for each unit. To distinguish the limitations associated with ramp rates from those associated with start-up times, the calculation of each unit's ramp rate focuses exclusively on hours when generation is above minimum operation. Outlier ramp rates that were within 5 percent of fewer than two other observed ramp rates over the entire study period were excluded from the analysis.

Using this dataset and analytical framework, we examined the operating patterns of seven generating units at three power plants between January 1, 2018, and September 30, 2022 (a period of 41,616 hours):

- Merrimack Units 1 and 2 (coal units)
- Schiller Units 4 and 6 (coal units) and Schiller Unit 5 (wood/biomass unit)
- Canal Units 1 and 2 (oil units)[19]

Results of resource limitation analysis

For each of the seven units, we analyzed start-up trends and time to reach minimum operating capacity from start-up. Each of the seven units operated at varying levels during the 41,616 hours analyzed. See Table 1 for additional information about how frequently each unit operated at some level throughout the study period, operated above minimum load, and operated above 90 percent of maximum load.

[19] Canal Units 1 and 2 primarily burn residual fuel oil, or RFO, according to Energy Information Administration Form 860. New England has generation resources capable of burning both RFO and distillate fuel oil (DFO).

Table 1. Operating levels throughout study period

Unit	Fuel Type	Hours Analyzed	Operating at Some Level (% of hours)	Operating Above Minimum Load (% of hours)	Operating Above 90% of Maximum Load (% of hours)
Merrimack Unit 1	Coal	41,616	15%	13%	7.4%
Merrimack Unit 2	Coal	41,616	12%	10%	4.1%
Schiller Unit 4	Coal	41,616 *(21,604*)*	7.6% *(15%*)*	5.4% *(11%*)*	0.2% *(0.4%*)*
Schiller Unit 6	Coal	41,616 *(21,315*)*	14% *(28%*)*	6.8% *(13%*)*	0.7% *(1.3%*)*
Schiller Unit 5	Biomass	41,616 *(21,086*)*	33% *(65%*)*	31% *(62%*)*	4.0% *(8.0%*)*
Canal Unit 1	Oil	41,616	2.3%	1.8%	0.7%
Canal Unit 2	Oil	41,616	2.4%	1.7%	0.4%

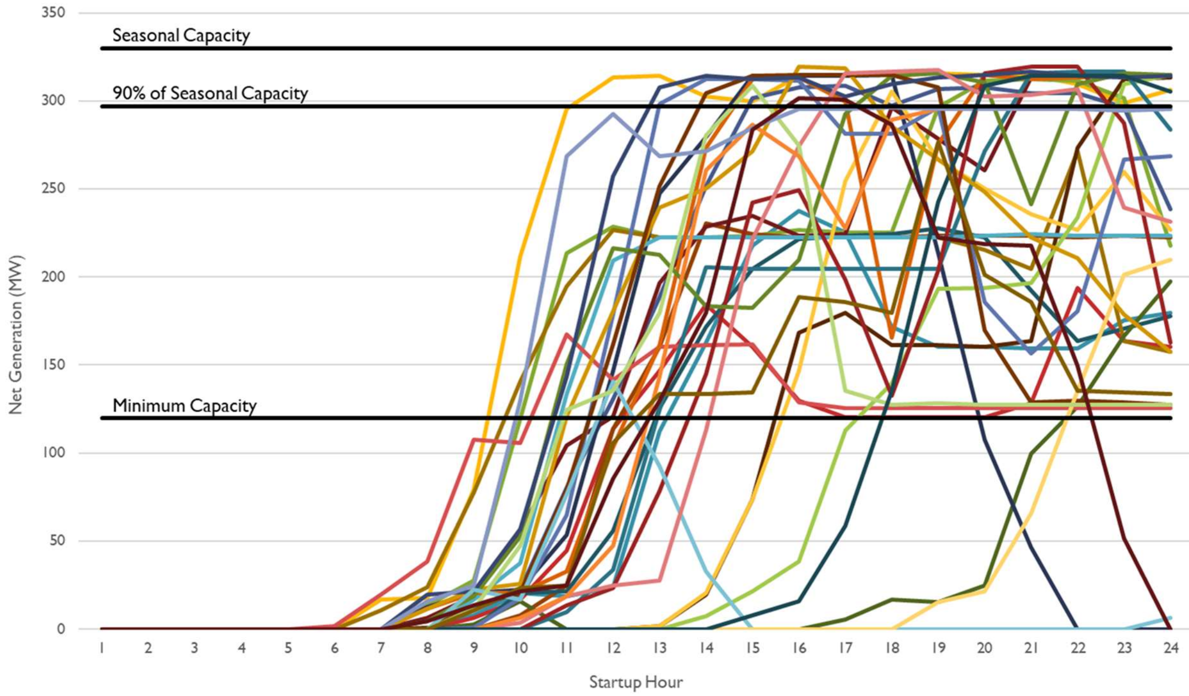
**The three Schiller units did not operate past June 2020. To account for this shutdown, the values in parentheses demonstrate their operating levels based on their operation from January 1, 2018, through each unit's final operating event in late May or early June 2020.*

Overall, the units analyzed operated less than one-third of the time during the almost five-year study period. Additionally, the units operated over 90 percent of their maximum load less than 10 percent of the time across all units.

The relatively limited operation of the seven units, and in particular the coal and oil units analyzed, increases the impact of each unit's cold start-up time on the plant's reliability value. Since each of these units is frequently offline, a long cold start-up time impacts their ability to provide reliability during unforeseen grid events.

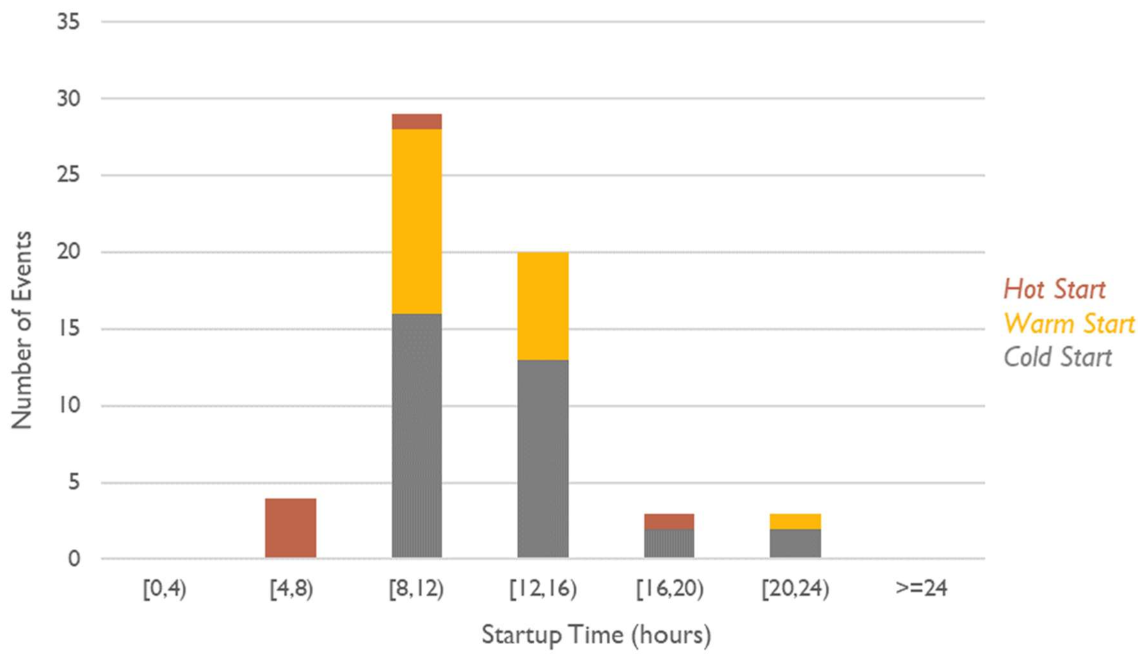
In this section, we include detailed results for Merrimack Unit 2 as a representative, larger unit among the study sample. Detailed results for other units can be found in the Appendix. Merrimack Unit 2 operated and reached its minimum operating capacity 60 times during the analysis period, including 14 instances where the unit never reached 90 percent of its maximum capacity. Unit 2's 60 operating events include 7 hot starts, 20 warm starts, and 33 cold starts. Figure 2, below, depicts the 33 cold-start operating events in which Merrimack Unit 2 reached its minimum operating capacity.

Figure 2. Merrimack Unit 2 cold start-up events



Merrimack Unit 2's start-up process typically began with six to ten (or more) hours of no generation, followed by two hours with a slight increase in net generation, before the unit quickly ramped up to a stable operating output after an additional two to four hours. In total, Merrimack Unit 2 took 9 to 21 hours to reach its minimum operating capacity from cold start, as shown in Figure 3. The same unit took 11 to 109 hours to reach 90 percent of its seasonal capacity from cold start (see the Appendix for the corresponding figure).

Figure 3. Merrimack Unit 2, start-up to minimum operating capacity



Note that "[" denotes the inclusion of the bound and "(" denotes the exclusion of the bound. For example, "[0,4)" denotes all numbers between 0 and 4, including 0 but excluding 4.

Merrimack Unit 2 exhibited ramp rates of up to 117 MW per hour, allowing the unit to ramp up fully in about two to three hours between its minimum and maximum operating capacities.

Many of the other units analyzed exhibit roughly similar start-up characteristics, differing most significantly in the length of non-generation time within the start-up period. We also observed somewhat similar ramp rates, though some units ramped a bit faster or slower relative to their seasonal capacities. Thus, for the units we analyzed, start-up time is likely to be the most constraining factor during unpredicted grid events. Corresponding charts for Merrimack Unit 1, the Schiller units, and the Canal units can be found in the Appendix.

Table 2 summarizes the start-up times of each of the seven units analyzed. These units took a minimum of 6 to 15 hours to reach their minimum operating capacity from cold start, with median start-up times of 7 to 23 hours. The four largest units by nameplate capacity (the Merrimack and Canal units) recorded fastest start-up times of 7–9 hours and median start-up times of 11–14 hours. For additional information about the time it takes for each of the analyzed units to reach 90 percent of their operating capacity, see the Appendix.

Table 2. Cold start to minimum operating capacity for each unit

Unit	Fuel Type	Fastest Cold Start (hours)	10th Percentile Cold Start (hours)	Median Cold Start (hours)
Merrimack Unit 1	Coal	9	12	14
Merrimack Unit 2	Coal	9	10	12
Schiller Unit 4	Coal	6	6.1	7
Schiller Unit 6	Coal	6	6	7
Schiller Unit 5	Wood/Biomass	15	16.2	23
Canal Unit 1	Oil	7	8	11
Canal Unit 2	Oil	8	9.4	12

While we focused on seven slow-starting units in New England, with a total nameplate capacity of 1.7 GW, the region has 25.7 GW of nameplate capacity that takes more than an hour to start up, according to EIA. This includes units representing 7.6 GW of capacity that take over 12 hours to start up.[20]

Table 3 shows the absolute and relative ramp rates for each of the seven units we studied. The units analyzed exhibited a range of ramp rates, both in absolute (MW) and relative (percent) terms. The relative ramp rates for the seven analyzed units ranged from 28 percent of seasonal capacity per hour to 54 percent of seasonal capacity per hour. The units with lower seasonal capacities had higher relative ramp rates, while units with larger seasonal capacities had lower relative ramp rates.

Table 3. Ramp rate for each unit

Unit	Fuel Type	Seasonal Capacity* *(MW)*	Highest Observed Ramp Rate** *(MW/hr)*	Highest Relative Ramp Rate *(% of seasonal capacity/hr)*
Merrimack Unit 1	Coal	108	48	44%
Merrimack Unit 2	Coal	330	117	35%
Schiller Unit 4	Coal	48	23	48%
Schiller Unit 6	Coal	48	26	54%
Schiller Unit 5	Wood/Biomass	43	19	44%
Canal Unit 1	Oil	560	158	28%
Canal Unit 2	Oil	559	160	29%

**The seasonal capacity shown in this table is the lower of the Net Summer Capacity and Net Winter Capacity as reported by EIA Form 860. For each of these units, the Net Summer Capacity and Net Winter Capacity were within 1.5 percent of each other.*

***The highest observed ramp rate excludes outliers. The highest ramp rate presented is the highest ramp rate with at least two additional ramp rates within 5 percent below the value presented. Higher ramp rates that did not have at least two additional values within 5 percent below the value were excluded.*

[20] U.S. Energy Information Administration. 2022. "EIA-860, 2021." Available at: https://www.eia.gov/electricity/data/eia860/.

Key takeaways

For the resources we studied, our analysis found that start-up time is the most important operating constraint of an inflexible resource during unpredicted grid stress and for determining proper capacity accreditation value. More specifically, resources with long start-up times will not be able to show up for a capacity or energy need within the operating day if they were not committed in advance. Because slow-start resources need a long lead time to start up before they can generate electricity, they are unable to reliably supply capacity during sudden grid shortage events. If the region enters a capacity shortage event after the operating day begins, resources with long start-up times over 8 or 12 hours would not be able to supply capacity during a 6:00 PM peak hour if the grid emergency began after 10:00 AM or 6:00 AM, respectively. This notably diminishes the potential reliability contribution of slow-start resources. While resources with long start-up times can turn on to meet forecasted capacity shortages, they are often unable to start up in time to offer reliability during unpredicted capacity shortages.

By comparison, the resources analyzed did have the ability to ramp between minimum and maximum generation in a period of several hours. These resources might still be less useful in particularly sudden emergencies, but we expect that long start-up times are a greater liability than the ramp rate limits we observed. While minimum downtime impacts were less clear than the other two variables analyzed in the data, the analyzed units only operate around one-third of the time at most, and most of the units operate much less than that. As a result, they typically start up after being offline for several days, if not weeks or months and are less likely to be limited by a minimum downtime constraint.

Furthermore, while we analyzed these constraints for seven resources, totaling 1.7 GW of nameplate capacity, New England has 7.5 GW of resources with start-up times over 12 hours and an additional 18.2 GW of resources with start-up times from one to 12 hours. These operational limitations are a widespread issue in the current electric generation fleet, with the potential to significantly degrade grid reliability during unpredicted system stress events.

2.2. Forecast uncertainty

Forecast uncertainties analyzed

The inflexible resources that we describe in the preceding section are least likely to contribute to reliability during events that are not forecasted. Over short timescales, these resources struggle to respond to dispatch instructions. Several factors can contribute to unexpected system generation shortages: when planned energy generation goes awry (such as with forced outages from aging power plants) and when forecasts for energy demand (load) and non-dispatchable renewables such as wind power are wrong. To protect against the risk of forced outages, ISO New England maintains operating reserves to ensure reliability even if the largest single unit on the system unexpectedly goes offline. The grid operator also produces forecasts for load and wind to develop a day-ahead operating plan that commits enough dispatchable resources. Even with these practices in place, in some hours, the system still faces unexpected challenges, and those instances merit further investigation to inform how resources are valued in ISO New England's capacity market.

Neither hourly outage data nor annual outage rates are publicly available at the plant level, so we did not model the anticipated distribution of hourly impacts of these outages. While more granular public data is limited, it is clear from historical events like Winter Storm Elliott that multiple simultaneous outages can occur and can cause generation capacity shortages. ISO New England should conduct additional analysis to examine the reliability impacts associated with unplanned outages given the New England grid's reliance on inflexible resources that struggle to respond quickly to unpredicted reductions in generation at other plants.

Load and variable generation forecast data is more readily available from ISO New England, so we were able to analyze the inherent uncertainty associated with ISO New England's forecasts for load and wind generation. The following section describes our results. We focused on wind in our analysis of renewable generation uncertainty; most New England solar is behind the meter, so solar output in New England today primarily impacts the load forecast. ISO New England does not currently publish a front-of-the-meter solar forecast.

Methodology for forecast uncertainty analysis

We calculated day-of peak load forecast errors by comparing peak load projections with the actual peak loads for five years' worth of historical data (from January 1, 2017, through September 22, 2022). We downloaded seven-day forecasts using ISO New England's web services API. These forecasts provide a summary of factors impacting the power system for the following week, including peak demand.[21] ISO New England produces the reports each morning around 8:30 AM. From each forecast, we pulled out the peak load projected for the first day (i.e., the same day the forecast is released). We then compared the projected peak loads to the actual peak loads for each day[22] and calculated the differences between the forecasted and actual values to find the forecast error.

For the wind forecast errors, we compared hourly wind power generation forecasts made 10 to 14 hours in advance with actual hourly wind output, again over the past five years. We first downloaded Seven-Day Wind Power Forecasts,[23] which ISO New England also updates each morning around 8:30 AM. The wind forecasts contain hourly projected generation for the hours ending 11–24 for the first day (i.e., the same day as the forecast is released), and then all hours for the following six days. From each forecast, we analyzed projected wind generation for the hours ending 19–23 (given the 8:30 AM forecast creation time, this time interval represents forecasts made 10–14 hours in advance). We then calculated the

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[21] ISO-NE's Seven-Day Capacity Forecast, available at: https://www.iso-ne.com/markets-operations/system-forecast-status/seven-day-capacity-forecast.

[22] ISO New England. 2022. "Variable Energy Resource (VER) Data." Available at: https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/.

[23] ISO-NE's Seven-Day Wind Power Forecast, available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seven-day-wind-power-forecast.

differences between these forecasts and the actual wind hourly wind generation in the same hours.[24] Because the amount of wind on the New England grid is expected to grow significantly over the next few decades, we normalized the historical forecast errors relative to the system-wide nameplate capacity on the system in the given year,[25] and reported them as a percent of nameplate capacity.

Results of forecast uncertainty analysis

Figure 4 summarizes our load forecast uncertainty findings. In the worst 10 percent of days, peak load is under-forecast by at least 1,247 MW, and in the worst 1 percent of days, peak load is under-forecast by 2,594 MW. By comparison, the ISO's real-time operating reserve requirement is typically between 2,000 MW and 3,000 MW, so these levels of forecast uncertainty can significantly impact the ISO's daily operating plan. These operating reserves must be maintained at all times to protect the system against an outage at one of its largest units (or transmission lines) and are not intended to be depleted to respond to forecast error.

Figure 5 shows historical wind power forecast error as a percent of wind nameplate system capacity operating in the given year. ISO New England's wind forecast is accurate to within 10 percent of nameplate capacity in most hours. Just like any forecast or forced outage risk, there are also a few hours with larger forecast error, and in those hours, it is critical to have flexible resources on the system. In the worst 10 percent of hours, hourly wind power is over-predicted by at least 14 percent of nameplate capacity and in the worst 1 percent of hours, hourly wind power is over-predicted by at least 29 percent of nameplate capacity. Currently, this means hourly wind power is over-predicted by at least 200 MW and 400 MW in the worst 10 percent and 1 percent of hours respectively. In the future, wind generation on the system (including offshore wind) will increase substantially, likely increasing the magnitude of the impacts of wind generation forecast uncertainty. With 19 GW of wind on the New England grid by 2040, as was projected by an Analysis Group Pathways study,[26] the same percent error in wind forecasts as we observed in the last five years would lead to over-forecasting by approximately 5,500 MW in the worst 1 percent of hours.

[24] ISO-NE's Daily Generation by Fuel Type, available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.

[25] U.S. Energy Information Administration. 2022. "EIA-860, 2021." Available at: https://www.eia.gov/electricity/data/eia860/.

[26] Schatzki et al., Analysis Group. 2022. *Pathways Study: Evaluation of Pathways to a Future Grid.* Available at: https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf.

Figure 4. Historical peak load forecast error histogram

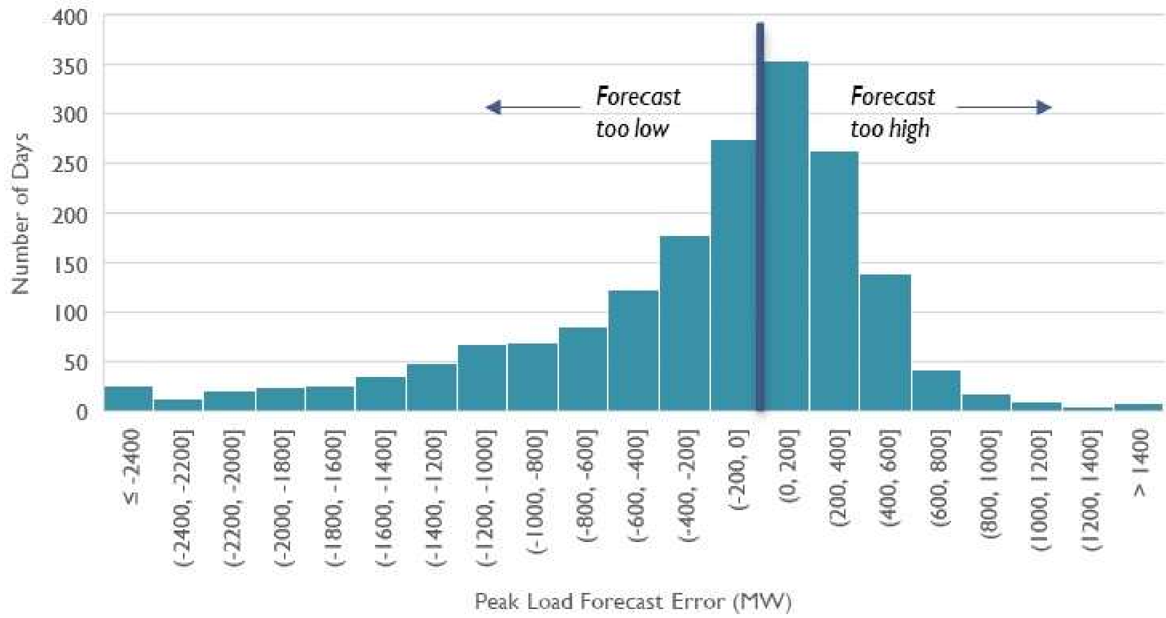
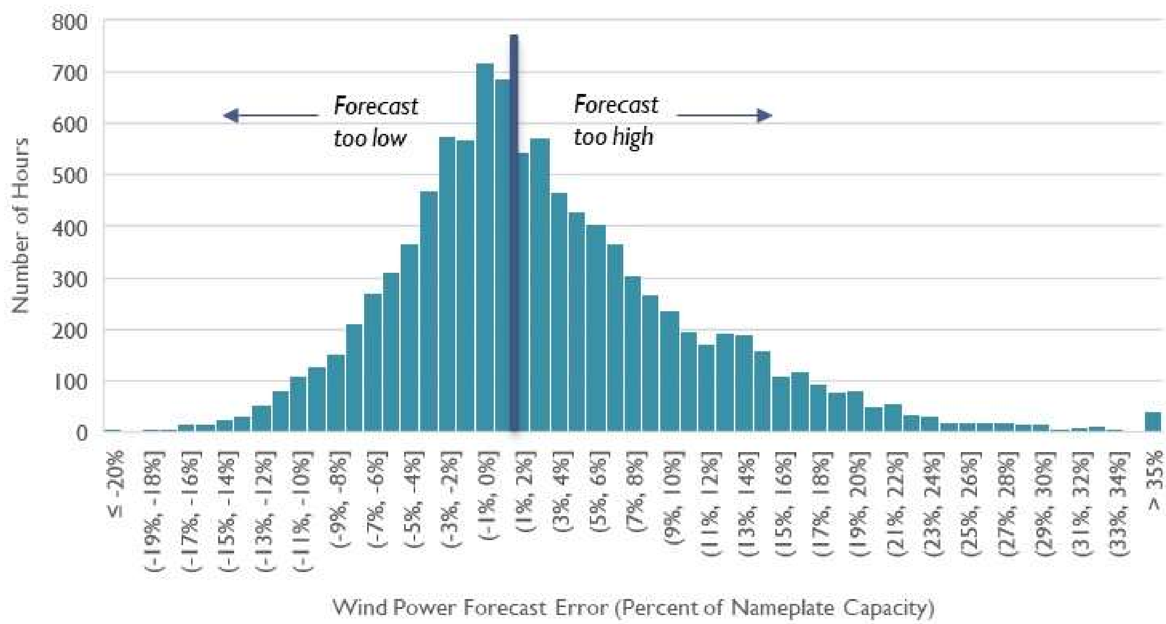


Figure 5. Historical wind power forecast error histogram



The ISO also analyzes its mean absolute errors in wind power forecasts on a rolling 30-day basis. Recent estimates by ISO New England[27] showed mean absolute errors between 10 and 15 percent for forecasts made less than 45 hours in advance.

Key takeaways

Our results show that ISO New England's load and wind generation forecast uncertainty is substantial and requires resources to be available with less than 10–14 hours' notice. In the future, climate change, extreme weather events, and a changing resource mix could all increase forecast uncertainty. Some amount of forecast uncertainty is essentially unavoidable and does not necessarily reflect poorly on the forecasts. The important takeaway is that this uncertainty is an important feature of how the grid operates. Inflexible thermal resources are poorly suited to support the system given this uncertainty, and capacity accreditation modeling that does not reflect this reality will fail to realize the benefits of procuring higher performing resources that can respond more rapidly.

3. IMPLICATIONS FOR CAPACITY ACCREDITATION

3.1. Inflexibility in accreditation calculations

New England's capacity accreditation framework is tasked with ensuring a reliable resource mix is procured through the capacity market. Leaving operational limitations out of the calculations can result in an overly optimistic assessment of the reliability that today's resource mix can provide. That can leave the region in trouble when faced with higher-than-expected loads or surprising operating-day forced outages, as occurred with Winter Storm Elliott. Furthermore, selectively excluding the limitations of particular resource types biases the capacity market against other classes of resources and unfairly compensates inflexible resources for more reliability than they can actually provide. If newer technologies such as battery storage can provide immediate response when the system needs them, that superior performance should be recognized by the capacity accreditation methodology. Otherwise, New England risks disadvantaging the very resources that could improve the grid's reliability, while incentivizing legacy, inflexible power plants to remain even if their value is limited.

Sudden, unanticipated events are not the only situations that can cause reliability challenges. But recent experience has demonstrated that this class of reliability events cannot be ignored; the last two reserve shortage incidents in December 2022 and September 2018 developed quickly as a result of unexpected circumstances. Excluding resources' operational limitations from the capacity accreditation calculation sets the region on a path of continued challenges in the face of these situations.

[27] NEPOOL Participants Committee Report Slide 35, December 2022. Available at: https://www.iso-ne.com/static-assets/documents/2022/11/december-2022-coo-report.pdf.

Substantial uncertainty and risk within resources' start-up windows

The two key components of our analysis—our evaluation of resource operational limitations and our forecast uncertainty analysis—together demonstrate how slow start-up resources can cause challenges for the grid. We find that older, thermal resources may take 12 or more hours to start up from an offline state, which creates a window of greater system risk in which these resources would effectively be unavailable. Within that time horizon, we observe substantial forecast uncertainty for both load and non-dispatchable generation, leaving the system at risk in the inevitable event that forecasts turn out to be incorrect. These forecast errors are too big to be ignored—they are on the same order of magnitude as the quantity of ISO New England's required operating reserves. And while we cannot analyze unit-specific outage data, we note that recent shortage events have demonstrated that unexpected, forced outages are another major risk factor within these start-up windows.

Forecast uncertainty is likely to continue to be a regular part of operating the grid. In some instances, it may even increase. Forecasting extreme, unusual, or unexpected weather events is even more difficult than forecasting a typical day, because the forecast models have less historical precedent on which to rely and train. This poses a significant challenge as climate change continues to bring new and more severe weather patterns over time. Given the uncertainty forecast models will likely have during these events, inflexible resources pose too high a risk of not being available when they are most needed.

In addition to contributing to forecast uncertainty, extreme weather events can exacerbate correlated forced outages of other resources on the grid, including imports from adjacent regions. These forced outages tend to occur with little notice, pushing the region into a potentially unexpected supply shortage. Correlated forced outage risk is yet another challenge for which inflexible resources have limited utility, even if they do not face outages themselves.[28] In order to procure a set of resources that delivers reliability in unexpected circumstances, the limits of these resources' reliability contributions should be factored into capacity accreditation.

3.2. Modeling the impact of resource inflexibility for accreditation

To develop a capacity accreditation process that accurately reflects the limitations of inflexible resources, it is necessary to use a modeling tool that can account for operating limitations, including cold start-up time. By contrast, the ISO is proposing to continue to use the GE MARS model for capacity accreditation.[29] The GE MARS model is missing two key features needed to model the limitations of inflexible resources: (a) commitment and dispatch, and (b) forecast and forced outage uncertainty.

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[28] Class average forced outage rates for generation resources in North America, as compiled by NERC, is available on the ISO New England website here: https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf. In addition, Astrapé Consulting analyzed the increased reliability risks associated with correlation of forced outages in its 2022 report *Accrediting Resource Adequacy Value to Thermal Generation*: https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf.

[29] Electric Power Research Institute. 2022. "Adequacy/tools." Available at: https://gridops.epri.com/Adequacy/tools.

Commitment and dispatch refer to the operating state of a generation resource. Resources that are committed are online and generating power. A resource's dispatch is the specific amount of power that it is generating at a given moment. Unlike a commitment or dispatch model, GE MARS does not select a specific subset of resources to be operating (based on their relative economics) to serve the load. GE MARS focuses on available capacity, so it simply compares the total capacity of available resources (only excluding maintenance and unplanned outages) with the total load in each hour. As long as available capacity meets or exceeds load, GE MARS determines the system to be reliable. Since inflexible units are not identified as operating (or equivalently, dispatched) in GE MARS, it is not possible for the model to determine if they need to go through a start-up process before they can begin generating energy. While commitment and dispatch are not incorporated into GE MARS, many models do identify and optimize these operating states.[30] To account for the impacts of inflexible resources on capacity value, a model would need to commit and dispatch resources (i.e., select which ones actually serve load in each hour).

In addition to accounting for commitment and dispatch, a model that quantifies the capacity limitations of inflexible resources would need to incorporate forecast and forced outage uncertainty. This is because inflexible resources increase risk to grid reliability during periods of unexpected grid stress, when it is essential for offline units to respond quickly. This uncertainty could be incorporated into a commitment and dispatch model by adjusting the input data and the optimization period over which the system is dispatched to minimize cost. Often, hourly load and renewable generation data, as well as randomly selected forced outages, are all inputs into these models. The actual load, generation, and outage data for future hours can then impact the optimized dispatch for an earlier hour, depending on the optimization period over which the model seeks a single, least-cost set of dispatch plans for each hour (or other modeled interval). In other words, the models can look ahead to future hours without any forecast uncertainty when choosing an optimal dispatch.

Capturing the limitations of inflexible resources requires a more sophisticated modeling process. Ideally, the system dispatch would only be solved one hour or interval at a time so that future conditions do not impact past dispatch choices. This ensures that the model does not have foresight that the system operator would not have in real-world conditions. In addition, a forecast of load and renewable generation should be incorporated as an input into each hour's dispatch, to represent the information that system operators actually have when they make dispatch decisions. These forecasts should extend far enough into the future to allow the model to begin starting up slower units in preparation for higher demand intervals on the horizon in order to most closely align the model with how system operators run the grid in the real world. The model design would also better reflect reality in that forecasts would change over time as the forecasted hour becomes closer and more information becomes available to system operators. Without this forecast uncertainty, a model cannot measure the full reliability value of

[30] These commitment and dispatch models (sometimes called production cost models) include EnCompass, PLEXOS, PROMOD, and ISO New England's Market Clearing Engine, among others. They are typically used to determine the least-cost operation of the electric grid at an approximately hourly level, which allows for the modeling of electricity prices, generation from each unit, and any related outputs.

units that can start up or ramp up quickly, or accurately compare the reliability values of slow starting and fast starting resources.

4. CONCLUSIONS

4.1. Resource inflexibility and system stress

We found that resource operational limitations can prevent resources, including those with capacity supply obligations, from serving load during unanticipated periods of system stress. When load or non-dispatchable generation forecasts differ from what happens in real time, or operating-day forced outages of local resources or imports create a gap in the day-ahead supply plan, slow-start-up resources can fail to generate power in time to avoid or help alleviate reliability events. In the last five years, the only two reserve shortages in New England have been caused by these types of unforeseen reliability events, demonstrating the risks of relying on inflexible resources to maintain system reliability.

4.2. Accounting for resource inflexibility in capacity accreditation

As New England develops market mechanisms to maintain a reliable grid into the future, it should account for these unpredicted incidents in its capacity accreditation framework. Excluding serious resource limitations from the capacity accreditation methodology leads to inaccurate market signals. The result is over-compensated power plants that might not be able to provide the reliability that consumers expect from them. At the same time, ISO New England misses the opportunity to create market signals that can attract newer resources and technologies that can improve reliability during unanticipated grid stress events.

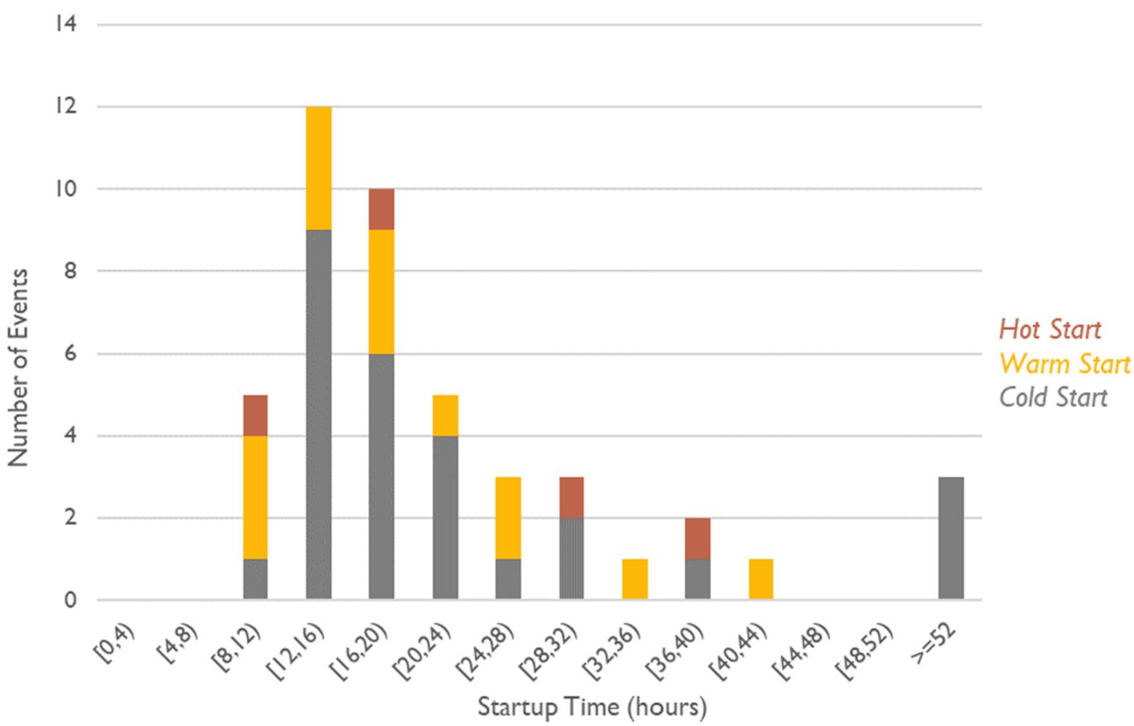
4.3. Including commitment, dispatch, and forecast uncertainty in ISO New England's RCA methodology

Incorporating operational limitations into the RCA framework will require new and more sophisticated modeling tools. These tools must be capable of modeling commitment and dispatch (which is readily available in existing modeling frameworks) *and* be able to account for forecast and forced outage uncertainty (which is less common in existing models). While new model development will take some time, these investments would create an improved RCA scheme that would better maintain system reliability during an important subset of reliability events in a cost-effective manner.

Appendix A. Unit-Specific Start-Up Data

This appendix includes additional information about Merrimack Unit 1, as well as the Schiller and Canal units analyzed. The section also includes information about Merrimack Unit 2's start-up to 90 percent of maximum capacity trends.

Figure 6. Merrimack Unit 2, start-up to 90% of seasonal capacity



Merrimack Unit 1 operated around 60 times during the analysis period, including around 7 instances where the unit never reached 90 percent of its maximum capacity. As shown in Figure 7, Unit 1 took 9 to 23 hours to reach its minimum operating capacity from cold start. The unit took 10 to 76 hours to reach 90 percent of its seasonal capacity from cold start.

Figure 7. Merrimack Unit 1, start-up to minimum operating capacity

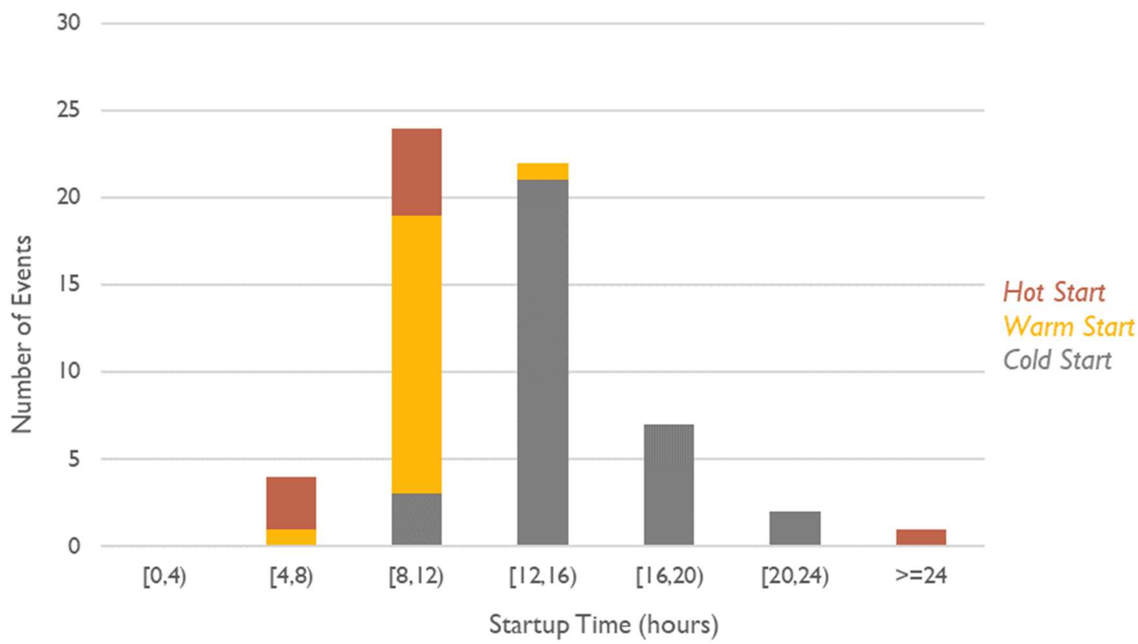
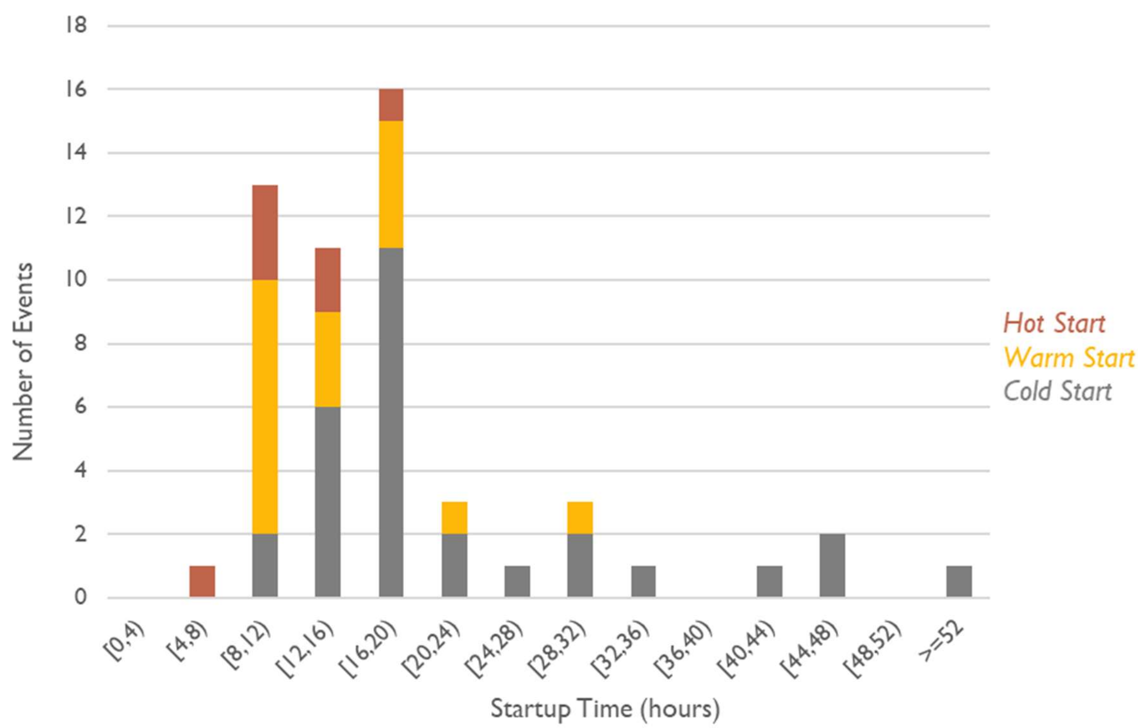


Figure 8. Merrimack Unit 1, start-up to 90% of seasonal capacity



The two Schiller coal units each operated 100 to 123 times during the analysis period, including over 90 instances where each unit never reached 90 percent of their seasonal operating capacities. Schiller Unit 4 took 6 to 11 hours to reach its minimum operating capacity from cold start, as shown in Figure 9. Schiller Unit 4 took 11 hours to reach 90 percent of its seasonal capacity during its one cold start-up that reached said threshold, as shown in Figure 10.

Figure 9. Schiller Unit 4, start-up to minimum operating capacity

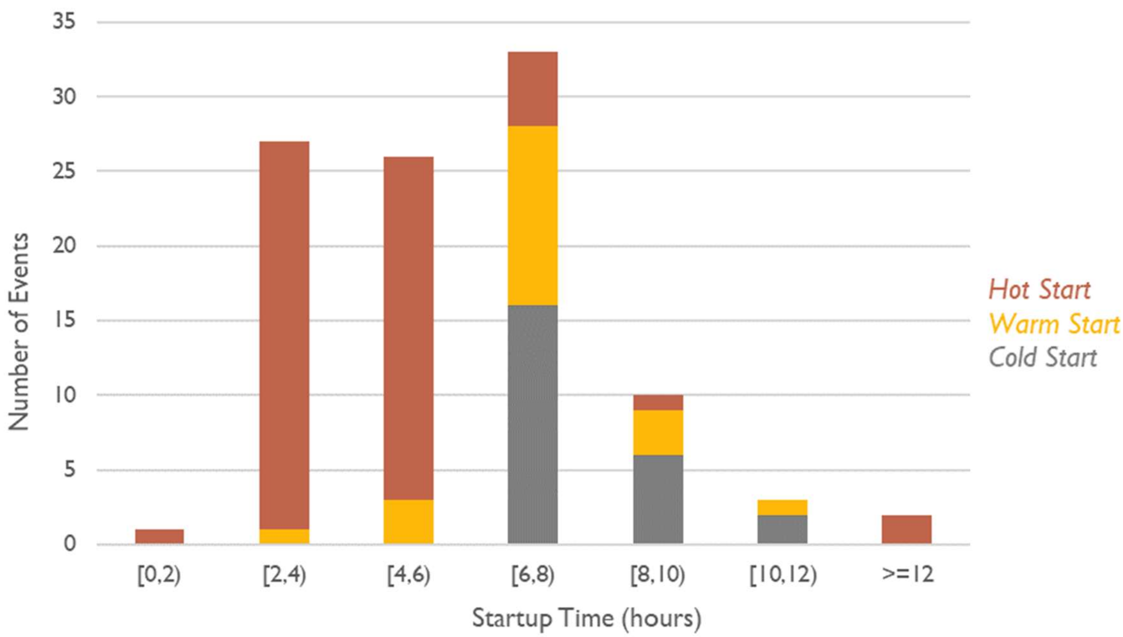
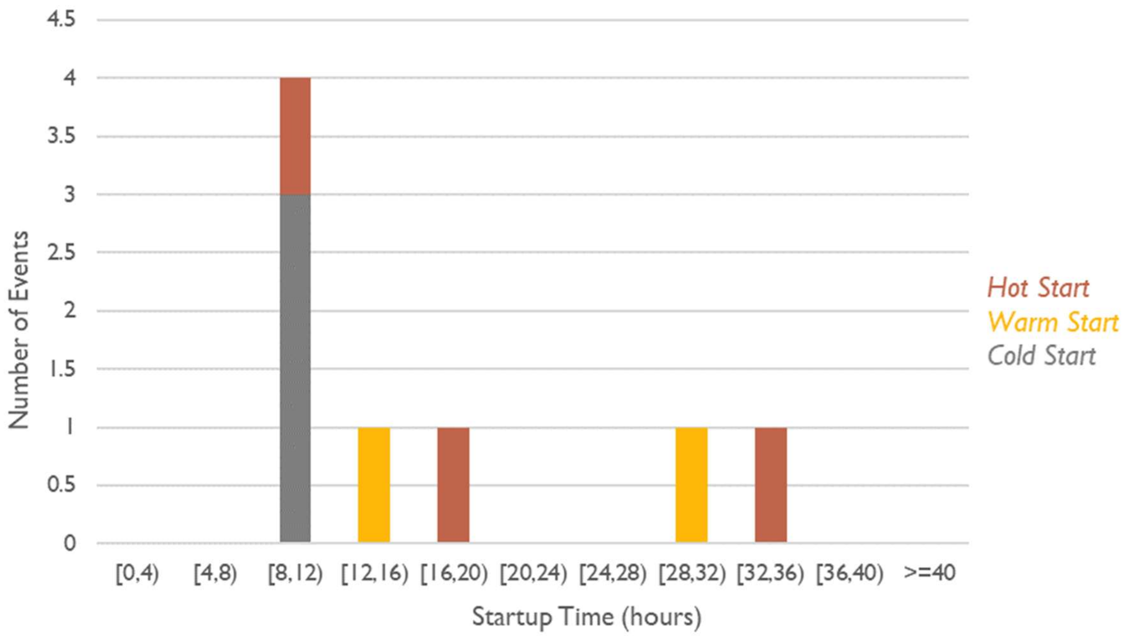


Figure 10. Schiller Unit 4, start-up to 90% of seasonal capacity



Schiller Unit 6 took 6 to 10 hours to reach its minimum operating capacity in all but one cold start, as shown in Figure 11. The unit also had one outlier during which the unit took 125 hours to reach its minimum operating capacity. Schiller Unit 6 took 8 to 41 hours to reach 90 percent of its seasonal capacity from cold start, as shown in Figure 12.

Figure 11. Schiller Unit 6, start-up to minimum operating capacity

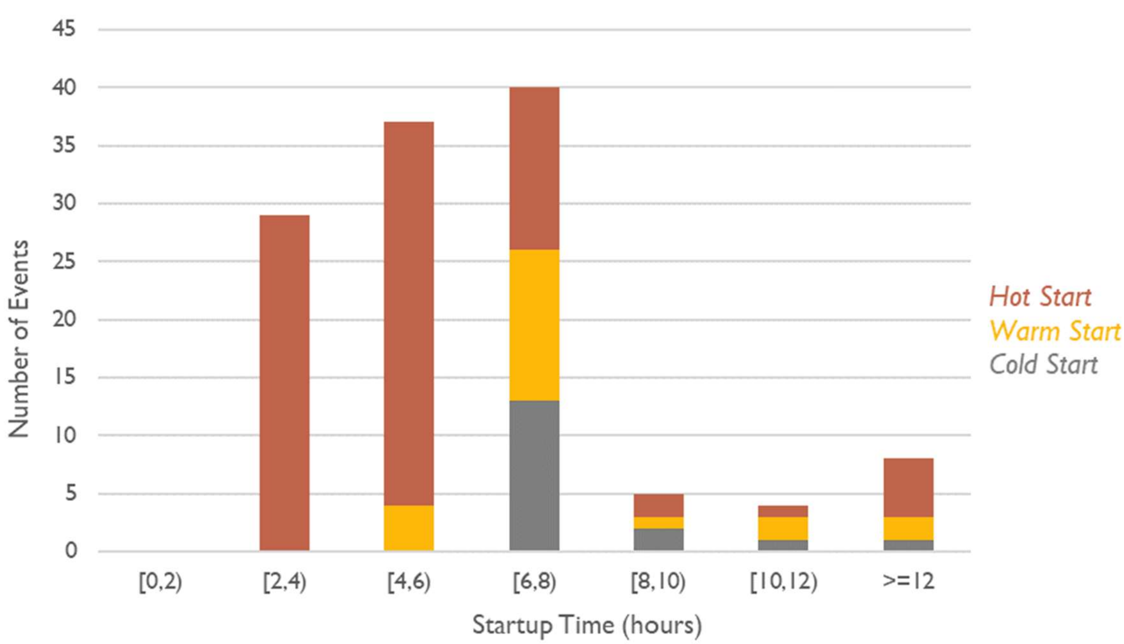
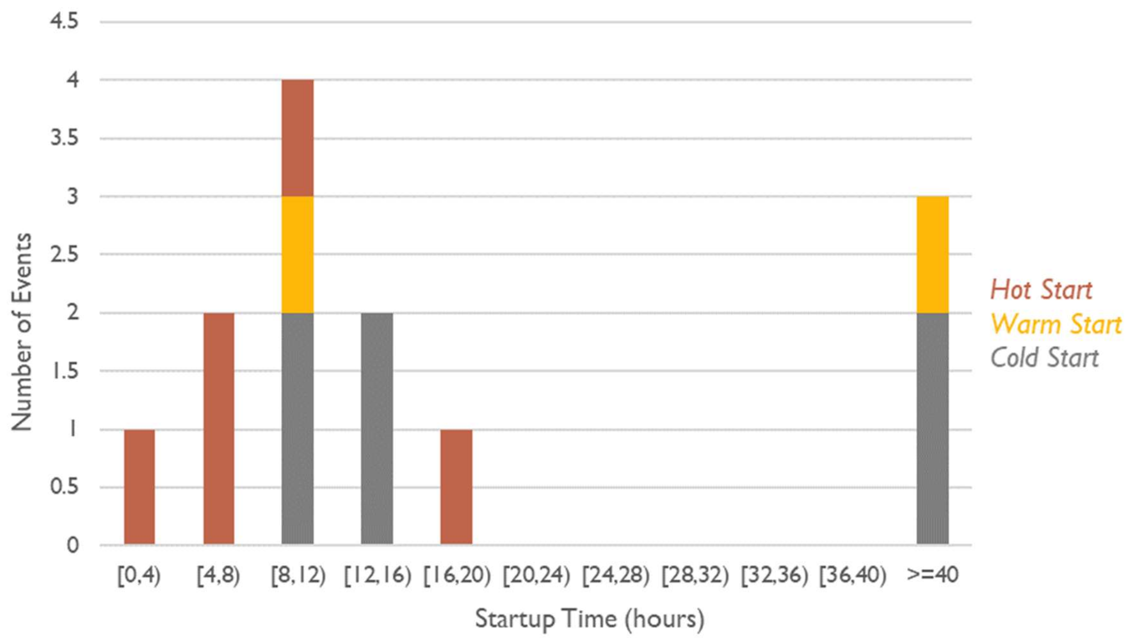


Figure 12. Schiller Unit 6, start-up to 90% of seasonal capacity



Schiller's Unit 5, a wood and biomass unit, operated 24 times during the analysis period. This includes 6 instances where the unit never reached 90 percent of its seasonal operating capacity, as shown in Figure 13. Schiller Unit 5 took 25 to 493 hours to reach its minimum operating capacity from cold start, as shown in Figure 14.

Figure 13. Schiller Unit 5, start-up to minimum operating capacity

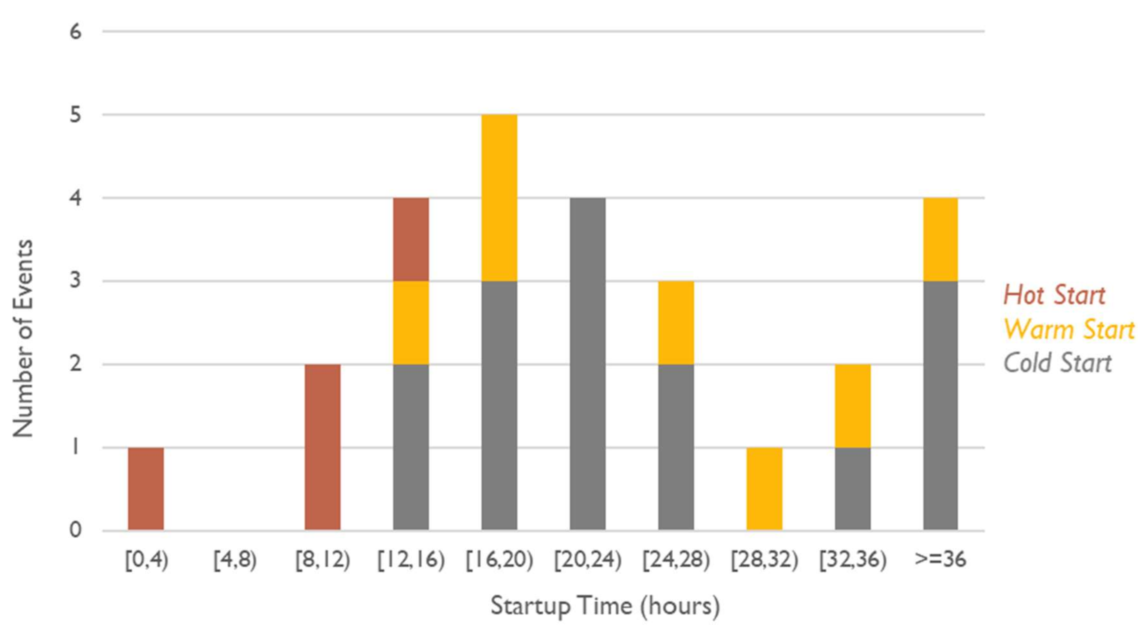
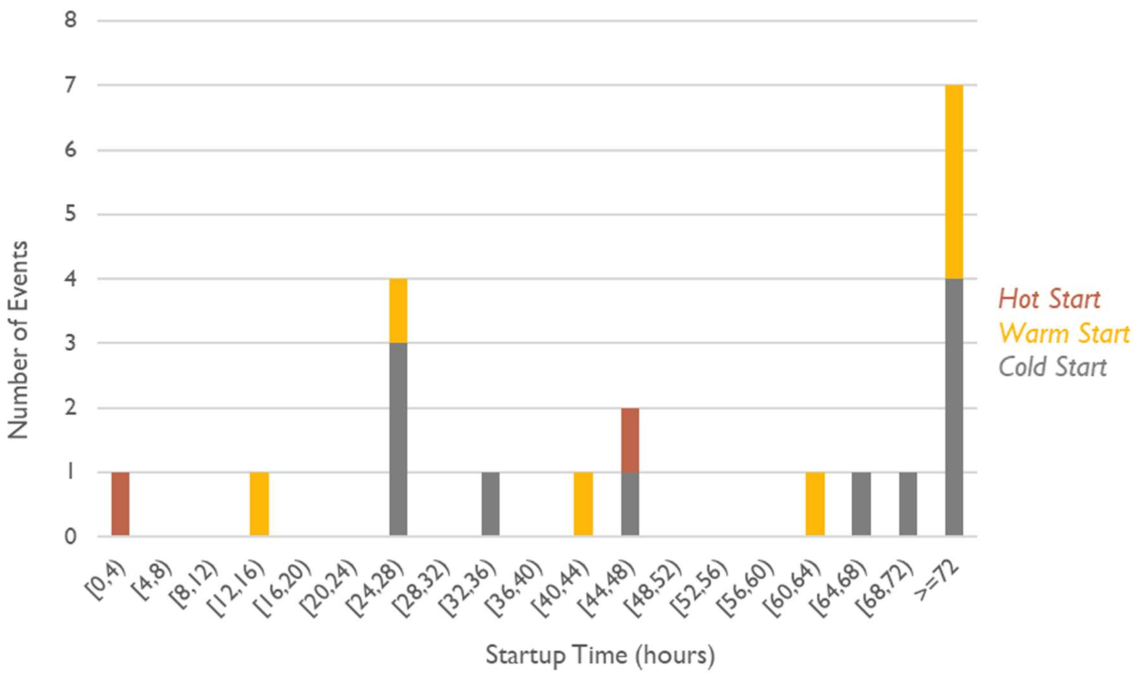


Figure 14. Schiller Unit 5, start-up to 90% of seasonal capacity



The two Canal units operated around 17 times over the analysis period, including 4 to 7 instances where each unit did not reach 90 percent of its seasonal operating capacity. Canal Unit 1 took 7 to 17 hours to reach its minimum operating capacity from cold start, as shown in Figure 15. The unit took 10 to 38 hours to reach 90 percent of its seasonal capacity from cold start, as shown in Figure 16.

Figure 15. Canal Unit 1, start-up to minimum operating capacity

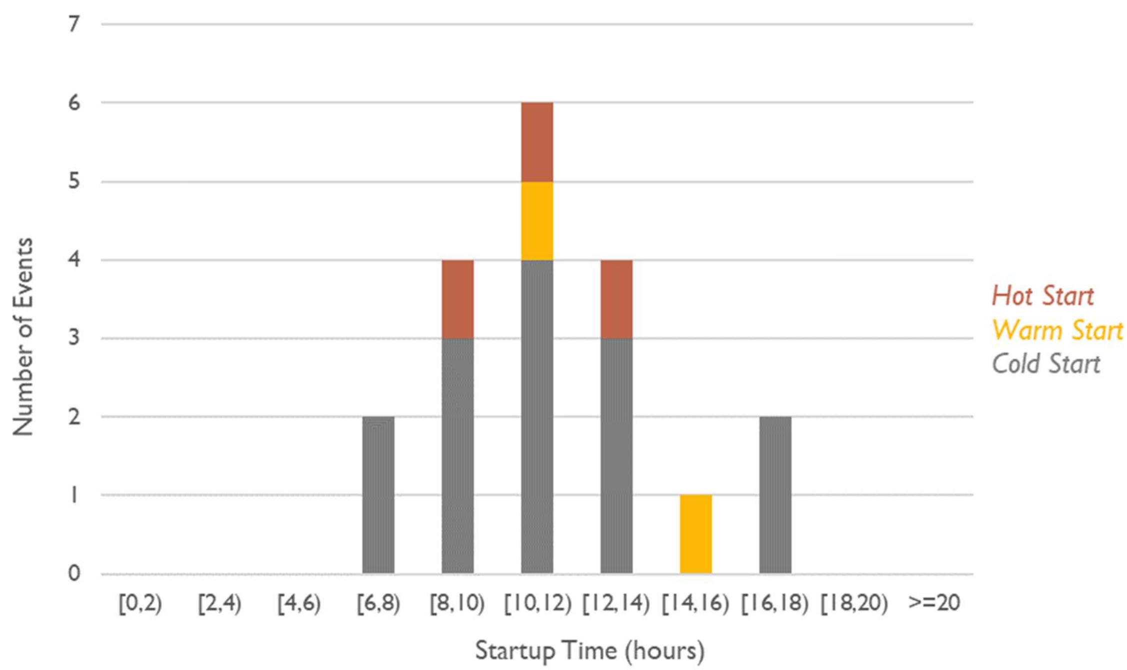
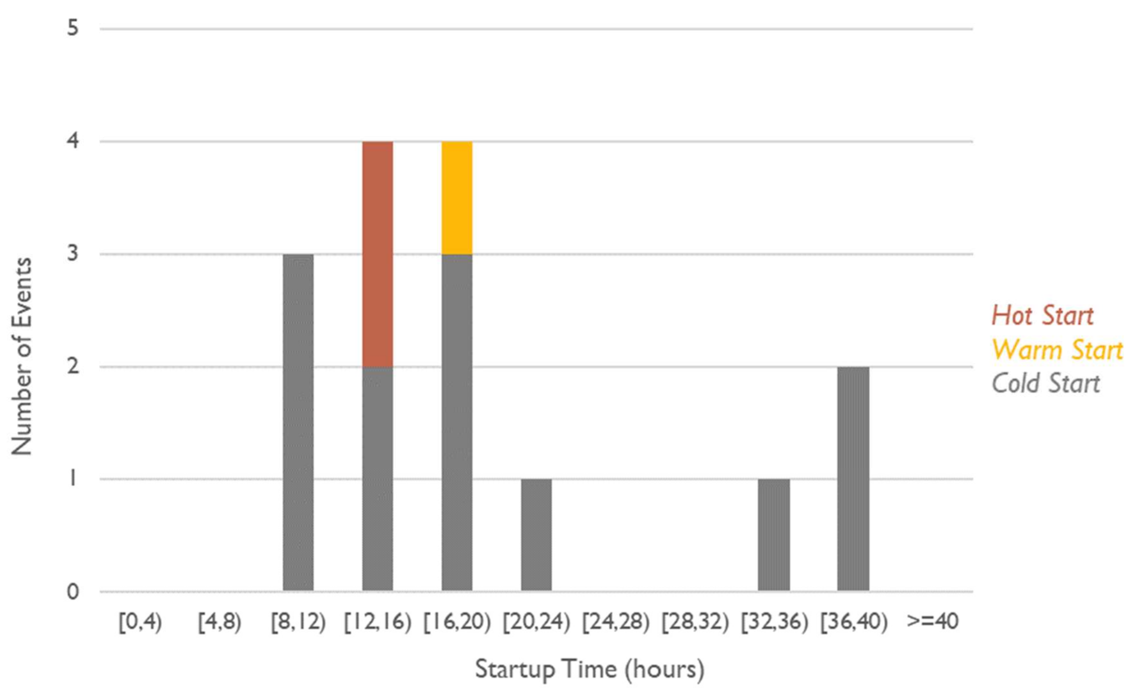


Figure 16. Canal Unit 1, start-up to 90% of seasonal capacity



Canal Unit 2 took 8 to 36 hours to reach its minimum operating capacity from cold start, as shown in Figure 17. Unit 2 took 14 to 43 hours to reach 90 percent of its seasonal capacity from cold start, as shown in Figure 18.

Figure 17. Canal Unit 2, start-up to minimum operating capacity

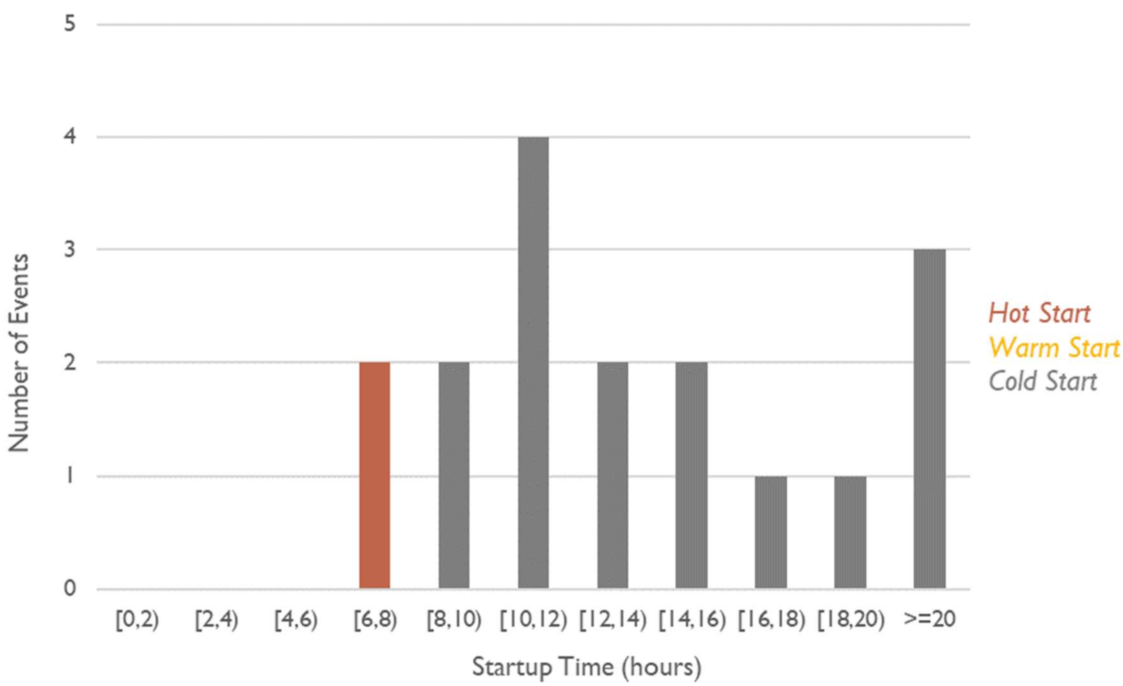
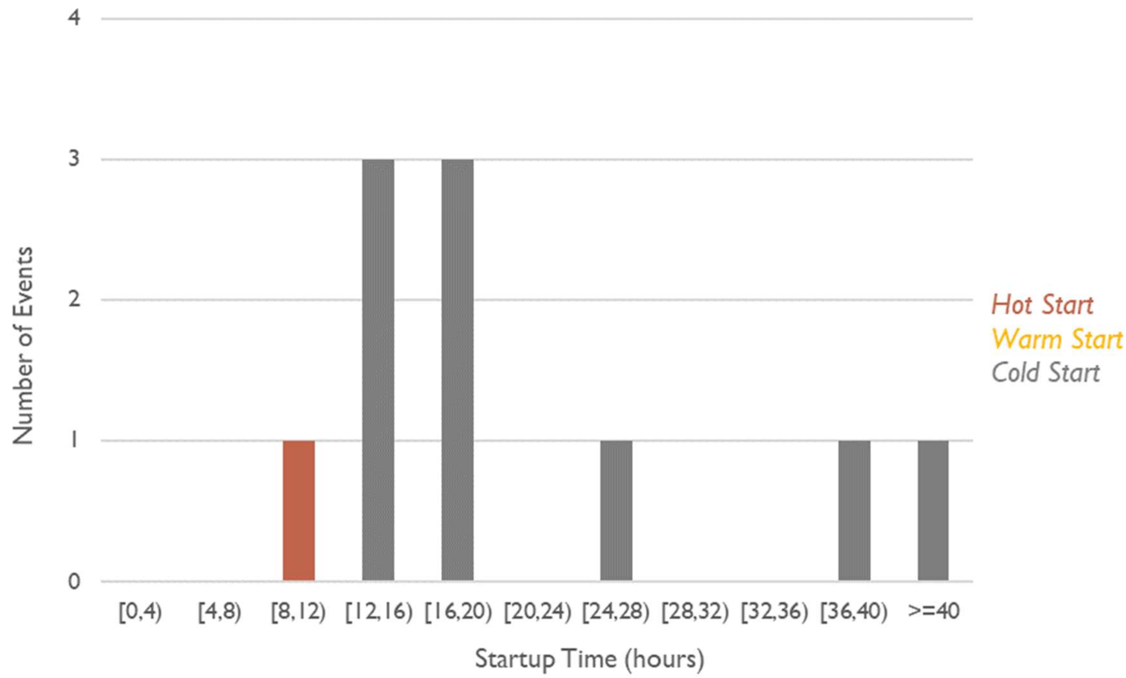


Figure 18. Canal Unit 2, start-up to 90% of seasonal capacity



Below are the start-up trends figures for the following units: Merrimack Unit 1 (Figure 19); Schiller Units 4 (Figure 20), 6 (Figure 21), and 5 (Figure 22); and Canal Units 1 (Figure 23) and 2 (Figure 24). Note that the Schiller Unit 5 figure captures the first 36 hours from start-up, compared to the first 24 hours for all of the other figures. We included more hours for Schiller Unit 5 due to its long start-up time.

Figure 19. Merrimack Unit 1 start-up trends

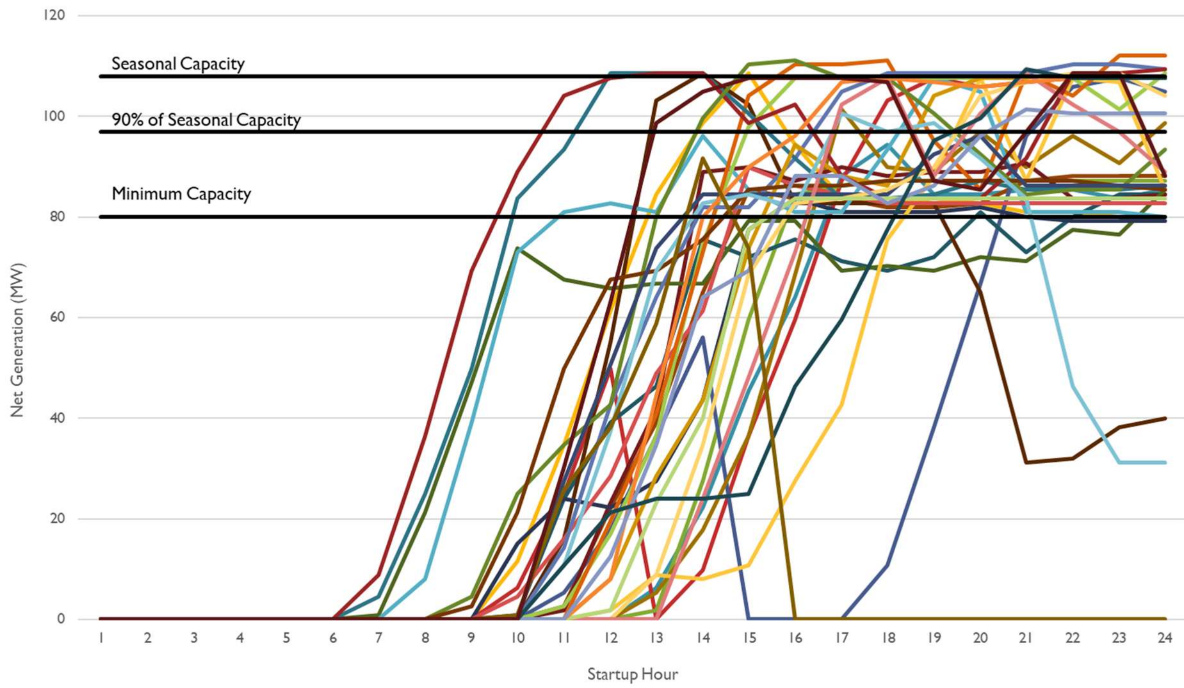


Figure 20. Schiller Unit 4 start-up trends

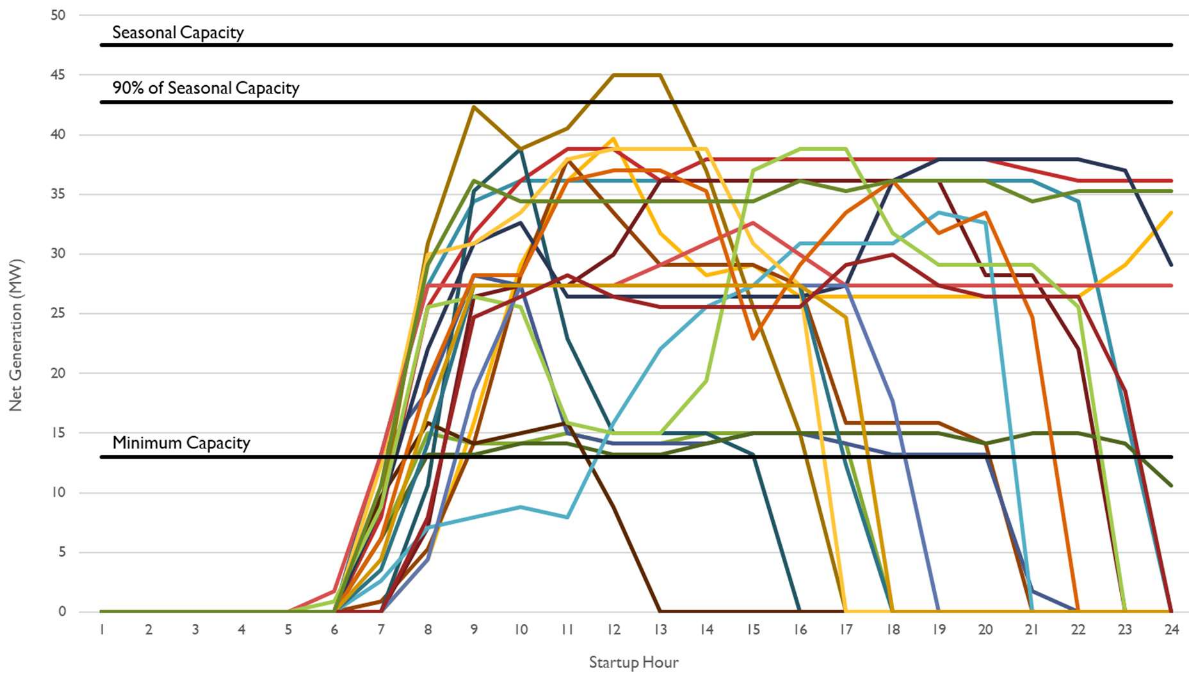


Figure 21. Schiller Unit 6 start-up trends

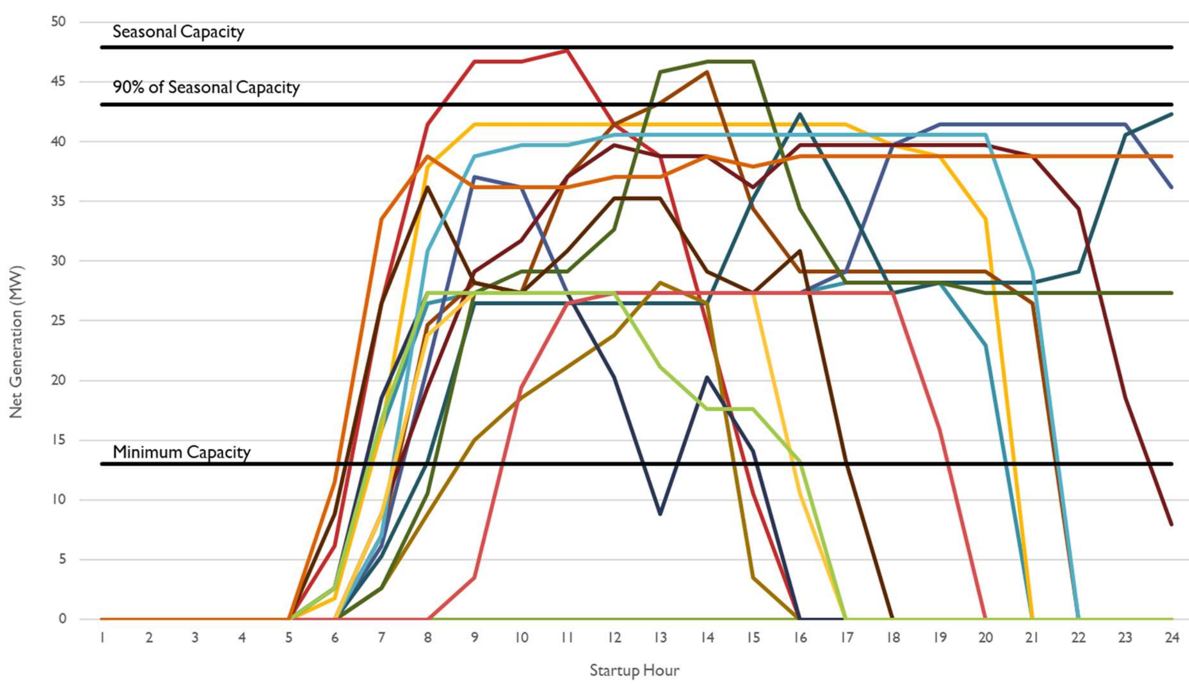


Figure 22. Schiller Unit 5 start-up trends

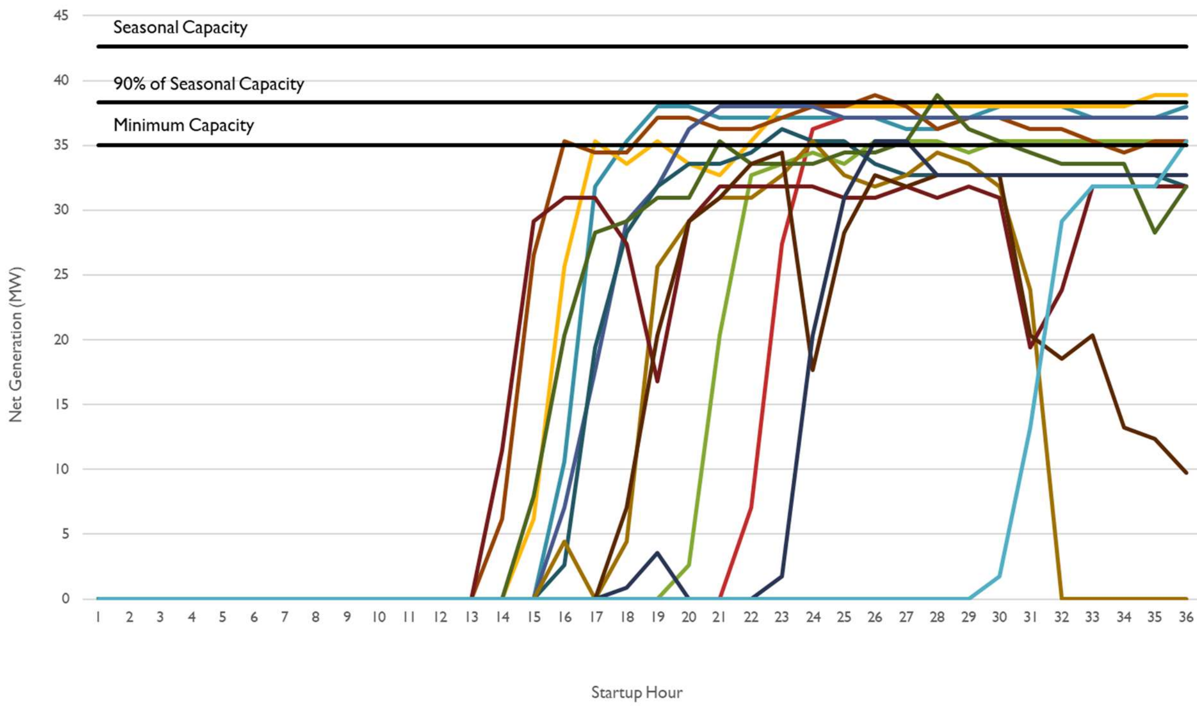


Figure 23. Canal Unit 1 start-up trends

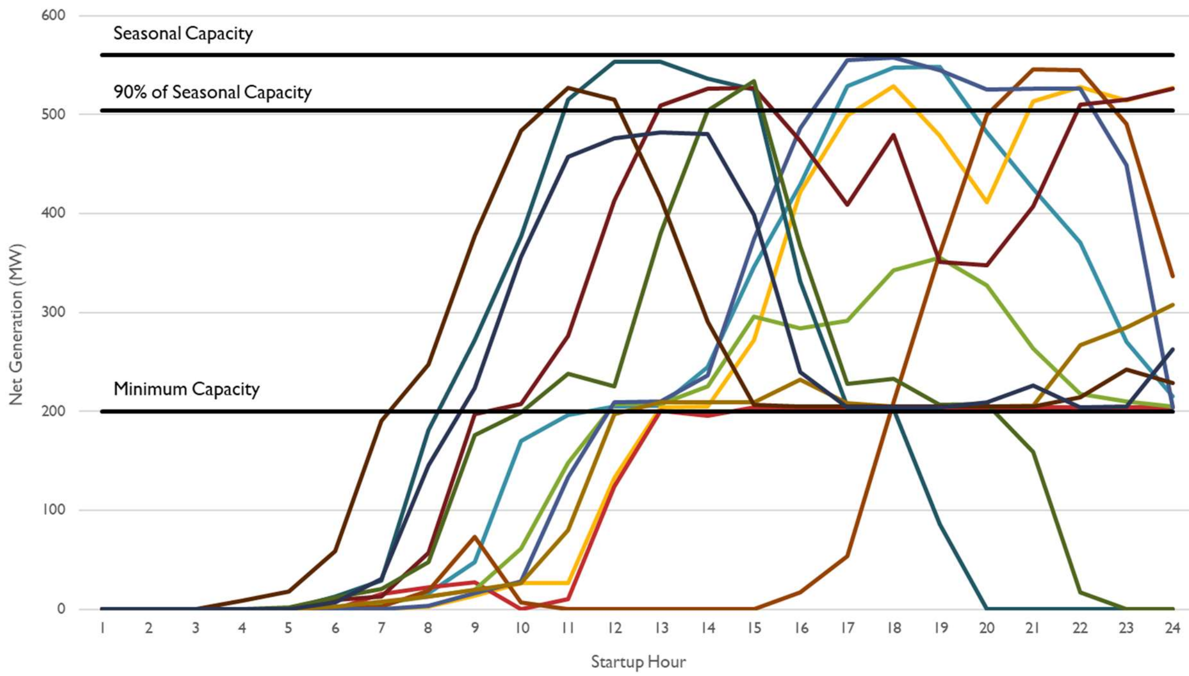


Figure 24. Canal Unit 2 start-up trends