EUC Resource Planning Working Group Questions

Batch 6

Submitted Friday, Nov 17

1) Please provide for 2020, 2021, 2022 and YTD 2023 the percentage of energy produced from each AE resource type (coal, gas, nuclear, wind, solar, biomass)

- Energy by fuel type as a percentage of total generation: Rounding contributes to the slight difference in the individual percentages for wind and solar and the total for renewables in any given year.

	2020	2021	2022	2023 YTD
Biomass	0.4%	1.4%	2.8%	2.1%
Coal	19.4%	20.4%	16.4%	11.5%
Gas	15.7%	13.4%	11.3%	15.2%
Nuclear	24.4%	21.7%	22.6%	24.1%
Solar	10.5%	10.6%	13.0%	13.4%
Wind	29.6%	32.6%	33.9%	33.8%
Renewable	40.4%	44.5%	49.8%	49.3%

General

2) On page 37 of the presentation, Austin Energy produces three colors for its summary matrix. Please list the cut-offs for the difference between green, yellow and red. As an example, under ERCOT market rules, the two green scenarios are assumed to cost $75 and $79 million, while scenarios that are yellow are listed as costing $85, $86 and $92 millions respectively, and red appears to be anything above $100 million. Please indicate the cut-offs for the Red, Yellow and Green criteria for the five columns to the right of the Summary Matrix.

- The cut-off across the portfolios for each scenario is determined based upon the percentage increase from the lowest risk in that scenario. The cut-off is further defined as:

  0 to 7.5% Increase from the lowest risk in that scenario = Green
  7.5% to 20% Increase from the lowest risk in that scenario = Yellow

>20% Increase from the lowest risk in that scenario = Red

3) On Page 37 of the presentation, please further explain what the listed costs assume. Does the cost represent an annual average of all costs over the planning horizon or is the cost the cost in 2035 for one year? Is the cost only the net wholesale energy cost, or does it include other costs like transmission etc? In other words, what is assumed in the costs.

- The costs are broken down into four categories and a total, with the categories being levelized cost, extreme weather risk, local congestion risk and ERCOT market rule change risk.
    - The levelized cost- includes the modeled wholesale energy cost plus the net of the incremental capital and O&M costs of new supply resources and the removal of O&M of existing supply resources when they are retired. It does not include any other fixed costs as they will be the same across all the portfolios. This cost is a one year calculation, but the cost of wholesale energy would be borne annually.
    - Extreme weather risk- this calculation is based upon the market risk modeled for a single extreme weather event such as Uri. There is no probability baked into this model, so this is not an average figure. For the planning horizon this type of event might never occur, or it could happen multiple times in a single year. Ideally this type of event, should it occur, would be paid through our reserve fund, but that would only be able to happen if there were sufficient funds to cover the cost. Barring that, there is no mechanism to recover for such an event prior to an occurrence. In that case, since the bill to ERCOT would be payable immediately the utility would be facing an immediate liquidity issue.
    - Local congestion risk- this is the modeled exposure the utility would face over a period of one year from local congestion costs arising from load zone price separation for each given portfolio.
    - ERCOT market rule change risk- this would be the modeled exposure the utility would face for a given generation portfolio based upon regulatory changes (See the response to question 8a for more details on ERCOT market rule change risks) should they pass. The model doesn't include any probability analysis of the legislation being passed. It is assumed, that should it pass, this risk would become annualized after passage.
    - Total cost/risk- is simply a summation of the four categories, with no assumptions made for probability of occurrence/realization.

4) What is the name of the software or model that Austin Energy used to run its scenario?

- Austin Energy uses UPLAN by LCG Consulting which is a production cost model that simulates the entire ERCOT Market using security constrained unit commitment and security constrained economic dispatch.

5) One of the scenarios modeled by Austin Energy discussed a bolstered DSM portfolio that was listed as providing 20% of the additional resources. Can Austin Energy discuss what assumptions were made for this extra 20% of 200 MWs of DSM? When would that extra DSM be available? Is it treated as a dispatchable resource, or does it simply reduce demand overall?

    - The portfolio with 20% DSM is heavier DSM above and beyond what is already included in the current Austin Energy Load forecast based on the historical trend. The 20% DSM is assumed to be gradually added over the planning horizon (2025-2035). The DSM is modeled as a price responsive dispatchable resource which is curtailed beyond a target price similar to controllable load resources in the current market.

6) Is Austin Energy able to model a scenario that includes a "Virtual Power Plant" resource using distributed resources?

    - We could model it. The portfolio with 20% DSM would provide a similar outcome as a Virtual Power Plant assuming it is transmission connected, dispatchable, all the distributed resources within the VPP respond similarly and have the same target price.

7) Austin Energy did not include geothermal resources in any of its portfolios, assuming that the technology is not ready and it could not address local congestion issues, since geothermal resources are generally less favorable in our load zone than in other areas of the state. Is Austin Energy able to model a geothermal resource if requested?

    - Geothermal could be modeled. It would be treated more like a traditional baseload asset. Location would be an important consideration in modeling as congestion would need to be figured into the mix.
    - While it is true that geothermal was not included in any of the portfolios/scenarios run, it will not be ruled out as a potential resource for meeting our overall (renewable) energy needs either through PPAs or direct ownership if opportunities develop over time.

8) Austin Energy looked at three scenarios for each of its 11 portfolios, including normal operations, "Extreme Weather Risk", "Local Congestion Risk" and "ERCOT Market Rule Change Risk".

- Please detail the assumptions that contribute to the results for these scenarios.

    - Extreme Weather Risk – This scenario assumes a high peak load, extreme unplanned thermal plant outages based on historic observations, and extreme low wind power production for a period of 7 days in Winter and 7 days in Summer.
    - Local Congestion Risk – This scenario is modeled based on the historical observations of the events in the Austin Energy service area after the retirement of the Decker Steam units that have led to load zone price separation.
    - ERCOT/Market Rule Change Risk - There are potential financial risks posed by proposed legislation. One such risk is the Performance Credit Mechanism (PCM). For a more detailed description please see the following link.

https://www.puc.texas.gov/agency/resources/pubs/news/2023/puct_adopts_performance_credit_mechanism_reliability_service.pdf

- What are the severity, duration and frequency of those events as well as their impact on the ERCOT grid and AE's ability to import power?

    - The projects above consider various combinations of weather events that should be modeled and or considered in the derivation of an ERCOT Reliability Standard. The frequency of these events varies from 12 hours to 40 hours and used for establishing reliability standard Austin Energy has assumed the 10 highest reliability hours in Winter and the 10 highest reliability hours in the Summer for the Market Rules Change Scenario. However, the studies performed by E3 for ERCOT considered 10 hours in Winter, 10 hours in Spring, 10 hours in Summer and 10 hours in Fall. The frequency duration of the local congestion is the outcome of the model and changes by year. It mainly occurs during Summer and depends on a variety of conditions in the model. .

- Please identify steps that are planned and/or could reasonably be taken to minimize these congestion risks during the time frame of the plan.

    - AE load zone price separation has become acute due to growth in load and the retirement of the Decker steam generating units. Austin Energy is looking first to demand-side options like DR and the ancillary services market, then to hedges such as Congestion Revenue Rights https://www.ercot.com/mktinfo/crr as well as concurrently looking longer-term at transmission and local resource options such as generation and energy storage.

- Please explain and detail the assumed costs related to the portfolio Effective Load Carrying Capacity.
    - In its assessment of ELCC impact, AE based its calculation on the ASTRAPE Consulting Final Report to ERCOT[1] dated December 2022 for capacity accreditation. Since the ASTRAPE study did not take storage into account, the accreditation for storage was based on an ASTRAPE study performed for the California Public Utility Commission[2] (a recent update of the report has lowered the accreditation value). Austin Energy has assumed the 10 highest reliability hours in the Winter and 10 highest reliability hours in the Summer. The method determines the effective capacity of the portfolio under those high reliability hours using the ELCC for each resource type. For those hours, it provides a credit for generation and a cost for load. The impact is the net of the load cost and generation credit.

[1] https://www.ercot.com/files/docs/2022/12/09/2022-ERCOT-ELCC-Study-Final-Report-12-9-2022.pdf

[2]http s://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20210831_irp_e3_astrape_incremental_elcc_study.pdf

9) For the "ERCOT Market Rule Change Risk" scenario, what assumptions were made in the modeling of that aspect?
    - Did Austin Energy assume that its renewable resources would need to be "firmed"?
        - No, Austin Energy did not assume firming of its renewable resources. Potential rules have not been clearly spelled out as to how they would be measured and implemented.
    - Did Austin Energy assume that the PCM would be implemented with a $1 billion Cap?
        - No. While AE is aware of the $1B cap on PCM, there remains the possibility that costs in excess of $1B could be assessed by some other mechanism.
    - Did Austin Energy assume that beyond any firming and PCM requirements there would be other load serving entity requirements?
        - AE did not consider the additional obligations imposed on load serving entities beyond current, existing obligations.
    - If some of these more restrictive PUCT and ERCOT requirements do not occur, could that change Austin Energy's preferred options going forward?
        - If the proposed PUCT/ERCOT requirements (Market Rule Change) do not materialize, the immediate risk Austin Energy would face from them would be diminished, but it

would not curtail other risks such as Local Congestion Risk and Extreme Weather Risk that need to be addressed to deliver power reliably and affordably. Any decision made needs to consider the entirety of the risk posed, both in potential dollars (like we have modeled) as well as other human consequences such as the potential for the exposure to forced outages due to transmission/distribution system limitations.

10) If the working group asks AE to determine the best possible mix of resources that excludes combustion sources, excludes new nuclear and achieves closure of all existing AE combustion generators (coal and gas) by 2030 or 2035, is staff prepared to offer a solution. Note: This would not need to be constrained by the 1,000 MW addition limit.

- Please see the attached memo that speaks to the evaluation and consideration of alternate portfolios.

11) What are the cumulative (2024-2035) emissions for each resource mix modeled (GHG and each criteria pollutant, separately)?

- Austin Energy is running these numbers and expects to have information available by the January EUC meeting.

Renewable Energy

12) In its presentation to the EUC on November 13th, Austin Energy stated that all 11 scenarios assumed that the renewable energy goals of the 2020 plan were met, that is achieving 65% of load through renewable energy by 2027.

- How many MWs of additional renewable energy capacity would be added compared to our present resources to meet the 65% goal?
- Is Austin Energy assuming all of this additional renewable capacity is utility-scale solar?
- Would all renewable energy being added assumed to be outside the load zone?
- What costs were assumed for that renewable energy acquisition?
    - There are 878 MW of renewables contracts that will expire during the planning horizon and will need to be renewed or replaced with other renewables to meet the renewable goal of 65%. Using optimization and taking into account the load growth and curtailment in the existing portfolio of assets resulted in the addition of approximately 1400 MW of utility scale solar outside of the Austin Energy load zone (due to better economics than wind). We assumed Austin Energy was able to establish

ownership for these resources by leveraging the tax incentives available through the Inflation Reduction Act.

The following table shows the assumptions for the costs used to model the utility scale solar. This is from a slide outlining key assumptions presented at the November EUC meeting.

Technology	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	First Year Available
Utility Solar	1,097	0	8	2025
Local Solar - Residential	0	99	0	2026
Local Solar - Community	0	92	0	2026
Hydrogen Capable Combined Cycle	1,000 - 1,100	4	11	2026
Battery Storage (2-4 hour duration)	1,099	0	15	2026
Battery Storage (8 hour duration)	2,352	0	15	2026
Demand Response	100 - 200	0	0	2026

13) Did Austin Energy take into account the fact that Community Solar Subscribers pay to participate in the program, thus buying down the cost of local solar to the utility and it's other customers?

- The modeling assumptions focused on wholesale level prices. Any premium that might be realized would offset the PSA not the cost of the asset.

14) The IRA provides additional tax incentives if certain clean energy resources including storage and renewable energy resources are located in Energy Communities as well as in low-income communities. Has Austin Energy considered these benefits when modeling certain resources?

- Austin Energy only assumed tax incentives that are known. Since the location of these potential resources is not known, Austin Energy did not include additional benefits attributable to siting resources in low-income communities.

Batteries:

15) Has AE evaluated an optimum mix of battery technologies, costs, durations and locations as a portfolio to reach Zero Carbon 2030 or 2035?

- We looked at enough portfolios of generic energy storage and renewable energy technologies to conclude that no battery-only solution or combination of energy storage and renewables could currently meet all of the boundary parameters outlined in the attached memo. Determining an "optimum" mix of energy storage at this time would require perfect information about the future including the timing and performance of new energy storage technologies as well as the actions of other energy market participants. This is not a realistic expectation, particularly when looking out to 2030. To simplify modeling, we assumed the performance of lithium-ion batteries as a baseline. One way to accommodate estimated future costs for other battery chemistries would be to conduct sensitivity analysis against lithium-ion battery cost assumptions.

We feel confident that energy storage will play an essential role in managing energy needs in the future, but we also understand that decisions we and other market participants make now and into the future will have a significant influence on the best future approach. Using sensitivity analysis in our modeling today will give us a better understanding of the potential for energy storage but cannot tell us what the perfect mix is in the face of an uncertain future.

16) Has AE evaluated a progressive buildout of a portfolio of batteries within the load zone to reach 500MW or 1000MW by 2035?

- No.

17) Why didn't Austin Energy model other forms of long duration energy storage, beyond lithium-ion batteries? Based on information provided by some vendors, is Austin Energy able to model a longer-term multi-day storage? For example, Form's (https://formenergy.com/) 100 hr. iron-based battery

- The performance of various energy storage chemistries will not have a significant impact on the type of modeling we have been conducting. We have looked at various combinations of energy (MWh) vs. capacity (MW) for generic energy storage systems to include energy/capacity mixes that would enable several days of dispatch. As stated already we did not find any realistic combination of energy/capacity for energy storage that meet the boundary parameters outlined.

  Austin Energy has had discussions with Form. At this time, no vendor has demonstrated a viable solution (performance and economics) with a projected timeframe to fit the planning horizon. We have not found a storage-only solution on the horizon that could pass both the affordability and extreme weather scenarios.

18) Has AE evaluated and modeled ESS Tech's (https://essinc.com/) 6 to 12 hr. iron-salt flow batteries?

- No, please see previous responses referencing specific chemistries.

19) Has AE evaluated and modeled vanadium flow batteries and from which companies?

- Austin Energy has looked at vendors offering a variety of battery chemistries. Please see the responses to previous questions for more context.

20) With a 30GW battery queue in ERCOT, has AE done any analysis of the types, applications and probable economics for these batteries?

- Austin Energy has analyzed the market and system potential for many types and configurations of energy storage. Determining when a technology pencils out is a straight-forward exercise. In addition to ongoing research into battery chemistries and vendors, Austin Energy routinely issues Requests for Proposals (RFPs) to keep abreast of vendors, technologies, applications and the economics for energy storage.

21) Can the model be adjusted to only allow battery charging when the market price that would be cost-effective?
- Yes, that assumption was built into the scenarios/portfolios we ran.

22) Why didn't AE examine battery technology options that don't rely on imported materials? These do exist.
- We did not exclude any particular technologies based upon an assumption that there would not be a domestic alternative. Sourcing was considered as a component of risk in the overall technology readiness evaluation for some portfolios.

<u>Hydrogen and Combined Cycle Generators:</u>

23) In its presentation to the EUC, Austin Energy assumed that the cost of new "hydrogen-capable combined cycle" plants would be in the $1,000 to $1,100 per Kilowatt range.

- What is that cost estimate based upon?

  - The cost estimates are based upon our discussions with manufacturers and developers.

- Is that the cost only for the plant itself, or does it also include the cost of electrolysis to supply the hydrogen?

  - It is the capital cost for the plant only. We have seen indicative pricing for hydrogen (fuel) with subsidies that claim to be able to reach cost parity with natural gas.

Ultimately, AE will be an off-taker on a $’s per unit contract, not in the business of making hydrogen.

24) What percentage of hydrogen would these modeled/proposed combined cycle plants burn for each year modeled?

- The resource can burn hydrogen on Day 1, but due to the unknowns of green hydrogen availability, we made some assumptions for modeling purposes. We have assumed 25% hydrogen for the first 3 years , 50% hydrogen for the next 3 years, 75% hydrogen for the following 3 years and 100% by 2035. Remember, these are projections made for modeling. Actual percentages may vary.

25) In its technology readiness assessment, Austin Energy notes that the supply of hydrogen is not currently available in the Austin area. Since the analysis gave a “Green” for technology readiness for HCCC, what assumptions are Austin Energy making about hydrogen being available in the Austin area? Please provide any sources to support these assumptions.

- HCCC was given a green for readiness based upon the combination of three factors.
    1. The ability to provide immediate, dispatchable power in a manner that passed the extreme weather and local congestion scenarios;
    2. The estimated capability of generation/combustion technologies to be 100% hydrogen capable at scale within the timeframe of the plan; and
    3. A credible pathway to affordable green hydrogen production made available locally, backed up with other renewable options such as importing green hydrogen by truck or pipeline, or using natural hydrogen, renewable natural gas or hydrogen production with carbon sequestration as potential bridge solutions. We would also consider renewable credits/offsets as an option of last resort until a workable source for hydrogen is developed.

26) Is Austin Energy assuming hydrogen production will take place co-located with renewable energy production?

- No. The location of hydrogen production will need to weigh issues around electricity transmission congestion as well as transport of hydrogen to its point of use among several considerations. Co-location with renewables is not out of the realm of possibilities but is not considered a given. Austin Energy is not looking to be a producer of hydrogen, but would look for a partner to produce hydrogen and develop the business case, to include the location for production.

27) Is Austin Energy assuming hydrogen production will be time-matched with renewable energy production?

- The current assumption is that hydrogen production will be timed to coincide with carbon-free generation.

28) Is Austin Energy assuming hydrogen production will rely on new renewable energy production procured for that purpose?

- We have not made assumptions about the source of power to produce hydrogen other than that it will be carbon-free.

29) Given that DOE shows power plant generation to be about the last economic use case for green hydrogen, when would AE anticipate being able to reach 100% green hydrogen?

- No one can say for certain when green hydrogen will have an economic business case. However, we see the potential for using IRA funds to expedite achievement of that objective and will look to actively pursue that avenue for project funding.

30) What does AE anticipate the levels of CO2 emissions to be from the plant by year until the conversion to 100% hydrogen and how does that fit into Austin's carbon reduction goals?

- We selected percentages by year for hydrogen for modeling, but cannot make predictions about how quickly the transition will actually occur. AE looks collectively to industry experts to anticipate timelines for technology advancement, sometimes citing the predictions of others that have been well vetted. The development of hydrogen technologies is one path for reaching Austin's carbon goals, but the plan also allows for alternative pathways to carbon-free. That said, all indications from subject matter experts in the hydrogen field are favorable that, based on current industry information, hydrogen should be a viable path to carbon-free by 2035.

31) What does AE anticipate the lifetime of the plant to be, including how many years running only natural gas, how many years of mix and how many years of 100% hydrogen?

- Austin Energy anticipates the hydrogen-capable plant will have a life of 35 to 40 years, similar to the lifespan of a gas plant. We expect it will be running on natural gas initially, and once green hydrogen is readily available, the fuel source would change. That said, the ultimate goal is future-proofing future generation. If another carbon-free fuel source is readily available and economic, Austin Energy will consider it as well.

32) How does AE anticipate dealing with NOx emissions from high temperature hydrogen combustion? What would resulting emissions be?

- Emissions from high temperature hydrogen combustion technologies are a specific point of focus for leading manufacturers such as Mitsubishi, Siemens and General Electric. Some of the existing OEMs have dropped the NOx output down to 3ppm in trials, which is the exiting output for current natural gas turbines. It seems reasonable that all OEMs will be able to meet or better their present emissions limits.

33) How and when does AE anticipate permitting and completing a pipeline suitable for hydrogen transmission to the proposed plant?

- Austin Energy does not have firm plans, at this time, for securing a supply of hydrogen. Permitting and transportation of hydrogen from the point of production to the point of use would be an integral part of any considerations for siting of hydrogen production and electricity generation. We would look to partner with a company or companies that can demonstrate the ability to site, permit, build and operate the appropriate infrastructure.

34) How many MW of wind and how many MW of utility scale solar are part of the resource mixes that were modeled?

- Assuming the question is referring to how much wind and utility scale solar is added to the portfolios to achieve the 65% renewable goal and maintain that level at a minimum thereafter, please see the response to Q12. For more information please see the table below:

Portfolios	Renewable resources PPA expiring in the planning horizon	Renewable Resources in MW added to meet 65% goal and maintain	Portfolio specic renewables addition in MW	
		Utility Scale	Behind the meter Solar	Community Solar
CF_2035	(878)	1400		
CF_2035 Without REACH	(878)	1400		
CF_2035 + LSOL	(878)	1400	500	500
CF_2035 + LDST	(878)	1400		
CF_2035 + HCCC	(878)	1400		
CF_2035 + LSOL+ HCCC	(878)	1400	100	100
CF_2035 + LDST + HCCC	(878)	1400		
CF_2035 + LSOL + LLDST + DST	(878)	1400	400	400
CF_2035 + LLDST + DST + HCCC	(878)	1400		
CF_2035 + LSOL + LLDST + DST + DSM	(878)	1400	300	300
CF_2035 + LSOL + LLDST + DST + HCCC	(878)	1400	100	100

35) In which location(s) does AE envision locating the new combined cycle plant(s)?

- Austin Energy has not determined the location of a potential new plant. This would be determined as a part of the due diligence prior to and during the RFP process.

Energy Efficiency:

36) In addition to the present tax rebates and AE incentives for many home EE opportunities, how is AE planning to expand the push for home electrification and EE in light of the potential 100% rebates for low-income homeowners and 50% rebates for medium income homeowners under the High Efficiency Electric Home Rebate Act (HEEHRA) portion of the IRA? Has AE modeled how this can contribute to expanding EE goals over the next 10 years? https://www.rewiringamerica.org/policy/high-efficiency-electric-home-rebate-act

- Energy Efficiency for low and middle-income customers is an area of particular interest for AE's Energy Efficiency programs. Tax rebates and incentives will likely be made available in two ways: direct to the customer incentives and incentives through grants received by Austin Energy. For incentives that go straight to the customer through tax incentives or cash payments, Austin Energy's role is first and foremost to support them through marketing campaigns making customers aware of these incentives. In addition, we will look to develop training for the local contracting community and possibly create marketing collateral supporting their work in making customers aware of these incentives.

  For incentives that are less than 100% there may be a role for additional Austin Energy incentives to push consumers to move. This would be determined on a program-by-program basis. Incentives that have been available in the past include insuring low/zero interest loans or additional direct incentives, both of which could be a path to aiding customer adoption.

  Austin Energy will continue to be a key partner for our customers to serve as a trusted adviser/gatekeeper to ensure that the products and services being installed are high quality and not predatory, and to support sustained workforce development. The wave of new technologies is exciting, but there will need to be whole teams of installers and maintenance support for many years to come to ensure appropriate technology implementation.

  Electrification as a trend has been baked into AE's load forecast, which then feeds our models. AE has not made any substantial changes to our forecasts in anticipation of an escalated rate of electrification due to the availability of additional IRA funds.

Beyond these baseline ways of integrating electrification into our planning, we are also working to update our generation plan to focus program goals on greenhouse gas reduction rather than megawatt savings in order to more effectively capture the opportunities of electrification as part of a broader climate strategy.

Geothermal:

37) Is any significant level of geothermal generation economically and technically feasible at the Fayette location?

- At this time, given the state of the technology and the industry, it does not appear feasible in the near future.

38) Why did AE assume geothermal resources are only available in South Texas? This doesn't align with the resource maps we've seen.

- We did not assume that South Texas resources were the only resources available. West Texas, in particular, has a significant amount of oil and gas production (petrothermal), and other areas of Texas have significant petrothermal and hydro-thermal resources. Indications from industry experts are that the short-term potential for petrothermal projects was more pronounced in South Texas due to the abundance of recently abandoned wells, the types of wells, and the depth of the resource. Hydrothermal production appears to be further down the road from a market readiness perspective for the types of resources found in Texas.

  Resources within the Austin Energy Load Zone appear to be deep underground and subject to a high degree of uncertainty for their short-term commercial viability.