Comments on the 2026 Standard Service Dockets 26-01-01/2 by Bob Keen 10-27-2025

A separate Winter (Dec, Jan, Feb) price for Standard Service should be provided that reflects the 2-3 times higher cost of providing service in the Winter months.

1. The attached figure 1 shows the actual cost of service for the last year. The winter months cost about 3-4 times the other months

2. The attached figure 2 shows the average winning bid price for 2021-25 for Eversource. The winter months are about 20c/kWh and are about twice the other months.

Continued average pricing will result in a large ($1+B) subsidy of heating load by the present base load.

Affordability means not encouraging load at expensive times. For the distribution system that means not encouraging load 4-7pm in summer and 7-10 am in winter after ~2035 if the system becomes winter peaking. For the generation system, affordability means not encouraging load during the expensive winter hours. The present semi annual average pricing encourages load during the expensive winter hours.

Generation affordability can be implemented by quarterly billing changes and does not require spending $1+B for advanced metering.

I also note that the ISO is going to a winter and summer capacity market due the differing cost characteristics of the two periods.

For more discussion on the cost of electrifying heating load see the EPCET report and the 2024 Economic Study. Also see my input to the CT IRP and my May 16, 2024 presentation to the DEEP technical session on heat pumps.

The EPCET presentation of Oct 18, 2023 analyzes the system with and without heating and electrification load and highlights the disproportionate cost of electrification especially heating:

1. In 2032 a 4.5% increase in load due to heating disproportionately increases the LSEEE energy cost 53% from $3B to $4.6 B per year.
2. By 2050 a 60% increase in load due to heating and transportation doubles the average price per MWH as the marginal cost of the electrification load is 4.3 times the cost of serving the base load.

The ISO-NE 2024 Economic Study echoes the same message: heating is extremely expensive.

No matter which supply resources are chosen (wind, solar, nuclear, gas, etc), heating is going to be expensive because it is a low load factor (13.7%) load that varies 2 times from warm to cold winter. The low load factor means that it takes 4 times the capacity to

to generate a MWH as the base load with a load factor of ~55%. The variability means that some capacity will only run several days every 2-3 years leading to financial viability concerns as discussed in the EPCET final report. Heating occurs at the most expensive time of the year when solar is not effective, so wind is built. 90% of the offshore wind is not needed without electrification.

Both heating and non-heating customers are going to become upset when the generation prices double due to subsidizing heating load.

Part of the solution is to accurately price winter generation.

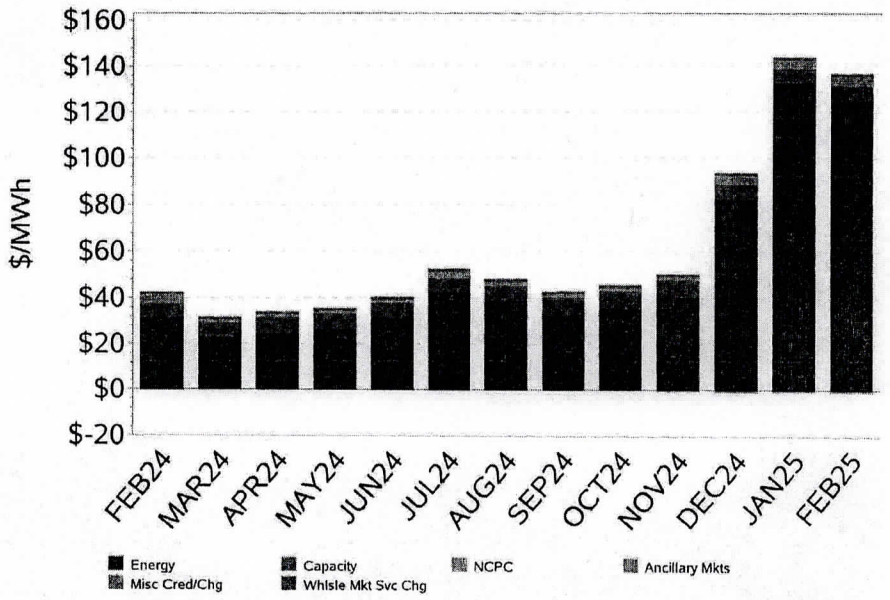
Thank you for the opportunity to comment.

Sincerely,

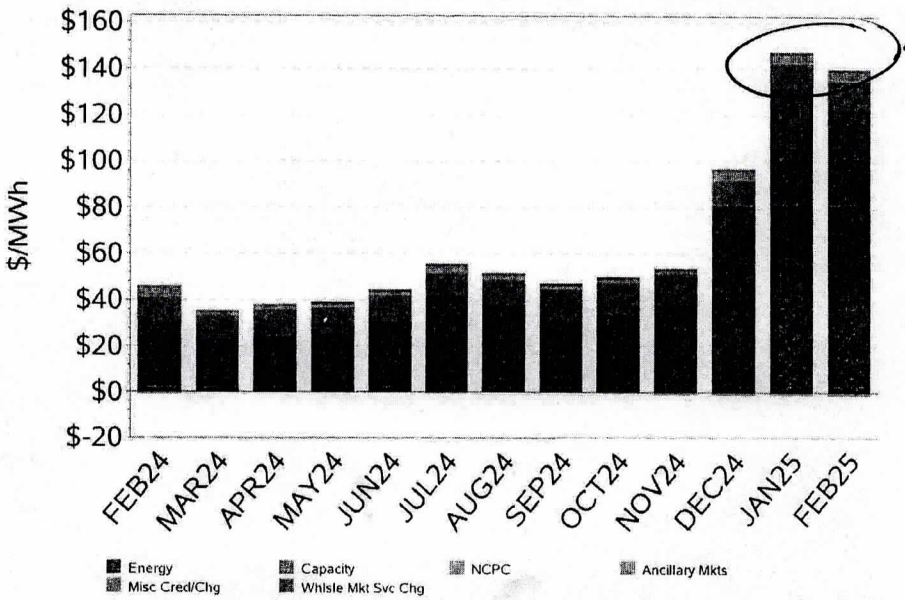
Bob Keen
Power Engineer

figure 1

Wholesale Load Cost - VT Load Zone
By Major Component, 13 Months Ending 28FEB25



Wholesale Load Cost - CT Load Zone
By Major Component, 13 Months Ending 28FEB25



3-4 x other months.

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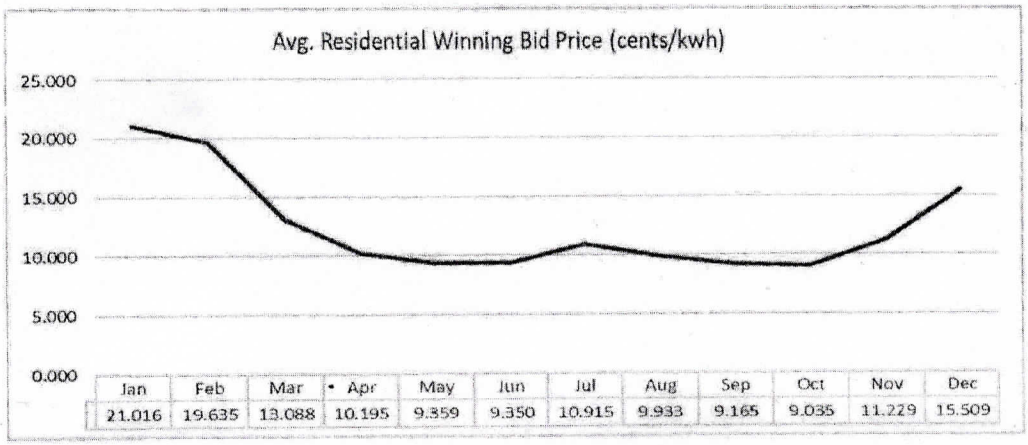
figure 2

. January and February typically are the highest priced months for wholesale electricity, particularly from a forward power price perspective, which is the relevant price metric (as opposed to spot power prices) used for SS/LRS rate setting. Please see Exhibit 1 below which shows the average winning bid price by month for residential SS from 2021-2025. Suppliers that participate in default service procurements such as SS base their bid prices on the forward market pricing at the time of submitting bids.

EVERSOURCE ENERGY

Exhibit 1.



Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
21.016	19.635	13.088	10.195	9.359	9.350	10.915	9.933	9.165	9.035	11.229	15.509

from 2025 IRP input

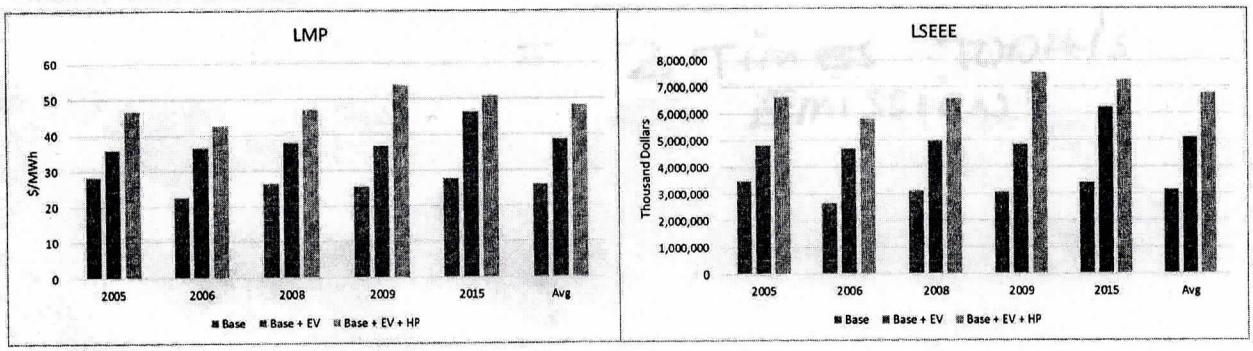
2032 No Electrified Load Scenario
EPCET Presentation 10-18-23

Sensitivity Takeaways

- Decarbonization of the electric sector would be progressing faster if other sectors (transportation, residential/commercial heating) were not decarbonizing in parallel and transferring their demand into the electric sector
- The trends between load increase and increases in other metrics are not proportional. For a 15.5% increase in load (from HP and EV demand):
  - Average LMPs increase by 84.1%
  - Average LSEEE increase by 114.2%
  - Average production costs increase by 63.6%
  - Average carbon emissions increase by 66.6%
- The additional power sector emissions are expected to be offset by emission reductions in other sectors
- A reduction in stored fuel generation may be possible without the additional electrified load. Because the additional heating and electrification load peak in colder conditions, the additional load likely requires more stored fuel generation

2032 Marginal Cost Calculation

LMPs and LSEEE



- The additional load is sometimes met by zero cost resources, but is also often served by more expensive generation having to run to meet higher loads and satisfy ramping needs
- Average LMPs increase from $26.18/MWh in the Base model to $38.75/MWh in the Base + EV model, then to $48.21/MWh in the Base + EV + HP model
- Cost to load (LSEEE) increases by $2 billion with EV load, then by another $1.6 billion with the HP load. In total, the cost to load will increase by 114% from the Base model to the Base + EV + HP model while LMPs increased 84%

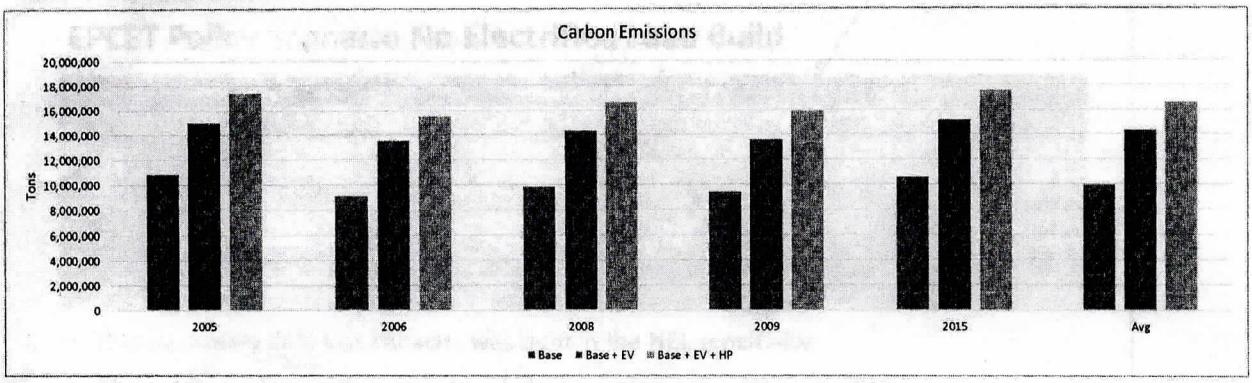
LSEEE BASE LOAD = $\frac{3000\text{ m\$}}{112\text{ m MWH}} = 26.7\ \frac{\$}{MWH}$

EV LOAD = $\frac{2000\text{ m\$}}{12,495} = 160\ \frac{\$}{MWH}$ (6x BASE)

HP LOAD = $\frac{1600}{4.8} = 333\ \$/MWH$ (12.5x BASE)

2032 NEL 10-18-23

Carbon Emissions



- The additional generation which runs to meet the electrified load tends to emit more
- Average emissions increase from 9.9 million tons in the Base model to 14.3 million tons in the Base + EV model, then to 16.6 million tons in the Base + EV + HP model
- Between the Base model and the Base + EV + HP model, average emissions increase by 67%

HP MARGINAL EMISSIONS = $\frac{2.3 \text{ MT } CO_2}{4.8 \text{ m MWH}}$

= 1/2 T / MWH

= 2 TIMES TODAY'S EMISSIONS

2050 EPCET FINAL SLIDES

EPCET Policy Scenario No Electrified Load Build

BIG DEAL

Technology	Reference (MW)	NEL (MW)
PV	27,538	22,539
LBW	7,500	4,900
OSW	34,406 → 90% REDUCTION	3,200
BESS 4	14,664 } 48% REDUCTION	8,016
BESS 8	13,000 }	6,460
Total	97,108 → 58%	41,525

- Approximately 58% less capacity was built in the NEL sensitivity.
- The model builds similar amounts of cheaper generation (PV and LBW) and a moderate amount of energy storage, but builds significantly less expensive generation.

OFFSHORE WIND

MARGINAL COST OF HEAT PUMP / ELECTRIC VEHICLE LOAD IS 4.3 TIMES THE COST OF THE BASE LOAD

EPCET Policy Scenario No Electrified Load Cost Data

Technology	Reference	NEL
2050 Capital Costs (Fixed + Annualized Build Cost) (Million $)	183 m MWH 24,502	113 m MWH 5,970
2050 Production Cost (Million $)	978	940
2050 Emissions (Tons)	826,862	593,730
2050 Curtailment (GWh)	61,834 (28%) !	3,312 (5%)
2050 Energy Export (GWh)	19,229 (9%)	3,279 (5%)
2050 Renewable Utilization (GWh)	140,245 (63%)	58,772 (90%)
Total Cost per MWh of Load ($/MWh)	139 ← 2.3x ←	61

- Capital costs are lower due to less generating and storage capacity needing to be built and the model only building cheaper generating resources.
- Utilization of the renewable resources is better due to a less significant overbuild being needed to reach decarbonization.
- The cost per MWh is lower by about 56% (note that the demand is significantly lower in the NEL case).

MARGINAL COST OF ELECTRIFIED LOAD = $\frac{25{,}480 - 6{,}910}{183 - 113} = \frac{18{,}570 \text{ m\$}}{70 \text{ m MWH}} = 265 \frac{\$}{\text{MWH}}$

(4.34 × NEL COST OF $61)

BASE LOAD (113 m MWH) COSTS $6.918 B/yr

ELECTRIFIED LOAD (70 m MWH) COSTS 18.57 B/yr (2.7 TIMES)

62% INCREASE TOTAL 25.48 B/yr