Economic Planning for the Clean Energy Transition

Final Benchmark and MENS Results

ECONOMIC STUDIES AND ENVIRONMENTAL OUTLOOK

ECONOMIC PLANNING FOR THE CLEAN ENERGY TRANSITION (EPCET)

EPCET Overview

- The Economic Planning for the Clean Energy Transition study piloted new tools and modeling methodologies for the new economic study process.
- Study was grounded in three main scenarios and one stakeholder-requested sensitivity:
  - Benchmark (2021, year prior to study, used to test model integrity)
  - Market Efficiency Needs (2032)
  - Policy (up to 2050)
  - Stakeholder-Requested
- EPCET modeled 33 scenarios and sensitivities and conducted 2,800 modeling runs.
- Work was performed from 2022 to April 2024. The report was published and a final presentation was given in August 2024.

EPCET Benchmark Scenario

- The EPCET Benchmark Scenario utilized a production cost model to model the previous calendar year (2021).
- The model used a large volume of historical data, including load profiles, wind and solar profiles, fuel prices, historical import and export flows, and generator outages.

EPCET Market Efficiency Needs Scenario

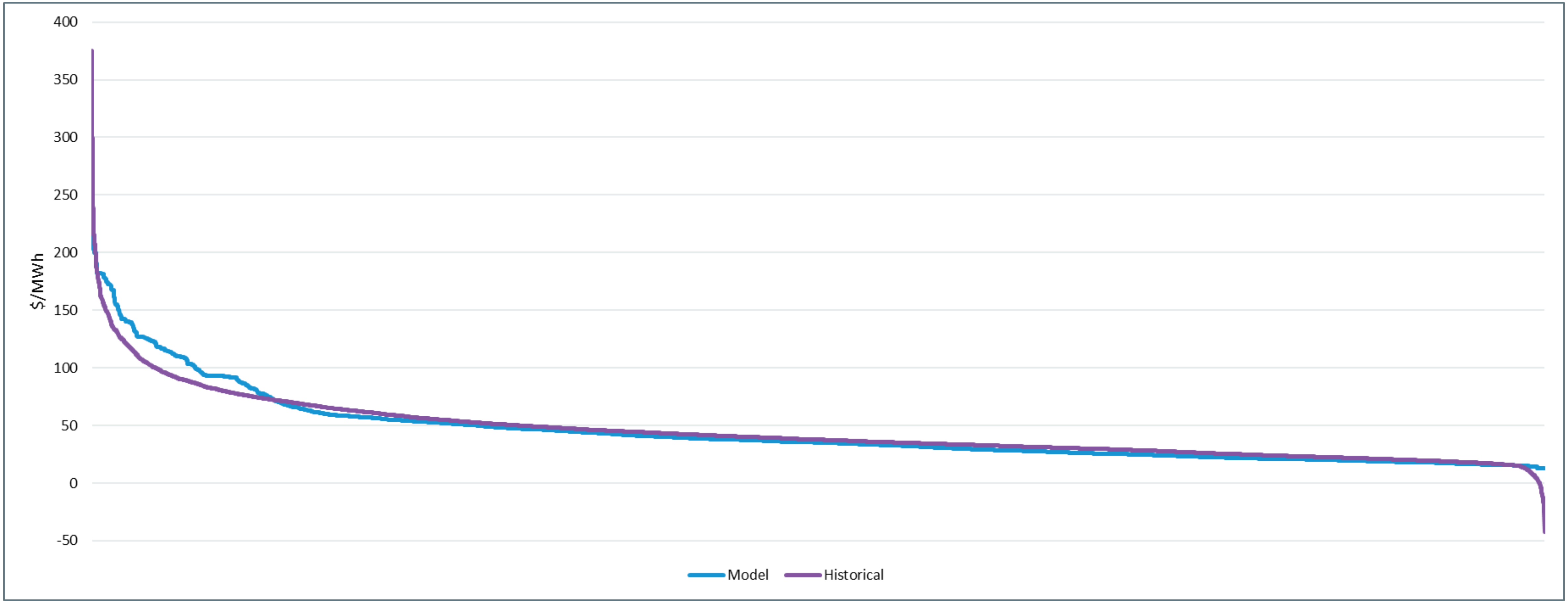
- The EPCET Market Efficiency Needs Scenario utilized a production cost model to model a 10-year-out system to identify potential market efficiency needs.
  - Because EPCET was a pilot study, no further action was taken with the results of the MENS case. However, future iterations of the economic study process will use the MENS case to identify and evaluate market efficiency issues.
- The MENS case used ISO forecasts for load and distributed generation and also included state contracted and FCM cleared resources.
- Significant stakeholder discussion existed regarding what to assume for imports, especially across the New Brunswick interface.
- The reference case of the Market Efficiency Needs Scenario did not identify significant congestion. However, a sensitivity where diurnal flows from New Brunswick and a new wind farm in Maine were added did have some congestion on the ME-NH interface.

EPCET BENCHMARK SCENARIO

EPCET Benchmark Scenario Overview

- The benchmark scenario results reasonably resembled historical results.
- Differences in generator dispatch were likely due to factors the ISO has no data on (generator specific fuel price contracts, alternative revenue streams, unit bidding strategies, etc.).
- Small amounts of congestion were observed in historically congested areas (Whitefield South, Sheffield Highgate, and Orrington South).
- Generation by fuel type closely lined up with historical generation by fuel type.
- While progressively adding changes to the model to test impact on LMPs, the most significant factor for accurately modeling LMPs was historical gas prices.

Benchmark LMPs



- Average modeled LMP of $44.14/MWh (compared to $45.92/MWh historically)
- Modeled LMP does not reach the extreme highs and lows of historical LMPs.

Benchmark Generation by Fuel Type

Fuel	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non-BTM)	Wind	Wood	Net Tie Flow	Total
2021 GWh	558.0	52,255.0	7,145.0	27,073.0	228.0	438.0	2,984.0	2,669.0	3,611.0	2,416.0	18,826.0	118,203.0
Model GWh	123.0	52,514.0	6,901.0	27,630.3	270.3	334.6	3,015.0	2,651.0	3,592.0	2,775.4	18,751.0	118,557.5
Observed – Model	435.0	-259.0	244.0	-557.3	-42.3	103.4	-30.9	18.0	19.0	-359.4	75.0	-354.5

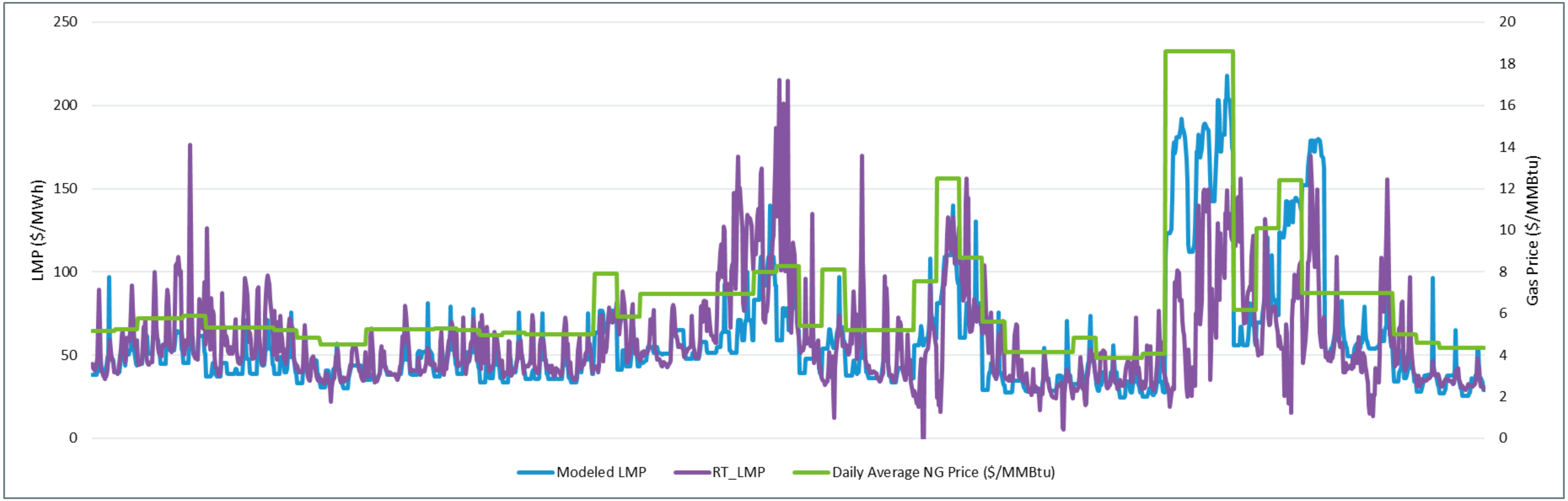
- Most generation by fuel type is very close. Small differences are due to the model dispatching to minimize cost while real units are dispatched based off of bids.

Benchmark Congested Interfaces

Interface Name	Hours Congested	Average Shadow Price ($/MWh)
Orrington South	109	22.75
Sheffield-Highgate	324	20.82
Whitefield South	281	25.81

- Minor congestion was observed in areas that have had congestion historically.

Benchmark Gas Prices and LMPs



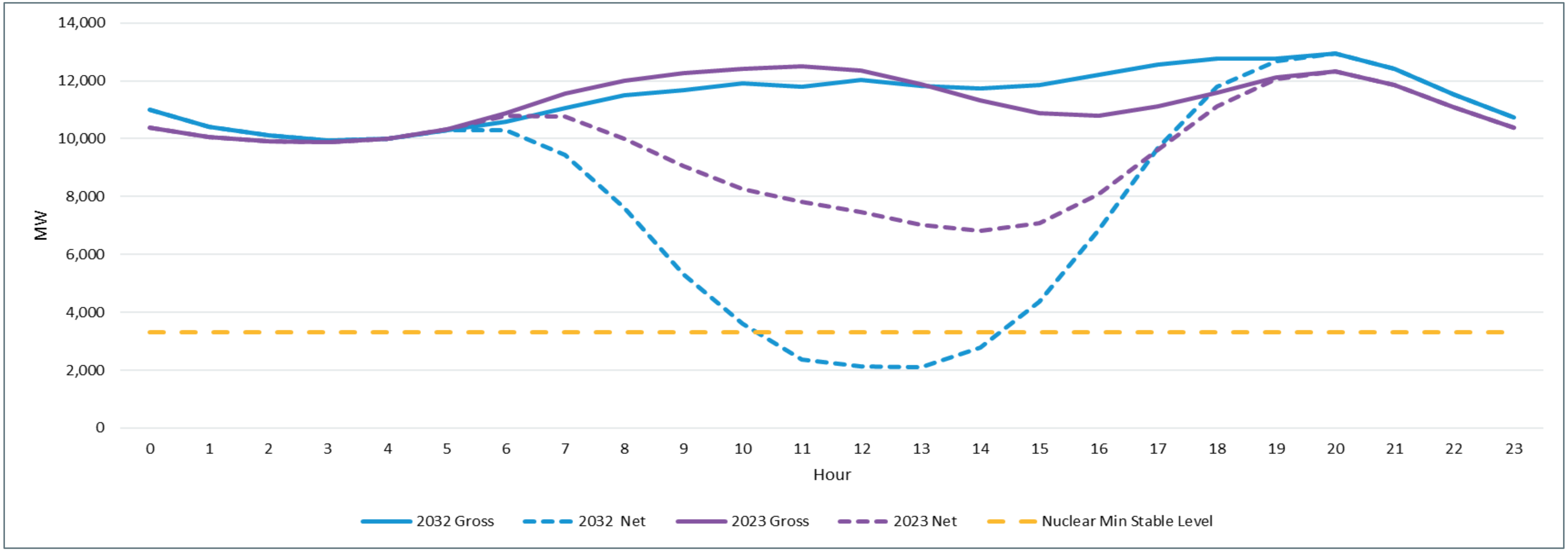
- One of the most important factors for matching historical LMPs was the historical gas prices.
- For future modeling, it is impossible to accurately forecast gas prices. Modeled future results may show more stable LMPs because gas price volatility cannot be captured.

EPCET MARKET EFFICIENCY NEEDS SCENARIO

EPCET Market Efficiency Needs Scenario Overview

- In the reference version of the Market Efficiency Scenario, small amounts of congestion were observed in historically congested areas.
- Very low minimum load conditions were observed in the model.
- Emissions are reduced compared to today's system due to additional PV and OSW generation and more imported energy via NECEC.
- Due to an increase in winter demand, significant amounts of stored fuel generation were observed.

EPCET Market Efficiency Needs Scenario – Duck Curves



- In 2032, demand is reduced by almost 10,000 MW during hour 13 to 2,115 MW.
- Net load falls below the aggregate minimum stable level of the New England nuclear generators.
- The model handles the ramping demands by energy storage charging in the middle of the day, many units being committed in the evening for ramping, and imports being strategically curtailed then un-curtailed to help with ramping.

EPCET Market Efficiency Needs Scenario Generation by Fuel Type

Fuel	ADR	Coal	Oil	LFG/MSW/ Wood	Gas	Nuclear	Hydro	PV	Wind	Imports
Generation (GWh)	0.4	601.1	951.5	2,041.1	47,639.4	27,458.2	4,679.5	14,891.6	18,244.5	23,120.4

- Significant amounts of energy are provided by PV, wind, and import resources.
- Moderate amounts of stored fuel resources still run on high load winter days.

EPCET Market Efficiency Needs Scenario Production Cost Data

	Constrained Model	Unconstrained Model	Constrained - Unconstrained
Production Cost (Million $)	2,379	2,374	4.5
Carbon Emissions (tons)	22,111,154	22,087,140	24,015
Curtailment (GWh)	141.5	119.5	22.0

- Across the system, about $4.5 million dollars of congestion was observed.
- This congestion caused an additional 24,000 tons of carbon emissions and 22 GWh of curtailment.

EPCET Market Efficiency Needs Scenario Most Congested Elements

Element	Element Type	Hours Binding	Average Shadow Price
ME-NH	Interface	417	29.13
North-South	Interface	107	11.87
S171	Line	773	6.61
3162	Line	827	0.65
E131	Line	677	4.64
Q195	Line	603	5.28

- Most congestion was minor and happened in locations that experience congestion today (Whitefield South, Rhode Island, etc.).

EPCET MENS SENSITIVITY: NB DIURNAL FLOWS AND NEW WIND FARM

EPCET MENS Sensitivity

- As a stakeholder-requested sensitivity, a version of the MENS case was run where diurnal imports from New Brunswick and a 1,000 MW wind farm in Aroostook county, ME were included.
- The changes were modeled incrementally:
  - A base case (Base)
  - A case with diurnal imports from NB (NB)
  - A case with the new wind farm (NW)
  - A case with diurnal imports and the new wind farm (NB + NW)
- All cases were run with and without transmission constraints.
  - Con and Uncon
- Because there has been a reduction in imports from New Brunswick, the diurnal flows in these results have been recalculated with the most recent data (2021 – 2023)/

EPCET MENS Sensitivity Takeaways

- As more zero cost resources were added to Maine, production cost and emissions decreased.
- Congestion and curtailment also increased. Congestion became most prevalent on the ME-NH interface.
- Total congestion costs started at $4.4 million in the base case and increased to $26.7 million in the NB + KP case.

EPCET Market Efficiency Needs Scenario Production Cost Data

	Con Base	Uncon Base	Con NB	Uncon NB	Con NW	Uncon NW	Con NW + NB	Uncon NW + NB
Production Cost (Million $)	2,379	2,374	2,279	2,271	2,187	2,174	2,102	2,075
Carbon Emissions (tons)	22,111,154	22,087,140	21,126,067	21,073,498	20,241,513	20,156,029	19,359,865	19,184,865
Curtailment (GWh)	141.5	119.5	167.7	133.2	278.1	179.5	411.0	189.3

- As more zero cost generation is added to the system, production costs and emissions fall while curtailment increases.
- Congestion also increases as more zero cost generation (NB imports and the new wind farm) are added to the system.

EPCET Market Efficiency Needs Scenario Interface Congestion

Interface	Base Hours Binding	NB Hours Binding	NW Hours Binding	NW + NB Hours Binding
ME-NH	417	1,457	3,383	4,722
North-South	107	175	244	263
NWVT Import	24	27	29	35

- Adding additional resources in Maine increase the amount of time where north to south interfaces are binding, especially on ME-NH.

Discussion of New Brunswick Imports in Market Efficiency Needs Scenario

- Throughout the EPCET pilot study, there were significant discussions with stakeholders about how to model interchange with New Brunswick.
- Use of historically averaged profiles did show congestion. However, both the New England system, the New Brunswick system, and the Quebec system are rapidly changing, and historical profiles are no guarantee of future interchange.
- Imports should also not be considered a zero-cost resource, as there is a non-zero cost to New England ratepayers for that energy. If imports are treated as a zero-cost resource, relieving congestion caused by imports will show inflated benefit to the system.
- The ISO experimented with modifying historical profiles and price profiles to create a more reasonable representation. More detail about a final methodology will be presented with phase 2 of the Economic Study tariff changes.

EPCET MENS SENSITIVITY: MULTIPLE WEATHER YEARS (2023 CELT LOADS)

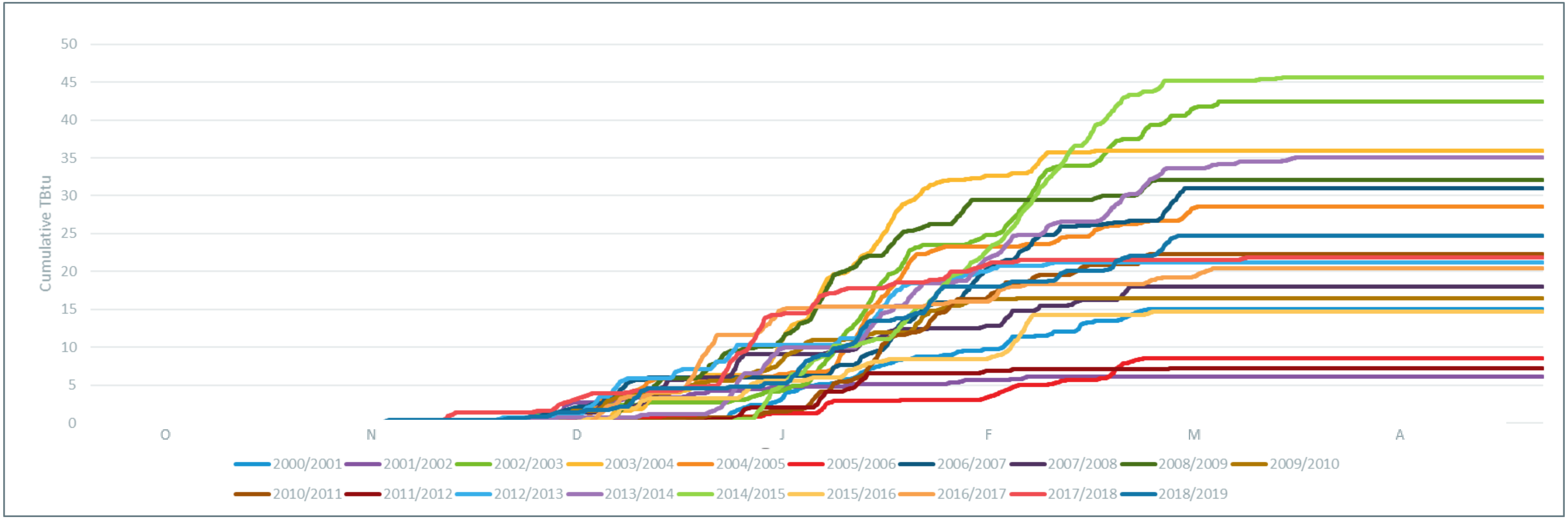
Overview of Sensitivity

- The ISO has previously presented 2032 results for the Market Efficiency Needs scenario (MENS).
  - These models were both constrained and unconstrained, and the main purpose was to show the economic impacts of congestion of the currently planned system.
- The ISO has since released the 2023 Capacity, Energy, Loads, and Transmission (CELT) Report which included new and augmented heating and transportation electrification forecasts.
- The 10-year horizon electrification load has increased significantly from previous forecasts. In particular, the winter peak demand was expected to increase by nearly 3% annually.
- To quantify the impacts of the increased electrification demand, the ISO has run 20 weather years of data through the 2032 MENS model with updated load profiles.
- Generator outages have not been modeled in these scenarios.

Overview of Results

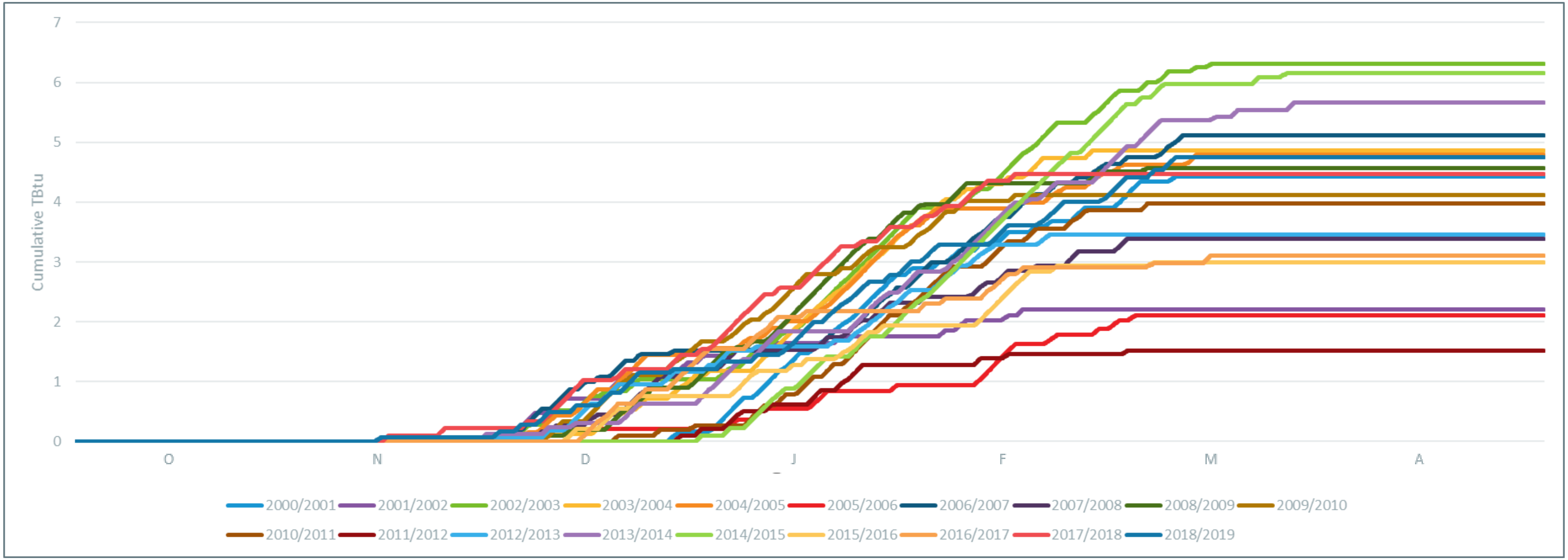
- With the additional electrified winter load, the ISO has observed significant stored fuel generation in winter months. Despite the contribution of new wind, PV, and imports, the stored fuel consumption is increased compared to historical levels.
- Daily pipeline gas and LNG consumption was constrained according to the ICF natural gas topology tool. However, LNG total inventories were not constrained, and there was no modeling of refueling.
  - Oil inventories were also not constrained. However, drawdowns have been tracked for each fuel type.
  - Rather than performing a reliability analysis by tracking inventories, this analysis seeks to examine the total fuel demand.
- Based on available generators and input fuel prices, dispatch order is (roughly):
  - NG -> LNG -> Coal -> Heavy Oil -> Light Oil
- The slides in this section will show fuel drawdowns over modeled 2032 winters (Oct – April).

Cumulative LNG Drawdown for 19 Winters



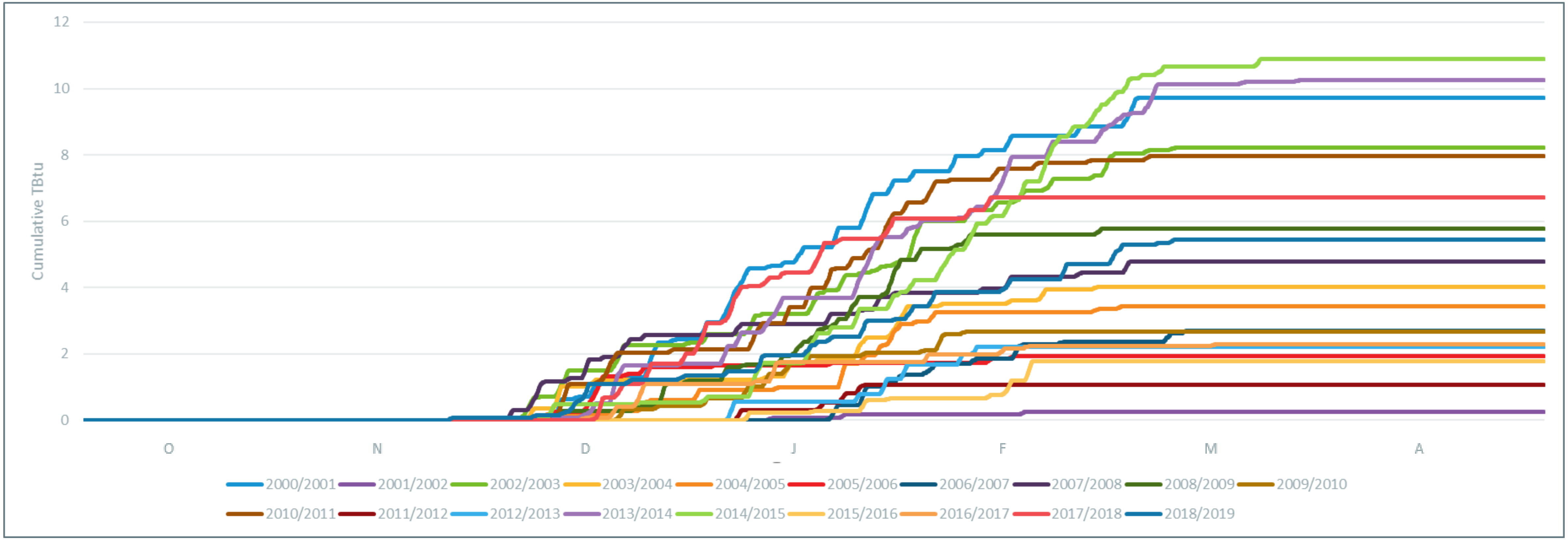
- 2014/2015 winter is highest drawdown scenario, consuming 45.6 Bcf of LNG.
- Approximate storage capacities of LNG facilities:
  - Everett: 3.5 Bcf, St. John: 10.4 Bcf, Northeast: 3.1-5.2 Bcf
  - Total of 19.1 Bcf
- To fulfil LNG demand for highest demand weather years, replenishment of LNG storage facilities would be needed.
  - If the inventory could not be replenished, other stored fuel types (coal, heavy oil, and light oil) would have to increase their generation.

Cumulative Coal Drawdown for 19 Winters



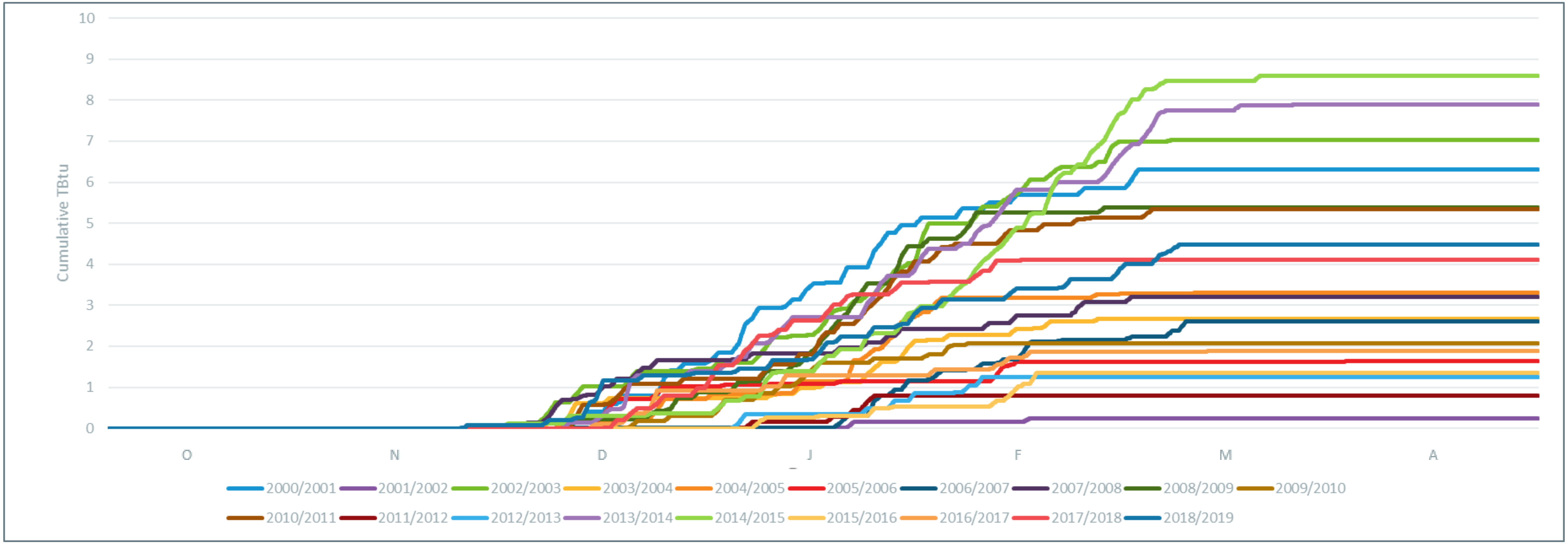
- 2002/2003 winter is highest drawdown year, consuming 6.3 TBtu of coal.

Cumulative Heavy Oil Drawdown for 19 Winters



- Oil inventories were not constrained in model, but aggregate fuel inventory of heavy oil units is 25.3 TBtu (~185 million gallons).
  - Depending on the pre-winter fuel level, oil replenishment is likely to be needed to satisfy high demand years.
  - 2014/2015 winter consumes 10.9 TBtu (~80 million gallons).

Cumulative Light Oil Drawdown for 19 Winters

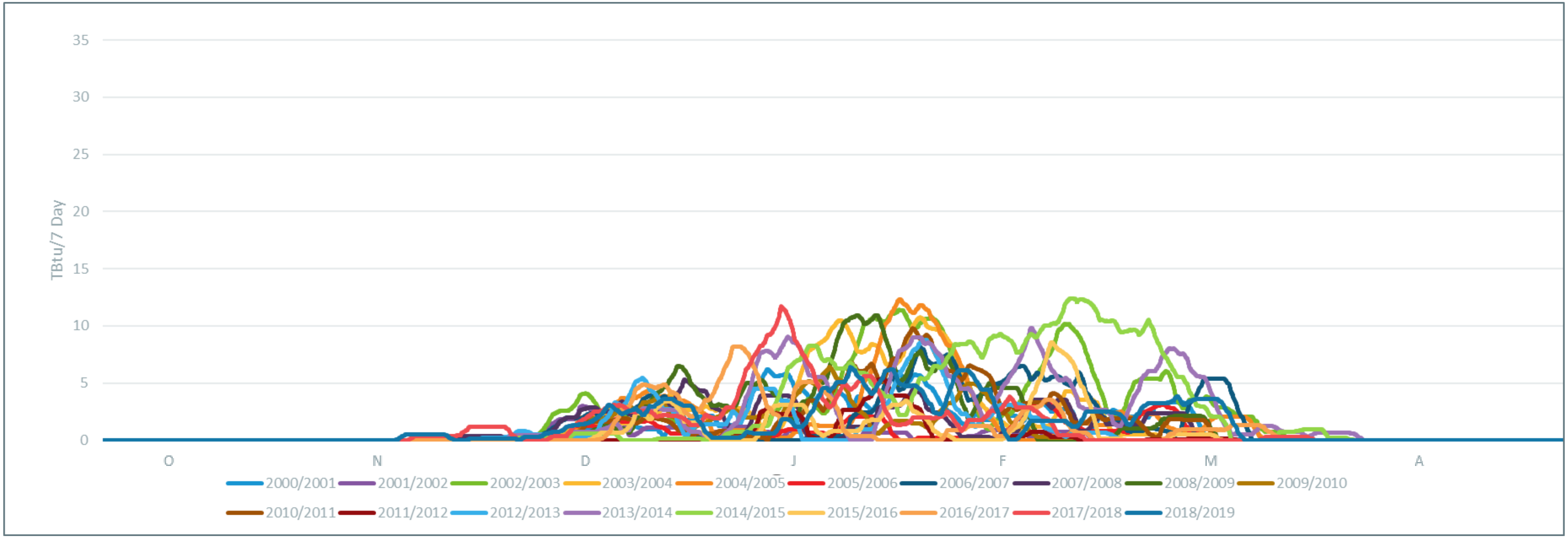


- Oil inventories were not constrained in model, but aggregate fuel inventories of light oil units is 9.3 TBtu (~67 million gallons).
  - To satisfy fuel demand of high drawdown years, replenishment is likely needed.
  - 2014/2015 winter consumes 8.6 TBtu (~63 million gallons).

Discussion of Fuel Drawdowns

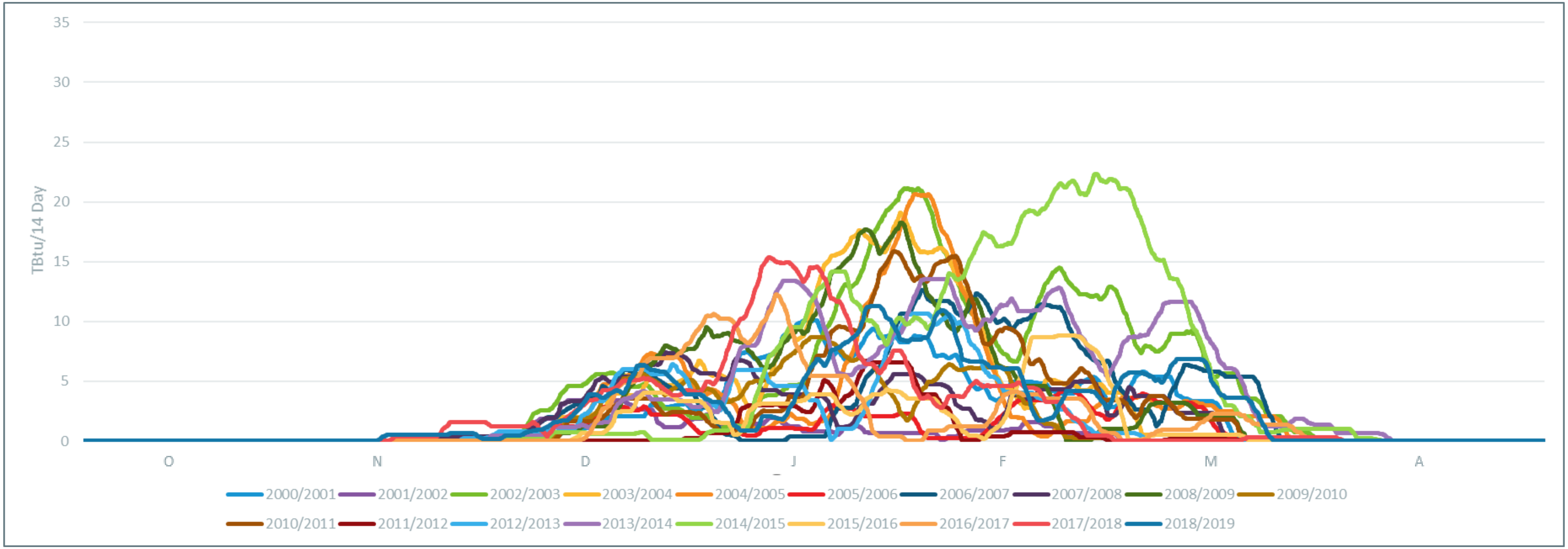
- Mild winters continue to not need significant generation from stored fuels. However, moderate and cold winters still have a significant need for stored fuels.
- Large portions of the total stored fuel inventories were consumed in the worst case year, making it extremely likely that deliveries/refills would be needed:
  - LNG: 45.6 Bcf consumed out of 19 Bcf inventory (240% consumed)
  - Heavy Oil: 10.9 TBtu (80 million gallons) consumed out of 25 TBtu inventory (44% consumed)
  - Light Oil: 8.6 TBtu (63 million gallons) consumed out of 9 TBtu inventory (96% consumed)
- Assuming an average tanker size of 3.1 Bcf, 15 LNG tankers would be needed over a 2014/2015 weather year winter.
  - From the 2018-2021 period, New England received between 11 and 14 tankers per winter.
- Fuel drawdowns can happen particularly fast over relatively short periods.

7 Day Stored Fuel Drawdown for 19 Winters



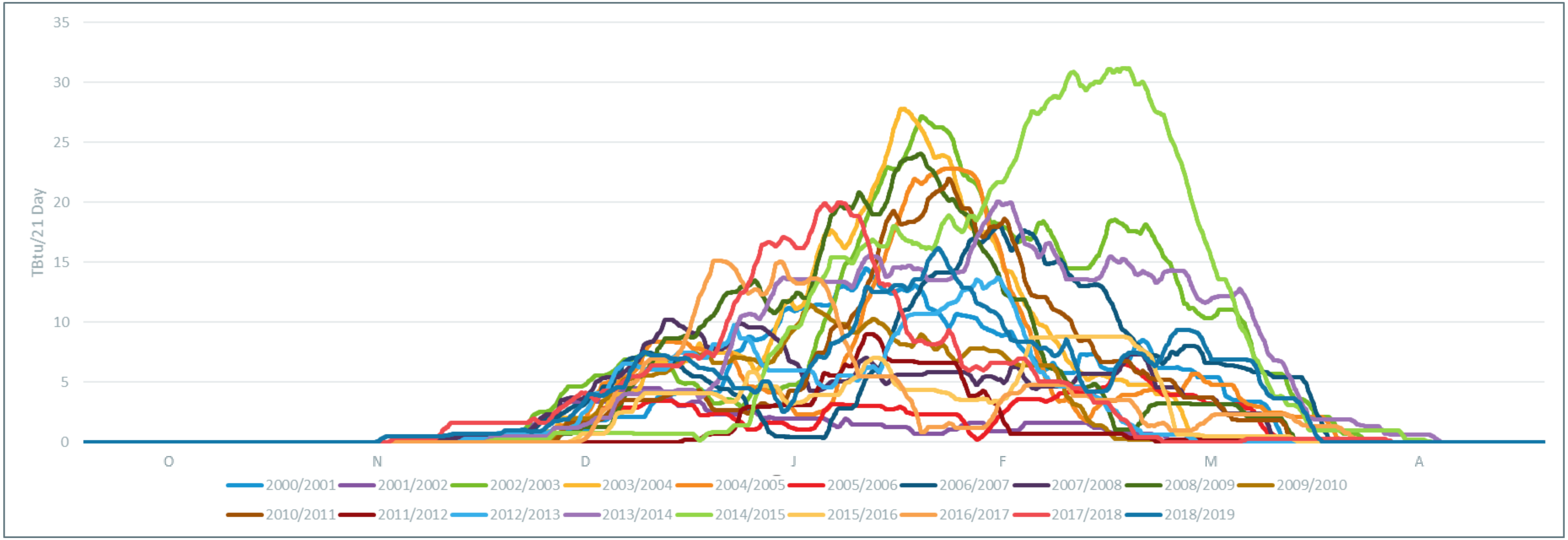
- Multiple weather years consume 10 – 13 TBtu over a one-week period.

14 Day Stored Fuel Drawdown for 19 Winters



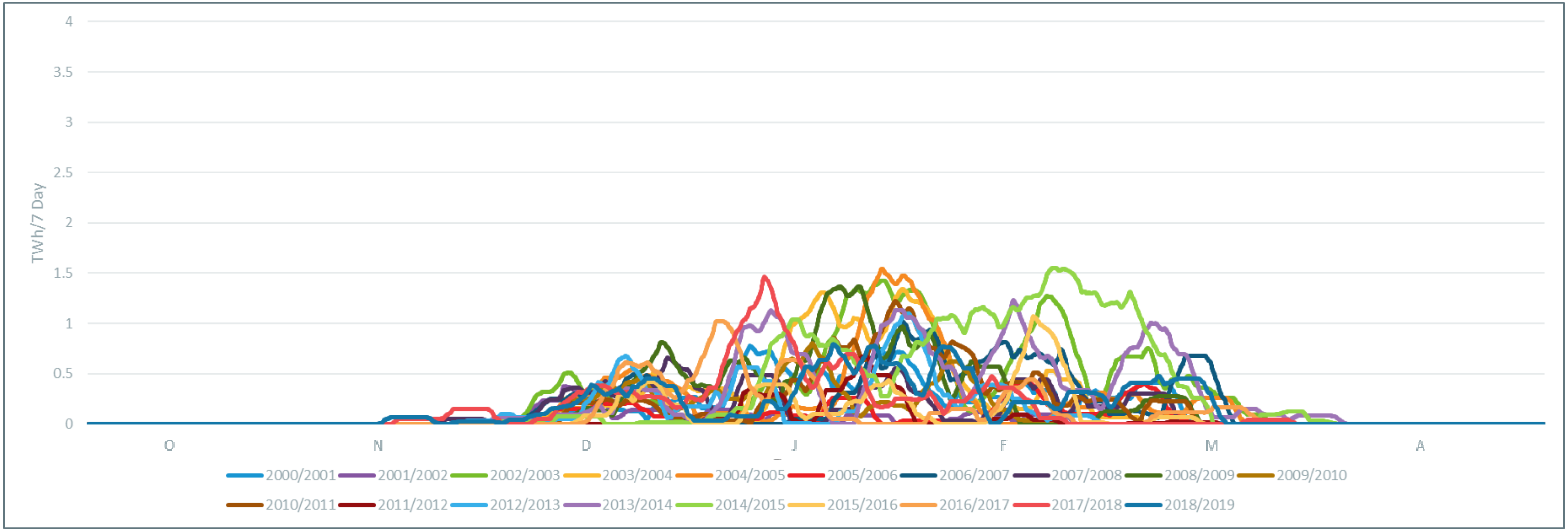
- Over a two-week window, the 2015 weather year now has the most significant drawdown, consuming 22 TBtu over two weeks.

21 Day Stored Fuel Drawdown for 19 Winters



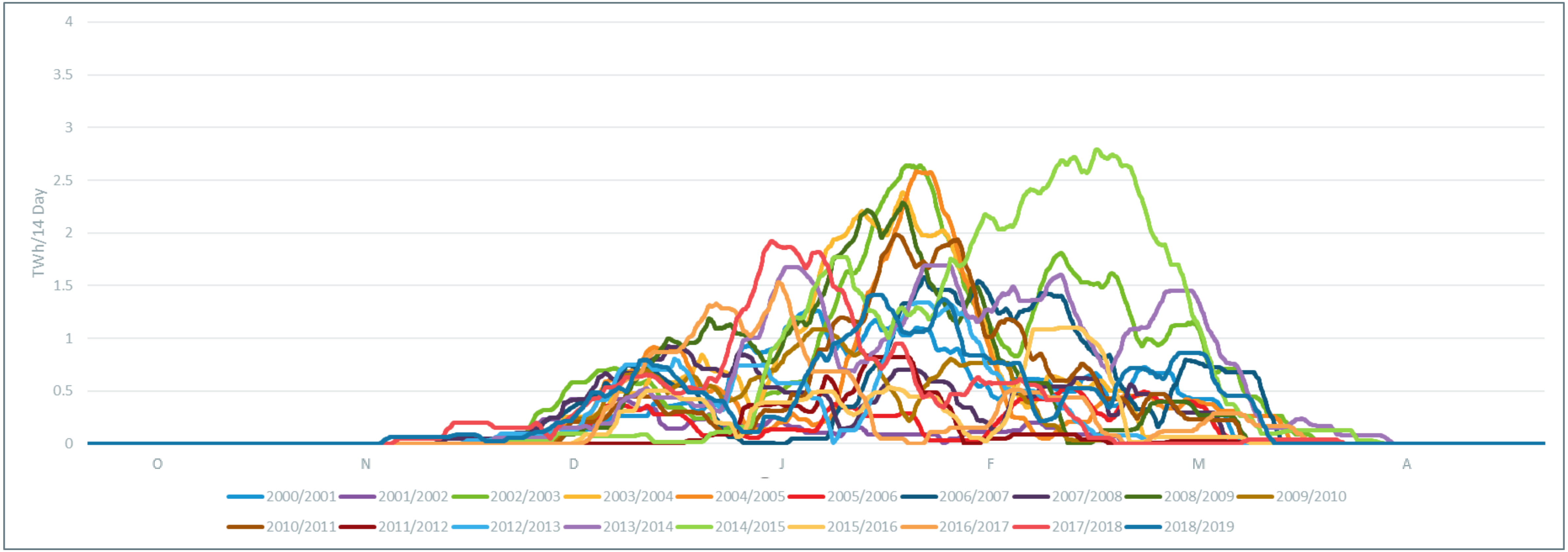
- Over a three-week window, the 2015 weather year consumes 31 TBtu of stored fuels.

7 Day Energy Drawdown for 19 Winters



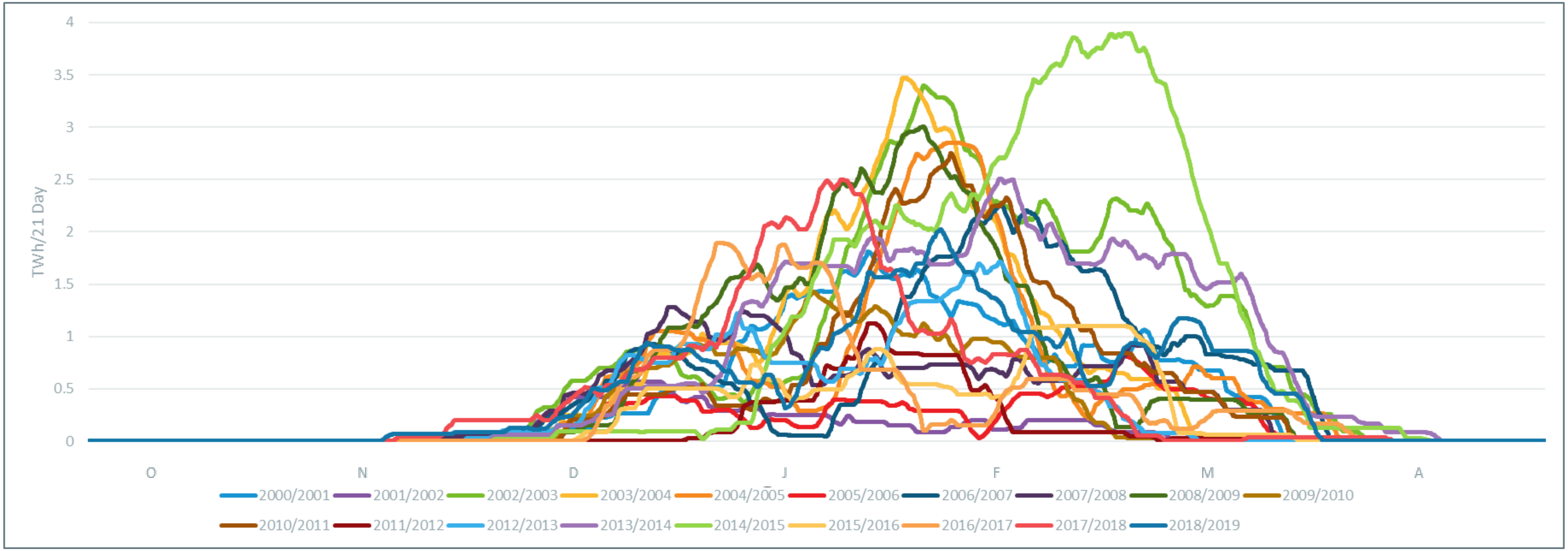
- Assuming 1 TBtu of fuel drawdown is equivalent to 0.125 TWh (@ 8 MMBtu/MWh), multiple winters draw down ~1.5 TWh.
- For comparison:
  - Existing pumped storage reservoirs ~= 0.011 TWh

14 Day Energy Drawdown for 19 Winters



- The 2015 weather year consumes almost 2.8 TWh of stored energy over a two-week window, with five other winters consuming more than 2 TWh.
- In FGRS Alternative D, there was 2.3 TWh of energy storage.

21 Day Energy Drawdown for 19 Winters



- Over a three-week window, stored fuels provide almost 3.9 TWh of energy for the 2014/2015 winter.

Energy Drawdown Equivalents (2014-2015 Cold Snap)

	Nameplate (MW)	Average Daily Generation (GWh)	Capacity Factor (%)	7 Day Average Generation (GWh)	14 Day Average Generation (GWh)	21 Day Average Generation (GWh)
PV	11,660	25.59	9.14	179.11	358.22	537.34
LBW	1,376	14.41	43.63	100.85	201.70	302.54
OSW	3,163	45.31	59.68	317.14	634.27	951.41
Total	16,199	85.30	-	597.09	1,194.19	1,791.28

- The total energy provided from stored fuels over a 7, 14, and 21 day period were 1.5, 2.8, and 3.9 TWh.
- Maintaining the existing ratio, the system would need another 40,659 MW of PV, LBW, and OSW to provide the same amount of energy (plus energy storage to shift the energy from when it is produced to when it is needed).
- Wind resources tend to be generating more than PV resources during this cold snap. To replace the equivalent amount of energy with just LBW and OSW, an additional 16,289 MW of wind would be needed (and would likely still require new energy storage units).

Discussion of Short Term Drawdowns

- More mild winters may not have a huge demand for stored fuel.
- However, moderate and severe winters have large demands, often concentrated over one or two week stretches of cold.
- Additional PV and wind resources beyond what is already in the model may help alleviate demand for dispatchable generation, but needed volume of energy is significant.
  - Some additional energy storage will likely be needed to shift the energy from when it is produced to when it will be needed.
- It is likely that some of the modeled stored fuel resources will retire by 2032, further decreasing the inventory the region has available.