TAP Resource Adequacy and Modeling Subgroup
Feedback on Proposed Energy Reserve Margin (ERM) Criteria
11/1/2021 and 11/18/2021

This feedback to HECO is based on HECO's slides and presentation on 11/1/2021 related to their proposed Energy Reserve Planning (ERM) criteria. It also answers additional questions posed to HECO from the PUC related to the TAP's view on ERM and related issues.

As with all TAP feedback, please consider these comments as recommendations – the final choices are yours of course. And some of these topics are quite complex, so the few sentences included here just scratch the surface and hopefully point in a direction we think might be helpful.

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TAP feedback and comments are divided into three categories:

1. Informational, no action needed
2. Action required, expected in coming months
3. Concern or suggestion, for future discussion or consideration
4. Clarification needed

High Level Summary

Detailed comments, suggestions and recommendations about HDC, ERM and other aspects of reliability and adequacy are provided below. In summary, the main points are:

- Full probabilistic resource adequacy analysis is still necessary as an additional step to verify the ERM for future portfolios as these are being developed
- HDC requires additional consideration and justification which can be addressed in the future, provided that the full resource adequacy analysis is utilized in the near-term.

Questions for TAP

<u>Capacity Expansion</u>

- Is it appropriate to use an ERM for long-term capacity expansion modeling?
    - Answer: Yes, it is sufficiently justified for a first use in the current IGP, provided additional consideration is done on the HDC values and that a probabilistic RA analysis is done as a way to verify the portfolio at appropriate points. It may also be possible to achieve generation adequacy using a simpler capacity credit framework, harmonized with ELCC found via iteration with an RA model.
- If so, what is the appropriate ERM %?
    - Answer: 30% seems appropriate for now, but need to revisit as system changes and more information on stage 1 and stage 2 projects known. Further analysis at 20% and 25% may also be useful to determine whether a lower number could be used. The appropriate ERM is the one that drives the capacity expansion model to select a portfolio that achieves adequate reliability at reasonable cost in the RA model.
- Is it appropriate to use production profiles or an HDC for capacity expansion modeling?
    - Answer: Suggest calibration and improvements to HDC. Ideally full RA analysis is also done but for Capacity expansion something like HDC might work, so long as tested. One possibility would be to run the capacity expansion model with each approach (or others suggested in this document) and adjust ERM for each approach until adequate reliability is found. Then compare all the different reliable plans, examine the significant differences that exist between them, and stress-test the lowest-cost plans (by conducting probabilistic analysis and closely examining the most difficult dispatch days). That would give guidance on which form of capacity credit works best.
- If HDCs are used, what value should be used? 1 sigma or 2 sigma?
    - Answer: Percentiles may be better. Calibration should be done.
- Applying ERM and HDC now, is there a risk of overbuilding/underbuilding? Does it leave sufficient flexibility for the future?
    - Answer: The risk is not necessarily overbuilding because most of the new capacity is being added to meet the renewable portfolio standard and/or due to lower cost energy from renewable resources. The question is rather – does the system have surplus capacity available to continue with thermal retirements as Stage 2 and additional renewable resources are added? A conservative approach to this question is reasonable given that new systems do not have operational experience and continued availability of

the thermal fleet is not prohibitively expensive. If ERM is set at a level that provides the desired reliability level in the RA model and HDCs are set in a way that minimizes cost, then the capacity decisions are by definition correct. It is possible that conditions in future years may differ from what is forecasted today, but there will be some time to adapt to that (the long-term plan is not locked-in) and that is not an ERM/HDC problem per se.

- Should the ERM or capacity expansion modeling account for the worst weather day? How is the worst weather day defined?
    - Answer: This could be captured in the resource adequacy back-check, but not necessarily needed in the RESOLVE capacity expansion step. Future work may want to examine how to ensure worst case days are included, and might consider worst PV day, worst wind day, worst wind+PV and worst load compared to renewables days. In later years, it may be more efficient to include poor weather days in the RESOLVE sample set, with appropriate weights, rather than relying entirely on iteration between RESOLVE and the RA model to find the right capacity credit for renewables.
- Should the ERM account for more extreme weather than historically observed?
    - Answer: No, this can be handled in the resource adequacy back check.

<u>Resource Adequacy</u>

- What methodology is appropriate for evaluation in the Resource Adequacy step?
    - Answer: Sequential Monte Carlo production cost simulations, with 500+ samples (at least for Oahu – smaller systems may have less thermal outage draws so 100-200 may be suitable)
- In the PLEXOS Resource Adequacy evaluation, what level of HDC is appropriate?
    - N/A, multiple weather years should be used with full chronology instead of an HDC approach in the resource adequacy evaluation.
- If there are capacity shortfalls in the resource adequacy process step of IGP, is it appropriate to re-run RESOLVE with an increased ERM %?
    - Answer: Yes, but inspection of the underlying shortfalls should be conducted first to understand the size, frequency, duration, and timing of shortfall events and compare the shortfalls against resource additions in RESOLVE. If the RA events occur in periods that are not represented in RESOLVE, consider adding them to provide the model with more information about the kind of stress events it needs to plan against. Also assess whether the capacity credits being used will direct RESOLVE to add the right type of capacity to serve these shortfalls.

TAP comments during meeting and HECO responses

1. **HDC discussion**
   Below discussion is about how HDC is calculated and can be improved. In general, TAP would suggest more justification is needed for HDC calculations, or HECO should adopt a framework that more directly accounts for each resource's contribution to generation adequacy. We agree with HECO that detailed RA analysis is still required as a check on the output of RESOLVE ERM analysis. RA analysis could also be used to set appropriate capacity targets and credits for use in RESOLVE, for individual resources or groups of resources, with iterations until an equilibrium between the RA assessment and RESOLVE modeling is reached. It was suggested by some of TAP that the current HDC might not be useful as it assumes a worst case availability for renewables in every hour combined with 100% availability for thermal plants. Some of the below additional analysis and potential changes may help address this. California's exceedance methodology was also suggested as an alternative to the HDC for HECO to review and consider. The TAP is unsure of the potential implications of the limitations for long term planning. The HDC approach may get an answer close enough from a system reliability perspective but may not count different resource contributions appropriately from a cost perspective and thus RESOLVE may not provide an optimal buildout. This needs further analysis in future planning cycles if it is not addressed at this stage.

TAP looked at HDC and had following comments/recommendations:

- HDC is based on historical production profiles, which have a mix of technology (e.g., fixed, single-axis, and dual-axis tracking for solar). Is this representative of future plants?
- There was concern raised by the TAP that historical production profiles were limited because 1) there is not a long historical record available to reflect the full range of weather variability, 2) future plant technology and configurations (like turbine height for wind or DC:AC ratios for solar) may not be represented by existing plants, and 3) more geographical averaging of resource will occur as capacity is added.
- HDC is calculated as the hourly average of a few years of historical production profiles. In the ERM evaluation, 1 sigma and 2 sigma are deducted from the production profiles to create additional cases. [HECO to clarify/provide additional information. Please specify the year/s currently considered.]
- The use of a relatively limited amount of time series data raises concern because of the possible omission of difficult days and months that need to be captured in the analysis.
- Using a 3 day sliding window may not be the best way to produce HDCs. 30-day sliding window or monthly aggregation approach may be better and should be investigated in this round with the view of adopting in future cycles. This would increase the sample size by 10x.
- The approach of using 1 sigma raises another concern because this technique is not based on the underlying distribution. Suggest using percentiles or give rationale for 1 or 2 sigma. General agreement that wind and solar should use same assumption unless there is a clear rationale as to why they are different.
- HDC for renewable and thermal plants and batteries in RESOLVE should be set at a level that reflects their contribution to adequacy as found in the resource adequacy model. This may be achievable by using expected availability de-rated by forced outage rates in the ERM calculations. Or it may be preferable to use a framework, such as an ELCC calculated in the

resource adequacy model for each resource (wind, solar, batteries, thermal capacity) and a capacity target equal to peak or average demand plus ERM.

- It is suggested that HDC approaches still need more analysis and experience, and there is a need to adjust these assumptions as more data is received (e.g. stage 1 and 2 in service).
- Potential to bifurcate 2035-2040 vs nearer term decisions. ERM may be more suitable in longer term, though need to ensure assumptions accurately reflect risks of each resource type and how the different resources interact (e.g. how storage operates at different levels of solar).
- Aspects like how to choose sliding window, percentile to be chosen, how many years, whether to use historical or synthesized profiles (e.g. based on NSRDB) for plants that don't exist, and other factors raised, should continue to be examined.
- Calibrate historical generation profiles with simulations using NSRDB resource data or similar by analyzing the degree to which historical and simulated profiles match and proposing a method for processing simulation data to be suitable for planning use. Using simulated data may be particularly important for new resources such as offshore wind, and such datasets also offer longer time series with realistic geographic averaging.
- Review California's exceedance method and compare to HDC.
- Calculate HDC for resource type portfolio rather than individual projects. [This is already done by resource type so HECO may just need to clarify].
- TAP suggests that if HDC is used, HECO may want to test a method that looks at the full day, and identify a 30 day rolling average of daily energy across 20+ simulated weather years. Then HDC could be mean of 30 day rolling average minus an appropriate percentile (instead of standard deviation). Daily energy would then be allocated to an hourly profiles based on the proportion of the average daily hourly profile. So if the HDC solar day has 20% of the energy as the average day, each hour of the solar profile would be reduced proportionally. While testing such an approach, HECO may also want to examine whether an HDC for thermal resources is appropriate.
- One member of TAP asked whether the RESOLVE modeling will allow batteries to charge from thermal plants in the 100% RPS cases? That could reduce the need for thermal capacity on low-sun days, because the thermal plants could run all day to charge batteries for the evening peak.
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2. Discussion on ERM

TAP discussed the ERM and following was main takeaways:

- HECO provided TAP a justification document.
- For now, it appears to be a suitable criteria given the current resource mix (refer to Telos analysis) but also show when and how one would change that number (change in portfolio, look ahead horizon, etc.). Some of the underlying factors assumed for current studies may change over time; for example, the impact of forced outages may decrease as generators are retired, but load uncertainty may increase with electrification.
- Further analysis could examine 20%, 25%, 30% ERM if resource mix is significantly different under different ERM levels.
- There is a concern regarding uncertainty and how do you do the transition. Some factors involved are how to capture mature vs immature outage rates and inclusion of longer mean-time-to-repair to

some selected outages. A root-cause analysis could be performed to identify these factors. Other utilities now make assumptions about outage rates to be conservative for new technologies.

- There is a potential disconnect on retirements. After Stage 2, the system will have surplus capacity, therefore the ERM will not be a binding constraint unless more capacity is retired. Therefore the ERM is critical for retirement decisions and does not necessarily influence timing or type of new renewables.
- ERM has no value in understanding the probability of losing load. Instead, there is a need for improved data availability and transparency of the results to inform the various conditions. Full RA analysis still needed
- ERM is more important to understand retirement implications than for wind/solar build analysis, given given required renewables buildout under Stage 1 and Stage 2.
- Identifying where the conservative buffers are may support future analysis. The current approach is layering in conservatism in multiple places for long term planning. Trying to move as much as this to one place, which can then be tweaked and examined in sensitivities would be helpful to understand how assumptions impact the results.
- ERM (or some other capacity measure) is needed to drive extra capacity into the RESOLVE plan to achieve adequacy in the RA analysis. However, great care must be taken in assigning HDC (or possibly annual dependable capacity) to each resource to ensure the capacity credits don't bias the model in favor of one resource or another. Capacity credits for each resource in RESOLVE should be harmonized with effective load carrying capacity found via resource adequacy analysis. This capacity contribution will vary depending on what else is included in the portfolio, so this will likely require iteration between RESOLVE and the RA model. Iteration is also needed to select an ERM for RESOLVE that will produce a plan that achieves the desired LOLE or LOLP in the RA model.

Other discussion/topics

3. Is the correlation between load and solar/wind profiles considered in the model?
   Based on the analysis of Telos, load variability is not as severe in Hawaii relative to mainland systems with more varied weather and extreme events. This is an area to consider in the future, with correlated wind/solar/load profiles examined, but current methodology is sufficient for the first phase.

    4. Slide 16 – clarify that PV+BESS capacity credit is based on what RESOLVE builds, not an ELCC or similar type metric.

5. How is the probabilistic model reflected in the RESOLVE model? (Slide 17)

   The RESOLVE model is deterministic. It uses the 2019 NREL data (NSRDB) for solar profiles and the 2018 load shape. The stochastic approach is done in PLEXOS model, particularly in the outages. There is no stochastic approach done on the weather side (or solar/wind profiles). [HECO to clarify/provide additional information. Please specify the year/s currently considered.]
   It is suggested is to rerun the RESOLVE model using multiple weather years, in addition to the year/s currently considered. This may take the form of different runs under each weather year, or including multiple years to determine representative days in RESOLVE – both should be examined.

Also please confirm which year is being used for load – ideally should be same as wind/solar (realizing above point about this potentially being less important in Hawaii).
HECO is also requested to provide more information about whether the worst weather day (and how that is defined) is included in the RESOLVE representative days.

6. Plot – ERM Target Percentage vs Unserved Energy (MWh): It is suggested to normalize the value of the y-axis (Unserve Energy) for easier comparison among islands.
7. How is demand response represented in the ERM model?
   There are several demand response resources included in the ERM model (see https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents). The demand response resources assumed in 2030 is listed in the table below. [HECO to clarify/provide additional information including resource definition (spell out acronyms and any additional information), number of MW per resource]. If not included already, please let TAP know if EVs are considered.

resource	period	conventional_dr_availability_hours_per_year	daily_capacity_factor
CIDLC	2030	30	1.00
FDR	2030	80	0.04
Load_reduce	2030	416	0.17
Load_reduce_3	2030	416	0.17
RDLC	2030	43	1.00
SBDLC	2030	4	1.00

8. What is the purpose of the PLEXOS model in the ERM testing process? Is it to assess ERM or to measure reliability?
   Using the expansion plan from the RESOLVE model, PLEXOS model is used to assess whether there is sufficient ERM, not to evaluate ERM itself.

   9. Is zonal analysis needed for some of this?

Telos/HNEI analysis

- Telos used NREL's NSRDB to represent the 21-year solar data (Note: HECOS's PLEXOS model used historical production profiles).
- It is suggested to utilize the historical production profiles for existing plants and use NSRDB for new plants without historical data. This practice is currently being done in the Australian NEM. They do not use NSRDB, but they use SAM to generate solar profiles using their solar data (GHI, DNI, and DHI).
- Telos assumed no outages for solar or battery plants as well as for transmission lines. These outages could be considered in the future.
- Suggest to continue using detailed probabilistic RA analysis as a check on portfolio, though not as an input to RESOLVE. Both ERM and RA should be used. [Others in TAP agreed with this point]
- Telos are updating with more wind data in Oahu and if results show that this is useful, suggest using similar approach.

- Telos show that 30% ERM seems right for current portfolio, though more calibration needed between 25%-35% (e.g. at least run 25%, 30%, 35% in testing – others in TAP agree). With offshore wind the answers do change, showing need to revisit 30% assumption as major changes happen. Note: not clear if the answer changes for offshore wind due to onshore being used for HDC in RESOLVE (but Telos using NREL data) or whether it is due to the actual changes in resource mix.

Hawaiian Electric Response:

The following are Hawaiian Electric's recommendations to proceed with ERM and HDC that incorporates many of the immediate recommendations (highlighted by red text) made by the TAP for this first IGP cycle.

Capacity Expansion Analyses in RESOLVE

- For the purposes of capacity expansion planning in the RESOLVE model, the Company recommends using the ERM methodology as previously described, with ERM targets validated by the TAP, [1] and HDC's validated by supplemental testing. (e.g., 30% ERM target for Oʻahu, Hawaiʻi Island, and Maui and 60% ERM target for Molokaʻi and Lānaʻi, and 2 sigma PV and 1 sigma wind HDCs)
  - The 30% / 60% ERM targets were initially based on providing replacement energy for the loss of the largest unit on each island. In addition the Oahu target was compared to its prior LOLP guideline to ensure similar reliability. The 30% targets were then validated and deemed reasonable based on independent analyses conducted by HNEI and Telos Energy.
  - Regarding the use of HDCs (2-sigma for PV and 1-sigma for Wind), the Company tested 30% ERM on Oʻahu for year 2030 using the proposed HDCs, substituting 1-sigma for PV, and replacing HDC with production profiles for wind and PV. In all 3 cases, the Company removed 367 MW of existing firm thermal capacity from the system (simulating a year 2030 case). The resource plans developed by the RESOLVE model did not result in any significant overbuilding when confirmed in the ERM test and production simulation conducted in PLEXOS. In the 2-sigma PV, 1-sigma wind case, RESOLVE built a new 57 MW firm capacity generator. In the 1-sigma PV and production profile case the model chose not to build the 57 MW of firm capacity. Having an additional 57 MW of firm capacity is relatively marginal given the size of the O`ahu system and may provide additional resilience benefits to customers that can serve the grid during an emergency situation (i.e., natural disasters damaging solar or wind plants, prolonged poor weather, etc.).
  - The results for Oʻahu described here are indicative of the results for Hawaiʻi Island, Maui, Molokaʻi, and Lānaʻi and in line with independent verification of the ERM conducted by Telos Energy for Oʻahu and Maui.
  - Further evaluation of the ERM with higher levels of variable renewables on the system is recommended once operational performance is realized, and real operational experience is gained with the hybrid solar and storage plants that are expected to come online in the next few years. Fundamentally, reliability analysis assesses the risk of

[1] See Telos Energy recommendations at pages 7, 9-10, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/technical_advisory_panel/20211101_tap_hnei_grid_integration_erm_calibration.pdf.

having sufficient generating resources to meet customer demand. Using the recommended approach by the Company for the first IGP cycle appropriately mitigates the risk of uncertainty of variable renewable contribution to demand at each hour of the year. As the first cycle of IGP is expected to focus on the next 5-10 year action plan there will be opportunities to make adjustments over the next 10-20 years when such operational experience is collected. In other words, using the approach proposed for this first IGP cycle does not crowd out future opportunities or the Company's ability to accelerate other generating unit retirements should operational experience allow us to do so.

However, if the Commission is inclined to not adopt the Company's ERM and/or HDC recommendation for use in RESOLVE for this first IGP cycle, then the Company proposes the following alternative to further analyze HDCs directly in line with the TAP's recommendations for this first IGP cycle. This alternative method relies upon simulated data to characterize the capacity value of variable renewables in lieu of actual production or the appropriate margins to mitigate errors in simulated data. Should real operational performance of existing variable renewables and new hybrid solar and storage plants prove that their calculated capacity values are overstated, the planning criteria may be violated and retirement of fossil generation may be delayed or an expedited procurement of new resources for reliability and capacity needs may be triggered.

- Evaluate alternative calculations for the HDC
    - The TAP expressed a desire to improve data availability for the variable renewable production using simulated data provided by NREL, given that the Company's historical records are limited.
    - An alternate HDC will be developed using simulated NREL weather data to expand the available dataset used in its calculation. The calculation method of this HDC will adopt the TAP's recommendation to average the aggregated monthly data for solar production. This will significantly expand the dataset.
    - The Company has reviewed the California exccedance methodology, and will adopt a similar approach. To determine the appropriate probability of exceedance the Company will compare the NREL simulated data to the Company's historical solar data.
    - To calculate the wind HDC the Company will use its longer historical dataset applying the same methodology as described above for solar by calculating the monthly averages on all historical production years. The probability of exceedance will be determined by comparing the monthly averages to different historical days.
    - NREL simulated wind data is not being used due to high variability of wind data and the lack of robust data from NREL.
    - The HDC will be expressed in terms of exceedance probability rather than standard deviation deductions. The effects of varying statistical confidence intervals on the available variable renewable production potential will be evaluated comparing exceedance probability vs actual production.
    - The Company will consult the TAP in determining the final probability of exceedance.

<u>Resource Adequacy Analyses and Validation in PLEXOS</u>

- Conduct a resource adequacy evaluation utilizing the hourly chronological PLEXOS model and probabilistic modeling techniques in selected plan years

- Telos Energy noted that while ERM can be used in RESOLVE, a resource adequacy back check is still needed to confirm the reliability of the resource portfolio.[2] Per the IGP modeling framework in Figure 3-1, this would entail developing a resource plan in RESOLVE and evaluating the reliability of the resulting plan in PLEXOS, with the understanding that the RESOLVE model cannot be used to solve for all situations and other tools should be integrated into the overall process.[3]
- The TAP recognized that resource adequacy evaluation methods using probabilistic modeling can be used to validate the deterministic approach to develop long term plans.

- Calculate unserved energy, unserved energy hours, LOLE, and effective ERM metrics for the evaluated resource plan
- Include the probabilistic modeling of forced outages for thermal units and weather years for variable renewable production
    - Initial comments from the TAP provided in the TAP Resource Adequacy Subgroup meeting on November 1, 2021 indicated that several stakeholders endorsed the probabilistic methodology utilized by Telos Energy to test multiple weather years for variable renewable production and multiple forced outage patterns for thermal units.
- Include the probabilistic modeling of forced outages for battery energy storage systems
    - Recognizing that storage resources may not exhibit perfect availability in actual implementation due to equipment failures,[4] an estimated nominal forced outage rate will be included to reflect an amount of unavailability. Grid-scale load shifting batteries are new to the electric utility industry and do not have a long track record of operations. Therefore, a forced outage rate based on operational experience is difficult to calculate in the near term so a nominal value such as 10% can be used initially until the industry gains sufficient experience to predict the reliability of battery storage systems.
    - In the November 1, 2021 TAP Resource Adequacy Subgroup meeting, the TAP commented on the usage of mature vs. immature forced outage rates or including a longer mean time to repair as a consideration for hybrid plant outages.

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[2] See Telos Energy recommendations at pages at 10.

[3] Grid Services and Planning Criteria Feedback filed on June 1, 2021 in Docket No. 2018-0165 at 4 and 10.

[4] While typical battery outages are expected to be a fraction of the total capacity for maintenance due to the modular nature of battery storage systems; there have been recent whole battery plant failures that warrant considering the availability of the battery. For example, https://www.reuters.com/world/asia-pacific/fire-breaks-out-tesla-australia-mega-battery-during-testing-2021-07-30/ , https://www.utilitydive.com/news/vistras-300-mw-moss-landing-storage-facility-remains-offline-after-overhea/606178/ , and https://www.azcentral.com/story/money/business/energy/2019/04/23/arizona-public-service-provides-update-investigation-battery-fire-aps-surprise/3540437002/