Austin Energy Resource and Generation Plan Modeling Results Review: EUC requests and AE responses

Comments/Requests	Commissioner(s)	Austin Energy Response
Can you explain why AE did not use the lower end pricing received from the renewables RFP in our range?	White, Reed, Tuttle (10/1 EUC office hours respondents)	Please see previous response to similar comment on modeling framework: *Some of the very low pricing proposals received as part of the RFP process were not included in the actionable cost range for modeling purposes due to an assessment by the AE review team that the proposals were untenable. The two primary reasons for rejecting those proposals are: 1) the proposed locations of the projects were either in areas where transmission congestion is currently very high or where AE already has a saturation of assets and thus would not gain better portfolio diversification, and/or 2) associated terms & conditions would affect the net value of the proposal as opposed to just the listed $/kW capital cost.*
Is AE able to provide any further detail on the renewables RFP that is not considered confidential (# of price proposals received in different cost ranges, etc.)? Same question as above for the batteries RFP from last year?	White, Reed, Tuttle (10/1 EUC office hours respondents)	AE has provided the maximum allowable level of granularity and detail about the proposals. AE is not able to provide data in a way that protects confidentiality of the RFP respondents. AE is confident that costs chosen are best estimates and representative of the average or expected costs of that particular technology.
Please explain AE's rationale for keeping the prices for batteries level (plus inflation) over the modeling period, as opposed to using declining costs per market trend expectations (their assessment)	White, Reed, Tuttle (10/1 EUC office hours respondents)	AE internal research suggests future utility-scale battery costs could either increase or decrease relative to current pricing, and therefore concluded current day pricing was an acceptable estimate of future costs. However, AE did perform additional analysis to evaluate costs of the round II portfolios using a declining forward battery cost curve developed by the National Renewable Energy Laboratory (NREL) and will present those results to the full commission. The average cost difference for the net present value of 20-year annual net costs is 2% lower using NREL cost estimates.
Confirm that the cost assumptions included in the modeling framework for new gas combustion turbines (CTs or peakers) and combined cycle units (CCs) is the same for	White, Reed, Tuttle (10/1 EUC office hours respondents)	Yes. That is correct and based on manufacturer-provided estimates of hydrogen-capable gas generation units.

natural gas-only and hydrogen.		
Can AE include improvements to our import capacity as a variable in the UPLAN model	9/30 Meeting	Yes. Three of the round II portfolios include a proxy resource that we believe approximates the same effect as reducing a transmission import constraint.
Please provide (re-send) the emission factor calculations used in our modeling inputs	White	Resent to Commissioner White on 10/2/2024
Find a less biased source for hydrogen emissions factors	White	AE believes the hydrogen emissions factors used in the modeling are representative and appropriate for this modeling exercise. The NOx emissions factors used in modeling to date for hydrogen generation are already higher than equivalent natural gas emissions factors for the same generator type. Please see Modeling Framework and companion hydrogen analysis files sent to EUC Commissioners on 7/23/24.
Do the conditions described (in reference below) align with the technology AE is modeling?https://research.gatech.edu/sites/default/files/inline-files/gt_epri_nox_emission_h2_short_paper.pdf	White	Yes. Confirmed via email 10/2/2024
Include the cost of damages done by climate change associated with greenhouse gas emissions, e.g. using a social cost of carbon approach	9/30 Meeting Commissioners and Public Comment	Austin Energy has carefully evaluated the request to quantify the social cost of carbon of its resource portfolio and agrees that an analysis of the indirect costs/benefits of resource decisions can be useful, but it needs to be more holistic than simply adding the costs of greenhouse gas emissions. A valid and meaningful analysis requires estimates of system-wide (ERCOT market-wide) net emissions changes due to AE portfolios as well as avoided emissions due to conservation programs, renewable energy investments, and strategies such as REACH. Resource and generation plan modeling also suggests there are significant tradeoffs when reducing emissions impacts, most importantly increased risk of outages as well as higher customer bills. Both of those outcomes also result in indirect costs to the local community, which would also need to be monetized for a fair comparison of indirect

		costs between portfolios. It is not feasible to complete an analysis of this scope within the timeline Austin Energy committed to complete a new resource and generation plan. We note that we have provided future portfolio emissions by year, which can be used by anyone to conduct their own analysis of the partial indirect costs of portfolios (eg due only to AE emissions changes alone) using their cost of carbon value and methodology of choice.
Analyze and add to the emissions totals the upstream emissions of natural gas during extraction/processing/ transport.	9/30 Meeting Commissioners and Public Comment	Austin Energy previously responded to this request and committed to further studying these impacts during resource plan implementation. Please see previous response to similar comment on modeling framework: *We interpret this comment to be related to a Life Cycle Assessment (LCA) methodology where the cradle-to-grave impacts of resources are estimated and accounted for when comparing different resource options. We agree with the merits of taking a wider life-cycle lens while recognizing the specialized expertise and time necessary to do so. A relevant and useful LCA would include both an understanding of the upstream and downstream impacts of all technology types using a common framework, as well as options for mitigating those impacts for the resources we invest in. Given the resources and time needed to finalize the Resource Generation Plan by end of calendar year 2024, AE will commit to seeking resources to undertake LCA studies to inform our resource and generation plan implementation.*
Electricity burden results need to be presented with different variations of rates for low-income customers or CAP program improvements	White	Defining and analyzing new rate values and options are beyond the scope of this resource and generation plan. AE's objective in estimating electricity burden was to provide a way to compare between portfolios using a measure that is commonly used to evaluate impacts to low to medium customers. Use of different rates is expected to result in the same relative differences in the measure between portfolios.
Can you please provide the DNV results for both economic and technical potentials	White and Reed	Summary of Austin Energy's business as usual (BAU) projections and DNV study projections provided via email 10/3/2024 to EUC Chair, co-chair and requesting commissioners
For the DNV study, I know we were told that only current solar programs were evaluated (so not the Solar Standard Offer or Solar for All). Was	White and Reed	Solar for All cost assumptions were included in the Modeling Framework as inputs so that program is included and was part of the DNV study. Solar Standard Offer program design details were not yet ready to include in the DNV study. Energy efficiency and DR analysis in the DNV study includes existing programs as well as potential new programs (residential battery DR, EV managed charging,

that also true for the energy efficiency and demand response analysis?		pool pumps, etc.). DNV leveraged their knowledge of how other DR/EE programs have functioned elsewhere based on standard technical specifications.
Can you please provide a table that shows the distribution of reliability risk hours by hour of the day for 2035 for portfolio 12? (i.e. 10 hours at 12pm, 100 hours at 11pm)	White and Reed	Data provided via email 10/3/2024 to EUC Chair, co-chair and requesting commissioners
We'd also like to see the distribution of battery charging by hour – particularly for 2035 for portfolio 12 and 13	White and Reed	Data and charts provided for Portfolio 9 in 2035 via email 10/3/2024 to EUC Chair, co-chair and requesting commissioners
On transmission import capacity – is the 2200 MW the current limit or assuming the 5 recommended upgrades from the study? Either way, how much are those upgrades expected to add? And it was mentioned at our meeting that up to 250 MW of additional import capacity could be worked into the assumptions. I'd like more information on why that is the limit. Or is it the limit? Does that include adding transmission import capacity on the west side of Austin?	White and Reed	The technical import capacity limit is a dynamic variable driven by many factors including real time market conditions and transmission grid status, and not determined solely by existing or planned transmission projects. 2200 MW is based on where AE typically sees load zone price separation, meaning the market is sending a pricing signal indicating some type of constraint. Load zone price separation may not always manifest when imports are at this level and could manifest when imports are higher or lower. A useful data point is to look at what happened on 8/7/2023. The temperature hit 105 in Austin and load reached above 2,900 MW. AE imports went above 2,300MW for a short time and ERCOT issued instructions to generating units inside AE load zone to avoid rolling blackouts. Austin Energy also sees load zone price separation happen in the model at approximately this level of imported power. 250 MW was identified as an approximate upper bound of how much capacity could increase by additional transmission improvements (beyond new projects accounted for in the model already) and absent other non-AE market transmission changes in ERCOT. This estimate was made by internal AE subject matter experts for modeling purposes and is not associated with specific new transmission projects.
Convert 2035 bill impact to real dollars	Rhodes	The 2% affordability target approved by Austin City Council is a straight 2% year-over-year cap in nominal dollars (ie, not adjusted for inflation). To maintain the 2% target as a

		useful reference, we do not adjust the calculated 2035 bill impacts values for inflation for consistency. For simplicity and to avoid any possible misinterpretation of results, we did not do this conversion.
Do you also have available load by hour for a hot summer day, a cold (but not catastrophic) winter day and a moderate day in the spring or fall?	White	Provided via email 10/3/2024 to EUC Chair, co-chair and requesting commissioners.
We need to see the effect of continuing to run the existing gas plants with REACH.	Tuttle	All round II portfolios include REACH applied to gas plants. Portfolio 15 retires the existing gas plants at the end of 2034, while portfolios 16 and 17 continue to run the existing gas plants through 2035, providing the comparison requested.
Include a non-Uri liquidity test (summer) and account for EPP	Reed	The liquidity risk analysis for 2035 has been repeated using the two new sets of assumptions (summer event, and Uri event assuming an Emergency Pricing Program (EPP) limit) and results will be presented for all original and new portfolios.

In addition to comments and requests listed above, Electric Utility Commission members collectively proposed three new portfolios that Austin Energy modeled and analyzed. Those portfolios are summarized below:

Portfolio EUC 3 (15)	625 MW local storage (350 MW 12-hr, 250 MW 4-hr, 25 MW 2-hr), 960 MW local solar, 325 MW demand response, 250 MW import capacity increase, 100% CF, 100% RE as % of load (2,500 MW wind/solar PPAs), REACH on gas, retire Decker/Sand Hill in 2034
Portfolio EUC 4 (16)	725 MW local storage (400 MW 12-hr, 300 MW 4-hr, 25 MW 2-hr), 860 MW local solar, 400 MW demand response, 250 MW import capacity increase, 100% RE as % of load (2,500 MW wind/solar PPAs), REACH on gas, Decker/Sand Hill run through 2035
Portfolio EUC 5 (17)	525 MW local storage (300 MW 12-hr, 200 MW 4-hr, 25 MW 2-hr), 700 MW local solar, 300 MW demand response, 100% RE as % of load (2,500 MW wind/solar PPAs), 100% CF, REACH on gas, Decker/Sand Hill run through 2035