Community Power Coalition of New Hampshire
Technical Assessment for Viability of Launch

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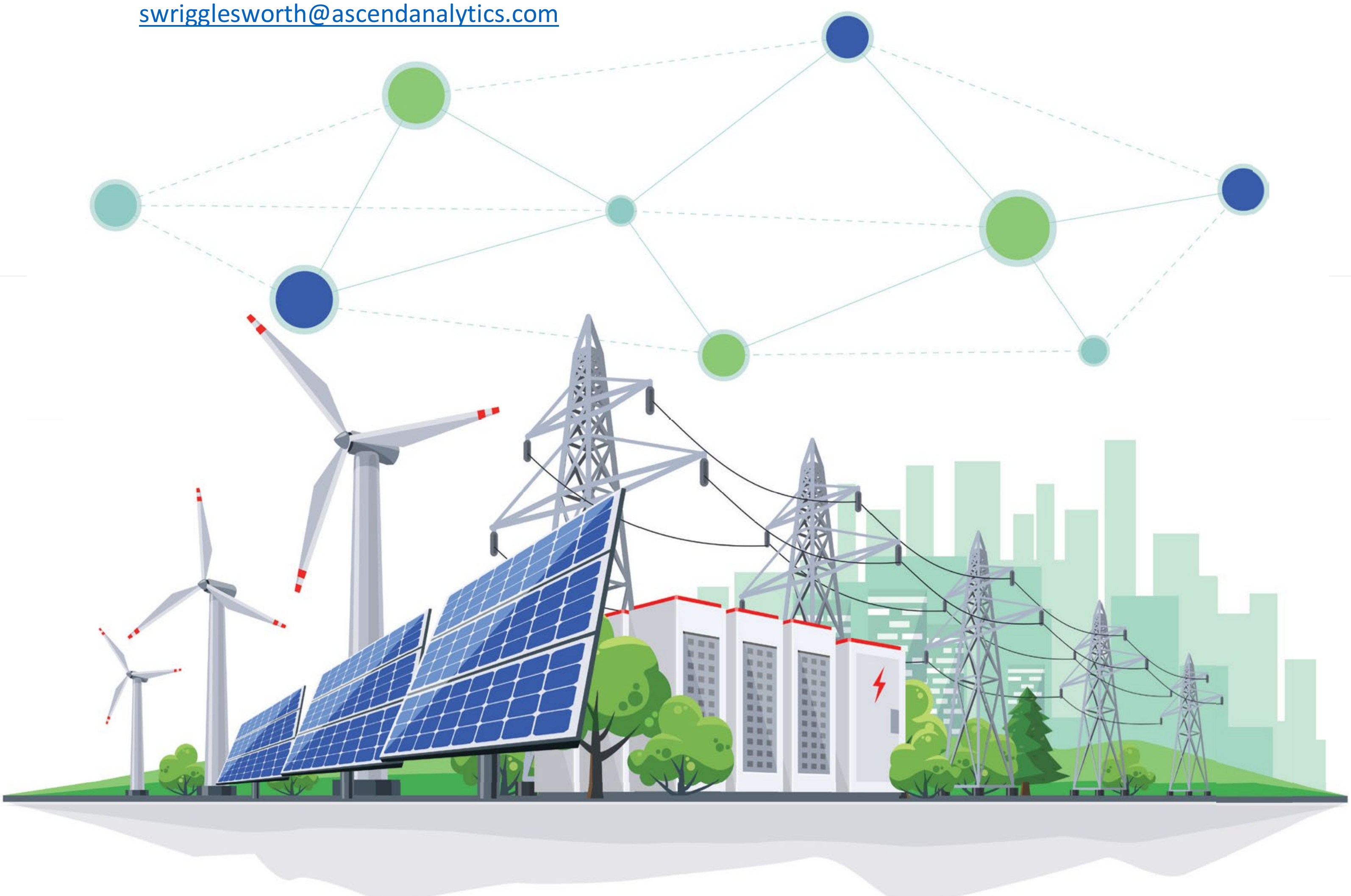

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Executive Summary

Ascend Analytics LLC (Ascend) conducted and prepared this comprehensive Technical Assessment[1] to advise on the viability of the Community Power Coalition of New Hampshire (CPCNH) launch. As it pertains to the scope of its Technical Assessment, Ascend is able to recommend to the CPCNH Board, Committees and Member CPAs that the Coalition is ready for launch.

To its knowledge, Ascend does not believe that any community power initiative has ever pursued its technical assessment with the rigor of stochastic analysis, as was performed in preparation of this assessment. Ascend conducted numerous scenarios, stress tests, and stochastic analysis on all anticipated outcomes of reasonable probability, and the results show that CPCNH remains a viable agency offering independent local control of power supply for it is communities while pursuing the clean energy transition across New Hampshire. Further, the aggregate benefit of a CPCNH launch for its CPA members is both quantitatively and qualitatively strong.

The Technical Assessment provides context and findings from Ascend Analytics review of many factors. However, it is important to point out three main elements for consideration of all seeking technical advisement on the viability of launch. Herein, Ascend concludes the following:

1. The financial benefit of launching CPA service in April 2023 are stronger than at any prior point in time analyzed by Ascend (dating back to 2018), due to how far above market utility default supply rates are under current and forecasted market conditions. Consequently, Wave 1 CPA Members should expect to realize strong results over the initial 3-year term of service offered under the Cost Sharing Agreement's Member Service Contract for CPCNH's "Complete Service Bundle".
2. While future-year price simulations are subject to a number of conservative assumptions made by Ascend, CPCNH's business model achieves a better value proposition relative to the cost savings a community is likely to achieve through a brokered power supply deal, based on what the latter model has demonstrated being capable of achieving on average in an adjacent market (i.e., Massachusetts).
3. Ascend's base case scenario assumes Nashua launches in May 2023, rather than in April with the other 'Wave 1' Members. However, CPCNH's viability and performance remains robust across all reasonable scenarios related to community participation levels, including the scenario in which Nashua never launches CPA service through CPCNH.

It should be understood upfront that Ascend's analysis does not speculate, quantitatively, on what may happen in the event of a prolonged and/or severe market disruption. As context:

- Such 'black swan' events are a residual risk, inherent to the industry, which may impact CPCNH's financial performance in securing and delivering power to customers at rates fixed for 6-month periods (mirroring utility default supply periods).
- However, CPCNH's risk management strategy, embodied in the framework created under CPCNH's Energy Portfolio Risk Management Policy, is liable to be compromised to this degree

[1] *Ascend provided a draft Technical Assessment at the end of 2022. Appendix H details updates made to modeling leading to revision of results from the original draft.*

only by a market disruption significant enough to impact not just CPCNH, but all major suppliers, including those under contract to provide utility default supply service.

- If multiple major power suppliers were to go bankrupt or otherwise exit the ISO-NE market, Ascend anticipates the high likelihood of customer rates being impacted to a comparable degree regardless of whether taking service through CPCNH or the utilities.

- In such an event, maintaining CPCNH's general competitive position — in terms of its ability to maintain competitive rates relative to utility default service so as to avoid customer switching to the degree that would erode CPCNH's financial viability — should be achievable.

As described herein, several key performance and financial metrics are identified and measured in a stochastic manner. It is important to understand the tradeoffs involved with different strategic decisions and market scenarios on those metrics. (For example, fulfilling an objective of providing greater customer savings generally presents a trade-off to the objective of building greater financial reserves.)

This assessment captures the financial performance implications and interdependencies inherent in trade-off decisions, models a variety of scenarios assuming different balances of trade-off decisions by CPCNH and its Members, and summarizes the results by generating a significant number of output metrics and charts, including financial reserves, customer savings, and the aggregate effective community benefit (the cumulative total of a Member's financial reserves and customer bill savings).

Based on our results, Ascend strongly recommends CPCNH maintain the April 2023 target launch date for Wave 1 CPA Members.

- Our recommendation is predicated on a variety of factors; chief among them are current market conditions, high utility auction premiums, and the resulting financial benefit that would be maximized by launching in April.

- Consequently, an April 2023 launch would ensure CPCNH achieves robust financial performance for Wave 1 Members — which, in turn, will maintain the recruitment of new communities and expansion of CPA program service for Wave 2 and across all subsequent future-year waves.

Regarding the opportunity to achieve CPCNH's broader value proposition, Ascend concludes that the Inflation Reduction Act and the pilot project framework authorized by Senate Bill 321 strongly support the business case for CPCNH to prioritize developing local projects on behalf of participating Members.

As detailed in this report and summarized in our concluding "Evaluation and Recommendations" section, Ascend has confirmed that the pathway most likely to maximize financial benefits for all Members is defined by (1) prioritizing the expansion of CPCNH's membership and (2) prioritizing the development of local projects, both of which generate significant surplus revenues and benefits for participating customers, communities, and the Joint Powers Agency.

In short, the findings of our Technical Assessment confirm CPCNH's economic viability, validate CPCNH's mission and strategic objectives, and encourage action and initiative be taken by all Members in light of these opportunities.

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CPCNH Technical Parameters & Assumptions

Communities and Customer Mix

The aggregation of communities gives CPCNH strength and economies of scale. The following figures detail the communities and customer count estimates by utility for those included in the Technical Assessment. This data represents the best available data for each community and/or estimates of volumes based upon populations. Figure 1 details the overall counts compiled in support of Base Case and scenario analysis. It should be noted at inception that while a relatively small number of New Hampshire Electric Cooperative (NHEC) customers are listed, for reasons explained later, NHEC customers are deemed to be 'opt-in' and will not be enrolled at launch, nor assumed to be added for assessment purposes.

Figure 1 : Overall Customer Counts under Different Scenarios

			TOTAL		Eversource		Liberty		NHEC		Unitil	
		Community	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
Launch April 2023	Initial Wave 1 Members	Cheshire	0	10	0	10	0	0			0	0
		Durham	2,854	405	2,854	405	0	0			0	0
		Enfield	2,273	317	16	2	2,257	315			0	0
		Exeter	6,500	1,702	5,850	1,531	0	0			650	171
		Hanover	2,695	414	96	20	2,599	394			0	0
		Harrisville	658	92	658	92	0	0			0	0
		Lebanon	6,548	1,326	0	0	6,548	1,326			0	0
		Nashua	32,558	4,969	32,558	4,969	0	0			0	0
		Plainfield	575	114	286	48	289	66			0	0
		Rye	2,802	502	2,802	502	0	0			0	0
		Walpole	1,667	270	0	0	1,667	270			0	0
	New Wave 1	Peterborough	2,378	632	2,378	632	0	0			0	0
	Wave 1 Total		61,507	10,752	47,498	8,211	13,359	2,370			650	171

			TOTAL		Eversource		Liberty		NHEC		Unitil	
		Community	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
Launch April 2024	Initial Wave 2 Members	Dover	13,934	2,015	13,934	2,015	0	0			0	0
		Hudson	9,128	1,774	9,128	1,774	0	0			0	0
		New London	2,380	455	2,380	455	0	0			0	0
		Newmarket	4,020	381	4,020	381	0	0			0	0
		Pembroke	2,860	401	2,574	361	0	0			286	40
		Portsmouth	10,554	2,414	10,554	2,414	0	0			0	0
		Warner	1,546	300	1,546	300	0	0			0	0
	New Wave 2	Webster	900	92	450	46	0	0			450	46
		Canterbury	931	85	409	40	0	0			517	45
		Hancock	641	171	641	171	0	0			0	0
		Sugar Hill	212	49	134	36	0	0			0	0
		Westmoreland	632	168	632	168	0	0			0	0
		Wilmot	538	122	339	90	0	0			0	0
	Wave 2 Total		48,276	8,427	46,741	8,251	0	0			1,253	131

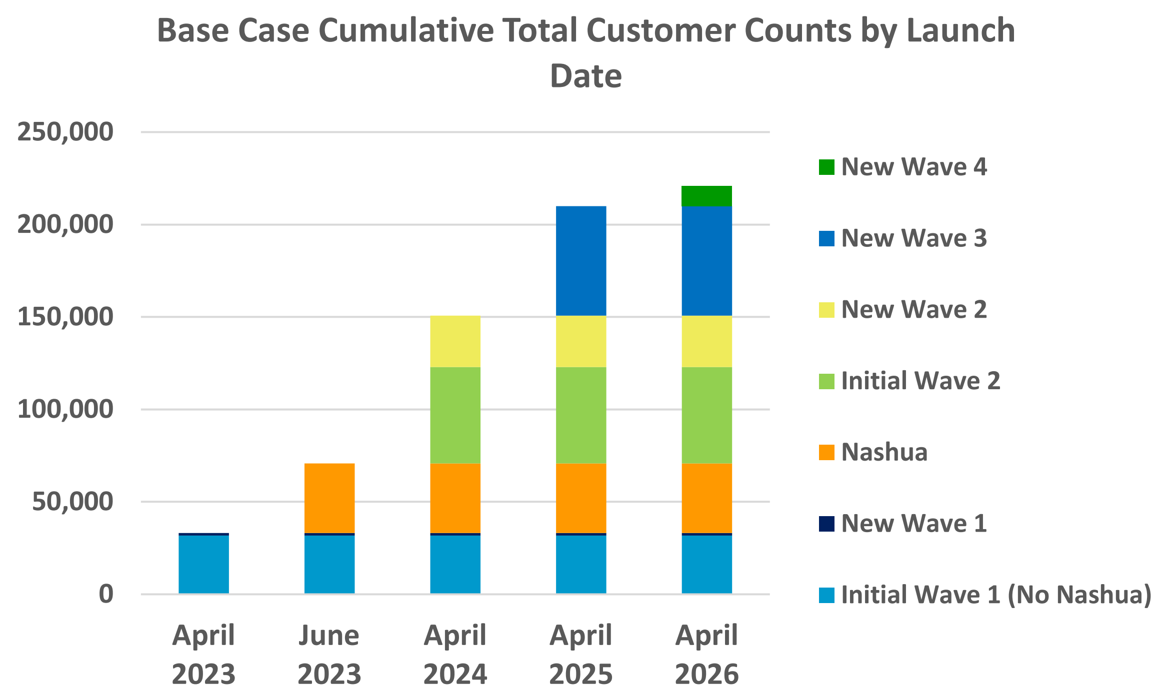
		TOTAL		Eversource		Liberty		NHEC		Unitil	
Launch	Additional Prospective Communities	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
April 2024	New Wave 2 Growth	35,217	15,978	17,372	13,094	2,860	508			14,985	2,376
April 2025	New Wave 3 Growth	94,379	24,029	84,627	22,410	3,799	675			5,953	944
April 2026	New Wave 4 Growth	17,769	4,317	13,672	3,621	2,423	430			1,674	266

The following describes the Base Case scenario for this assessment along with a cross section of P50 scenarios for alternate possible outcomes on future CPCNH CPA participation levels. Due to the significant size of Nashua, several scenarios explore outcomes related to Nashua's timing and participation. Part of the value proposition CPCNH brings as a coalition is economies of scale. Thus, scenarios explore changes in participation. As a reminder, this section details assumptions while the next section presents the key findings.

Base Case Assumption:

Initial Wave 1 & 2 communities, with a Nashua launch delay[2] of one month, plus 50% of new wave 1-4 communities. Figure 2 illustrates the cumulative customer counts at various launch dates associated with this scenario.

Figure 2 : Base Case Cumulative Total Customer Counts by Launch Date



[2] Nashua, as a wave 1 member, has expressed likely delays due to due diligence efforts. The Base Case scenario assumes Nashua delays 2 months and launches in June. Other scenarios address further delays on Nashua's part, and the impact on the Coalition were Nashua choose to not participate at all.

Figure 3 highlights identified members by size and Figure 4 shows residential and non-residential customer counts by utility.

Figure 3 : Identified or Prospective Members by Total Customer Count

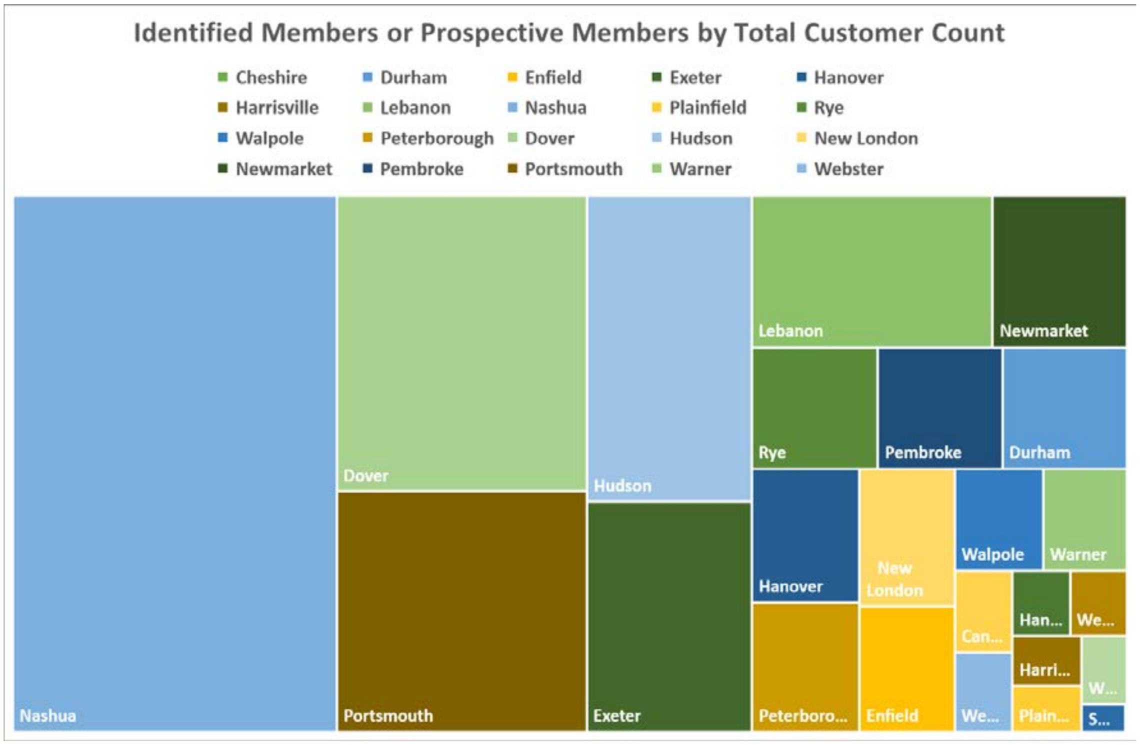
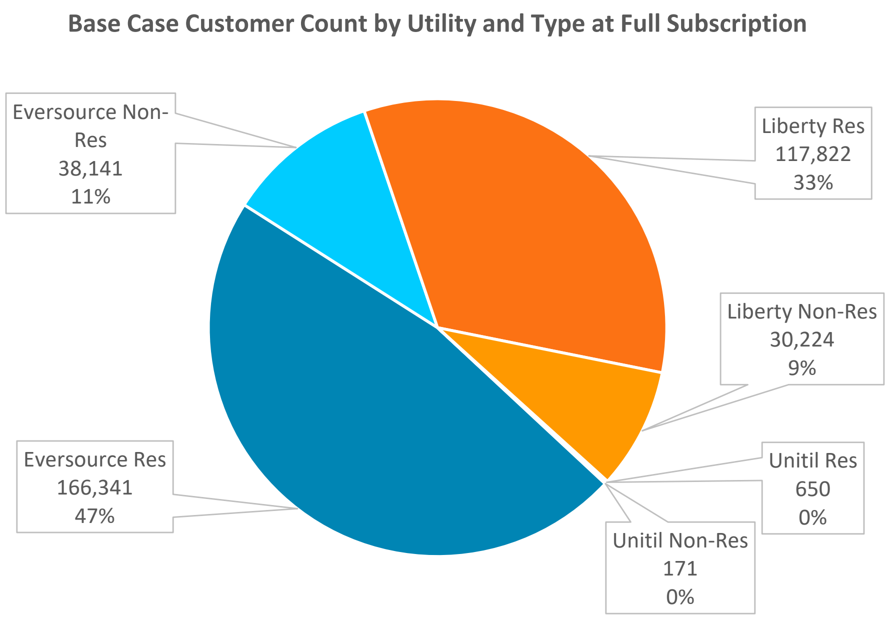


Figure 4 : Base Case Count by Utility and Type at Full Subscription

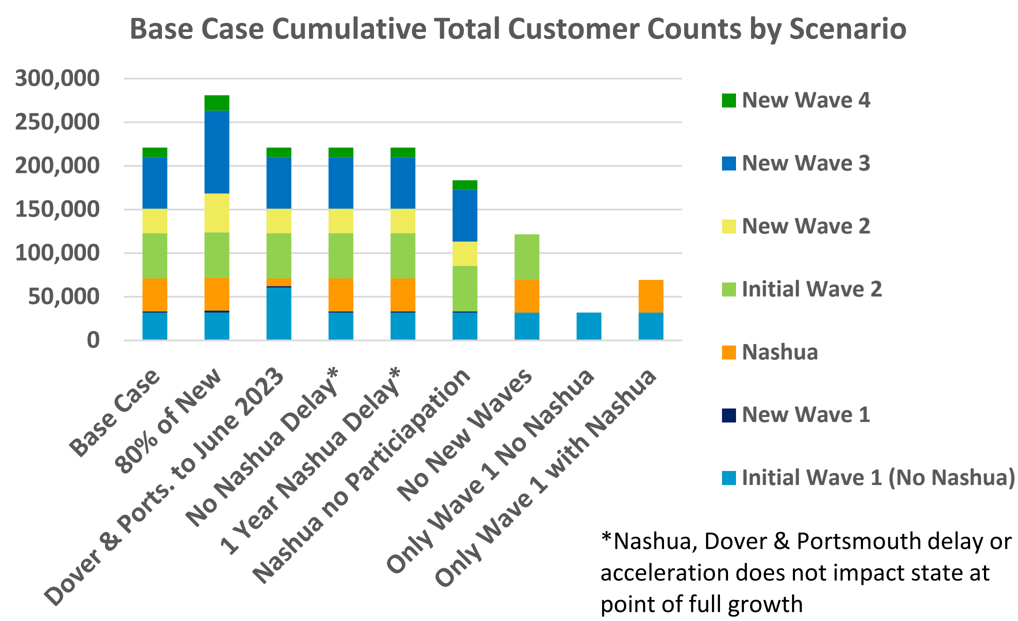


Ascend tested the following scenarios to assess the CPCNH's financial performance across various levels of Membership participation in CPA service:

- Base case, but 80% of new communities
- Base case, but no Nashua delay
- Base case, but Nashua delays 1 year instead of 1 months
- Base case, but Nashua never participates
- Base case, but no New Wave communities
- Base case, but no Nashua and no future waves after wave 1
- Base case, but no future waves after wave 1
- Base case, Dover & Portsmouth accelerate launch to June 2023

Figure 5 demonstrates the overall total customer counts associated with eventual full subscription in future years.

Figure 5 : Base Case Cumulative Total Customer Counts by Participation Scenario



Expected Initial Enrollment and Opt-out

For the technical analysis, opt-out assumptions are uniform across all scenarios. Ascend deems these opt-out assumptions to be conservative and reasonable for Opt-out aggregation, especially given that default utility loads have possessed retail choice for some time. Customers taking default service in an evolved choice market are generally more 'sticky' than early adopters who have likely already selected a retail energy supplier. The cumulative opt-out assumptions are in shown in Figure 6.

Figure 6 : Cumulative Opt-Out assumption by month for Residential and Non-residential

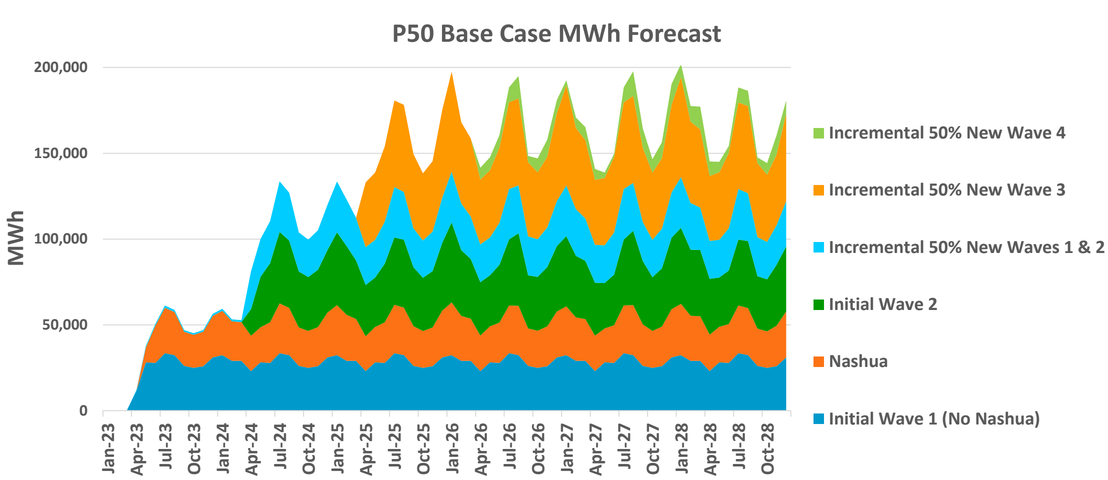
Months Since	Cumulative Opt-Out	
Enrollment	**Residential**	**Non-Residential**
1	1%	2%
2	2%	4%
3	4%	6%
4	5%	8%

Projected Electricity Consumption

Ascend used a mosaic approach to compile the best possible picture of the eligible load participants. The data sources used in this process include public data from utility retail electric supplier websites, community specific customer lists obtained by individual CPAs from the utilities, as well as other publicly available information including population data. All data is subject to change as more accurate and/or detailed information is obtained via new CPA requests, new utility reporting requirements, new community participation interest, and the receipt of official pre-enrollment lists. After analyzing the existing data, Ascend believes it is reliable and useful for analysis.

After applying opt-out assumptions, CPCNH Initial Wave 1 members including Nashua equate to 639,000 MWh per year (73 MW Avg / ~145 MW Peak). Wave 2 is roughly 426,000 MWh per year (48 MW Avg / ~97 MW Peak). The Base Case assumes 50% of New Wave communities which equates to 944,000 MWh (107 MW Avg / ~215 MW Peak). Figure 7 shows projected total MWh across the forecast horizon for the assessment Base Case. When specific community data is unavailable, the analysis is based on average customer size to approximate the amount of load based upon customer count.

Figure 7: P50 Base Case MWh Forecast



Renewable Energy Portfolio Requirements

New Hampshire has a state Renewable Portfolio Standard (RPS) target that increases over time. *Figure 8* illustrates the base and scenario compliance/over-compliance targets and projected RPS costs on a per MWh served basis. The wholesale cost section of this report details the calculation of RPS cost to serve customers.

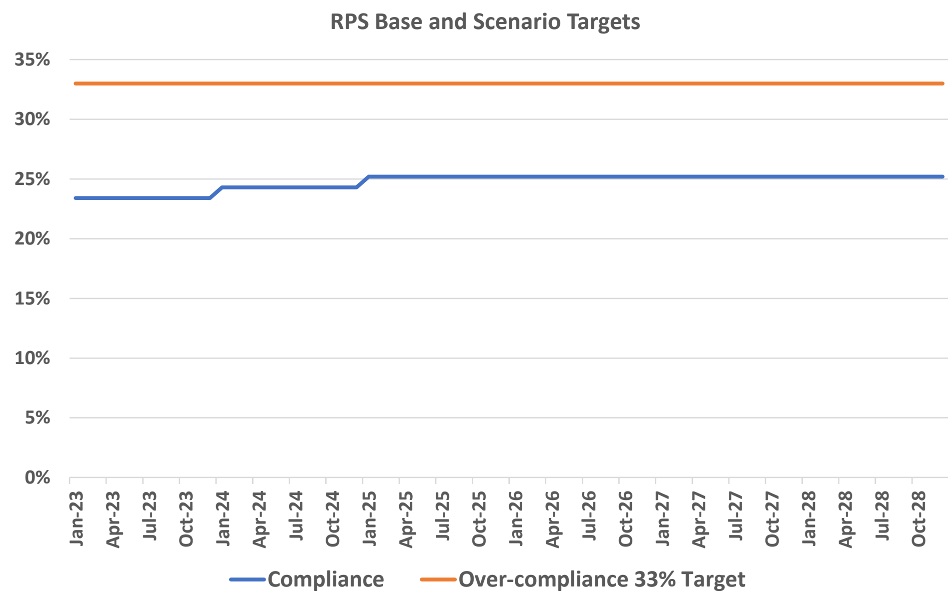
Base Case Assumption:

CPCNH launches with an RPS target based upon compliance.

Alternate Scenario:

CPCNH establishes its own default 33% RPS target as part of its default product content.

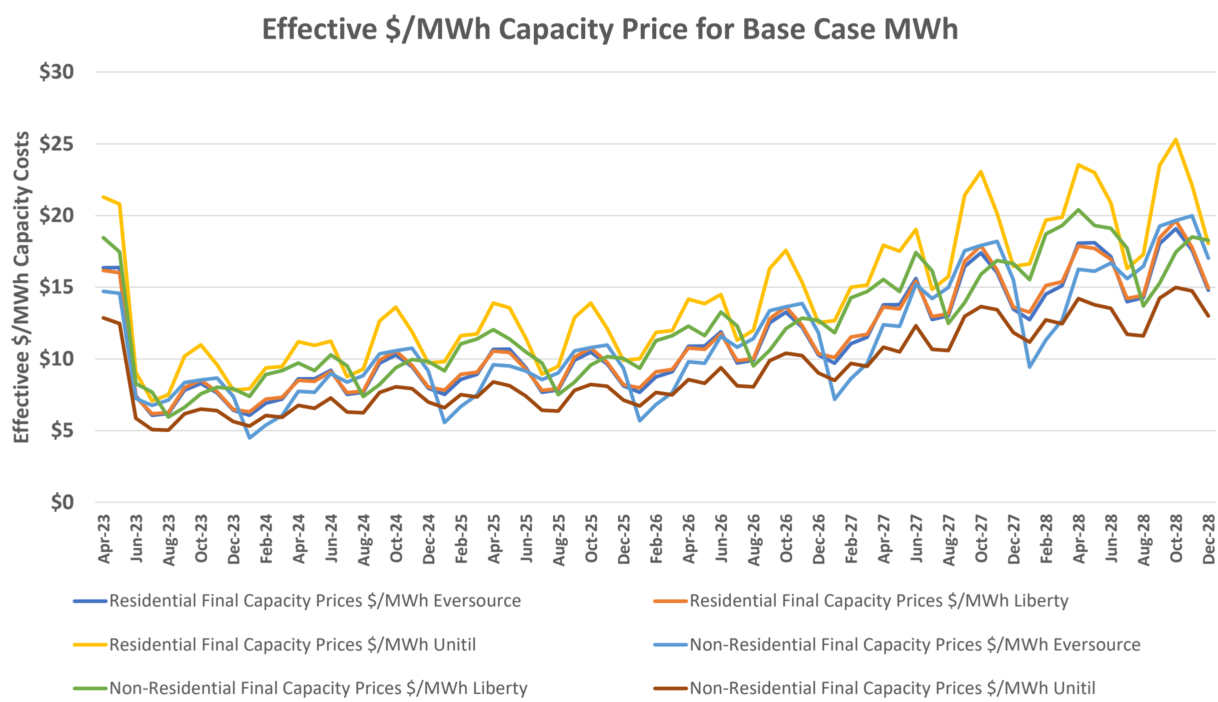
Figure 8: RPS Base and Scenario Targets



Capacity Requirements

Due to the limited availability of capacity requirement data, Ascend estimated capacity ICAP requirements based upon utility load asset ID profiles. For this Technical Assessment, Ascend performed pricing of capacity (described in the Cost-of-Service Elements section) on a $/MWh profile basis. ISO-NE ICAP Obligations for load are estimated on a $/MWh forecast as part of the cost of supply based upon utility load asset IDs. Figure 9 shows this forecast in terms of $/MWh. The Base Case and all scenarios use the same assumption on capacity cost as sensitivity to capacity pricing is limited given all market participants (utilities, retail suppliers, brokers, CPAs) generally pass capacity costs through in the build-up of market pricing.

Figure 9: Effective $/MWh Capacity Price for Base Case MWh



Revenue Assumptions and Elements

Rate Setting

For this Technical Assessment, CPCNH advised Ascend to pursue a rate setting methodology based upon a discount to utility tariff approach. This approach is prudent as it ensures customers receive a discount to utility tariff in an equitable and assured fashion. The following describes the utility tariff forecasting process used in this Technical Assessment. Actual future rate-setting decisions will be made with the best available information in the future and these assumptions or scenarios should not be considered instructive to any rate-setting decision mak

Base Case Assumption:

- 7.5% off Eversource, with the same rates extended to Liberty and Unitil customers for the first four months. Then, 7.5% off each respective utilities rates for August 2023 – January 2024. Thereafter, a 5% discount to utility tariff unless the discount needs to be reduced to maintain debt service coverage ratios (DSCR).

Alternate Scenarios:

- 7.5% discount to utility tariff unless the discount needs to be reduced to maintain DSCR.

Tariff Forecast

Utility Auction Risk Premiums

With the exception of NHEC, utility auctions for the energy supply for default customers clear in the month or two leading up to a utility default service period. For a variety of reasons, including uncertainty of load volumes and load shape, market price uncertainty, market liquidity (depth of market participation in the auctions), and requirements to hold winning bids open until PUC approval is obtained, the auctions clear at a premium to the observed market forwards on the day of the auction. Ascend analysts performed research of past auctions to monitor the trends and recent behavior of utility auctions. Eversource and Liberty's residential / small commercial auctions cleared prior to the completion of this Technical Assessment and model results were updated to reflect the recent results.

Figure 10 shows the historical auction results for small customer Asset IDs (residential and small commercial customers), and Figure 11 shows the historical auction premiums for large customer Asset IDs (larger commercial and industrial customers.

Figure 10: Small Historical Headroom Analysis

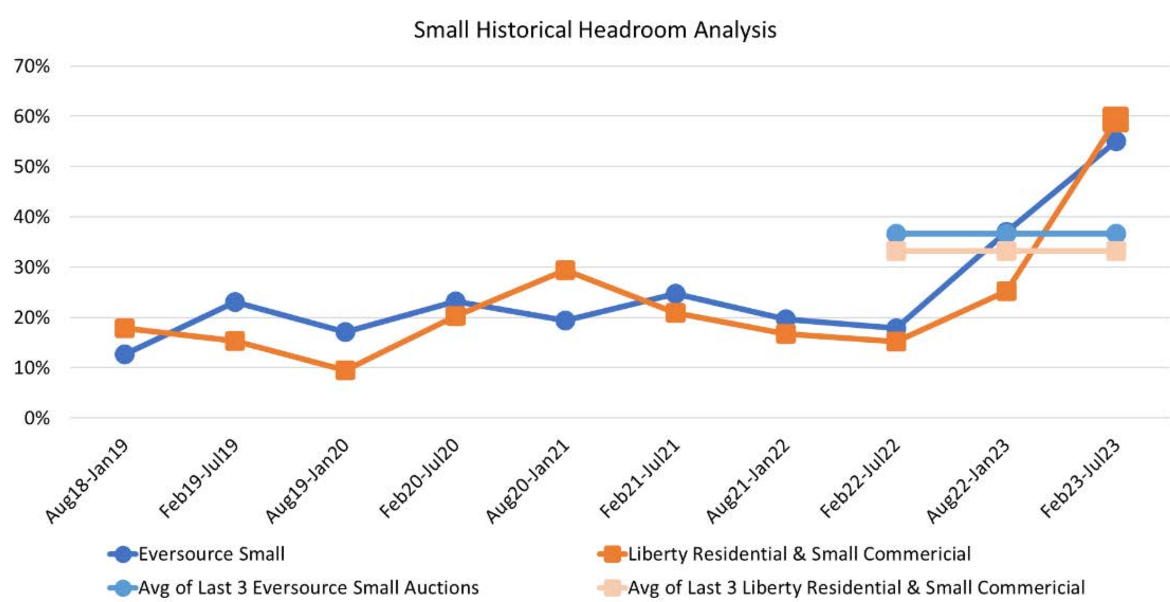
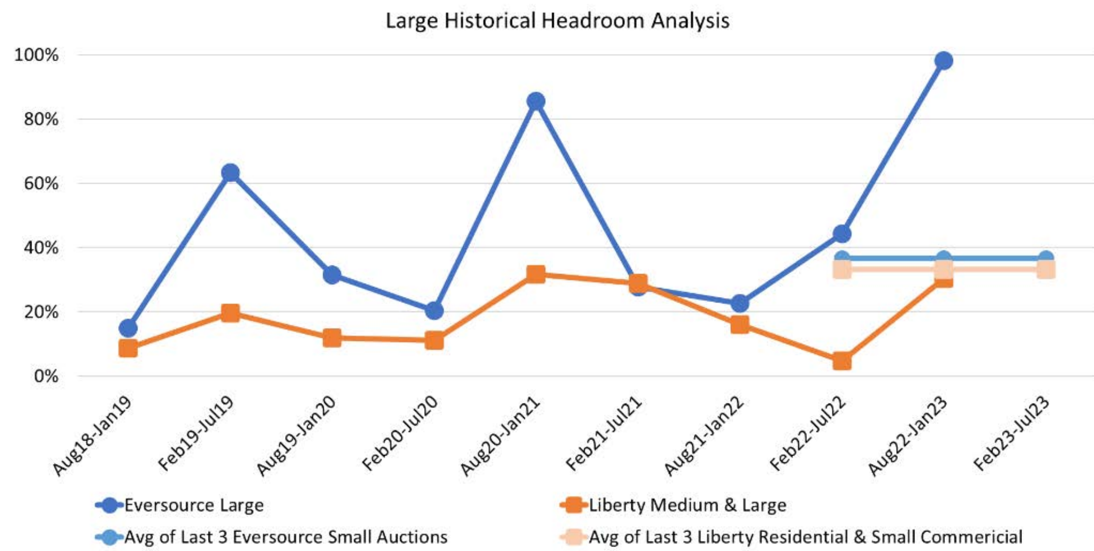


Figure 11: Large Historical Headroom Analysis



Ascend concluded that, due to market dynamics in ISO-NE and market volatility and uncertainty conditions, the average of the last three auctions is the appropriate forecast assumption moving forward. Consequently:

- For the February through July default service period, Ascend's model employs headroom assumptions based on the latest utility auctions and current posted utility rates.
- The forecasted auction premiums, based on applying the 3-year prior average premiums shown above, apply after July 2023; this may be conservative, as the 3-year prior average premiums are lower than the premiums from the current period.

Lastly, Ascend further opted to employ a conservative assumption in applying the small customer premium to the large customer Asset IDs, as the latter have been more volatile from auction to auction. (While higher future premiums could be justified, CPCNH's large customer load is relatively less compared to residential and small commercial load.)

Appendix D provides detail behind the determination of the premiums.

Current Competitive Supply Offers

Figure 12 provides posted supplier retail choice offers as of 12/19/2022. Since default utility load and eventual CPCNH opt-out load is not contractually bound, nor has a cancellation fee to leave CPCNH. Generally, most proactive energy choice customers have already left utility default service. The value proposition of competitive open access suppliers is limited, and pricing offered to customers may require long-term commitments to obtain favorable rates. The longer-term rates offer immediate savings, but based on forward markets, are likely to be above future utility rates. The competitive offers of suppliers is something CPCNH must monitor but may not warrant undue concern given the one-by-one nature of customer acquisition and the absence of a compelling missing for renewable and local community power.

Figure 12: Select Posted Supplier Retail Choice Offers (12/19/2022)

Class	Utility	Supplier	Months	$/KWH	Cancel fee	RE%
SML COM	Eversource	Direct	12	$ 0.19	$0	0
SML COM	Eversource	Direct	24	$ 0.17	$0	0
SML COM	Eversource	ENH Power	12	$ 0.19	$100	0
SML COM	Eversource	Xoom	12	$ 0.19	$500	0
SML COM	Eversource	Xoom	24	$ 0.18	$1,000	0
RES	Eversource	Direct	12	$ 0.20	$0	0
RES	Eversource	Direct	24	$ 0.18	$0	1
RES	Eversource	Direct	30	$ 0.17	$0	0
RES	Eversource	N. American	10	$ 0.19	$10	0.25
RES	Eversource	N. American	18	$ 0.19	$10	0.25
SML COM	Liberty	ENH Power	12	$ 0.20	$100	0
RES	Liberty	N. American	12	$ 0.19	$10	0.25
RES	Liberty	N. American	12	$ 0.20	$10	1
RES	Liberty	ENH Power	12	$ 0.20	$100	0
RES	Eversource	Ambit	12	$ 0.20	$0	0
RES	Eversource	Ambit	12	$ 0.19	$0	0
RES	Eversource	Smart	12	$ 0.23	$0	1
RES	Eversource	Townsquare	12	$ 0.20	$0	0
RES	Eversource	Xoom	12	$ 0.20	$110	0
RES	Eversource	Xoom	24	$ 0.19	$200	0
RES	Liberty	Ambit	12	$ 0.20	$0	0
RES	NHEC	Ambit	12	$ 0.19	$0	0
RES	NHEC	ENH Power	12	$ 0.21	$100	0
SML COM	NHEC	ENH Power	12	$ 0.21	$100	0
RES	Unitil	Ambit	12	$ 0.20	$0	0
RES	Unitil	ENH Power	12	$ 0.20	$100	0
RES	Unitil	N. American	10	$ 0.19	$10	0.25
RES	Unitil	N. American	18	$ 0.19	$10	0.25
RES	Unitil	Smart	12	$ 0.23	$0	1
RES	Unitil	Townsquare	12	$ 0.20	$0	0
SML COM	Unitil	ENH Power	12	$ 0.20	$100	0

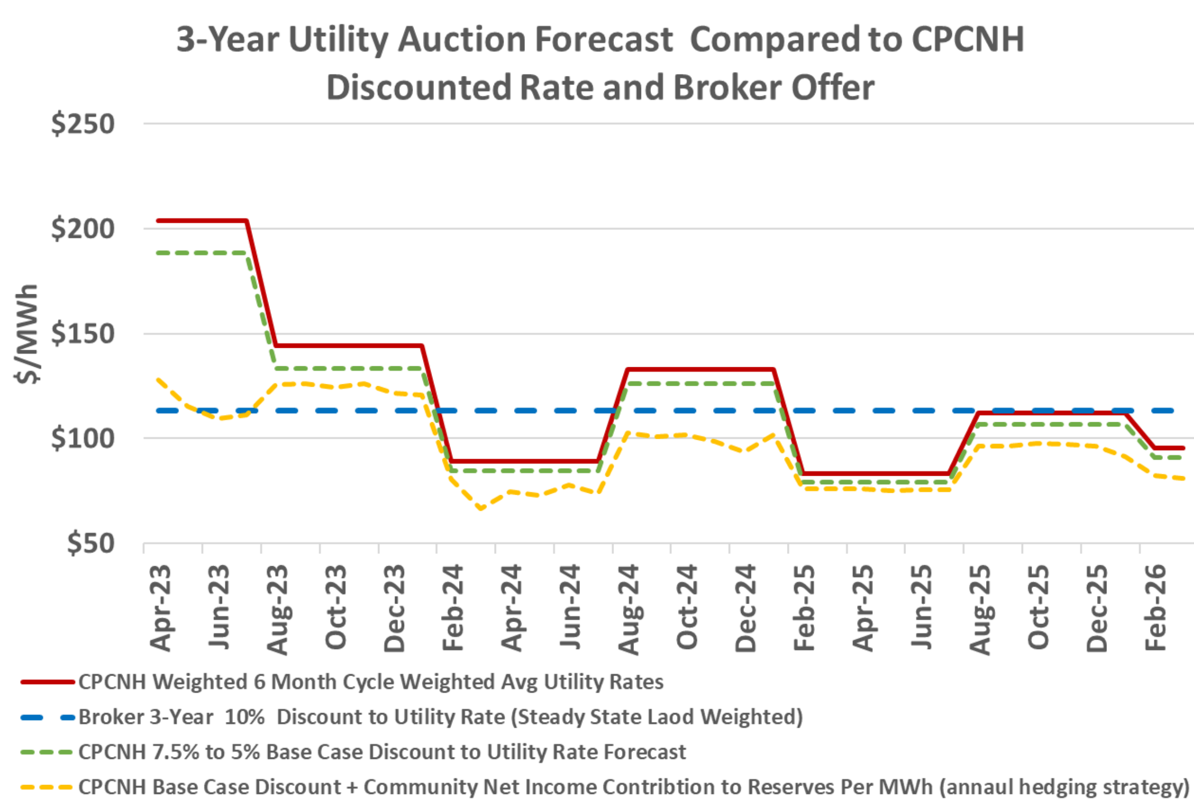
CPCNH Value Proposition vs the Broker Model

Ascend forecasted the default utility rate over future periods by applying the auction premiums to market forward prices, and incorporating non-energy wholesale costs. This assessment is important for clarity, as CPAs *could potentially* take a brokered deal for power supply independent of CPCNH. Such an election would result in the CPA losing many of the non-price related value proposition of CPCNH (portfolio management, local power, a mission for the energy transition, etc.). However, as is with most commodities, alternatives aside, economics are the most pressing factor in decision making:

- Proponents of the 'broker model' have pointed to assessments of the Massachusetts market, representing that customer savings of ~10% 'on average' are achievable and expected.
- CPCNH offers rate decreases and also accrues financial reserves on behalf of Members. In this context, CPCNH's Cost Sharing Agreement permits Wave 1 Members the option of terminating their continued participation in CPCNH at the end of their initial 3-year term, and to "cash out" at this juncture, using any accrued financial reserves to provide a rebate to customers (for example).
- Therefore, the question communities may ask is whether the "total potential savings" with CPCNH (computed by adding cumulative forecasted rate decreases and financial reserves) will outweigh the discount to the current rate committed to under a brokered power supply contract.

Figure 13 illustrates the following initial steps in Ascend's analysis of this question: given the utility rate forecast (red), achieving an average 10% discount over a 3-year term would imply a fixed price of approximately $113/MWh (blue); savings are large over the first 10 months, slightly better the next 12 months, before going above utility rates for the subsequent 14 months. In comparison, CPCNH's base case assumption is to offer a 7.5% discount down to 5% discount to utility rates in each period (green). Consequently, the broker price would appear favorable, purely on the basis of immediate-term rate savings. However, adding the financial reserves to the customer bill discounts on a dollar per MWh basis reveals that CPCNH Members would pay less for supply service over the 36-month period (yellow). The yellow line averages ~$95/MWh for a total effective community benefit rate compared to a $113/MWh broker offer, and equates to 17% total benefit as compared to 10%.

Figure 13: 2-year Utility Auction Forecast Compared to CPCNH Discounted Rate and Broker Offer

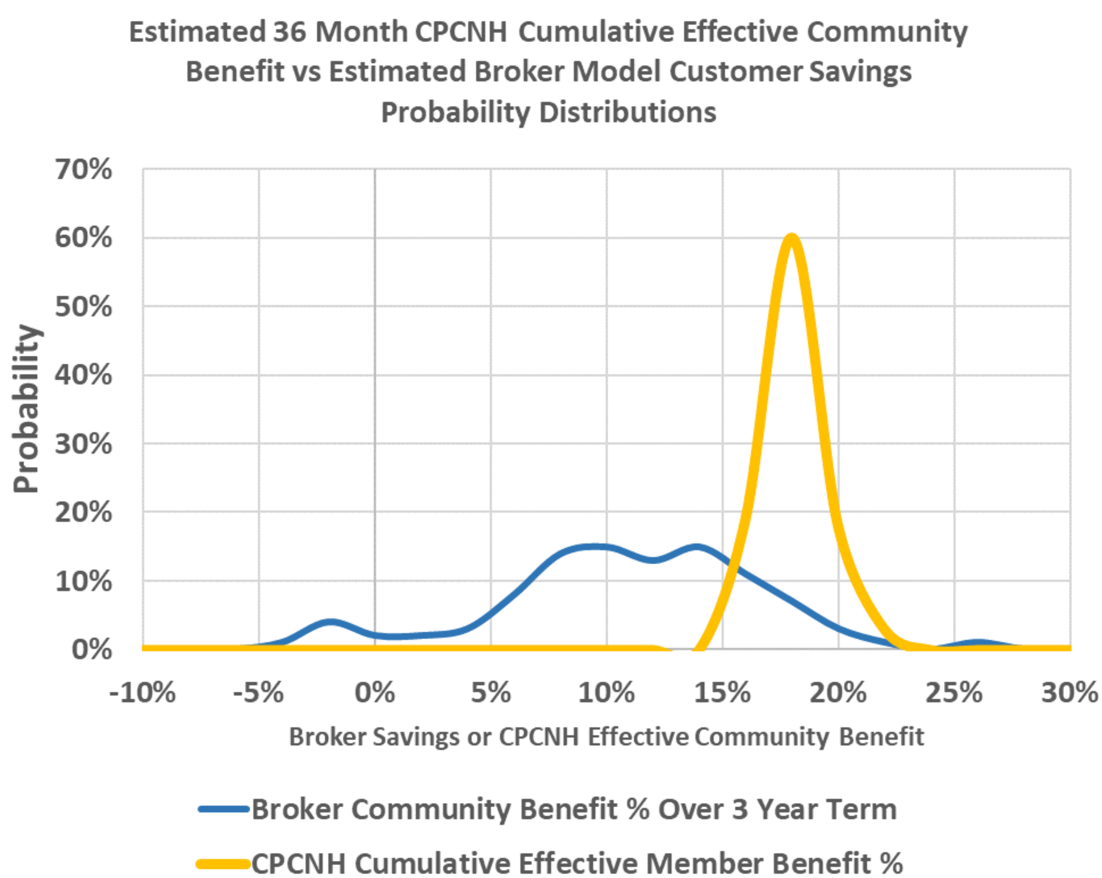


However, a single forecast based on an assumed "known" utility rate is not sufficient to ensure informed decision-making for Members evaluating whether to participate in CPCNH, because the financial benefit offered under both models is dependent upon future utility rates.

Ascend therefore stochastically simulated and analyzed the results from over 100 different scenarios of market price movements and corresponding utility default service rates. Comparing the initial fixed-price assumed under the brokered power supply deal to what utility rates would be in each scenario revealed that actual customer savings could fluctuate between -6% and 25% over the 36-month initial period. In comparison, the "total potential savings" that a Member would achieve taking service from CPCNH, given the same scenarios, fell between 15% and 22%.

These probability distributions are presented in Figure 14 below. However, it is important to note that, while the distributions overlap, the financial benefits for a Member participating in CPCNH were larger than what the Member would have gained by contracting for the fixed-price brokered supply deal <u>in 92% of scenarios.</u>

Figure 14 : Probability distribution of estimated 36 month CPCNH cumulative effective community benefit vs. estimated broker model customer savings



Headroom

Headroom is the difference between the utility tariff and the CPCNH market build-up cost of supply. Figure 15 and Figure 16 below illustrate the headroom during the first portion of the initial four months of operation as of December 2023 (April - July 2023) during the utilities' February – July 2023 default service period. The significant headroom in the current market environment is a major advantage as CPCNH establishes its market position and builds initial reserves. The headroom for the first four months after launch has only grown from December into January as power market process have dropped since utilities conducted their auctions It is important to note the absence of headroom within NHEC. It is for this reason Ascend recommends CPCNH designate NHEC customers as opt-in, so as to not offer a discount and take a loss on customers, nor charge customers over their existing tariff. Headroom is before accounting for operating costs. An illustration in the findings sections shows headroom net of operating costs over a six-year period for the Technical Assessment Base Case.

Figure 15: Estimated Small Headroom Comparison

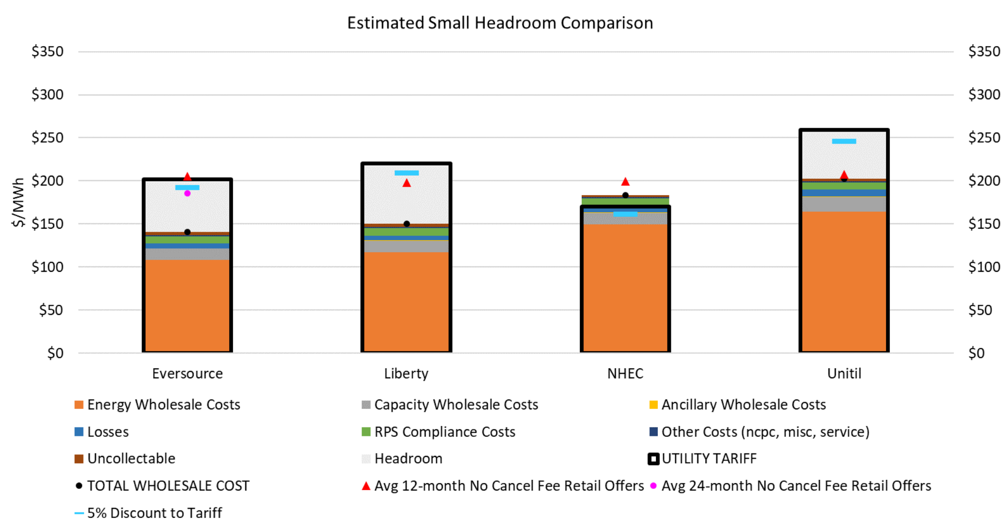
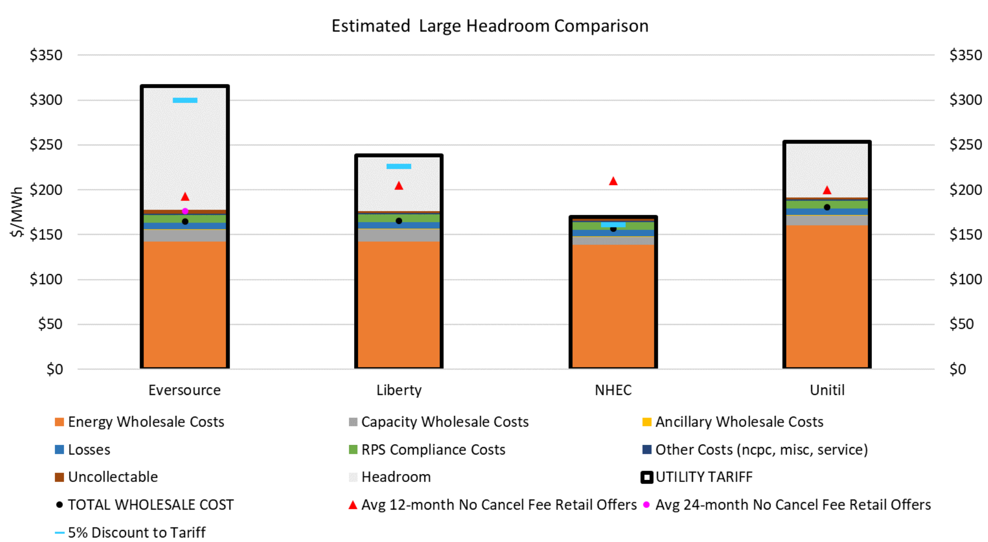


Figure 16: Estimated Large Headroom Comparison



Cost of Service Elements

Energy

To simulate the loads that will be served by CPCNH, Ascend harvested publicly available historical hourly load data from Eversource, Until, Liberty, and NHEC for each available asset ID. Table A below summarizes the asset IDs that were available. These historical loads are correlated with historical weather to simulate potential future loads. These potential load futures are coupled with simulated prices to arrive at the cost of supplying energy. The asset IDs considered can be observed in Figure 17. Although NHEC Asset IDs were evaluated, NHEC was excluded from final results for reasons explained in this Technical Assessment.

Figure 17: Asset ID, Utility and Asset Type

Utility	Asset ID	Asset Type	Rate Classes
Eversource	43493	Small Customer Load	R, R-OTOD, G, G-OTOD, OL, EOL
Eversource	752	Large Customer Load	CV, LG, B, OL
NHEC	RESIDENT	Residential	Residential - Single Phase, Residential - Mulit Phase
NHEC	PRIMARYG	General/Primary Service	General - Single Phase, General - Multi - Phase, Primary Service
NHEC	COMLARGE	Primary Service - Ski	Primary Service -Ski
NHEC	COMMERCL	Group Net Metering Host	Group Net Metering Host
NHEC	STREETLT	Street Lights	Outdoor Lighting - Metered, Outdoor Lighting Service
Liberty	11436	Small Customer Load	D, D-10, C-3, M, T, V
Liberty	11437	Large Customer Load	G-1, G-2
Unitil	11451	Small Customer Load	D
Unitil	11452	Medium Customer Load	G2, OL
Unitil	10019	Large Customer Load	C1

Energy Cost of Supply

Asset ID Profiles

Historical hourly profiles for the asset IDs covering the New Hampshire load served by each of the utilities considered were harvested from each utilities' respective websites. Eversource and Liberty had data available between 2015-2021, Unitil had data between 2017-7/2022, and NHEC data available for 2021. With these historic load profiles, a weather-load correlation was established that is used in PowerSIMM to simulate stochastic load scenarios based on simulated weather scenarios.

Weather is the driver of the meaningful uncertainty connecting both the price simulation and the load simulations. For example, extreme weather scenarios result in higher loads to support the increased demand for heating and cooling, and this spike in loads drives up the price of power and gas commodities. These historically observed relationships are evident in the weather, load, and price simulations that this technical assessment relies on. On average the load simulations will scale to the expected load forecast, and on average the hourly spot price simulations will scale to the expected forwards as harvested from ICE futures price quotes. However, each stochastic scenario represents a unique weather simulation, and therefore the model can capture potential high load high price futures and low load low price futures in order to assess forward looking risks that are anchored in historically observed trends.

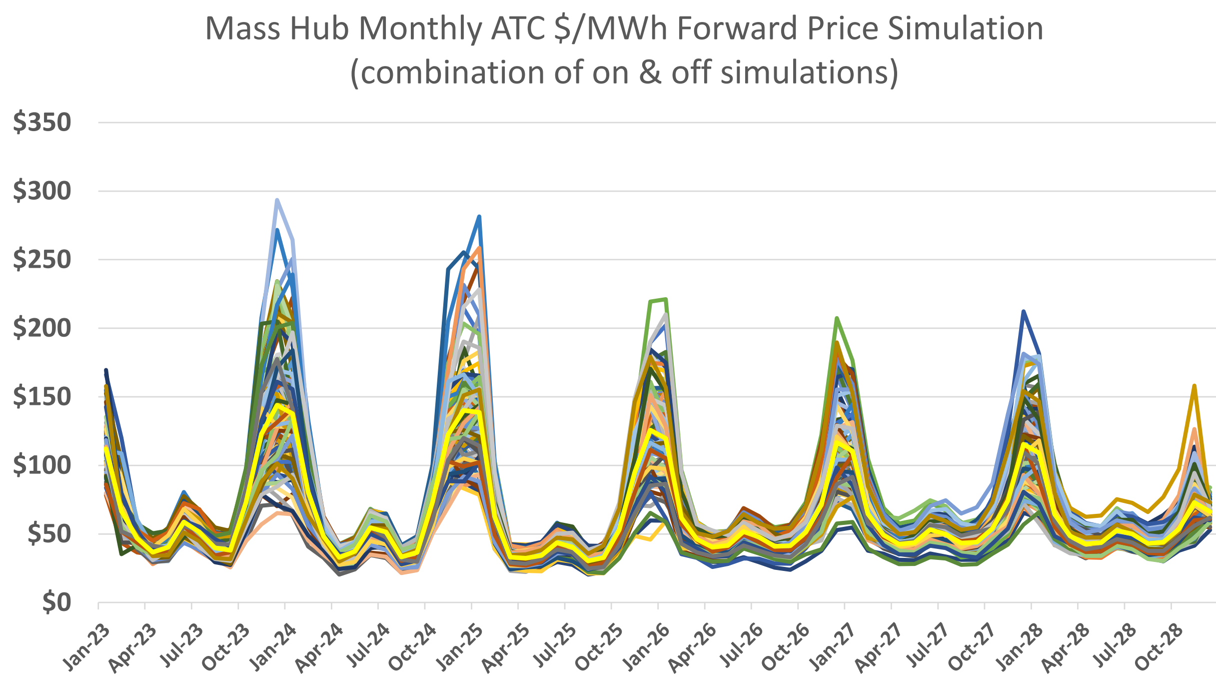
Figure 18: Historical Load Data used in PowerSIMM

For more information on load simulations and their relationship to weather and price simulations please refer to Appendices E and F (available upon request).

Market Prices

Forward contract prices are modeled with an Autoregressive, or AR, model with volatilities and correlations estimated from historical data or with inputs provided in the Forward Price Constraints. Forward price simulations follow a random process with a reversion term that pull back to the monthly mean values based on the mean reversion rate. As seen in Figure 19: Mass Hub Monthly ATC $/MWh Forward Price Simulations Figure 19 below, Ascend forward price simulations are unique across iterations. To ensure consistency with the forward curve, the average of the forward price simulations converges to the forward market prices used as of the time of the simulation. However, there is a range of prices simulated which is consistent with the volatility assumptions. Figure 19 shows Mass Hub Monthly ATC $/MWh Forward Price Simulation (combination of on and off-peak simulations).

Figure 19: Mass Hub Monthly ATC $/MWh Forward Price Simulations



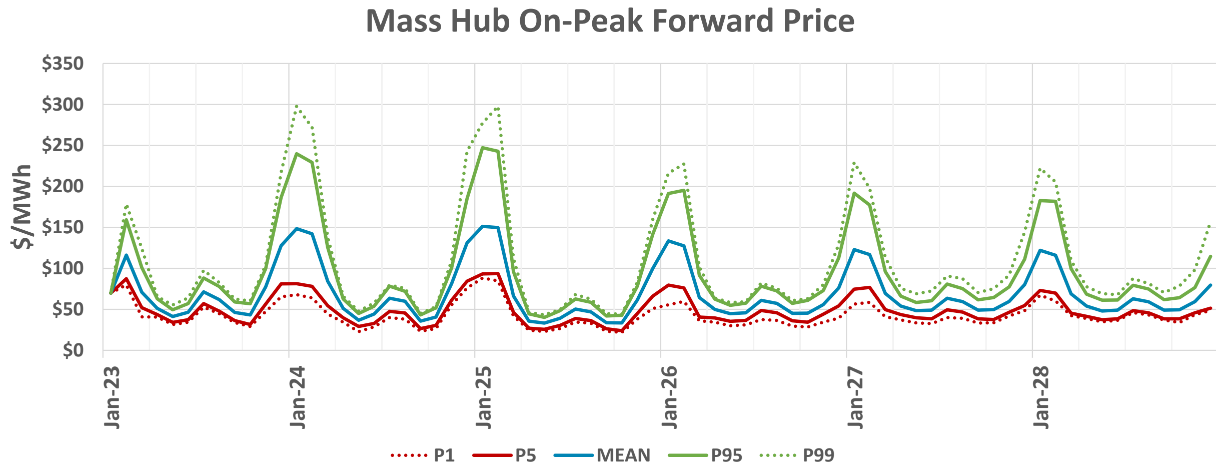
Power and Natural Gas Prices

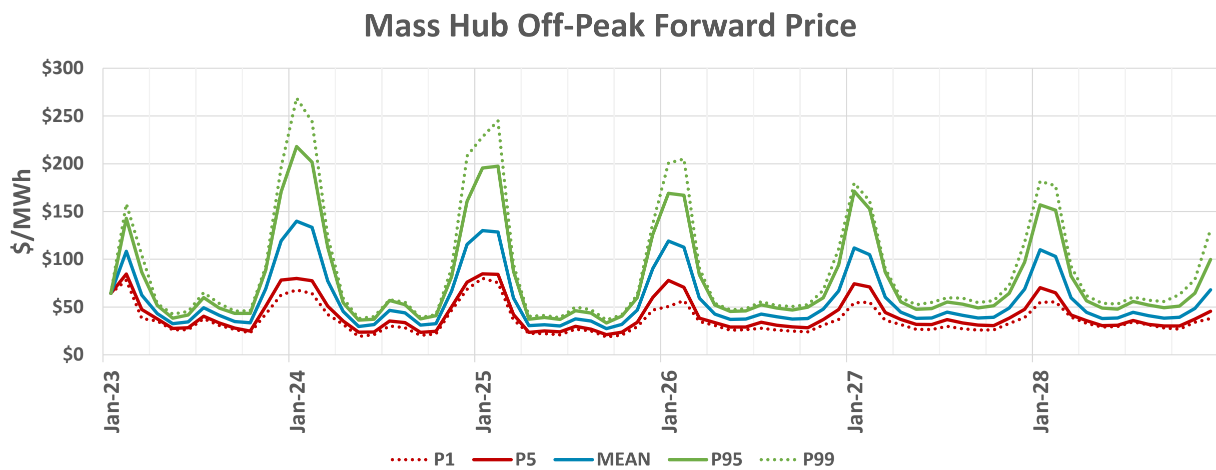
This technical assessment is based on forward price quotes as of January 20, 2023 harvested from ICE. The mean price in the forward price simulation converges to these market quotes, but the price in any given iteration/weather simulated scenario will vary based on forward curve constraints imposed on the model, namely the volatility and correlation constraints. Ascend implements a term structure volatility which is updated monthly to best capture market dynamics that tend to have greater volatility in the short term than in the long term, for this reason the range of uncertainly around the mean price captured by the P5 and P95 price differential is highest at the front end of the sims and declines through time.

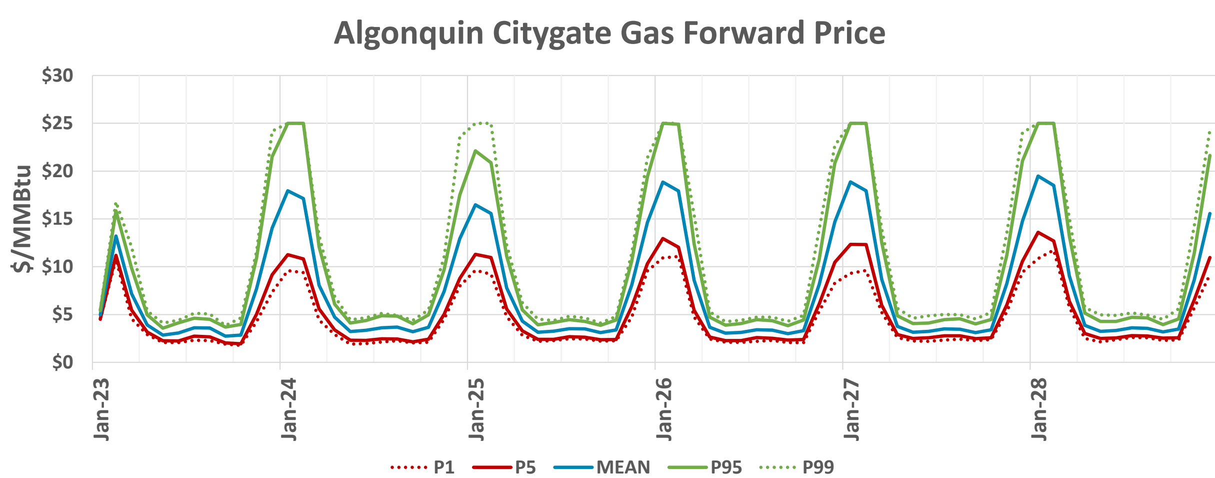
Forward prices are simulated using an autoregressive (AR) model with a lag of one while limiting the coefficient to a value of less than 1. An AR coefficient less than 1 is equivalent to a Geometric Brownian Motion (GBM) model with mean reversion. Thus, simulated forward prices follow a random walk with a constant pull back to the monthly mean values. The extent to which these simulated forward prices can deviate from mean values is determined by the forward volatility limits discussed previously.

When specifying correlation constraints Ascend ensures that the correlation matrix is positive semi-definite where each commodity (on-peak power, off-peak power, gas, etc.) is correlated with itself and each other commodity both within each month and across all months. This process ensures that expected commodity relationships are maintained such as those between gas prices, off peak and on peak power prices. Figures 20 shows the P5, mean and P95 values from simulated forward curves for Mass Hub on-peak and off-peak forward prices as well the Algonquin Citygate forward gas prices.

Figures 20 : Simulated P5, Mean and P95 for Mass Hub On Peak, Off Peak and Algonquin Citygate



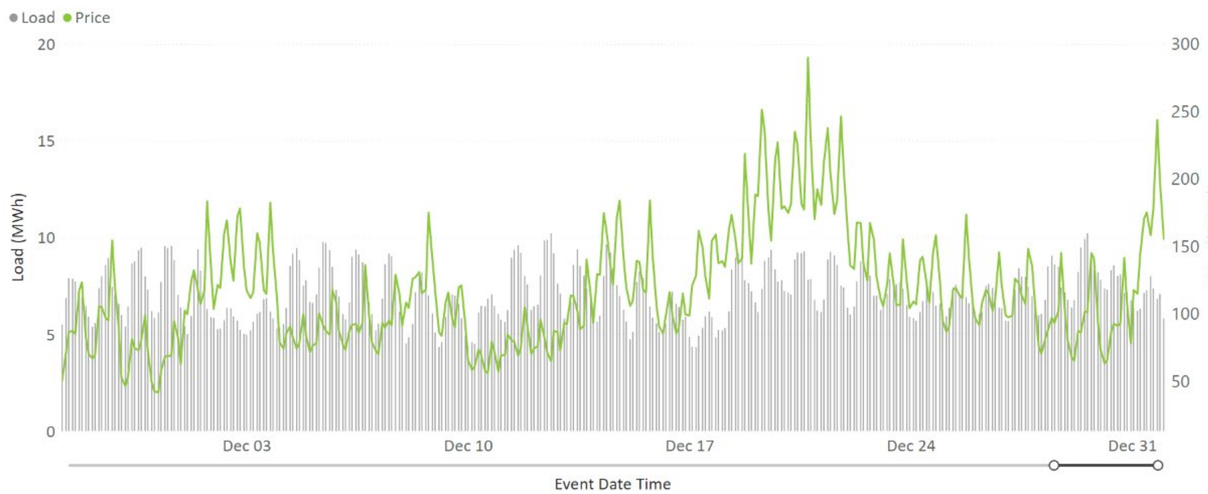




For more information on the mechanics behind Forward Price simulations refer to Appendix F (available upon request).

PowerSIMM also simulates hourly load and power prices. Figure 21 shows a sample of one iteration of PowerSIMM's stochastic hourly simulation of load and price. While summaries and figures are reported in aggregate figures, it is important to note the rigor of price simulations. Appendix E provides more content on the validations of simulation data.

Figure 21 : Sample Iteration of Simulated Hourly Loads and Prices



Non-Energy Wholesale Costs

In addition to modeling energy costs, Ascend also developed forecasts for a number of different non-energy cost expectations. The methodology and input assumptions for the relevant non-energy cost forecasts is discussed below:

Capacity Costs

For capacity cost of service information, a $/MWh capacity cost was estimated for each month utilizing ISONE website data on cleared auction information as well as long term Ascend Market Intelligence capacity price forecasts. Cleared auction results for capacity markets are available through May 2026 as of now. Once the next auction clears for 2026/2027, the Ascend team will update its forecast to align with the new cleared capacity auction information. Long-term Ascend Market Intelligence capacity price forecasts are updated on a regular basis after evaluating fundamental factors in ISONE that may contribute to potential changes in price expectations.

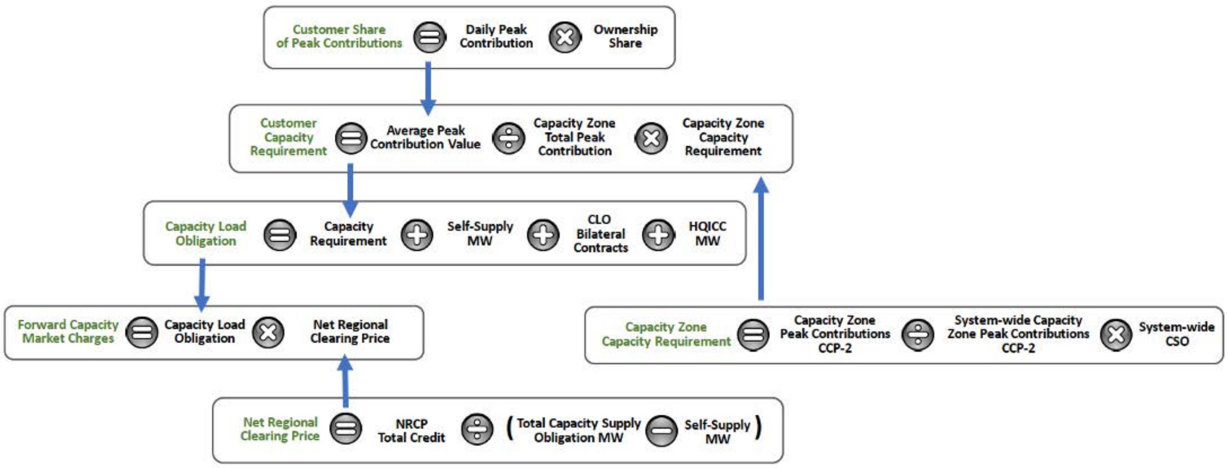
To derive a capacity cost in dollars for each Asset ID, the monthly $/MWh capacity cost value is used as an input into PowerSIMM and applied to the same MWh load forecast for each month in each iteration of the model results. These costs represent not only the expected cost of service for capacity but also the distribution of possible outcomes for capacity cost of service for the electric load owned by CPCNH.

The Forward Capacity Market (FMC) ensures that ISONE will have sufficient resources to meet future demand for electricity (Source: ISONE.com). Each year, an auction is conducted by the ISO to determine the $/kW-mo price for capacity delivered three years into the future. Thus, at any point in time, there is a known cleared capacity price for at least the next three years. For example, as of 2022, there are cleared capacity prices through May 2026. Ascend's $/kW-mo capacity price forecast starts with these cleared capacity prices and then uses Ascend's Market Intelligence team forecast for future months where prices have not cleared yet. The Market Intelligence price forecast methodology includes forecasted supply & demand of electricity in ISONE as well as future costs of new entry for various types of generation.

Once the forecast for the $/kW-mo cleared capacity price has been estimated, the next step consists on converting it into a final $/MWh rate that can be applied to all load MWh to calculate total capacity costs going forward.

As a first step, Ascend uses the ISONE website to identify zonal capacity obligations for the northern new England zone that New Hampshire is in. All the information required to determine zonal capacity obligations is available for the cleared auction periods. In the next step, settlement data and ICAP tag information for each utility is obtained from the utility websites to identify how much unaccounted for energy is in the ICAP tags. The utility MWs are then used to forecast the zonal capacity obligation for each utility by class (Small/Large). These obligations are applied to the $/kW-mo capacity price to estimate capacity costs in dollars. These are then divided into the wholesale MWh for each utility to arrive at a $/MWh capacity price. The various elements considered in the modeling of capacity $/MWh price assumptions are shown in Figure 22 below. An additional assumption is that the factors contributing to converting $/kW-mo capacity prices into $/MWh beyond the cleared capacity market are consistent with the last cleared auction information.

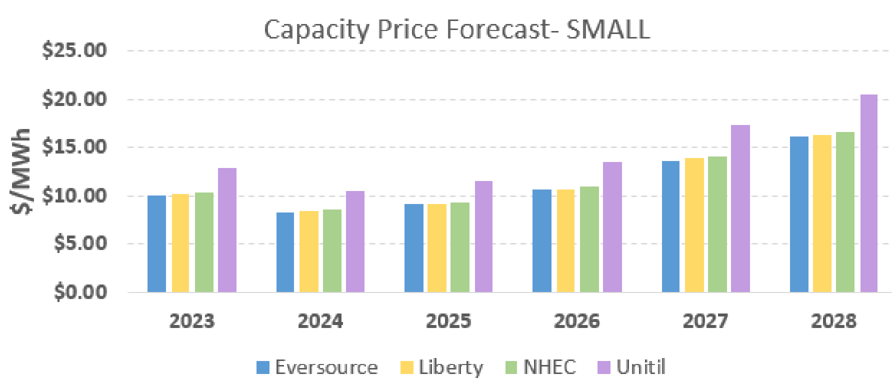
Figure 22: Elements considered to model capacity $/MWh price assumptions

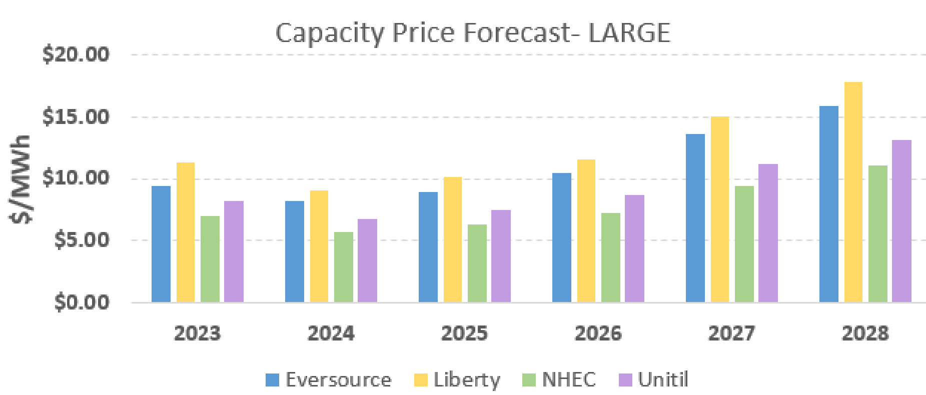


source: ISO-NE tariff

Capacity price forecast ($/MWh) for Small and Large Segments by Utility are shown in Figure 23

Figure 23: Capacity Price Forecast for Small and Large Segments





Ancillary Markets

Ancillary Market modeling includes the following cost components that are charged to electricity providers: Regulation, Reserves (Forward & Real-Time), and Financial Transmission Auction Rights.

The Regulation market pays generators that can increase or decrease supply every four seconds. This includes assets that can be controlled by the ISO automatically. Reserve markets are for assets that the ISO needs to be ready to generate if needed but that might not actually turn on and thus need to be compensated outside of the energy markets for the costs associated with being ready to turn on at short notice. Financial transmission rights are related to congestion between two different price locations.

All of these markets have payments that are paid to generators by the ISO and then charged to load owners based on how much electric load they serve. While these costs are significantly smaller than energy and capacity market costs, it is still important to include them as costs in the analysis.

For this Technical Assessment, a $/MWh price that represents ancillary costs is input into the model. The starting point is the average of the last 12 months of ancillary costs in the wholesale market report for New Hampshire on ISONE website (Source: https://www.iso-ne.com/static-assets/documents/2022/09/2022_08_wlc.pdf). Figure 24 shows NH Load Zone Cost Components for All hours, On Peak and Off Peak. The initial price is adjusted year over year at the same rate of change used in Ascend's Market Intelligence ancillary price forecast for generators in ISONE. The Market Intelligence forecast is developed by looking at a variety of fundamental factors that impact ancillary markets in ISONE.

Figure 24: NH Load Zone Wholesale Load Cost Component

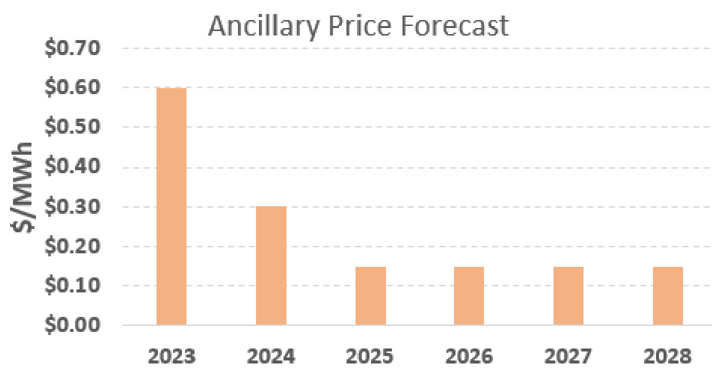
3.3.2 New Hampshire Load Zone Wholesale Load Cost Components, Last 13 Months

Component (All Hours)	AUG2021	SEP2021	OCT2021	NOV2021	DEC2021	JAN2022	FEB2022	MAR2022	APR2022	MAY2022	JUN2022	JUL2022	AUG2022
Total Wholesale Rate ($/MWh)	$58.02	$54.84	$64.52	$67.47	$68.15	$156.48	$117.73	$74.22	$66.40	$86.09	$87.24	$106.54	$109.73
Energy	$49.59	$46.86	$56.35	$59.39	$59.96	$148.63	$109.31	$66.14	$58.36	$74.08	$72.31	$91.72	$96.78
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$0.84	$0.42	$0.79	$0.73	$0.95	$1.27	$1.11	$0.86	$0.64	$1.45	$0.82	$2.50	$1.38
Ancillary Markets	$0.62	$0.43	$0.42	$0.45	$0.41	$0.60	$0.59	$0.58	$0.43	$0.57	$1.35	$1.63	$1.27
Misc Credit/Charge	($0.24)	($0.31)	($0.28)	($0.46)	($0.54)	($1.20)	($1.14)	($0.63)	($0.42)	($0.38)	($0.40)	($0.47)	($0.68)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(1,139,651)	(899,494)	(864,897)	(892,934)	(1,009,920)	(1,094,003)	(928,288)	(938,240)	(815,101)	(876,000)	(909,130)	(1,122,788)	(1,136,920)
Total Cost	$66,123,467	$49,327,165	$55,802,653	$60,250,655	$68,830,765	$171,186,534	$109,283,328	$69,636,492	$54,122,619	$75,412,536	$79,309,668	$119,621,435	$124,754,102
Component (On Peak)	**AUG2021**	**SEP2021**	**OCT2021**	**NOV2021**	**DEC2021**	**JAN2022**	**FEB2022**	**MAR2022**	**APR2022**	**MAY2022**	**JUN2022**	**JUL2022**	**AUG2022**
Total Wholesale Rate ($/MWh)	$70.63	$60.14	$71.95	$70.84	$73.91	$169.99	$123.19	$74.12	$69.90	$94.09	$92.26	$125.34	$122.04
Energy	$61.60	$51.98	$63.53	$62.50	$65.61	$161.75	$114.78	$65.75	$61.82	$79.46	$76.33	$109.32	$108.26
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$1.02	$0.39	$0.83	$0.85	$1.00	$1.53	$0.93	$0.95	$0.52	$1.77	$0.70	$2.52	$1.42
Ancillary Markets	$1.07	$0.68	$0.65	$0.62	$0.53	$0.82	$0.81	$0.81	$0.62	$0.79	$2.55	$2.92	$2.22
Misc Credit/Charge	($0.29)	($0.35)	($0.31)	($0.49)	($0.60)	($1.28)	($1.19)	($0.67)	($0.46)	($0.42)	($0.47)	($0.57)	($0.84)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(620,406)	(473,952)	(439,504)	(458,803)	(547,897)	(537,744)	(476,623)	(505,516)	(416,909)	(429,765)	(500,310)	(554,588)	(636,013)
Total Cost	$43,816,412	$28,502,192	$31,620,135	$32,502,500	$40,493,725	$91,409,858	$58,713,918	$37,466,739	$29,140,384	$40,435,510	$46,157,539	$69,511,394	$77,621,077
Component (Off Peak)	**AUG2021**	**SEP2021**	**OCT2021**	**NOV2021**	**DEC2021**	**JAN2022**	**FEB2022**	**MAR2022**	**APR2022**	**MAY2022**	**JUN2022**	**JUL2022**	**AUG2022**
Total Wholesale Rate ($/MWh)	$46.70	$50.20	$58.40	$64.54	$62.52	$145.35	$112.76	$74.32	$63.34	$79.50	$82.43	$92.35	$97.68
Energy	$38.81	$42.38	$50.44	$56.68	$54.44	$137.83	$104.34	$66.52	$55.34	$69.65	$68.47	$78.45	$85.54
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$0.67	$0.45	$0.76	$0.62	$0.91	$1.05	$1.27	$0.78	$0.74	$1.18	$0.93	$2.48	$1.33
Ancillary Markets	$0.21	$0.21	$0.23	$0.30	$0.29	$0.43	$0.39	$0.35	$0.27	$0.38	$0.21	$0.66	$0.33
Misc Credit/Charge	($0.20)	($0.27)	($0.27)	($0.43)	($0.48)	($1.13)	($1.10)	($0.59)	($0.39)	($0.35)	($0.33)	($0.39)	($0.51)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(519,245)	(425,542)	(425,393)	(434,132)	(462,023)	(556,258)	(451,665)	(432,723)	(398,191)	(446,235)	(408,820)	(568,200)	(500,907)
Total Cost	$24,249,988	$21,363,317	$24,844,737	$28,017,267	$28,887,615	$80,852,764	$50,929,980	$32,161,293	$25,221,702	$35,475,252	$33,700,742	$52,474,183	$48,927,862

Source: ISONE.com

Ancillary price forecasts ($/MWh) for 2023 to 2028 are shown in Figure 25

Figure 25: Ancillary Price Forecast ($/MWh)



RPS Compliance Costs

In 2007, the New Hampshire Department of Energy enacted a Renewable Portfolio Standard requirement which requires each electricity provider to purchase a certain amount of renewable supply to serve its customers' loads. The percentage requirement information, as well as information on historical prices for compliance payments for those entities that do not purchase RECs (renewable energy credits) or own enough renewable generation to meet their requirements can be found online (Renewable Portfolio Standard | NH Department of Energy). Figure 26 shows Renewable Portfolio Standard Obligations by Year by Class.

Figure 26: Renewable Portfolio Standard Obligations by Year

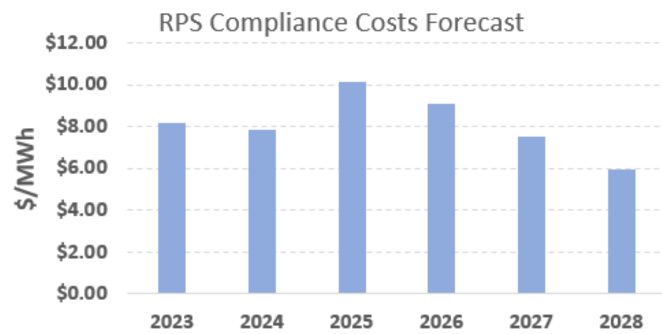
Renewable Portfolio Standard Obligations

Calendar Year	Total RPS Requirement	Class I Non-Thermal*	Class I Thermal	Total Class I	Class II	Class III	Class IV
2008	**4.00%**	0.00%	0.00%	**0.00%**	**0.00%**	**3.50%**	**0.50%**
2009	**6.00%**	0.50%	0.00%	**0.50%**	**0.00%**	**4.50%**	**1.00%**
2010	**7.54%**	1.00%	0.00%	**1.00%**	**0.04%**	**5.50%**	**1.00%**
2011	**9.58%**	2.00%	0.00%	**2.00%**	**0.08%**	**6.50%**	**1.00%**
2012	**5.55%**	3.00%	0.00%	**3.00%**	**0.15%**	**1.40%**	**1.00%**
2013	**5.80%**	3.80%	0.00%	**3.80%**	**0.20%**	**0.50%**	**1.30%**
2014	**7.20%**	4.60%	0.40%	**5.00%**	**0.30%**	**0.50%**	**1.40%**
2015	**8.30%**	5.40%	0.60%	**6.00%**	**0.30%**	**0.50%**	**1.50%**
2016	**8.50%**	5.60%	0.60%	**6.20%**	**0.30%**	**0.50%**	**1.50%**
2017	**17.60%**	6.80%	1.00%	**7.80%**	**0.30%**	**8.00%**	**1.50%**
2018	**18.70%**	7.50%	1.20%	**8.70%**	**0.50%**	**8.00%**	**1.50%**
2019	**19.70%**	8.20%	1.40%	**9.60%**	**0.60%**	**8.00%**	**1.50%**
2020	**14.70%**	8.90%	1.60%	**10.50%**	**0.70%**	**2.00%**	**1.50%**
2021	**14.60%**	9.60%	1.80%	**11.40%**	**0.70%**	**1.00%**	**1.50%**
2022	**22.50%**	10.30%	2.00%	**12.30%**	**0.70%**	**8.00%**	**1.50%**
2023	**23.40%**	11.00%	2.20%	**13.20%**	**0.70%**	**8.00%**	**1.50%**
2024	**24.30%**	11.90%	2.20%	**14.10%**	**0.70%**	**8.00%**	**1.50%**
2025 and thereafter	**25.20%**	12.80%	2.20%	**15.00%**	**0.70%**	**8.00%**	**1.50%**

Source: energy.nh.gov

In this Technical Assessment, an RPS requirement percentage was applied to Ascend's Market Intelligence forecast for REC prices in ISONE to create a $/MWh price that can be applied to all load MWh owned. Ascend's REC price forecasts are developed by modeling expected supply and demand for renewables over time. RPS compliance cost forecasts from 2023 to 2028 are shown in Figure 27

Figure 27: RPS Compliance Costs Forecast ($/MWh)



Other Costs

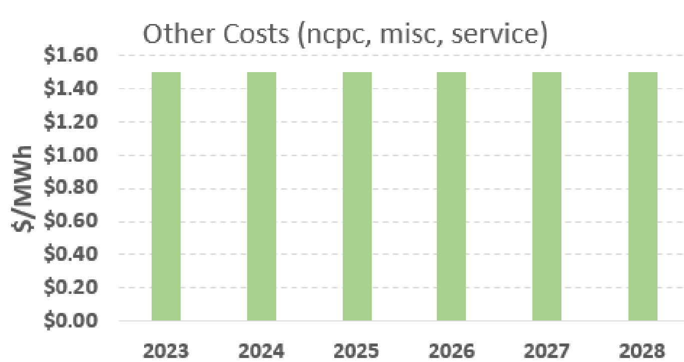
Net Commitment Period Compensation (NCPC), Miscellaneous Charges, and Wholesale Market Service Charges are also forecasted as costs in this Technical Assessment.

According to ISONE, "**NCPC** is the payment to a market participant for its generator or external transaction that did not recover its effective offer costs from the energy market during an operating day. The **NCPC** payment is intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule." (Source: Net Commitment-Period Compensation (iso-ne.com)). These payments are made by the ISO to generators and then charged by the ISO to load owners.

Miscellaneous Charges and Wholesale Service Charges represent other costs that load owners pay to the ISO. The assumptions for these costs were developed taking the average of the last 12 months in the New Hampshire Wholesale Load cost report found on ISONE's website. Given that these costs are small and do not vary much month to month, these costs are assumed to remain constant in all future months of the forecast. These costs are applied as a $/MWh value to all load MWh owned.

Others cost forecasts ($/MWh), including NCPC, miscellaneous and other service are shown in Figure 28

Figure 28: Other Costs (NCPC, Miscellaneous, Wholesale Market Service Charges)



Non-Wholesale Operating Costs

Ascend worked with CPCNH regarding its staffing, vendor and general overhead budgeting to comprehensively include all costs in the Technical Assessment. The following is a brief overview of those assumptions which were held static across scenarios.

Operating Budget Assumptions

Staffing

CPCNH has identified initial roles for 11 staff members it projects to hire over the 30 months of operations. CPCNH is actively recruiting a CEO targeting March 2023 onboarding. Six other positions are slated to start in 2023, with the remaining four in 2025. This hiring is realistic and prudent as CPCNH builds in-house capabilities. While not tested in scenarios, CPCNH financials should be able to withstand a more aggressive hiring pace should the various considerations learned in the initial months and year of operations inform changes to the expected hiring shown in Figure 29.

Figure 29: Start Date Assumptions for

Staff Starts	
Mar-23	CEO
May-23	CFO
Jul-23	General Counsel
Jul-23	Director, Policy & Regulatory Affairs
Jul-25	Director, Technology & Analytics
Jul-23	Director, Marketing & Customer Services
Sep-23	Strategic Accounts Manager
Jun-25	Power Resources Manager
Sep-23	Analyst 1
Sep-25	Analyst 2
Sep-25	Analyst 3

Operating Costs

Figure 30 shows CPCNH's operational costs based on total dollars or unit costs. When those costs are variable, these elements are incorporated in the financial model to fluctuate with the customer counts and changes by scenario.

Figure 30: CPCNH Operational Cost Assumptions

	2022	2023	2024	2025	2026	2027	2028	
Non-Contracted Cost Increase Assumption		6.4%	6.2%	5.0%	4.2%	4.0%	4.0%	
Overhead								
Office & Equipment		$30,000	$31,847	$33,424	$34,819	$36,208	$37,653	
Miscellaneous Overhead		$10,000	$10,616	$11,141	$11,606	$12,069	$12,551	
Outreach & Communications Materials								
Enrollment Mailers (enrollments & churn)		$1	$1	$1	$1	$1	$1	***$/MWh***
Events and Marketing		$20,000	$30,000	$15,000	$15,000	$15,000	$15,000	$
Portfolio Risk Management & Operations				**applied Oct 24 onward**		Assume 1/3 cost after 36th month of Ascend service		
Ascend Analytics		$82,062	$87,114	$91,428	$95,244			***$/Month***
LSE		$45,000	$60,000	$240,000	$240,000	$240,000	$240,000	***Annualized Cost***
Scheduling & ISO Credit Support		$1.00	$0.50	$0.45	$0.40	$1.00	$1.00	***$/MWh***
Vendor Operating Credit $2.5MM (First 18 Months)		12.5%	12.5%	22.5%	22.5%	22.5%	22.5%	***Rate on Loan (4.5%+Prime)***
Vendor Support Line of Credit $1MM (First 18 Months)		12.5%	12.5%	22.5%	22.5%	22.5%	22.5%	***Rate on Loan (4.5%+Prime)***
Other Operations								
Calpine (Platform, Utility Data, Billing)		$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	***Cost Per Meter***
	OR	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	***Cost Per Meter***
	plus	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	***Cost Per Customer Per Month***
Support Services								
Accounting and Audits		$140,000	$148,618	$155,979	$162,488	$168,971	$175,713	***Annualized Cost***
Marketing and Branding		$150,000	$159,234	$167,120	$174,094	$181,040	$188,264	***Annualized Cost***
Legal Advice and Regulatory Engagement (DWGP)		$300,066	$318,538	$334,314	$0	$0	$0	***Annualized Cost***
Community Choice Partners		$0	$0	$0	$0	$0	$0	
Herdon Enterprises		$121,478	$128,956	$135,343	$140,991	$146,616	$152,466	
Clean Energy New Hampshire		$76,600	$81,315	$85,343	$88,904	$92,451	$96,140	
Utility Fees		$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	***Cost Per Customer Per Month***
NEPOOL Expenses		$0	$19,200	$19,200	$19,200	$19,200	$19,200	***Cost Per Year***

Deferred Compensation Repayment

CPCNH relies on five vendors that have committed to support pre-launch activities in exchange for payment after launch of CPA service, on the at-risk, deferred compensation basis assumed below:

Figure 31: Aggregate Deferred Compensation Repayment

Aggregate Deferred Compensation Repayment			
2023	**2024**	**2025**	**2026**
$485,903	$796,286	$572,831	$183,095

Total Deferred Compensation Dollars	$2,038,116
Base Case MWh from Five Year Allocation Period	10,620,659
Projected $/MWh Cost of Deferred Start Up Cost	$0.19
Projected ¢/kWh Cost of Deferred Start Up Cost	0.019¢

Cash Flow Assumptions

Across all scenarios and stochastics, static Line of Credit (LOC) assumptions are utilized in the modeling. Modeled draws may differ across scenarios and stochastics but the assumptions on the cost of various facilities are as follows:

- LSE LOC for ISO-NE initial float and collateral for the ISO credit support listed in the prior operating cost section, assumed in place from launch to be utilized through March 2024.
- Vendor Operating line of credit at Prime + 4.5% for initial coverage of operating costs from launch through March 2024.
- From April 2024 onward, an expected transition to CPCNH's own Line of Credit assumed at 3-Month SOFR + 2.26%

It is worth noting that given an on-schedule launch, CPCNH establishes ample reserves such that a draw on lines of credit is not needed beyond the first year of operation in financial modeling. It is also worth noting that CPCNH may elect to use lines of credit to fund future activities. However, in the Technical Assessment Ascend did not attempt to weigh the qualitative factors that may lead to such a decision. Instead Ascend built the Technical Assessment model to conservatively assume CPCNH weathers poor market conditions by drawing on reserves and/or temporarily reducing customer discounts. In reality, Ascend acknowledges other strategies may be employed, but this method of assessment in the financial modeling takes a conservative approach to such conditions.

Also impacting cash flows are the fact that CPCNH customers will consume power and remit payment to utilities on the utility billing cycles. Those revenues will be lagged as the revenues are collected and funds are transfer to CPCNH's secured revenue account. Ascend estimated the retail billing lag factors shown in Figure 32 for its adjustment of revenue cash flows:

Figure 32: Retail Billing Lag Factors

	Month 1	Month 2	Month 3
Retail Billing Lag Factors	2%	60%	38%

Local Projects

A major value proposition for CPCNH is its ability to bring local projects to the forefront through the market-based pilot mechanism authorized under Senate Bill 321. SB321 permits CPCNH to launch up to 2 MW of capacity in each utility service territory. These projects benefit from not only renewable production for energy and RPS credits, but also avoided capacity and transmission costs.

Base Case:

- 2 MW of Local Projects

Alternate Scenarios:

- A full 8 MW up to the SB321 Cap
- 10 MW additional for a total of 18 MW assuming the SB321 cap may be lifted

The Tables in Figure 33, Figure 34 and Figure 35 are excerpts from the base scenarios for the purpose of highlighting the value of Local projects to CPCNH and to affirm the competitive advantage that local projects provide to the Coalition.

Figure 33: Base Case Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.00**	**$0.09**	**$0.19**	**$0.19**	**$0.19**	**$0.21**
Market Energy Value	$0.00	$0.19	$0.27	$0.24	$0.23	$0.25
Renewable Energy Credit Value	$0.00	$0.11	$0.19	$0.15	$0.12	$0.10
Capacity Credit Value	$0.00	$0.00	$0.02	$0.04	$0.05	$0.06
Transmission Credit Value	$0.00	$0.17	$0.23	$0.22	$0.24	$0.26
PPA Cost	$0.00	$0.39	$0.52	$0.47	$0.46	$0.46
Local Projects Revenue (Cost Reduction)	**$0**	**$98,108**	**$343,541**	**$378,603**	**$388,564**	**$421,166**
Market Energy Value	$0	$222,182	$480,880	$480,680	$470,280	$500,820
Renewable Energy Credit Value	$0	$126,680	$331,209	$301,256	$247,283	$197,636
Capacity Credit Value	$0	$0	$40,450	$80,054	$103,694	$121,669
Transmission Credit Value	$0	$191,160	$412,906	$445,938	$481,613	$520,142
PPA Cost	$0	$441,914	$921,903	$929,326	$914,305	$919,100

Figure 34: 8 MW Scenario Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.00**	**$0.68**	**$1.13**	**$1.13**	**$1.22**	**$1.31**
Market Energy Value	$0.00	$0.36	$0.51	$0.48	$0.46	$0.49
Renewable Energy Credit Value	$0.00	$0.19	$0.34	$0.28	$0.23	$0.18
Capacity Credit Value	$0.00	$0.00	$0.09	$0.16	$0.21	$0.24
Transmission Credit Value	$0.00	$0.67	$0.94	$0.90	$0.96	$1.04
PPA Cost	$0.00	$0.53	$0.74	$0.68	$0.63	$0.63
Local Projects Revenue (Cost Reduction)	**$0**	**$779,948**	**$1,998,140**	**$2,257,873**	**$2,449,047**	**$2,634,132**
Market Energy Value	$0	$407,408	$903,068	$954,471	$913,061	$975,620
Renewable Energy Credit Value	$0	$216,688	$592,013	$561,752	$451,935	$365,948
Capacity Credit Value	$0	$0	$161,799	$320,217	$414,774	$486,675
Transmission Credit Value	$0	$764,640	$1,651,622	$1,783,752	$1,926,452	$2,080,569
PPA Cost	$0	$608,788	$1,310,361	$1,362,320	$1,257,176	$1,274,679

Figure 35: 18 MW Scenario Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.00**	**$0.68**	**$1.60**	**$2.06**	**$2.17**	**$2.28**
Market Energy Value	$0.00	$0.36	$0.74	$0.93	$0.89	$0.94
Renewable Energy Credit Value	$0.00	$0.19	$0.52	$0.58	$0.47	$0.38
Capacity Credit Value	$0.00	$0.00	$0.13	$0.24	$0.31	$0.36
Transmission Credit Value	$0.00	$0.67	$1.22	$1.43	$1.53	$1.64
PPA Cost	$0.00	$0.53	$1.01	$1.12	$1.04	$1.04
Local Projects Revenue (Cost Reduction)	**$0**	**$779,948**	**$2,814,092**	**$4,113,526**	**$4,339,874**	**$4,577,274**
Market Energy Value	$0	$407,408	$1,305,558	$1,848,341	$1,788,253	$1,880,067
Renewable Energy Credit Value	$0	$216,688	$910,656	$1,161,659	$944,841	$754,387
Capacity Credit Value	$0	$0	$231,141	$480,325	$622,162	$730,012
Transmission Credit Value	$0	$764,640	$2,153,303	$2,854,004	$3,067,875	$3,297,701
PPA Cost	$0	$608,788	$1,786,564	$2,230,803	$2,083,257	$2,084,893

Active Portfolio Management for Load Scheduling & Hedging

Ascend Analytics believes active portfolio management increases value to CPCNH. Ascend assessed technical analysis of Mass Hub forward prices and believes roughly 1.5% improvement in hedge pricing can be achieved through ongoing market monitoring to add incremental hedges when market conditions are favorable.

Further, Ascend believes that in concert with CPCNH's risk management committee, another 1% reduction in hedge cost is practical given good judgment to hedge timing can be employed beyond a 'set-it-and-forget-it' programmatically timed hedge strategy. Therefore, Ascend believes that 2.5% hedging cost reduction through active portfolio management of forward hedges is reasonable for the Technical Assessment. Ascend conducted a perfect foresight analysis on stochastic market simulation data and found, that if hedging decisions were always made at the exact best time, 20% savings is achievable. Given this upper bound, 2.5% is a conservative 'on-average' expectation.

Further, Ascend is committed to integrate its SmartBidder solutions to realize additional value from CPCNH's native short position through balancing the risk and return of day-ahead (DA) versus real-time (RT) commitments to serve CPCNH load (forming the day-ahead to real-time price spread referred to as the DART spread). Based on application of a mosaic of models that combine to probabilistic assess the DART spread, SmartBidder provides suggested quantity commitment allocation between DA and RT realization of load to market prices. The bidding strategies of SmartBidder are supplied to the LSE for submission to the ISO. Based upon historical absolute DART spreads, Ascend expects 1.5% savings over uniformly scheduling all load into the day-ahead market. The 1.5% assumed improvement in costs also follow a risk/return assessment measured through the Sharp ratio of the same or improved over the traditional all load committed in the day-ahead market.

CPCNH Technical Assessment Findings

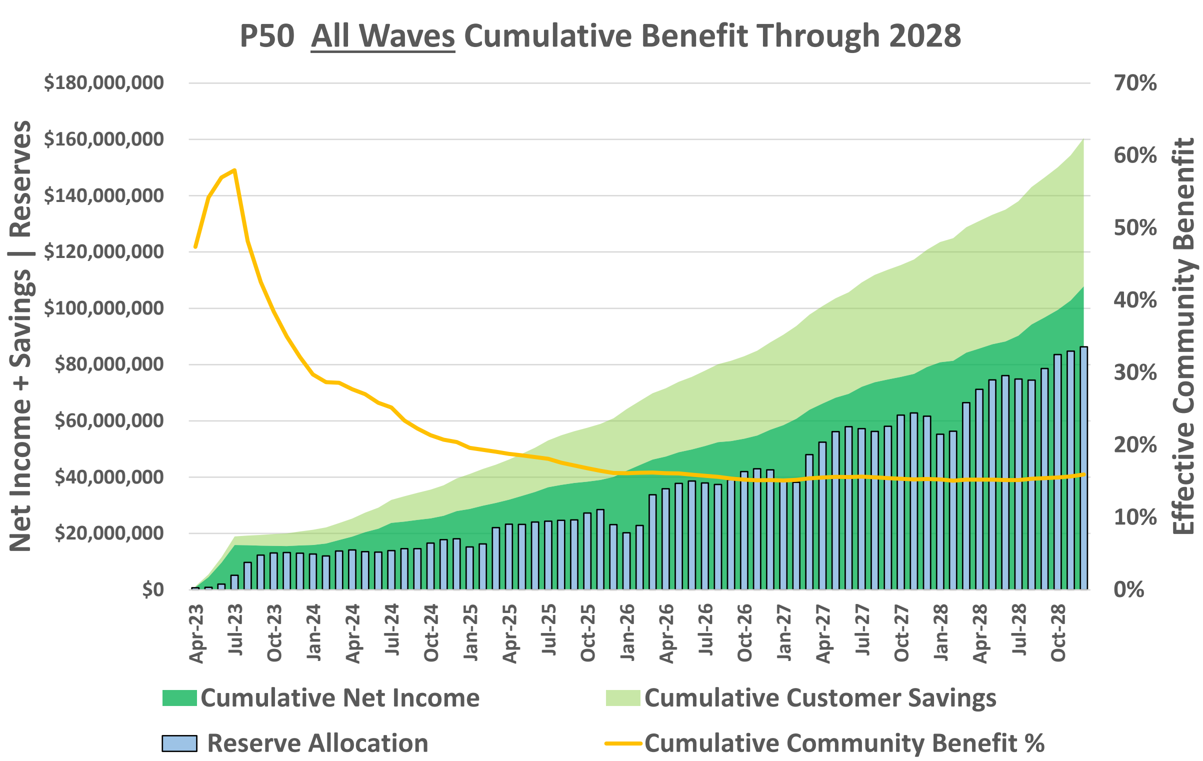
The following details the results of Ascend's analysis surrounding the various Base Case, stochastic and alternative scenario analysis. Several key metrics are assessed to convey not only potential outcomes, but potential trade-offs between events or decisions that may impact the CPCNH portfolio. While not exhaustive of possible scenarios, or combinations thereof, Ascend believes that this Technical Assessment provides sufficient review of 'what-ifs' to inform its members for a decision on whether to launch. To its knowledge, no CPA implementation assessment has ever performed comparably rigorous stochastic analysis of potential outcomes to support the launch of service.

Base Case P50

The Base Case assumptions are P50 is the 50th percentile, statistically the median across the 100 Base Case simulations performed in PowerSIMM as defined by the simulation producing the median cumulative member benefit percentage at the end of 2028. Appendix B contains detailed annual income statement information for the P50 Base Case. The following section illustrates the key takeaways from the Base Case given the assumptions and methodology highlighted in previous sections.

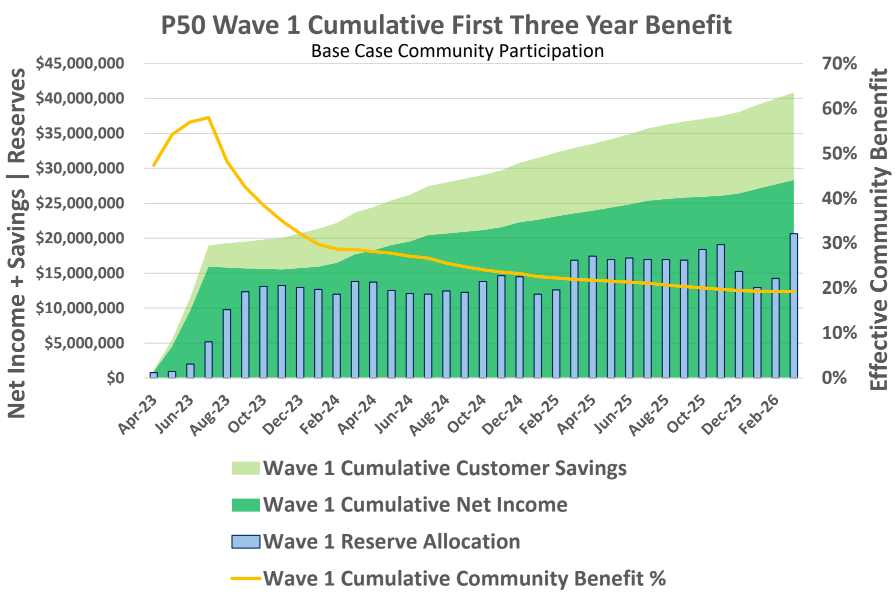
Figure 36 shows the P50 Base Case through 2028 cumulative net income, cumulative customer savings, cumulative community benefit percent metrics, and reserve allocation for initial and projected CPCNH members. Base Case finding demonstrates that by year end 2028 over $86MM in reserves will be amassed and 6-year cumulative effective community benefit will be approximately16% inclusive of nearly $55MM in customer utility bill savings.

Figure 36: P50 Base Case Cumulative Benefit through 2028 for All Waves



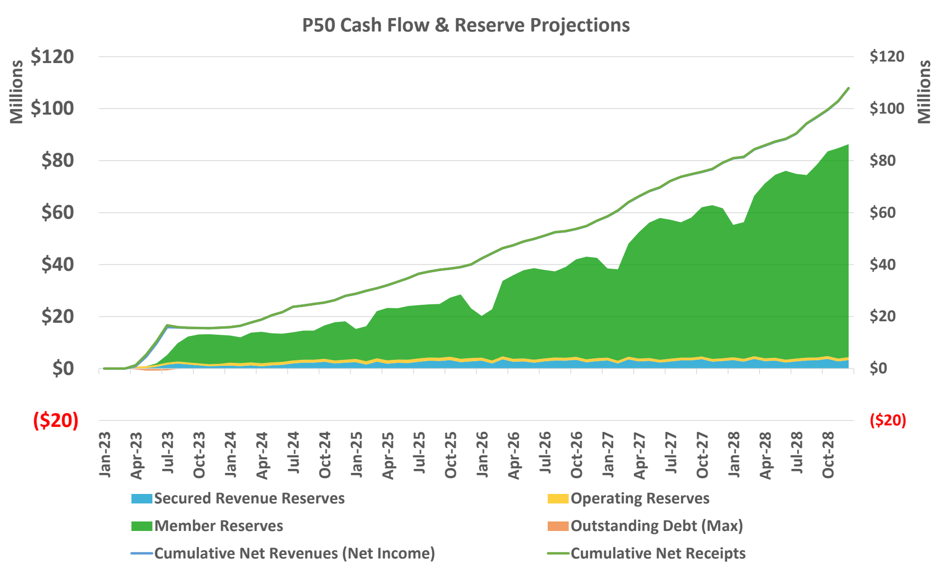
Given a decision to launch is at the discretion of initial Wave 1 members, Ascend investigated the same metrics for the Wave 1 members for just the initial 36-month commitment term. The P50 three-year cumulative net income, cumulative customer savings, cumulative community benefit % metrics for Wave 1 as well as all other reserve allocation can be seen in Figure 37. It demonstrates that after 36 months Wave 1 member allocations should be between $20-27MM with over $10MM in savings for customer utility bills equating to a 19% benefit for Wave 1 members.

Figure 37: P50 Wave 1 Cumulative First Three Year Benefit



The projection of the level of reserves can be seen in Figure 38. CPCNH member reserves are expected to grow gradually over time and reach levels to meet policy targets and provide financial stability.

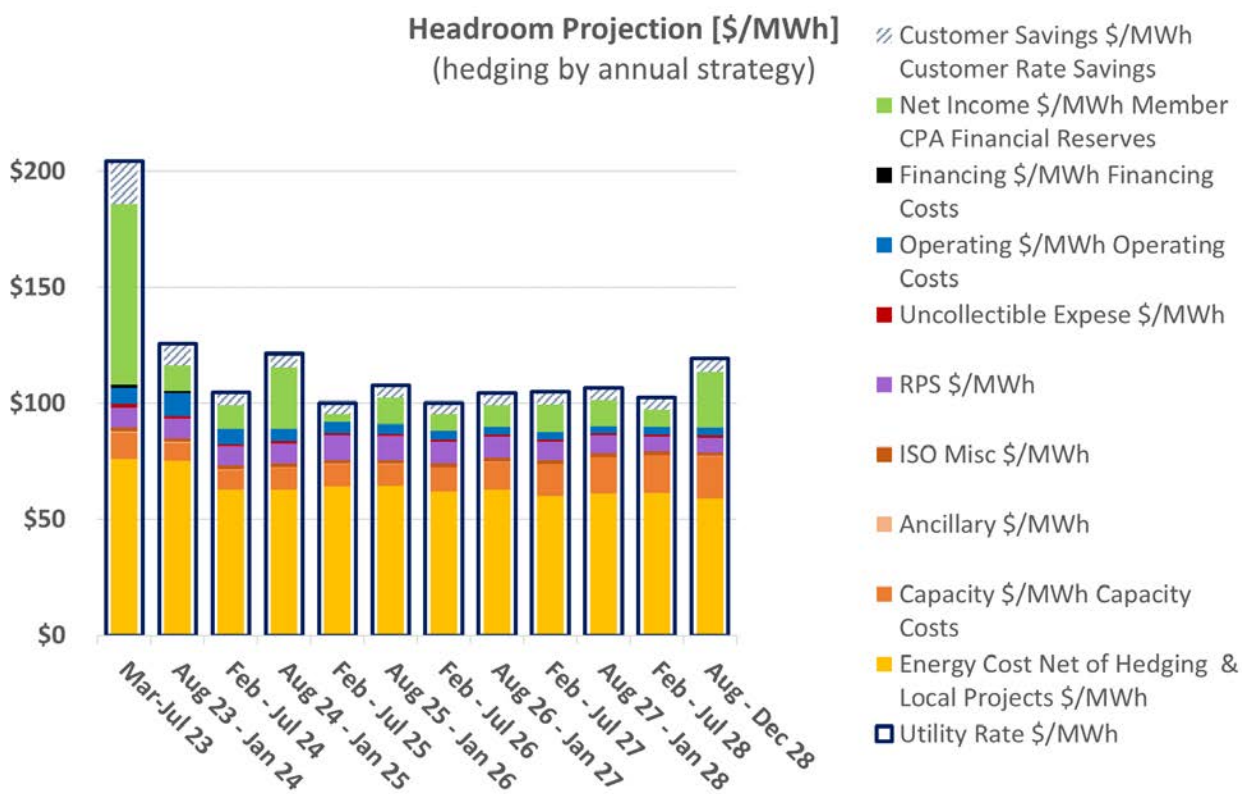
Figure 38: Reserve Projection 2023-2028

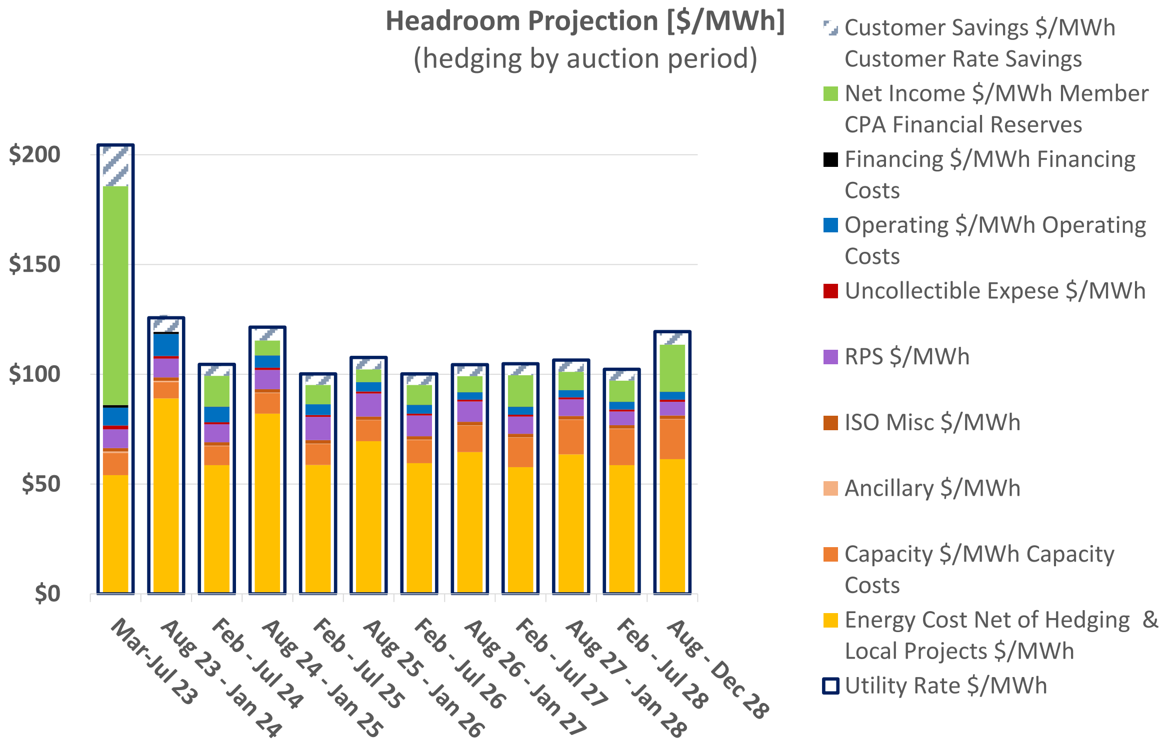


The P50 Base Case for the Annual Headroom projection measured in $/MWh is shown in Figures 39 a & b. The analysis also provides details on the different components that determine headroom levels on a yearly basis from 2023 to 2028. Two charts are shown, the first assumes annual hedging strategy and the second utility auction periods (six month) hedging strategy. Actual seasonal hedging results are likely to land between the two.

- Headroom in 2023 is high due to high market prices coupled with high utility auction premiums.
- In 2024 and 2025, headroom tightens as the forward curve show lower future prices and additional waves of participation are effectively weight averaged into the subsequent years (not exclusively giving the spring launch benefit on all CPCNH load like the first year).
- Years 2026 and 2027 are the tightest for three reasons: 1) the forward curve is at its lowest point in those years, 2) new wave volume has an even lesser impact on a weighted average basis, 3) the P50 base case is shown, which is one discrete simulation outcome (i.e., some simulations may be better, while others have negative headroom requiring rate adjustment).

Figures 39 a & b: P50 Base Case CPCNH Annual Headroom Projection ($/MWh)
(with (a) annual hedging approach and (b) auction period hedging approach)



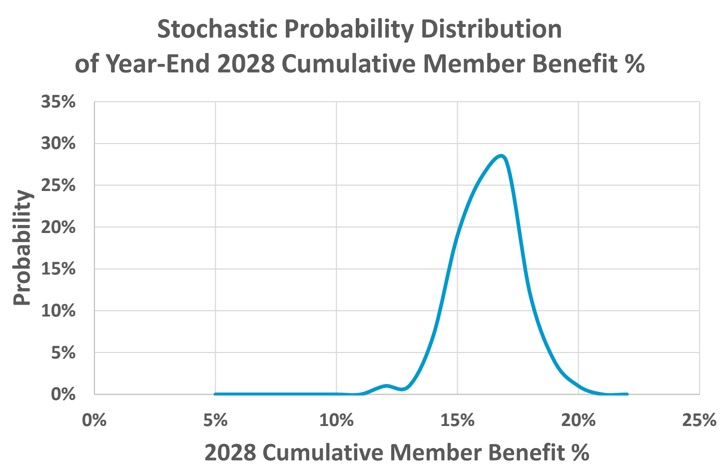


Stochastic Analysis

This section presents results from stochastic analysis to understand the expected range of outcomes for key metric over time with meaningful uncertainty.

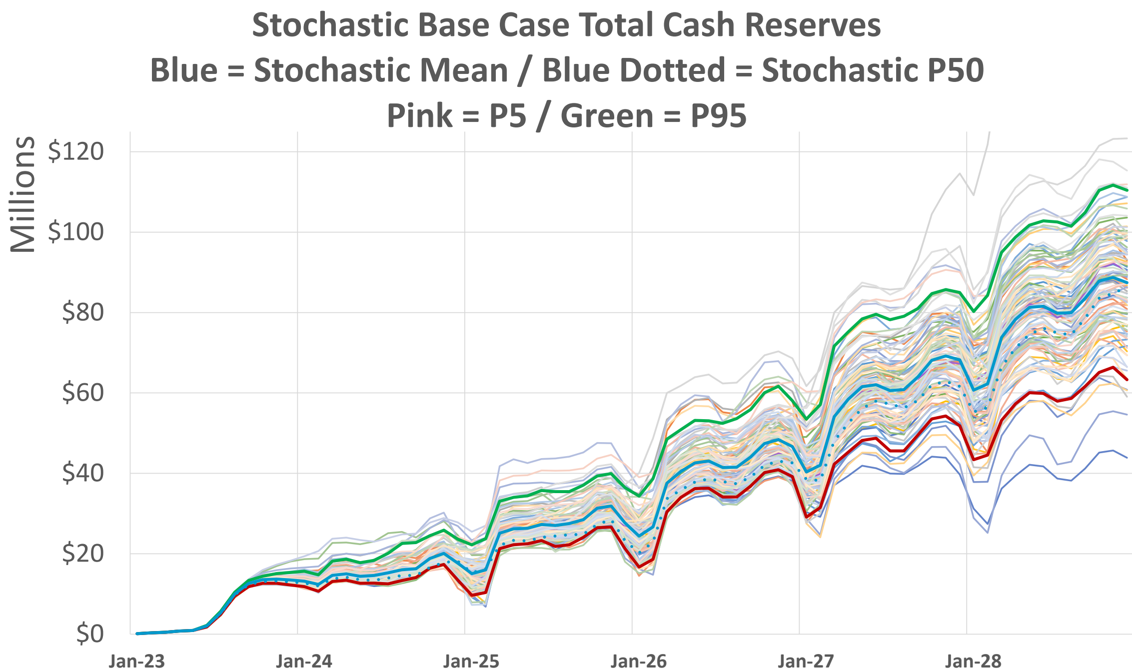
The stochastic probability distribution of year-end 2028 cumulative member benefit percentage is shown in Figure 40. The cumulative benefits average 16% ranging from 11% to slightly above 12%, and a number larger than 15% in a significant number of stochastic scenarios. This outcome assumes the 2023-2028 horizon and the base case member participation described in the assumptions section of this Assessment.

Figure 40: Stochastic Probability Distribution of Year-End 2028 Cumulative Member Benefit %



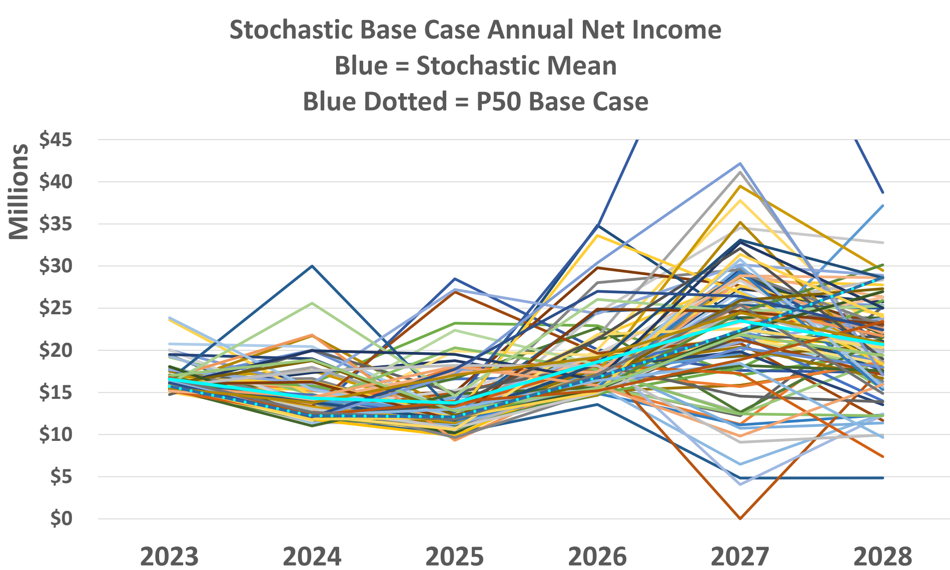
The Base Case total cash reserves by month under different stochastic scenarios over time is shown in Figure 41. Using the last simulated period results to determine the percentiles, the chart below show the stochastic mean, the stochastic P50, the P05 and P95 total cash reserves over time. It also shows each of the 100 simulations, illustrating the range of potential outcome and the rigor of the Assessment.

Figure 41: Stochastic Base Case Total Cash Reserves



The Base Case annual net income under different stochastic scenarios over time is shown in Figure 42. The stochastic mean is shown in blue. Annual Net Income is expected to be positive under most scenarios with an annual average value between $10-$25 million per year for the simulated period.

Figure 42: Stochastic Base Case Annual Net Income



The financial reserves policy sets three target levels of Joint Reserves, which shall be in addition to any financial covenants entered into by CPCNH, relative to the forecasted expense of operations as reflected in CPCNH's budget. Those target levels are:

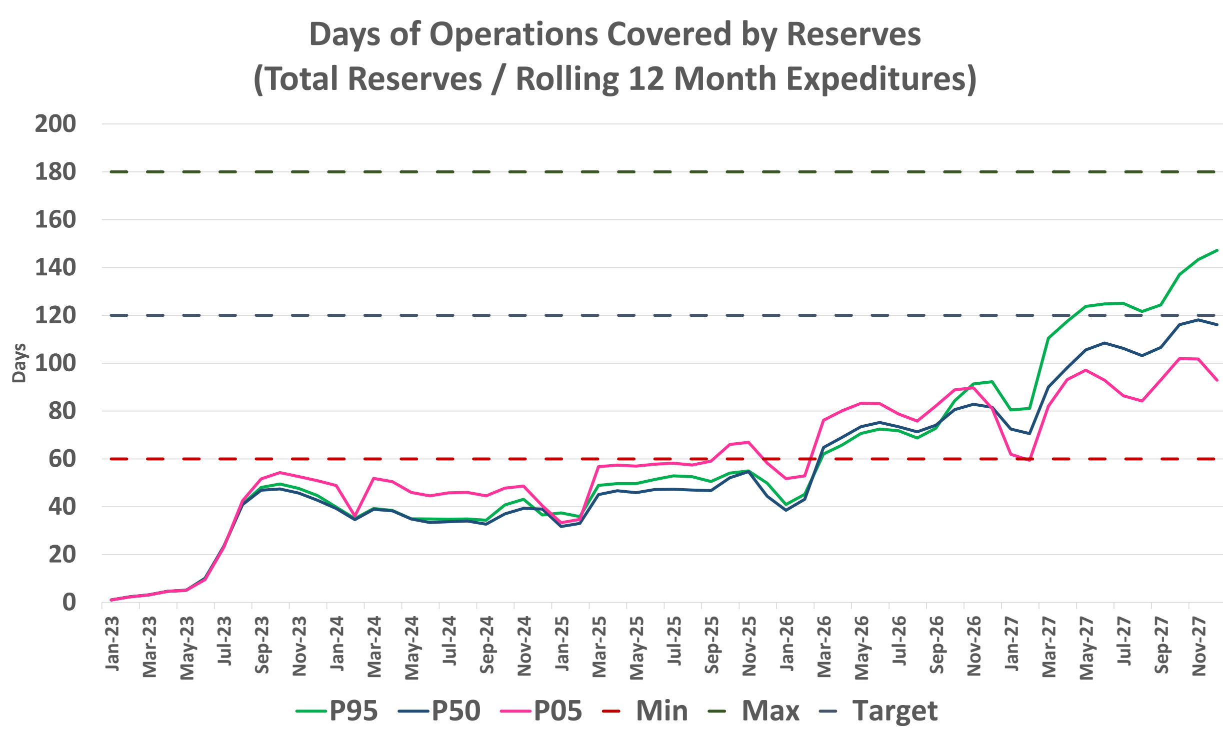
- Minimum Operating Reserve: 60 days of operations.
- Target Operating Reserve: 120 days of operations.
- Maximum Operating Reserve: 180 days of operations.

Figure 43 shows the P5, P50, P95 levels of Days of Operations Covered by Reserves as well as the Minimum, Maximum and Target levels. Based on the expected accumulation of reserves, the target levels would be met in the following timelines:

- The Minimum Operating Reserve level would be reached within 3 years.
- To Target Operating Reserve level would be reached within 5 years.

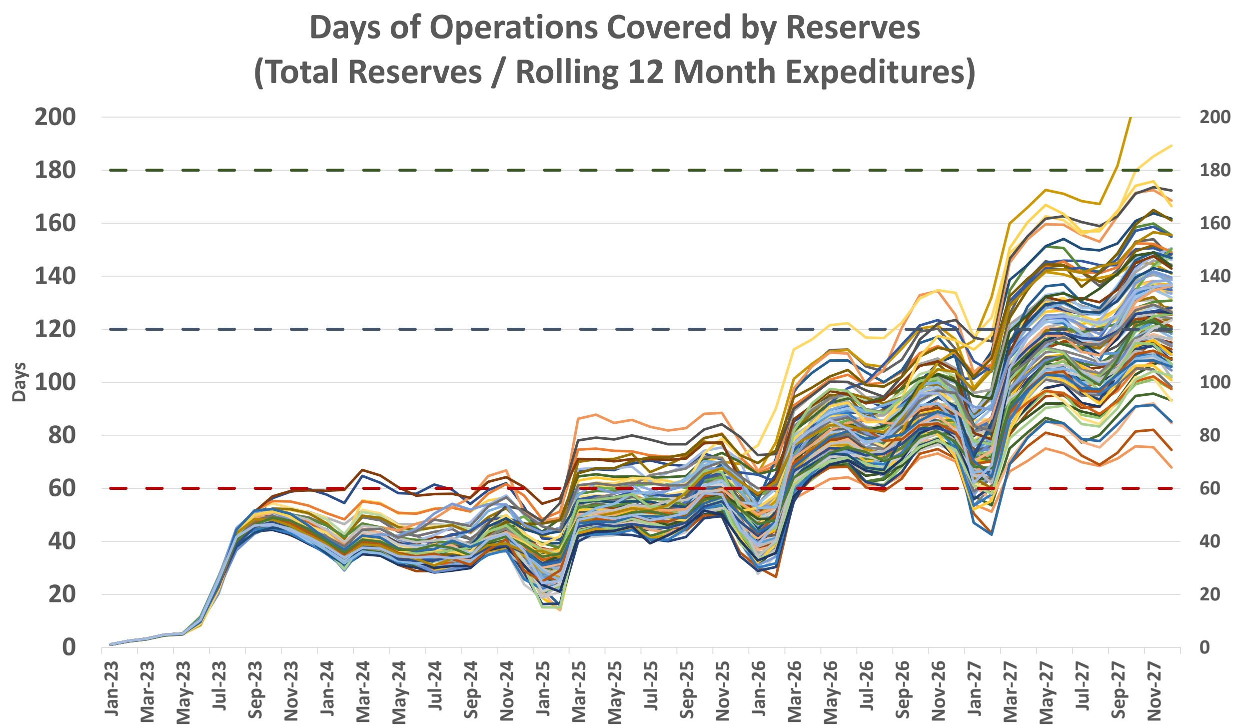
The Maximum Reserve level would provide strong protections against any significant adverse events and represents a longer-term goal.

Figure 43 : Days of Operations Covered by Reserves (P5, P50, P95, Min, Max, Target)



The stochastic scenarios of days of operations covered by reserves are presented in Figure 44. The analysis shows the level of reserves under 100 different stochastic scenarios relative to the Minimum, Target and maximum levels set in the Financial Reserves Policy. These results are based upon Base Case assumptions and do not include potential upsides like expansion of Local Projects for added contribution to reserves.

Figure 44: Stochastic Scenarios of Days of Operations Covered by Reserves



P50 Scenario Analysis

This section presents scenario analysis results around different plausible variations from the P50 case. Appendix A contains summary scorecards for the annual results of key metrics by year. In this section summary results are presented for three key cumulative metrics after 36 months and through the end of 2028. These metrics are: 1) Customer Savings, 2) Accumulated Total Reserves, 3) Effective Community Benefit Percentage.

Community Participation Scenarios

For purposes of illustrating various outcomes related to community participation, Ascend compiled the following tests against the P50 simulation. The 'what-ifs' for Wave 1 Members are important to lead in the decision to launch. Figure 45 conveys results for the initial three-year commitment period and what also for each scenario through the end of 2028. Ascend believes it important to point out the impact of delaying launch until June 2023 instead of April 2023.

Figure 45 : Cumulative Savings, Cumulative Reserves and Cumulative Effective Community Benefit under different scenarios

	3-Year Period Ending March 2026			6-Year Period Ending December 2028		
	Cumulative Savings [$MM]	Cumulative Reserves [$MM]	Cumulative Effective Community Benefit	Cumulative Savings	Cumulative Reserves	Cumulative Effective Community Benefit
P50 Base Case	$23.5	$33.7	16.2%	$52.6	$86.4	15.9%
80% of New Waves	$27.3	$38.9	16.6%	$64.6	$109.5	16.4%
No Nashua Delay	$24.6	$37.8	16.9%	$54.0	$91.1	16.3%
1 Year Nashua Delay	$20.6	$29.4	15.6%	$50.0	$82.6	15.7%
Nashua never Participates	$17.2	$23.4	15.2%	$42.0	$66.7	15.3%
Wave 1 only with Nashua	$11.9	$14.5	14.1%	$20.7	$23.1	12.7%
Wave 1 only without Nashua	$2.1	$6.1	8.7%	$3.6	$7.7	6.8%

The P50 cumulative cash reserves by each scenario considered are shown in Figure 46. The results also point out the financial impact of delaying launch until June 2023 instead of April 2023.

Figure 46: P50 Cumulative Cash Reserves by Scenario

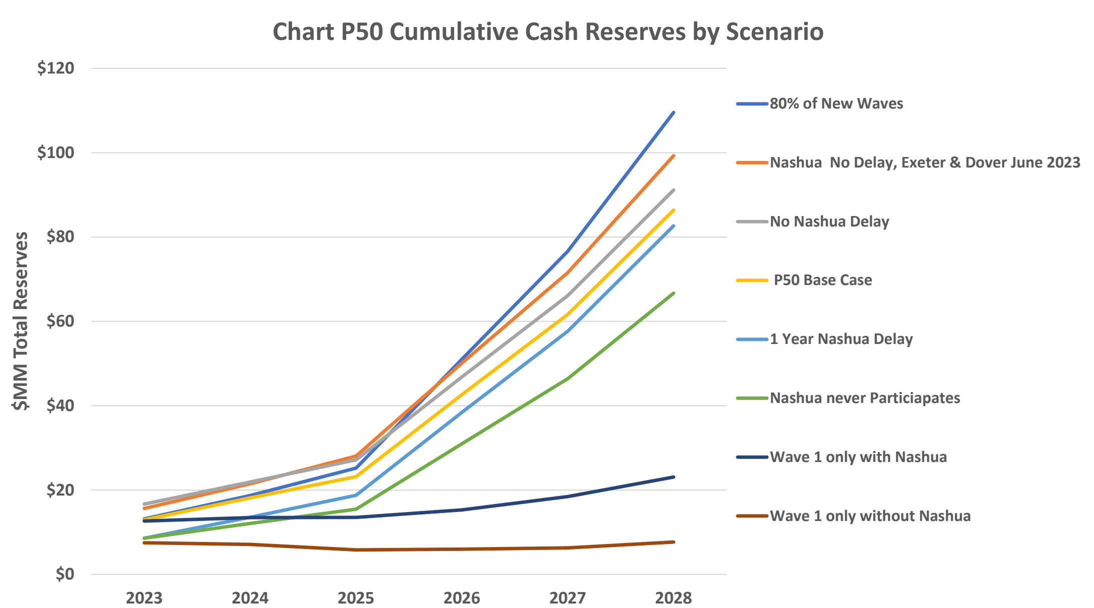
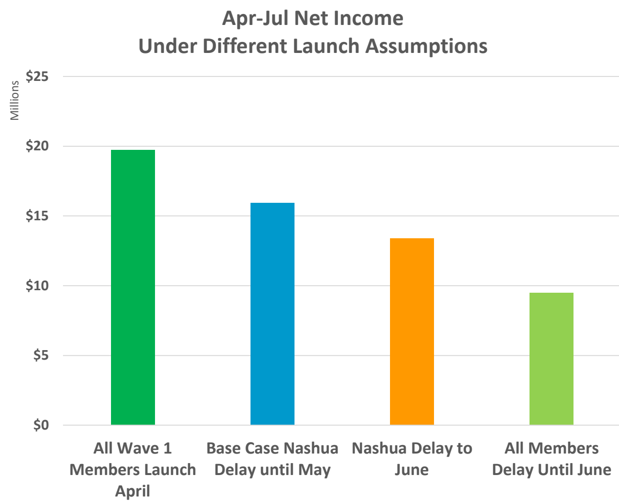


Figure 47 shows the Net Income over the first four months (April-Jul) under difference launch timing for Wave 1 and Nahua. The financial impact is also significant under the different scenarios.

Figure 47: Expected Net Income under different assumptions for April to June 2023



Ascend provides more insight below into the 3-Year period for Wave 1 members in the Base Case, a scenario where only ever Wave 1 members launch with Nashua on a 1-month delay, and only ever Wave members launch without Nashua. While these two scenarios' departures from Base Case seem unlikely, they may shed some insights into how participation levels in CPCNH may evolve over time. These two scenarios result in limited economies of scale, but it is important to note they do not produce extreme negative outcomes across the initial 3-year commitment period.

Figure 48: P50 Wave 1 Cumulative Benefit for first three years under Base Case of community participation (same as figure 34 presented earlier; here for reference)

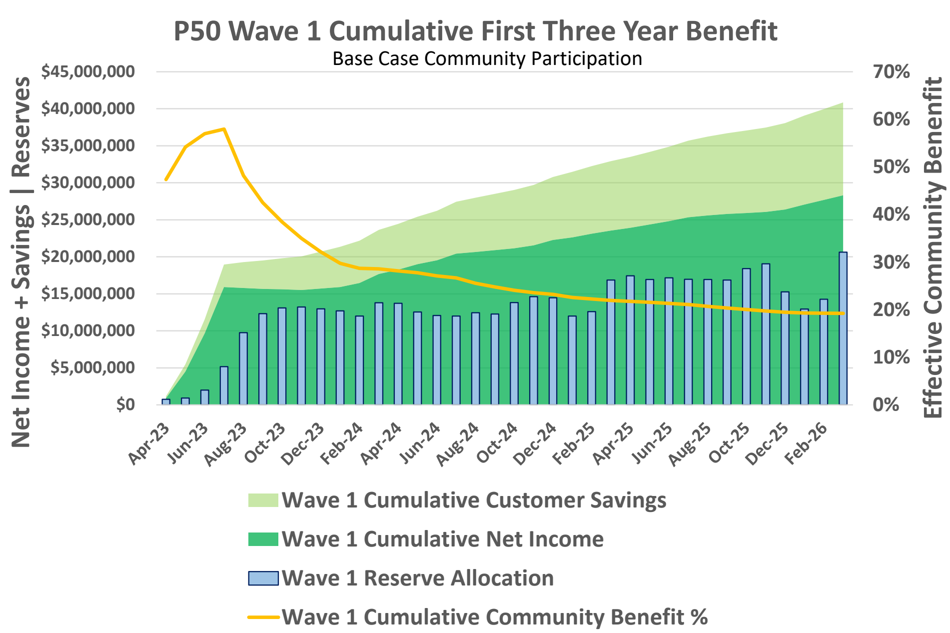


Figure 49: P50 Wave 1 Cumulative Benefit for first three years with Nashua

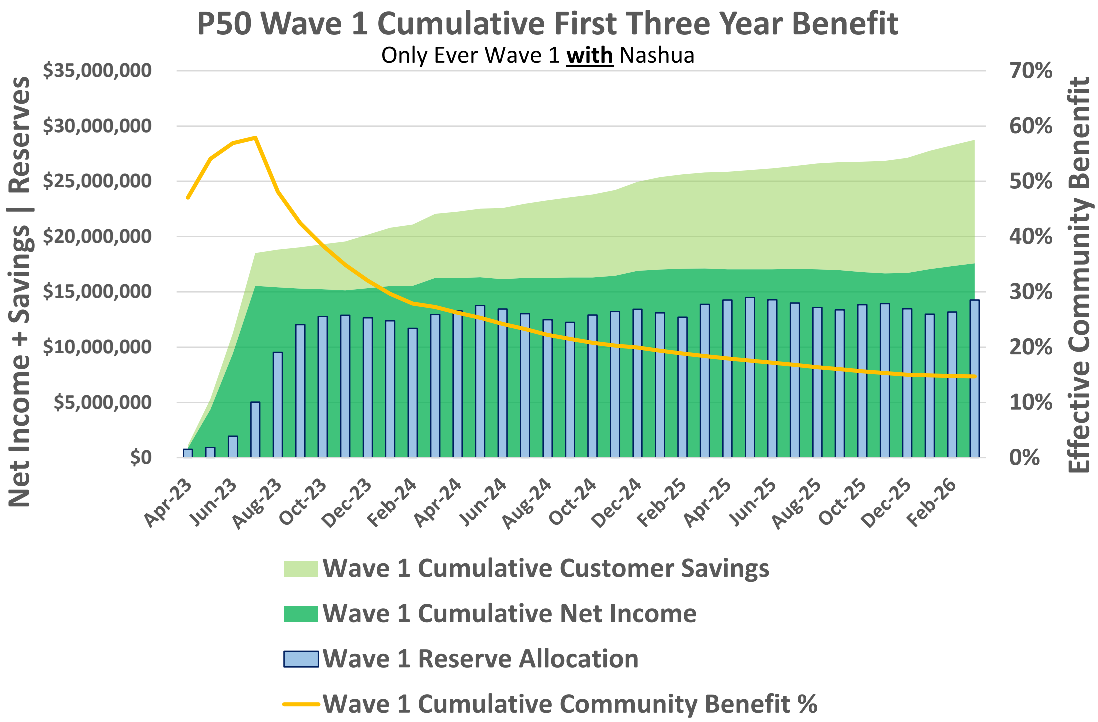
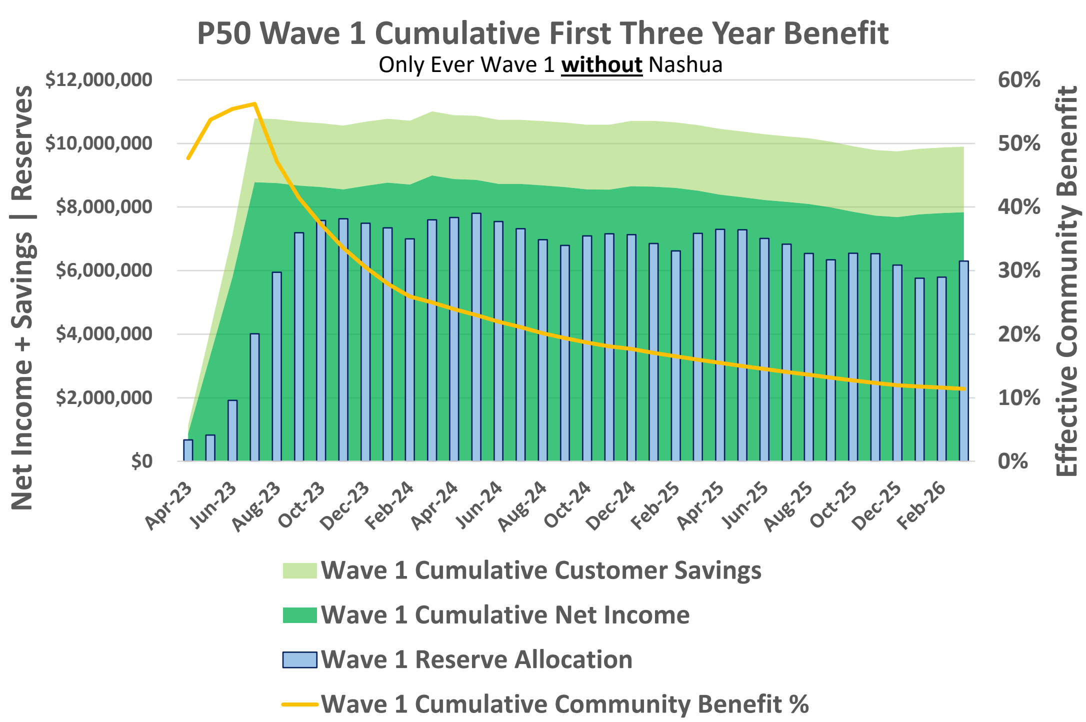


Figure 50 : P50 Wave 1 Cumulative Benefit for first three years without Nashua



Other Stress Test Scenarios

Ascend further analyzed the following scenarios relative to the P50 Base Case:

- **P50 Base Case**
  The 'P50', or median, is the middle simulation of a stochastic (100 simulation Monte Carlo analysis) in which market prices and customer load volumes vary. The P50 case represents the expected outcome given modeling and serves as an anchor for other scenarios and probabilistic outcomes. The assumptions of this case are exhaustive and should be reviewed and understood in the assumptions section of this Technical Assessment.

- **18 MW of Local Projects**

  The Base Case calls for a conservative 2 MW of local projects to be built. It is the goal of CPCNH to advocate for SB 321 2 MW per utility caps to be lifted. In this scenario, 10 MW extra in local projects is pursued, growing to a noteworthy amount of CPCNH's supply portfolio and lowering costs for customers.

- **8 MW of Local Projects**

  Given the base case calls for a conservative 2 MW of local projects, this scenario assumes CPCNH is able to fully leverage local projects under current SB 321 limits to not miss out on any value allowed under current regulations.

- **33% RPS Target**

  New Hampshire's Renewable Portfolio Standard (RPS) calls for a renewable goal of approximately 25% over time. This scenario supposes that CPCNH over-complies with the standard and procures 33% RPS at a modest incremental expense as the default service offering with no incremental rate increase from the base 5% discount assumption.

- **7.5% Discount to Utility (instead of 5%)**

  The Base Case assumption is that CPCNH offers a 7.5% discount to Eversource for all customers (initially), followed by 7.5% to each utility and then 5% thereafter to customer utility bill generation supply. This scenario modifies this base case assumption to suppose a 7.5% discount is made the default offering for the duration of the entire forecast.

- **Lower Auction Premium**

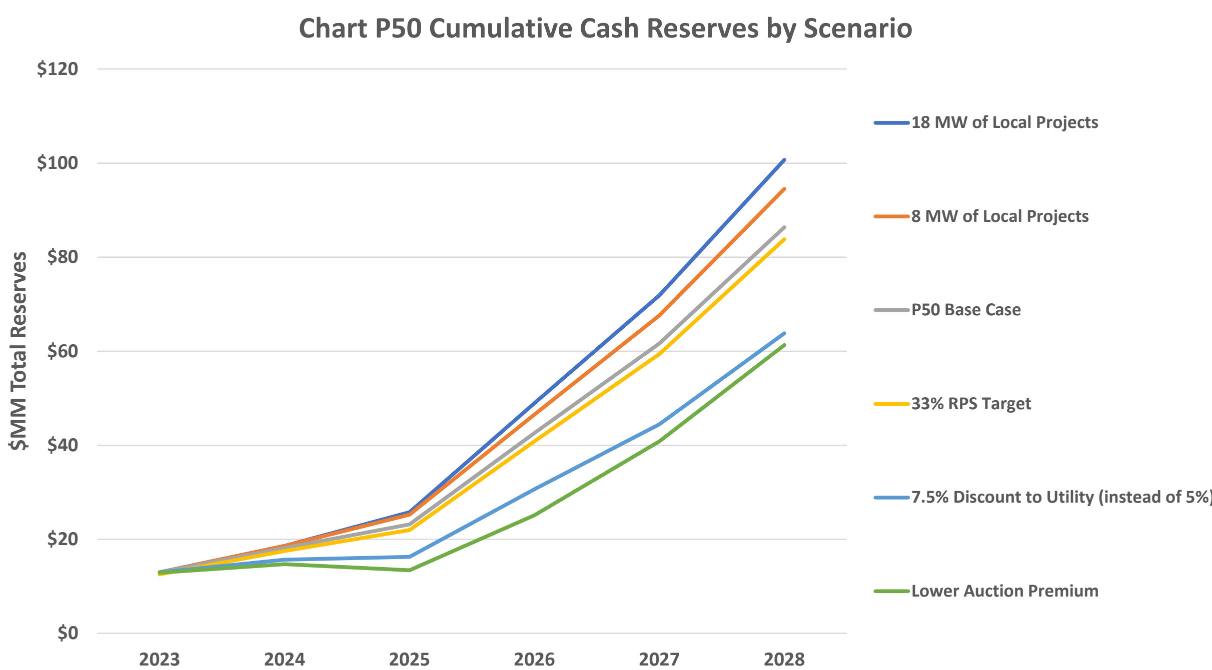
  The Base Case assumes that future utility auctions clear with the average auction premiums observed in the last three small asset ID (residential/small commercial) auctions of each utility. Market option quote data suggest that the premiums will be 25% lower if regulatory change is implemented to shorten the PUC approval process (which currently poses added risk for winning suppliers). This scenario lowers future auction premiums 25% from the Base Case.

Figure 51: Cumulative Savings, Cumulative Reserves and Cumulative Effective Community Benefit under other stress scenarios

	3-Year Period Ending March 2026			6-Year Period Ending December 2028		
	Cumulative Savings [$MM]	Cumulative Reserves [$MM]	Cumulative Effective Community Benefit	Cumulative Savings	Cumulative Reserves	Cumulative Effective Community Benefit
P50 Base Case	$23.5	$33.7	16.2%	$52.6	$86.4	15.9%
18 MW of Local Projects	$23.5	$37.3	17.2%	$52.6	$100.7	17.4%
8 MW of Local Projects	$23.5	$36.3	16.9%	$52.6	$94.5	16.8%
33% RPS Target	$24.0	$32.4	15.6%	$53.7	$83.8	15.4%
7.5% Discount to Utility (instead of 5%)	$32.6	$25.4	16.2%	$76.3	$63.8	15.9%
Lower Auction Premium	$20.7	$23.6	13.3%	$49.1	$61.3	13.5%

Figure 52 shows the P50 Cumulative Cash Reserves under each of the scenarios considered. The best results from a cumulative cash reserve perspective correspond to the two scenarios with 18MW and 8MW of Local Projects. Lower auction premiums and higher discount rates relative to utility rates show the lowest level of reserve accumulation under the P50 assumptions.

Figure 52: P50 Cumulative Cash Reserves by Scenario



Qualitative Explanation of Risks and Mitigations

This Technical Assessment, to varying degrees, incorporates and/or gives consideration to the following key risks that CPCNH may face in future operation and management of its portfolio. These risk certainly do not cover *all* risk but address key risks associated with managing a power portfolio.

The following subsections describe the nature of each risk, and the degree to which it is considered in the results of this Technical Assessment. Ascend has prepared an executive-level Business and Operations Plan for CPCNH, which will further present and analyze key risks, and provide mitigating strategies, drawing upon the findings from this Technical Assessment.

CPCNH’s participation in the wholesale energy markets exposes member CPAs to certain risks with material financial implications:

Market Risk

Market risk is the uncertainty of CPCNH’s financial performance due to variable commodity market prices (market price risk) and uncertain price relationships (basis risk). Variability in market prices creates uncertainty in CPCNH’s procurement costs, which has a direct impact on customer rates and the ability to accumulate reserves to meet the Financial Reserve Policy minimum and target levels. Stochastic model results in this Technical Assessment are based on simulation of forward, spot market prices and other material portfolio risk drivers under different scenarios. The stochastic results of the Base Case fully contemplate market price risk as described in the Energy Cost of Supply section. The implications of ‘black swan’ events are not contemplated in the ‘1 in 100’ range of outcomes performed in the full hourly stochastic simulation. In practice, sound portfolio risk management will cover most exposures to extreme events. Further, as CPCNH build reserves it will have resources to weather unforeseen events. Overall, members should be aware that while probabilities are small, no energy portfolio is completely insulated from extreme events.

Volumetric Risk

Volumetric risk reflects the potential adverse financial outcomes due to the uncertainty in the quantity of different power supply products required to meet the needs of CPCNH and its members. Customer load is subject to fluctuation due to customer opt-outs or departures, temperature deviation from normal, unforeseen changes in the growth of behind the meter generation by CPCNH customers, unanticipated energy efficiency gains, new or improved technologies, as well as local, state, and national economic conditions. The interaction between market and volumetric risk is particularly critical for CPCNH financial performance. Stochastic model results in this Technical Assessment are based on simulation of material portfolio risk drivers, including volumetric risk, under different scenarios (PowerSIMM technical documentation is available upon request).

Imbalance Risk (Deviations between Actual Energy Use and Contracted Purchases)

Power portfolio hedging will often use expected block power transactions as a financial offset to load obligation. The basic concept is that if the cost of load at the ISO goes up, the value of the hedge goes up for CPCNH largely offsetting the increase in costs. There is a risk that due to unexpectedly high or low load upon power flow may create inadequate hedge coverage or over coverage. Retail power has always struggled with this dynamic in every market.

Further, when over-hedged market prices are often low, resulting in the excess hedge yielding less value and when underhedged market prices are often high yielding higher cost related to filling the open position with spot purchases. Sound portfolio management understands these risks and chooses hedge levels that financially (not volumetrically) minimize risk. Further, if prudent, the market does offer other hedging instruments like options to assist in mitigating risk in high price scenarios.

The Technical Assessment Base Case stochastic results largely consider all these risks and the implication of these risks are represented in model outcomes across the stochastic Base Case representations. For the Technical Assessment it is assumed that CPCNH enters each delivery period with a 100% hedge ratio at the expected (mean) load level.

CPCNH will likely hedge its ISO load obligations using Internal Bilateral Transactions (IBTs). IBTs carry with them three beneficial factors that Ascend contemplated in the Technical Assessment modeling:

1. IBTs can be purchased with a flat annual (or period) price. In doing so there is some measure of cash flow smoothing that reduces cash reserve volatility. This is due to the flat price hedge paying off in the money seasonally (all else equal) and thus offsetting higher ISO settlement cost periods. Conversely it settles out of the money when ISO load costs are low.
2. IBTs are scheduled in as physical generation for the variable revenue side of the hedge's payoff. This results in the hedge netting with load obligations and reducing ISO load collateral posting obligations.
3. IBTs are invoiced by the counterparty for the fixed side cost of the hedge in the subsequent calendar month permitting a greater amount of meter read billing cycle customer revenues to be received for use in paying the fixed power cost invoice.

Legislative and Regulatory Risk

CPCNH is subject to an evolving and uncertain legal and regulatory landscape at the state and federal level. Regulatory risk encompasses risks associated with shifting state and federal regulatory policies, rules, and regulations that could negatively impact CPCNH. Legislative risk is associated with actions by federal and state legislative bodies, such as any adverse changes or requirements that may infringe on CPCNH's autonomy, increase its costs, impact its customer base, or otherwise negatively impact CPCNH's ability to fulfill its mission. The Technical Assessment is based on existing policies, rules and regulations that impact CPCNH such as NH Senate Bill 321 passed on June 2022.

In this Technical Assessment one Regulatory risk was contemplated. This risk is related to utility requests to shorten the utility auction approval windows to attempt to reduce risk premiums. Auction suppliers are often required to hold their pricing open for one to three weeks while the PUC undertakes its approval process. Ascend obtained a market option quote for the time near a utility auction and determined that the cost of holding the position open two weeks was roughly 25% of the auction premium. Thus, the scenario representing lower auction premiums represents a regulatory risk. Other regulatory risks are numerous and even unknown. They are often difficult to quantify. Many of these risks face end power consumers with or without the existence of CPCNH as suppliers and utilities seek to pass costs associated with regulatory changes on to customers as soon as practical.

Counterparty / Collateral Call Risk

During the normal course of business CPCNH is exposed to both counterparty credit risk from non-performance from a counterparty in bilateral power transactions as well as liquidity risk to fund operations, meet ISO-NE collateral requirements and potential collateral obligations from bilateral power transactions. Results from this Technical Assessment do not model explicitly potential credit losses from counterparty risk exposures or potential collateral calls from hedges. Such exposures are subject to the pending negotiation of enabling agreements or arrangements for forward power purchase through credit sleeves. CPCNH intend to use such arrangements, in concert with lock box guarantees, to minimize this exposure. This is possible due to the dynamics addressed in the following section.

Evaluation and Recommendations

Ascend Analytics advises that it is opportunistic to achieve a spring 2023 launch of its member CPAs as organized and operated by CPCNH. Launch in the spring ensures a firm start to the accrual of reserves while serving the four lesser priced months of the six-month utility auction. Further, an April 2023 launch also allows CPCNH to maximize member benefit. The Coalition is viable irrespective of Nashua's launch timing, although Nashua's participation brings a boost to achieving economies of scale.

Wave 1 members, the pioneers of CPCNH, are projected to see significant benefit for their communities. Wave 1 cumulative effective savings (the "community benefit" of customer rate decreases combined with accrual of financial reserves) across the initial 3-year commitment period is 19%. Considering that CPCNH structured the Cost Sharing Agreement to permit a Wave 1 member the option of terminating their continued participation in CPCNH at the end of their initial 3-year term, and "cash out" at this juncture, this figure can be thought of as the proper "risk-adjusted return" or "potential total savings" for communities that initially commit to taking service through CPCNH.

Our comparative analysis of the range of potential future market price movements demonstrates that the Coalition's business model presents a stronger value proposition here relative to the cost savings a community is likely to achieve through a brokered power supply deal, based on what the latter model has demonstrated being capable of achieving on average over a number of years in an adjacent market (i.e., Massachusetts).

- The Coalition's stronger value proposition here, purely in terms of cumulative effective savings, holds firm across the hundreds of scenarios and stochastic forecasts of market price movements analyzed.
- While our analysis necessarily focused on evaluating the relative benefits for Wave 1 members (based on current and forecasted market conditions), Ascend expects the relative results of this analysis to hold firm, going forward — such that refreshing the same analysis for future wave communities (with then-current market conditions) will continue to demonstrate the superiority of CPCNH's value proposition for future wave Members.
- Ascend therefore believes it is unlikely that many communities, properly informed, will elect to take a brokered power supply deal over participating in CPCNH.

Consequently, Ascend expects CPCNH's membership to continue to grow, achieving the financial benefits of economy of scale for all Members, and positioning CPCNH to succeed in achieving the membership's broader vision regarding the provision of innovative services and programs to customers, the continued achievement of political success regarding the passage of new laws and regulations, and the development of local energy projects and infrastructure investments (within the service territories of participating communities).

The experience of other markets where CPAs have achieved success on these same outcomes (e.g., California) strongly suggests that communities are not likely to opt-out of participating in CPCNH so long as they continue to derive such substantial benefits from participating.

On this basis, Ascend concludes that the Coalition may launch with a high degree of confidence in achieving the membership's objectives for the enterprise — namely, short-term financial benefits, long-term fiscal stability, and the multitude of capabilities, and benefits, that inherently accrue by virtue of operating a democratically-governed power agency.

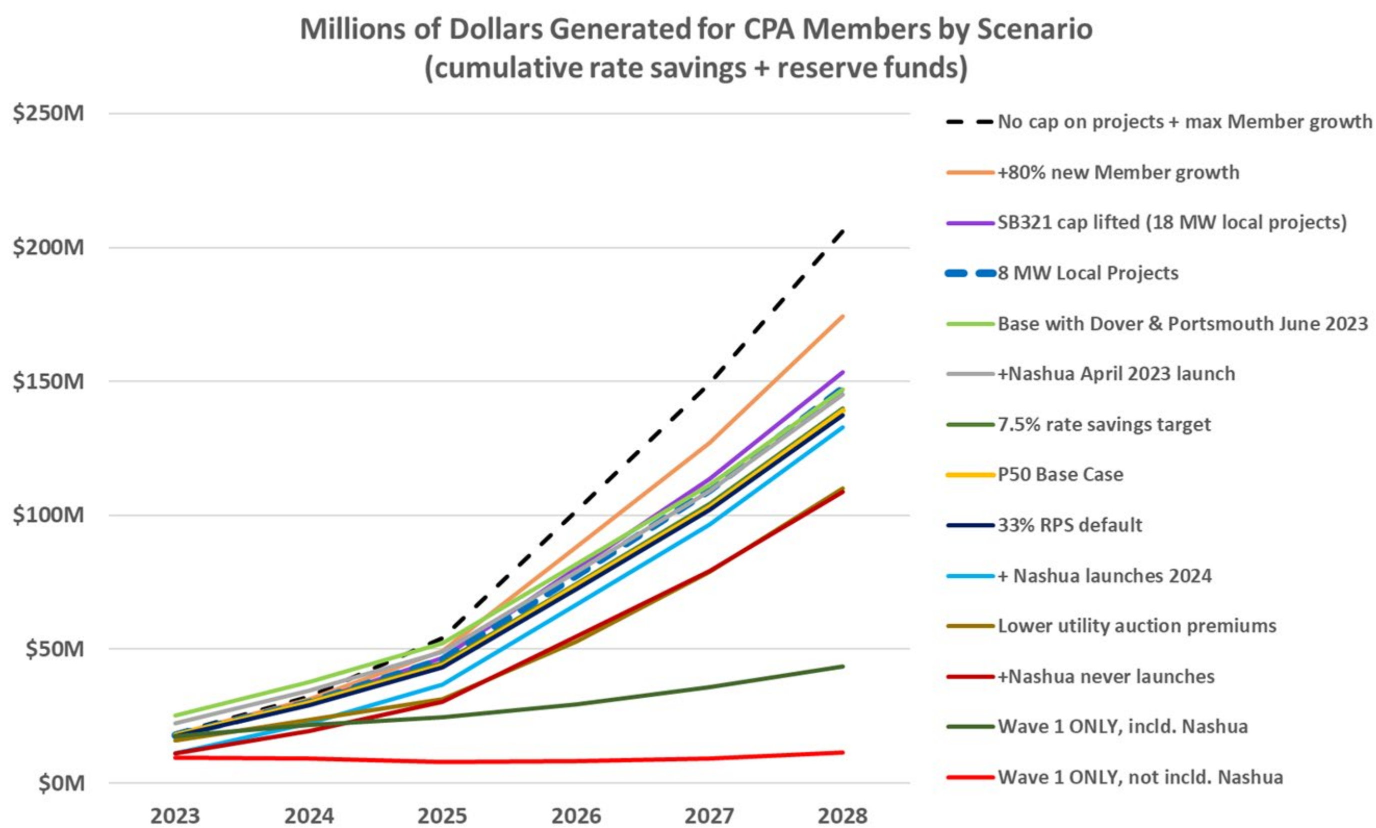
When Ascend set out on the journey of compiling the contents of this Technical Assessment it did not know what the analysis would yield. Ascend believes it is the best at performing 'Analytics that Power the Energy Transition' and trusts this Technical Assessment affords members good context for decision making. To this end, Ascend has intentionally attempted to present conservative scenarios without compounding positive outcomes for communities that participate in CPCNH.

However, in a world where the communities of New Hampshire see the success of Wave 1 Members and decide to participate and benefit from the realization of CPCNH's vision, Ascend has prepared a concluding scenario to approximate the potential benefits of full success. This scenario assumes:

- Out of the ~50 communities that have expressed interest in joining CPCNH become Members, almost all (e.g., 95%) decide to join and launch CPA service.
- The Membership prioritizes near-term engagement at the Legislature to remove the current caps (under SB 321) limiting the development of local projects to 8 Megawatts; CPCNH is subsequently able to develop a total of 18 Megawatts of distributed generation and storage across the Membership service territory by 2025.

As shown by the dotted black line in the chart below, this scenario achieves the maximum creation of net financial benefit for CPA Members compared to all other scenarios in this report (net financial benefit is defined as the sum of cumulative customer rate savings and reserves accrued over time):Figure 53

Figure 53: Net Financial Benefits by Scenario



In this scenario, CPCNH will become the effective leader driving and accelerating New Hampshire's energy transition, for the benefit of communities and customers. This scenario results, by the end of 2028, in the creation of $97,400,000 in additional financial benefit for participating Member CPAs over the base case.

- Most of the new value is created by and accrues to new Members, accessing the benefits of CPCNH's market-based pricing; forecasted supply bill savings for these new customers would total $28,600,000, and financial reserves for these new Members would total $53,900,000.
- The remaining $14,900,000 in new benefits would be net revenues generated by the local clean energy projects CPCNH would develop, which would accrue to all Members participating in the Project Contracts. This positive business case reflects Ascend's confirmation that developing local, small-scale and clean projects in New Hampshire is cost-effective — significantly so, in that such projects increase net revenues relative to continuing to purchase wholesale power from the ISO-NE market — under the market-based framework established by Senate Bill 321.

To conclude, Ascend's technical assessment demonstrates that the pathway to maximize risk-adjusted financial returns for all Members is to (1) prioritize the recruitment and onboarding of new Member communities, and (2) achieve the political reforms necessary to allow CPCNH to freely contract for the development of local projects on behalf of participating Members.

Appendices

Appendix A: Scenario Scorecards

P50 Base Case Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$5.0	$6.6	$9.3	$10.2	$10.6	$11.0
Net Income ($MM)	$15.7	$12.2	$12.1	$16.8	$22.3	$28.7
Member Benefit* (%)	32.2%	14.6%	11.6%	13.3%	15.7%	18.2%
End of Year Reserves ($MM)	$13.0	$18.2	$23.2	$42.6	$61.6	$86.4
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	Baa	A
Days Liquidity	75.3	53.4	54.3	79.4	118.4	159.5

**Annual Savings & Net Income / (Revenues+Savings)*

Base Case P50 with 80% New Wave Participation Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	29	40	62	62	62
Annual Average Customers	61,933	145,048	245,406	269,364	269,231	269,231
Annual MWh	421,188	1,280,290	2,180,937	2,545,422	2,566,086	2,575,679
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$5.1	$7.4	$11.5	$13.1	$13.5	$14.1
Net Income ($MM)	$16.0	$14.7	$17.7	$22.8	$29.8	$37.9
Member Benefit* (%)	32.2%	15.3%	12.8%	13.8%	16.2%	18.6%
End of Year Reserves ($MM)	$13.2	$18.7	$25.2	$51.0	$76.6	$109.5
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	Baa	A
Days Liquidity	74.6	50.8	49.3	74.4	114.8	157.8

**Annual Savings & Net Income / (Revenues+Savings)*

Base Case P50 with No Nashua Delay Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	67,750	131,851	198,059	212,969	212,887	212,887
Annual MWh	461,219	1,167,260	1,783,349	2,013,359	2,022,581	2,030,135
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$5.8	$6.7	$9.4	$10.3	$10.7	$11.1
Net Income ($MM)	$19.5	$12.5	$12.3	$17.0	$22.6	$29.0
Member Benefit* (%)	34.7%	14.6%	11.7%	13.4%	15.7%	18.2%
End of Year Reserves ($MM)	$16.7	$21.9	$27.1	$46.8	$66.1	$91.1
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	Ba	Ba	Ba	A	A
Days Liquidity	69.8	65.9	62.7	87.3	126.4	167.6

**Annual Savings & Net Income / (Revenues+Savings)*

Base Case P50 with a 1-Year Nashua Delay Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	28	35	49	49	49
Annual Average Customers	23,257	124,465	198,149	213,059	212,977	212,977
Annual MWh	251,574	1,087,951	1,780,334	2,010,353	2,019,620	2,027,122
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$2.5	$6.1	$9.4	$10.3	$10.7	$11.1
Net Income ($MM)	$10.0	$13.6	$12.3	$17.0	$22.6	$29.0
Member Benefit* (%)	31.4%	16.0%	11.7%	13.4%	15.7%	18.2%
End of Year Reserves ($MM)	$8.6	$13.6	$18.7	$38.4	$57.7	$82.6
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	Baa	A
Days Liquidity	76.9	43.4	43.7	69.9	108.9	150.2

Annual Savings & Net Income / (Revenues+Savings)

Base Case P50 without Nashua Ever Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	27	34	48	48	48
Annual Average Customers	23,257	100,568	173,404	189,411	189,321	189,321
Annual MWh	251,574	860,838	1,467,228	1,695,495	1,707,368	1,713,969
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$2.5	$4.8	$7.7	$8.7	$9.0	$9.4
Net Income ($MM)	$10.0	$8.9	$9.7	$13.5	$18.3	$23.7
Member Benefit* (%)	31.4%	14.1%	11.4%	12.9%	15.3%	17.8%
End of Year Reserves ($MM)	$8.6	$12.1	$15.5	$31.0	$46.4	$66.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	Baa	A
Days Liquidity	76.9	48.0	42.7	65.3	102.3	141.3

Annual Savings & Net Income / (Revenues+Savings)

Only Ever Wave 1 without Nashua Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	11	11	11	11	11
Annual Average Customers	21,218	40,545	44,247	44,247	44,247	44,246
Annual MWh	221,437	311,093	311,836	313,322	310,319	311,972
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$2.0	$0.1	$0.0	$0.0	$0.8	$0.8
Net Income ($MM)	$8.7	$0.0	($1.4)	$0.3	$0.6	$1.7
Member Benefit* (%)	30.5%	0.0%	-4.2%	0.8%	4.4%	7.2%
End of Year Reserves ($MM)	$7.5	$7.1	$5.8	$6.0	$6.3	$7.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	Ba	Ba	Ba	Ba	Ba
Days Liquidity	79.9	76.2	71.2	70.0	75.9	82.5

Annual Savings & Net Income / (Revenues+Savings)

Only Ever Wave 1 with Nashua Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	12	12	12	12	12
Annual Average Customers	59,679	73,273	74,670	74,670	74,670	74,669
Annual MWh	406,774	604,637	606,819	609,959	604,503	607,001
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$4.8	$3.5	$2.7	$3.1	$3.2	$3.3
Net Income ($MM)	$15.3	$1.7	($0.2)	$1.9	$3.7	$5.6
Member Benefit* (%)	32.0%	7.6%	4.0%	8.1%	11.0%	13.6%
End of Year Reserves ($MM)	$12.7	$13.5	$13.5	$15.3	$18.5	$23.1
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	Ba	Ba	Baa	Baa	A
Days Liquidity	76.8	76.4	84.6	96.2	115.9	135.2

**Annual Savings & Net Income / (Revenues+Savings)*

SB 321 Cap Lifted and 18 MW of Local Projects Installed Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	8	18	18	18	18
Customer Savings ($MM)	$5.0	$6.6	$9.3	$10.2	$10.6	$11.0
Net Income ($MM)	$15.7	$12.9	$14.6	$20.5	$26.3	$32.8
Member Benefit* (%)	32.2%	15.1%	13.0%	15.2%	17.6%	20.1%
End of Year Reserves ($MM)	$13.0	$18.6	$25.8	$49.0	$71.9	$100.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Baa	A	A
Days Liquidity	75.3	54.0	58.7	91.9	139.9	190.8

**Annual Savings & Net Income / (Revenues+Savings)*

SB 321 Cap Maximized to 8 MW of Local Projects Installed Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	8	8	8	8	8
Customer Savings ($MM)	$5.0	$6.6	$9.3	$10.2	$10.6	$11.0
Net Income ($MM)	$15.7	$12.9	$13.8	$18.7	$24.4	$30.9
Member Benefit* (%)	32.2%	15.1%	12.5%	14.3%	16.7%	19.2%
End of Year Reserves ($MM)	$13.0	$18.6	$25.2	$46.5	$67.6	$94.5
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	A	A
Days Liquidity	75.3	54.0	58.2	87.2	130.8	177.1

**Annual Savings & Net Income / (Revenues+Savings)*

33% RPS Target Instead of Compliance Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$4.9	$6.8	$9.5	$10.5	$10.8	$11.2
Net Income ($MM)	$15.3	$12.0	$11.5	$16.2	$21.9	$28.4
Member Benefit* (%)	31.0%	14.1%	11.1%	12.8%	15.3%	17.8%
End of Year Reserves ($MM)	$12.6	$17.5	$22.0	$40.8	$59.4	$83.8
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	Baa	A
Days Liquidity	72.5	50.1	50.3	73.7	111.0	151.0

Annual Savings & Net Income / (Revenues+Savings)

Target 7.5% Discount to Utility Tariff Indefinitely Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$5.0	$9.7	$13.9	$15.3	$15.8	$16.5
Net Income ($MM)	$15.7	$9.2	$7.5	$11.7	$17.1	$23.2
Member Benefit* (%)	32.2%	14.6%	11.7%	13.3%	15.7%	18.2%
End of Year Reserves ($MM)	$13.0	$15.7	$16.3	$30.6	$44.5	$63.8
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	B	Ba	Baa
Days Liquidity	75.3	50.1	42.7	58.1	86.6	116.7

Annual Savings & Net Income / (Revenues+Savings)

Lower Utility Auction Premium Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	61,088	130,554	196,966	211,940	211,857	211,857
Annual MWh	415,783	1,146,189	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$3.1	$5.9	$9.0	$9.7	$10.4	$10.8
Net Income ($MM)	$15.7	$7.7	$6.9	$7.7	$20.0	$24.8
Member Benefit* (%)	30.1%	11.0%	8.9%	9.0%	14.7%	16.6%
End of Year Reserves ($MM)	$12.9	$14.7	$13.4	$25.1	$40.8	$61.3
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	B	Ba	Baa
Days Liquidity	75.1	49.5	36.0	50.4	75.9	109.5

Annual Savings & Net Income / (Revenues+Savings)

SB 321 Cap Lifted and 18 MW of Local Projects with 95% New Wave Participation Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	33	45	70	70	70
Annual Average Customers	62,356	152,295	269,626	298,075	297,918	297,918
Annual MWh	423,891	1,347,341	2,390,299	2,822,067	2,848,354	2,859,018
Local Project Year End MW	0	8	18	18	18	18
Customer Savings ($MM)	$5.1	$7.8	$12.6	$14.5	$15.0	$15.7
Net Income ($MM)	$16.1	$16.7	$22.9	$29.5	$37.5	$46.7
Member Benefit* (%)	32.3%	16.1%	14.3%	15.3%	17.6%	20.1%
End of Year Reserves ($MM)	$13.3	$19.4	$28.8	$61.6	$94.3	$135.5
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	B	B	Ba	A	A
Days Liquidity	74.2	50.1	50.5	81.1	128.4	179.1

Annual Savings & Net Income / (Revenues+Savings)

Nashua in for April 2023 Launch and Dover & Portsmouth in June 2023 Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	14	33	45	70	70	70
Annual Average Customers	86,040	134,949	196,966	211,940	211,857	211,857
Annual MWh	571,463	1,208,113	1,762,211	1,992,131	2,001,552	2,008,999
Local Project Year End MW	0	2	2	2	2	2
Customer Savings ($MM)	$7.2	$7.1	$9.3	$10.2	$10.6	$11.0
Net Income ($MM)	$22.1	$11.3	$12.1	$16.8	$22.3	$28.7
Member Benefit* (%)	33.2%	13.5%	11.6%	13.3%	15.7%	18.2%
End of Year Reserves ($MM)	$18.1	$23.5	$28.6	$48.0	$67.0	$91.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	Ba	Ba	Ba	Baa	A	A
Days Liquidity	77.7	65.7	66.8	90.7	129.8	170.8

Annual Savings & Net Income / (Revenues+Savings)

Appendix B: P50 Annual Net Income Statement

Month	2023	2024	2025	2026	2027	2028
Customer Counts	**61,088**	**130,554**	**196,966**	**211,940**	**211,857**	**211,857**
Residential	**51,186**	**101,388**	**151,865**	**169,147**	**171,198**	**171,198**
Eversource Residential	38,523	81,119	125,842	140,526	142,104	142,104
Liberty Residential	12,075	13,712	15,416	16,725	17,005	17,005
NHEC Residential	0	0	0	0	0	0
Unitil Residential	588	6,557	10,607	11,896	12,089	12,089
Non-Residential	**9,902**	**22,777**	**35,627**	**40,143**	**40,659**	**40,659**
Eversource Non-Residential	7,361	19,074	30,943	35,000	35,433	35,433
Liberty Non-Residential	2,370	2,563	2,881	3,125	3,177	3,177
NHEC Non-Residential	0	0	0	0	0	0
Unitil Non-Residential	171	1,139	1,804	2,018	2,050	2,050
OPT OUT FREE NEW WAVE VOLUME						
Retail Load at the Meters (MWh)	**415,783**	**1,146,189**	**1,762,211**	**1,992,131**	**2,001,552**	**2,008,999**
Residential						
Eversource Residential	210,072	578,119	901,426	1,018,013	1,022,367	1,024,972
Liberty Residential	71,661	109,704	123,845	135,320	136,101	137,291
NHEC Residential	0	0	0	0	0	0
Unitil Residential	4,273	46,887	76,704	87,125	87,381	87,990
Non-Residential						
Eversource Non-Residential	75,408	312,339	538,334	617,978	620,940	623,314
Liberty Non-Residential	51,454	76,905	86,701	94,065	94,824	95,278
NHEC Non-Residential	0	0	0	0	0	0
Unitil Non-Residential	2,914	22,235	35,201	39,631	39,940	40,154
Losses	*-18,941*	*-53,533*	*-83,752*	*-96,168*	*-96,785*	*-97,057*
Effective Loss Rate	*-5%*	*-5%*	*-5%*	*-5%*	*-5%*	*-5%*
Wholesale Load ISO Energy Settlement (MWh)	**(434,724)**	**(1,199,722)**	**(1,845,963)**	**(2,088,300)**	**(2,098,337)**	**(2,106,056)**
Residential						
Eversource Residential	(219,986)	(605,753)	(945,090)	(1,068,135)	(1,072,774)	(1,075,466)
Liberty Residential	(74,950)	(115,064)	(129,894)	(141,950)	(142,784)	(144,027)
NHEC Residential	0	0	0	0	0	0
Unitil Residential	(4,469)	(49,045)	(80,418)	(91,398)	(91,674)	(92,309)
Non-Residential						
Eversource Non-Residential	(78,811)	(326,435)	(563,286)	(647,180)	(650,338)	(652,789)
Liberty Non-Residential	(53,460)	(80,160)	(90,368)	(98,064)	(98,865)	(99,341)
NHEC Non-Residential	0	0	0	0	0	0
Unitil Non-Residential	(3,048)	(23,265)	(36,907)	(41,572)	(41,900)	(42,125)

Month	2023	2024	2025	2026	2027	2028
Retail Revenue ($)	**$59,398,303**	**$122,656,185**	**$174,270,146**	**$192,400,332**	**$198,598,840**	**$207,336,985**
Residential Uncollectible Expense	($588,018)	($1,137,679)	($1,572,498)	($1,732,523)	($1,782,843)	($1,859,778)
Non-Residential Uncollectible Expense	($46,558)	($109,463)	($163,166)	($180,762)	($187,542)	($196,056)
Residential						
Eversource Residential	$30,331,210	$63,359,759	$90,682,232	$100,368,720	$103,012,294	$107,320,696
Liberty Residential	$10,454,540	$11,689,865	$12,300,717	$13,073,240	$13,532,862	$14,203,201
NHEC Residential	$0	$0	$0	$0	$0	$0
Unitil Residential	$623,944	$5,068,583	$7,756,343	$8,566,669	$9,007,194	$9,446,356
Non-Residential						
Eversource Non-Residential	$10,729,623	$33,488,173	$53,512,817	$59,744,472	$62,062,856	$64,818,858
Liberty Non-Residential	$7,481,210	$8,037,368	$8,417,281	$8,937,466	$9,205,420	$9,690,961
NHEC Non-Residential	$0	$0	$0	$0	$0	$0
Unitil Non-Residential	$412,350	$2,259,579	$3,336,421	$3,623,049	$3,748,600	$3,912,746
Wholesale Load ISO Energy Settlement Cost ($) &	**$28,890,283**	**$76,542,255**	**$102,598,613**	**$117,375,223**	**$116,413,422**	**$124,845,373**
Active Management: Load Bidding Optimizatio	($439,954)	($1,165,618)	($1,562,415)	($1,787,440)	($1,772,793)	($1,901,199)
Residential						
Eversource Residential	$15,007,478	$39,540,224	$53,346,331	$60,986,160	$60,439,181	$64,832,469
Liberty Residential	$5,025,960	$8,330,060	$7,508,981	$8,030,530	$7,997,422	$8,627,708
NHEC Residential	$0	$0	$0	$0	$0	$0
Unitil Residential	$304,387	$2,813,533	$4,593,247	$5,225,014	$5,174,832	$5,602,974
Non-Residential						
Eversource Non-Residential	$5,334,187	$20,118,519	$31,627,535	$37,210,343	$36,859,388	$39,469,379
Liberty Non-Residential	$3,455,396	$5,583,930	$5,025,106	$5,395,105	$5,406,249	$5,746,152
NHEC Non-Residential	$0	$0	$0	$0	$0	$0
Unitil Non-Residential	$202,830	$1,321,607	$2,059,829	$2,315,511	$2,309,143	$2,467,889
Wholesale Total On-Peak	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Wholesale Total Off-Peak	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Hedging IBT MtM & Active Management	**($2,522,592)**	**($5,344,709)**	**($13,480,849)**	**($6,903,457)**	**($5,332,408)**	**$2,501,812**
Active Management: Forward Hedging Strateg	$753,701	$2,055,606	$2,829,474	$3,155,446	$3,145,416	$3,199,911
Executed IBT Hedges	n/a	n/a	n/a	n/a	n/a	n/a
'What-If' IBT Hedges (Hyptheticals)	($3,276,292)	($7,400,315)	($16,310,323)	($10,058,903)	($8,477,824)	($698,099)
Excuted IBTs Variable Revenue	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Executed IBTS Fixed Cost	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
'What-If' IBT Varialbe Revenue	*$26,871,738*	*$74,823,935*	*$96,868,646*	*$116,158,938*	*$117,338,813*	*$127,298,355*
'What-If' IBT Fixed Cost	*$30,148,031*	*$82,224,250*	*$113,178,968*	*$126,217,841*	*$125,816,637*	*$127,996,455*
Local Projects Revenue (Cost Reduction)	**$0**	**$98,108**	**$343,541**	**$378,603**	**$388,564**	**$421,166**
Market Energy Value	$0	$222,182	$480,880	$480,680	$470,280	$500,820
Renewable Energy Credit Value	$0	$126,680	$331,209	$301,256	$247,283	$197,636
Capacity Credit Value	$0	$0	$40,450	$80,054	$103,694	$121,669
Transmission Credit Value	$0	$191,160	$412,906	$445,938	$481,613	$520,142
PPA Cost	$0	$441,914	$921,903	$929,326	$914,305	$919,100
NON-ENERGY Costs ($)	**$8,072,732**	**$21,921,682**	**$38,693,675**	**$44,531,436**	**$48,037,767**	**$49,759,567**
Capacity Post Adjustments						
Residential						
Eversource Residential	**$1,726,833**	**$5,091,983**	**$8,546,083**	**$11,174,286**	**$14,550,364**	**$17,075,849**
Liberty Residential	**$637,096**	**$956,374**	**$1,185,153**	**$1,506,866**	**$1,964,199**	**$2,319,237**
NHEC Residential	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unitil Residential	**$47,503**	**$531,153**	**$922,185**	**$1,213,328**	**$1,578,843**	**$1,864,879**
Non-Residential						
Eversource Non-Residential	**$655,677**	**$2,860,015**	**$5,075,894**	**$6,702,708**	**$8,756,758**	**$10,153,779**
Liberty Non-Residential	**$511,736**	**$725,778**	**$907,382**	**$1,134,968**	**$1,477,751**	**$1,761,298**
NHEC Non-Residential	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unitil Non-Residential	**$20,573**	**$162,133**	**$272,207**	**$357,516**	**$466,754**	**$548,673**
Ancillary Prices	**$260,835**	**$359,916**	**$276,894**	**$313,245**	**$314,751**	**$315,908**
RPS Compliance Costs	**$3,560,393**	**$9,434,747**	**$18,738,932**	**$18,996,069**	**$15,780,842**	**$12,560,860**
Other Costs (ncpc, misc, service)	**$652,087**	**$1,799,582**	**$2,768,945**	**$3,132,449**	**$3,147,505**	**$3,159,084**
Gross Margin ($)	**$19,912,697**	**$18,945,647**	**$19,840,550**	**$23,968,819**	**$29,203,808**	**$35,655,023**

Month	2023	2024	2025	2026	2027	2028
Other Start-Up Revenue	**$600,000**					
Donations	$0					
Grant - NHCF	$0					
Calpine Start-Up Funding	$600,000					
Pre-Launch Start-Up Costs	**$764,303**	**$0**	**$0**	**$0**	**$0**	**$0**
Staffing & Overhead	$214,204					
Personnel	*$150,000*					
CEO	*$108,333*					
CFO	*$41,667*					
Benefits Loading	$37,500					
Office & Equipment	$6,000					
Miscellaneous Overhead	$20,704					
Outreach & Communications Materials	**$163,800**					
Events and Marketing	$163,800					
Support Services	**$386,299**					
Contractors	$386,299					
Expenses from Operating Activities	**$3,430,746**	**$7,418,777**	**$8,290,948**	**$7,341,332**	**$6,846,164**	**$6,957,695**
Non-Power Supply Expenses	**$2,944,843**	**$6,398,205**	**$7,487,717**	**$6,927,837**	**$6,615,764**	**$6,727,295**
Staffing & Overhead	**$912,708**	**$1,980,150**	**$2,376,335**	**$2,832,879**	**$2,918,325**	**$3,006,352**
Personnel	*$714,167*	*$1,550,150*	*$1,865,416*	*$2,229,163*	*$2,296,038*	*$2,364,919*
CEO	*$162,500*	*$334,750*	*$344,793*	*$355,136*	*$365,790*	*$376,764*
CFO	*$125,000*	*$257,500*	*$265,225*	*$273,182*	*$281,377*	*$289,819*
General Counsel	*$150,000*	*$309,000*	*$318,270*	*$327,818*	*$337,653*	*$347,782*
Director, Policy & Regulatory Affairs	*$100,000*	*$206,000*	*$212,180*	*$218,545*	*$225,102*	*$231,855*
Director, Technology & Analytics	*$0*	*$0*	*$119,351*	*$245,864*	*$253,239*	*$260,837*
Director, Marketing & Customer Services	*$100,000*	*$206,000*	*$212,180*	*$218,545*	*$225,102*	*$231,855*
Strategic Accounts Manager	*$50,000*	*$154,500*	*$159,135*	*$163,909*	*$168,826*	*$173,891*
Power Resources Manager	*$0*	*$0*	*$92,829*	*$163,909*	*$168,826*	*$173,891*
Analyst 1	*$26,667*	*$82,400*	*$84,872*	*$87,418*	*$90,041*	*$92,742*
Analyst 2	*$0*	*$0*	*$28,291*	*$87,418*	*$90,041*	*$92,742*
Analyst 3	*$0*	*$0*	*$28,291*	*$87,418*	*$90,041*	*$92,742*
Benefits Loading	$178,542	$387,538	$466,354	$557,291	$574,009	$591,230
Office & Equipment	$15,000	$31,847	$33,424	$34,819	$36,208	$37,653
Miscellaneous Overhead	$5,000	$10,616	$11,141	$11,606	$12,069	$12,551
Local Programs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Outreach & Communications Materials	**$73,463**	**$103,429**	**$78,935**	**$38,208**	**$30,254**	**$30,254**
Enrollment Mailers (enrollments & churn)	$58,463	$73,429	$63,935	$23,208	$15,254	$15,254
Events and Marketing	$15,000	$30,000	$15,000	$15,000	$15,000	$15,000
Operational Services	**$1,367,564**	**$2,687,794**	**$3,581,516**	**$3,307,176**	**$3,078,107**	**$3,078,107**
Portfolio Risk Management & Operations	$817,772	$1,197,824	$1,379,108	$872,418	$617,165	$617,165
Ascend Analytics	*$784,022*	*$1,092,824*	*$1,139,108*	*$632,418*	*$377,165*	*$377,165*
LSE	*$33,750*	*$105,000*	*$240,000*	*$240,000*	*$240,000*	*$240,000*
Calpine (Platform, Utility Data, Billing)	$549,791	$1,489,970	$2,202,408	$2,434,759	$2,460,942	$2,460,942
Support Services	**$591,108**	**$836,661**	**$878,099**	**$566,478**	**$589,079**	**$612,582**
Accounting and Audits	$105,000	$148,618	$155,979	$162,488	$168,971	$175,713
Marketing and Branding	$112,500	$159,234	$167,120	$174,094	$181,040	$188,264
Legal Advice and Regulatory Engagement (	$225,050	$318,538	$334,314	$0	$0	$0
Community Choice Partners	$0	$0	$0	$0	$0	$0
Herdon Enterprises	$91,109	$128,956	$135,343	$140,991	$146,616	$152,466
Clean Energy New Hampshire	$57,450	$81,315	$85,343	$88,904	$92,451	$96,140
Utility Fees	**$38,485**	**$104,298**	**$157,494**	**$175,804**	**$177,960**	**$177,960**
At-Risk Contracting Repayment	**$485,903**	**$790,171**	**$572,831**	**$183,095**	**$0**	**$0**
Deferred Comp Schedule	$485,903	$790,171	$572,831	$183,095	$0	$0
NEPOOL Expenses	**$0**	**$230,400**	**$230,400**	**$230,400**	**$230,400**	**$230,400**
Operating Margin ($)	**$17,081,951**	**$11,526,871**	**$11,549,602**	**$16,627,487**	**$22,357,643**	**$28,697,328**

Month	2023	2024	2025	2026	2027	2028
Non-Capital Financing Activities	**($465,073)**	**($87,451)**	**$0**	**$0**	**$0**	**$0**
CREDIT FACILITIES	$793,143	$0	$0	$0	$0	$0
Energy LOC Funding	$0	$0	$0	$0	$0	$0
Non-Energy LOC Funding	$793,143	$0	$0	$0	$0	$0
DEBT SERVICE	($1,258,216)	($87,451)	$0	$0	$0	$0
Principal	($793,143)	$0	$0	$0	$0	$0
Energy LOC Repayment	$0	$0	$0	$0	$0	$0
Non-Energy LOC Repayment	($793,143)	$0	$0	$0	$0	$0
Interest/Fees	($465,073)	($87,451)	$0	$0	$0	$0
Energy LOC Fee/Interest	($434,724)	($87,451)	$0	$0	$0	$0
Non-Energy LOC Interest	($30,348)	$0	$0	$0	$0	$0
Commitment Fees for CPCNH LOC	$0	$0	($15,450)	($36,776)	($30,378)	($46,444)
Line of Credit (LOC) Fee	$0	$0	$0	$0	$0	$0
Letter of Credit (LC) Fee	$0	$0	($15,450)	($36,776)	($30,378)	($46,444)
Net Income ($)	**$15,727,575**	**$12,229,591**	**$12,106,983**	**$16,773,806**	**$22,327,265**	**$28,650,884**

Appendix C: Effective $/MWh Income Statement

Month	2023	2024	2025	2026	2027	2028
Utility Retail Rate Projections ($/MWh)	**$156.35**	**$113.86**	**$105.13**	**$102.67**	**$105.48**	**$109.71**
Block+Auction Premium+Capacity+Ancillary+Basis+ISOFees+Loses+Uncollectible Premium						
Auction Premium Check	92%	31%	32%	27%	27%	29%
Residential						
Eversource Residential	$154.85	$115.44	$105.89	$103.78	$106.06	$110.22
Liberty Residential	$164.09	$112.29	$104.55	$101.69	$104.67	$108.90
NHEC Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential	$180.49	$113.81	$106.44	$103.50	$108.50	$113.01
Non-Residential						
Eversource Non-Residential	$152.62	$112.91	$104.64	$101.77	$105.21	$109.46
Liberty Non-Residential	$154.07	$110.12	$102.19	$100.01	$102.19	$107.07
NHEC Non-Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential	$175.17	$106.99	$99.77	$96.23	$98.80	$102.57
CPCNH Revenue Rates, (Applying Discount to Uti	**$144.39**	**$108.10**	**$99.88**	**$97.54**	**$100.21**	**$104.23**
Residential Uncollectable Adjustment	1.42%	1.42%	1.42%	1.42%	1.42%	1.42%
Non-Residential Uncollectible Adjustment	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
Residential						
Eversource Residential	$144.38	$109.60	$100.60	$98.59	$100.76	$104.71
Liberty Residential	$145.89	$106.56	$99.32	$96.61	$99.43	$103.45
NHEC Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential	$146.02	$108.10	$101.12	$98.33	$103.08	$107.36
Non-Residential						
Eversource Non-Residential	$142.29	$107.22	$99.40	$96.68	$99.95	$103.99
Liberty Non-Residential	$145.40	$104.51	$97.08	$95.01	$97.08	$101.71
NHEC Non-Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential	$141.49	$101.62	$94.78	$91.42	$93.86	$97.44
ENERGY Forward Prices ($/MWh)	**$69.48**	**$66.78**	**$58.22**	**$58.92**	**$58.16**	**$62.14**
Mass Hub ATC	$62.53	$70.89	$60.97	$61.35	$61.96	$61.59
Mass Hub On-Peak	$68.04	$76.49	$66.50	$66.84	$68.16	$67.98
Mass Hub Off-Peak	$57.76	$66.00	$56.14	$56.52	$56.52	$56.05
New Hampshire Zone ATC	$62.92	$69.02	$60.87	$58.62	$56.96	$58.50
New Hampshire Zone On-Peak	$67.25	$72.25	$65.40	$63.90	$61.61	$63.44
New Hampshire Zone Off-Peak	$59.17	$66.21	$56.92	$53.98	$52.88	$54.22
Effective Load Weighted (ISO Obligation/Meter	$66.46	$63.80	$55.58	$56.21	$55.48	$59.28
Active Management: Demand Bidding DART	($1.06)	($1.02)	($0.89)	($0.90)	($0.89)	($0.95)
Residential						
Eversource Residential	$71.44	$68.39	$59.18	$59.91	$59.12	$63.25
Liberty Residential	$70.14	$75.93	$60.63	$59.34	$58.76	$62.84
NHEC Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential	$71.23	$60.01	$59.88	$59.97	$59.22	$63.68
Non-Residential						
Eversource Non-Residential	$70.74	$64.41	$58.75	$60.21	$59.36	$63.32
Liberty Non-Residential	$67.15	$72.61	$57.96	$57.36	$57.01	$60.31
NHEC Non-Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential	$69.60	$59.44	$58.52	$58.43	$57.82	$61.46

Month	2023	2024	2025	2026	2027	2028
Hedging IBT MtM ($/MWh)	**($6.07)**	**($4.66)**	**($7.65)**	**($3.47)**	**($2.66)**	**$1.25**
Active Management: Hedging Strategy	$1.81	$1.79	$1.61	$1.58	$1.57	$1.59
'What-If' IBT Hedges (Hyptheticals)	($7.88)	($6.46)	($9.26)	($5.05)	($4.24)	($0.35)
Local Projects Revenue (Cost Reduction) ($/MV	**$0.00**	**$0.09**	**$0.19**	**$0.19**	**$0.19**	**$0.21**
Market Energy Value	$0.00	$0.19	$0.27	$0.24	$0.23	$0.25
Renewable Energy Credit Value	$0.00	$0.11	$0.19	$0.15	$0.12	$0.10
Capacity Credit Value	$0.00	$0.00	$0.02	$0.04	$0.05	$0.06
Transmission Credit Value	$0.00	$0.17	$0.23	$0.22	$0.24	$0.26
PPA Cost	$0.00	$0.39	$0.52	$0.47	$0.46	$0.46
NON-ENERGY Prices ($/MWh; $/kW-Mo; %)	**$20.64**	**$18.75**	**$20.94**	**$22.05**	**$23.30**	**$25.57**
Capacity [$/kW-month]	$2.75	$2.28	$2.51	$2.92	$3.78	$4.44
Capacity Post Adjustments [$/MWh]	$8.66	$9.01	$9.60	$11.09	$14.39	$16.79
Residential						
Eversource Residential	$7.86	$7.89	$8.52	$9.74	$12.19	$15.55
Liberty Residential	$8.52	$8.14	$8.89	$9.82	$12.35	$15.76
NHEC Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential	$10.66	$9.80	$10.91	$12.29	$15.38	$19.93
Non-Residential						
Eversource Non-Residential	$8.33	$8.01	$8.36	$9.56	$12.01	$15.18
Liberty Non-Residential	$9.62	$8.86	$9.80	$10.79	$13.65	$17.34
NHEC Non-Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential	$6.77	$6.24	$6.99	$7.94	$10.07	$12.66
Ancillary Prices	$0.60	$0.30	$0.16	$0.15	$0.15	$0.15
RPS Compliance Costs	$8.19	$7.45	$9.31	$9.22	$7.93	$6.73
Other Costs (ncpc, misc, service)	$1.50	$1.42	$1.42	$1.48	$1.48	$1.53
Gross Margin $/MWh	**$48.19**	**$17.99**	**$13.26**	**$13.30**	**$16.27**	**$17.97**
Residential						
Eversource Residential	$47.73	$19.03	$14.01	$14.32	$16.87	$18.40
Liberty Residential	$49.86	$8.26	$10.93	$12.85	$15.76	$17.37
NHEC Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential	$46.75	$24.04	$11.43	$11.45	$15.87	$16.21
Non-Residential						
Eversource Non-Residential	$45.90	$20.55	$13.42	$12.31	$16.01	$18.00
Liberty Non-Residential	$51.26	$8.83	$10.49	$12.30	$13.89	$16.61
NHEC Non-Residential	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential	$47.82	$21.78	$10.47	$10.53	$13.49	$15.93
Operational Costs ($/MWh)	**$8.25**	**$6.47**	**$4.70**	**$3.69**	**$3.42**	**$3.46**
Operating Margin ($/MWh)	**$39.94**	**$11.52**	**$8.55**	**$9.61**	**$12.85**	**$14.51**
Financing Costs	**$1.12**	**$0.08**	**$0.01**	**$0.02**	**$0.02**	**$0.02**
Net Income	**$38.82**	**$11.44**	**$8.54**	**$9.60**	**$12.84**	**$14.49**

Appendix D: Utility Tariff Auction Premium Backcasts & Utility Migration Data

Eversource Small Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23	Feb23-Jul23
Fixed Retail Rate	$ 94.1	$ 99.9	$ 88.3	$ 83.1	$ 70.7	$ 66.3	$ 88.3	$ 106.7	$ 225.7	$ 202.2
Total Eversource RPS + ES Adj.	$ 4.6	$ 3.7	$ 7.0	$ 9.0	$ 5.8	$ 5.7	$ 4.4	$ 4.7	$ 5.8	$ 5.9
Base ES Rate (Average)	$ 89.6	$ 96.1	$ 81.2	$ 74.0	$ 64.9	$ 60.6	$ 83.8	$ 102.0	$ 219.9	$ 196.3
Wholesale Cost + Losses	$ 83.0	$ 83.9	$ 73.4	$ 64.9	$ 58.0	$ 52.6	$ 73.0	$ 89.4	$ 164.7	$ 128.7
Energy Only Cost + Losses	$ 51.6	$ 52.9	$ 45.9	$ 39.5	$ 35.7	$ 32.3	$ 55.1	$ 70.9	$ 149.2	$ 113.7
$/MWh Auction Premium Over Block	$ 6.6	$ 12.2	$ 7.9	$ 9.2	$ 6.9	$ 8.0	$ 10.8	$ 12.6	$ 55.2	$ 67.7
% Auction Premium to Block	13%	23%	17%	23%	19%	25%	20%	18%	37%	55%

Liberty Small Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23	Feb23-Jul23
Retail Rate	$83.0	$83.0	$77.1	$71.9	$68.3	$64.3	$84.0	$111.2	$222.3	$220.1
ES Reconciliation	-$9.7	-$9.7	-$8.2	-$8.2	-$3.8	-$3.8	$1.5	$1.5	$1.0	$1.0
ES Cost Reclassificiation Adj	-$1.2	-$1.2	$1.3	$1.3	$0.4	$0.4	$0.5	$0.5	$0.6	$0.6
RPS Adder	$2.9	$2.9	$5.4	$7.1	$7.4	$7.4	$6.8	$6.8	$7.8	$7.8
Base ES Rate (Average)	$91.0	$91.0	$78.7	$71.8	$64.2	$60.2	$75.2	$102.4	$212.9	$210.7
Wholesale Cost + Losses	$82.3	$83.5	$74.4	$63.9	$53.8	$53.0	$66.7	$91.1	$173.2	$138.0
Energy Only Cost + Losses	$48.6	$49.5	$44.8	$38.5	$35.5	$34.8	$50.5	$74.5	$157.5	$122.7
$/MWh Auction Premium Over Block	$8.7	$7.6	$4.2	$7.8	$10.5	$7.3	$8.5	$11.3	$39.7	$72.7
% Auction Premium to Block	18%	15%	9%	20%	29%	21%	17%	15%	25%	59%

Eversource Large Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23
Average Retail Rate	$98.0	$125.0	$93.8	$83.1	$90.8	$67.7	$90.8	$119.0	$315.4
Total Eversource RPS + ES Adj.	$4.6	$3.7	$8.7	$10.7	$6.3	$9.3	$6.3	$4.7	$3.5
Base ES Rate (Average)	$93.5	$121.3	$85.1	$72.4	$84.4	$58.4	$84.4	$114.4	$311.9
Wholesale Cost + Losses	$86.1	$88.0	$70.9	$64.5	$53.5	$49.8	$72.2	$84.5	$165.1
Energy Only Cost + Losses	$49.3	$52.4	$45.3	$39.2	$36.1	$31.1	$54.1	$67.5	$149.5
$/MWh Auction Premium Over Block	$7.4	$33.2	$14.2	$8.0	$30.9	$8.6	$12.3	$29.9	$146.8
% Auction Premium to Block	15%	63%	31%	20%	86%	28%	23%	44%	98%

Liberty Large Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23
Retail Rate	$78.3	$79.0	$73.2	$67.4	$69.8	$66.6	$83.3	$108.4	$222.3
ES Reconciliation	-$9.7	-$9.7	-$8.2	-$8.2	-$3.8	-$3.8	$1.5	$1.5	$1.0
ES Cost Reclassificiation Adj	-$2.3	-$2.3	$2.6	$2.6	$0.8	$0.8	-$1.2	-$1.2	$2.5
RPS Adder	$4.6	$2.9	$5.4	$7.1	$7.4	$7.4	$6.8	$6.8	$7.8
Base ES Rate (Average)	$85.7	$88.1	$73.5	$65.9	$65.3	$62.1	$76.1	$101.3	$211.0
Wholesale Cost + Losses	$81.2	$78.3	$68.0	$61.6	$53.9	$52.0	$67.8	$97.6	$165.6
Energy Only Cost + Losses	$52.0	$50.4	$45.8	$39.0	$36.1	$34.9	$51.9	$78.8	$149.8
$/MWh Auction Premium Over Block	$4.5	$9.8	$5.4	$4.3	$11.4	$10.1	$8.3	$3.7	$45.4
% Auction Premium to Block	9%	20%	12%	11%	32%	29%	16%	5%	30%

Unitil Auction Premium Backcast

	Jun22-Nov22	Dec22-Jul23
Retail Rate	101.17	259.25
Reconciliation	$1.64	-$1.23
RPS	$4.38	$5.28
Base ES Rate (Average)	$96.79	$253.97
Wholesale Cost + Losses	$ 84.97	$ 180.75
Energy Only Cost + Losses	$ 65.76	$ 167.43
$/MWh Auction Premium Over Block	$11.82	$73.22
% Auction Premium to Block	18%	44%

Class:		Small			
Utility:		Eversource	Liberty	NHEC	Unitil
Date of Most Recent Available Auction		12/6/2022	12/13/2022	6/28/2022	9/20/2022
Energy Wholesale Costs	$/MWh	$108.43	$117.03	$149.72	$164.10
Capacity Wholesale Costs	$/MWh	$12.77	$13.03	$13.34	$16.91
Ancillary Wholesale Costs	$/MWh	$0.70	$0.70	$0.70	$0.70
Losses	$/MWh	$5.26	$5.70	$7.27	$7.96
Other Costs (ncpc, misc, service)	$/MWh	$1.50	$1.50	$1.50	$1.50
TOTAL WHOLESALE COST	$/MWh	$128.66	$137.96	$172.53	$191.17

Class:		Large			
Utility:		Eversource	Liberty	NHEC	Unitil
Date of Most Recent Available Auction		6/14/2022	6/7/2022	6/28/2022	9/20/2022
Energy Wholesale Costs	$/MWh	$142.32	$142.57	$138.45	$160.10
Capacity Wholesale Costs	$/MWh	$13.40	$13.62	$9.18	$11.12
Ancillary Wholesale Costs	$/MWh	$0.70	$0.70	$0.70	$0.70
Losses	$/MWh	$7.17	$7.19	$6.98	$7.33
Other Costs (ncpc, misc, service)	$/MWh	$1.50	$1.50	$1.50	$1.50
TOTAL WHOLESALE COST	$/MWh	$165.09	$165.57	$156.81	$180.75

Most Recently Reported 12 Month Utility Customer Migration

Utility	Segment	Total Utility MWh	Segment Share of Utility Load	Migrated Load	Remaining Default Load	Segment Share of Default Load
Eversource	Residential	3,433,211	44%	537,891	2,895,320	74%
	Small Commercial	1,644,923	21%	846,179	798,744	20%
	Large Commercial	2,765,000	35%	2,549,251	215,749	6%
Liberty	Residential	294,617	33%	18,781	275,837	60%
	Small Commercial	108,621	12%	23,160	85,461	19%
	Large Commercial	499,710	55%	400,629	99,080	22%
Unitil	Residential	521,496	45%	44,976	476,520	67%
	Small Commercial	316,143	27%	139,606	176,537	25%
	Large Commercial	327,374	28%	271,979	55,395	8%

Note: Eversource & Unitil data available for period ending Q3 2022, Liberty ending Q1 2022.

Appendix E: PowerSIMM Model CPCNH Simulation Validation

As a part of the model stand up process ascend conducts validations of PowerSIMM's Simulation Engines (namely Load, Weather, and Forward Sims) to ensure that the model can accurately capture historically observed trends in forecasts. This is generally done by comparing simulated, historical, and back cast data. To read more in depth information about the simulation engines refer to Appendix F.

The first simulation engine is weather: weather is the driver of uncertainty. To simulate weather, Ascend harvests 30 years of historical daily Min and Max drybulb temperatures for weather stations across New Hampshire from the National Climatic Data Center (NCDC). Weather stations simulated included Berlin, Concord, Jaffrey, Lebanon, Manchester, Rochester, and Whitefield. Historic weather is fed to the model to inform the simulations, and ensure that the simulated mean, P5, and P95 temperatures are in line with the historically observed temperature conditions. This is confirmed at both a monthly level as seen in Figure 54, and at a daily level as seen in Figure 55. In the daily validation plot shown in Figure 55, the historical observations in red produce a line that shows more variability because our simulations are the averaging of over 100 weather futures, whereas the historical timeseries represent the single history that has occurred.

Figure 54: Sample Monthly Min Dry Bulb Temperature Validation Plot for Jaffrey, NH.

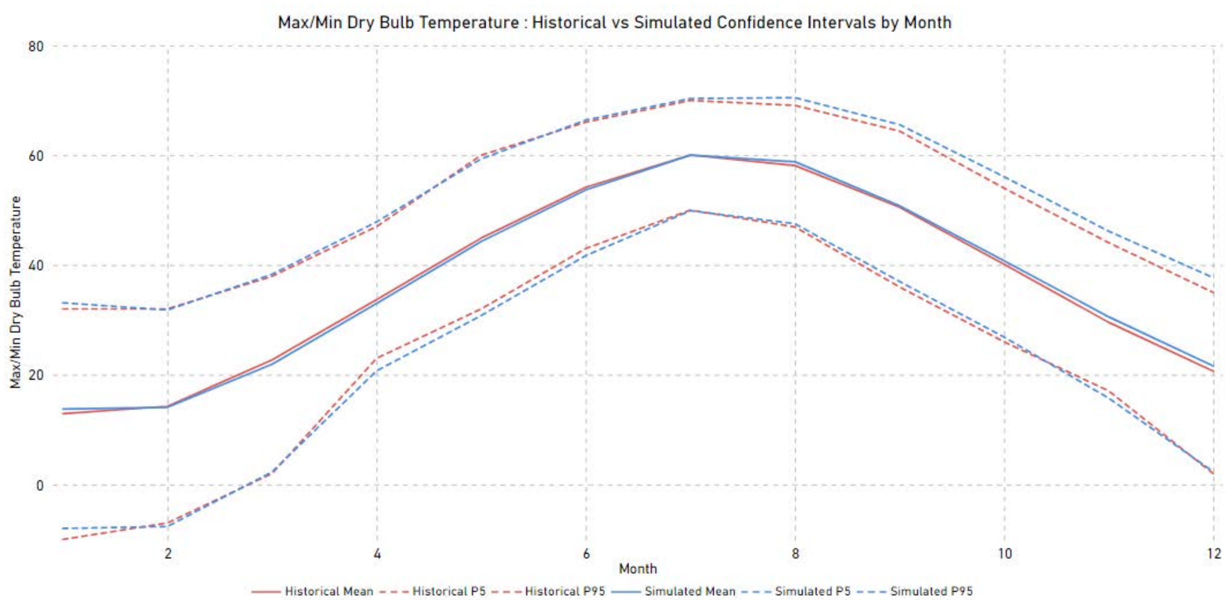
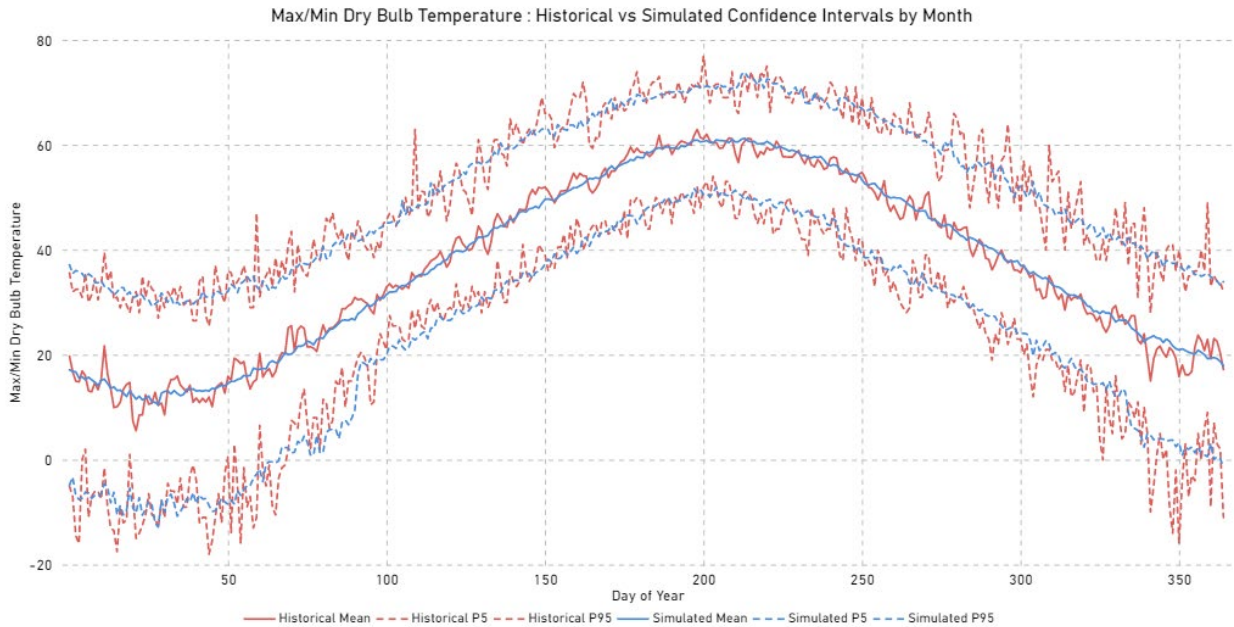


Figure 55: Sample Daily Min Dry Bulb Temperature Validation Plot for Jaffrey, NH.



PowerSIMM uses the historical weather-load correlation to simulate load once weather has been simulated. below shows the historic and backcast load vs temperature relationship – load is highest at the more extreme cold and hot temperatures.

While weather is simulated on a daily basis, load gets simulated on an hourly basis, so in addition to ensuring that the simulations match the monthly and daily historically observed patters discussed above with weather validations we also ensure that historically observed hourly load patterns are maintained. This validation is shown in below where the mean, P5, and P95 hourly loads for simulated and backcast load are compared. The simulated backcast data match the historical mean exactly with simulated P5 and P95s well in line with historical data.

Figure 56: Historical vs Backcast Load vs Temperature Relationship for Eversource Load

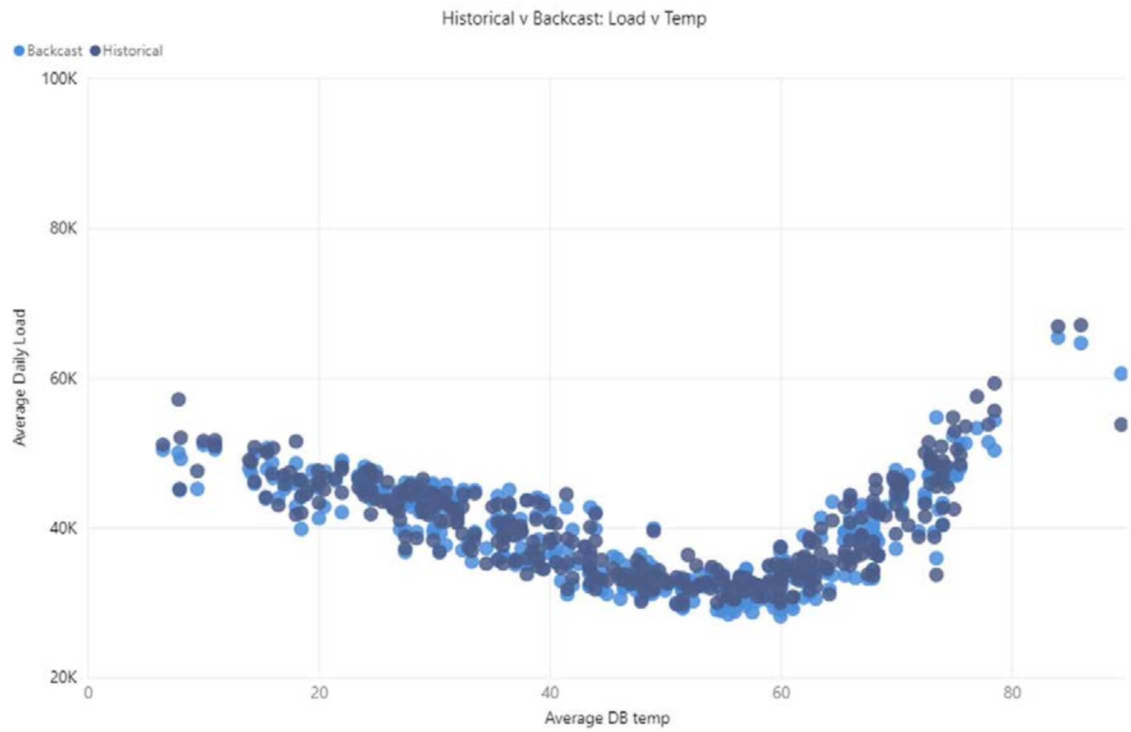
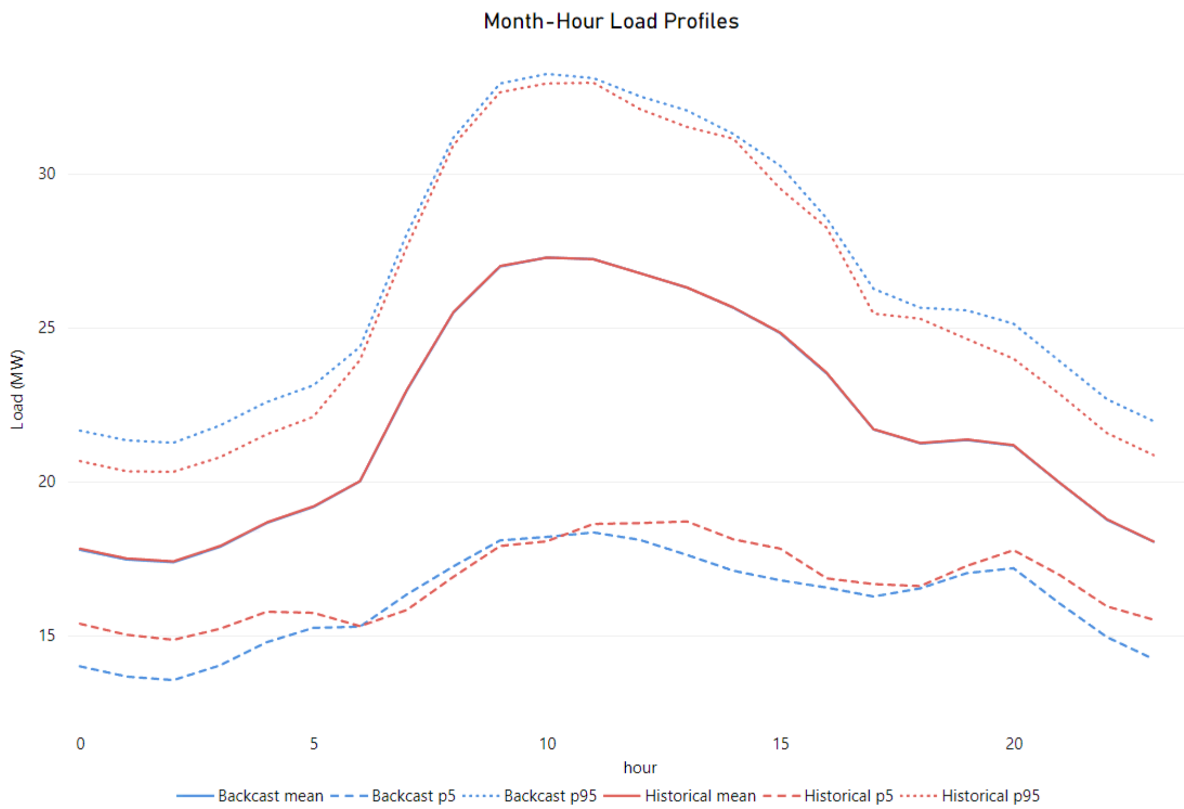


Figure 57: Month – Hour Load Shape



Appendix F: PowerSIMM Level 1 Documentation

Available upon request to Member CPAs subject to Non-Disclosure Agreement and agreement to not redistribute

Appendix G: Ascend ISO-NE Market Report

Available upon request to Member CPAs subject to Non-Disclosure Agreement and agreement to not redistribute

Appendix H: Updates Since Release of Initial Draft Technical Assessment

An CPCNH circulated an earlier, initial draft of the Technical Assessment. This version incorporates feedback from CPA members, updates due to significant market price changes and correction of errors/clarifications/improvements deemed appropriate given the preparation of the update. These items are largely listed here.

- Market prices updated to 1/20 COB marks
- Updates to forward volatility constraints
- 7.5% discount for first 2 auctions with first auction pegged to discounted Eversource rate for all 'small' customers; thereafter 5%
- Base case Nashua to May start
- Local Projects delayed 1 year
- Exclusion of LG, C1 and G1 customer MWh
- Corrected Portsmouth customer count
- Corrected missing budget line items in year 1
- Corrected wrong sign (+/-) on active management benefit for hedging
- LSE cost $20k per month after 18 months
- Corrected calculation of range of uncertainty on broker offer comparison chart