Improving Generation Reliability Assessment

by

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ERCOT[2] uses a spreadsheet approximation to estimate the capacity value of wind and solar resources in its CDR[3] and SARA[4] reports. Average levels of wind and solar power are calculated for peak demand hours to estimate their peak load contributions. Solar has an 80% capacity value aligning well with the peak loads. As solar grows, it results in a net load shape called the duck curve[5] shifting the net peaks to nighttime. ERCOT's analysis misses that the solar capacity decreases. Conventional generators serve the net load after subtracting wind and solar. Net firm load[6] not served is measured as a loss of load expectation or LOLE[7].

When the net peak load shifts to nighttime, adding solar does not pick up more load. I reported this effect in 2015 at an IEEE Power Engineering Society meeting[8], which led to NERC[9] hiring me to study the capacity values of wind and solar and reserve margins needed. These were published in an IEEE paper[10] in 2016. NERC gave a list of recommendations at the end of the poster session presentation[11]. This paper updates the 2016 study using 2021 data.

The RTS3[12] software is open source in both Matlab and Fortran code. It has been benchmarked against an exact solution to the IEEE RTS[13] accurate to five decimal places. The math used in RTS3 retains its exactness accuracy for large systems and executes at very high speeds. All the files needed to run this study are posted at https://egpreston.com/2022Bas.zip.

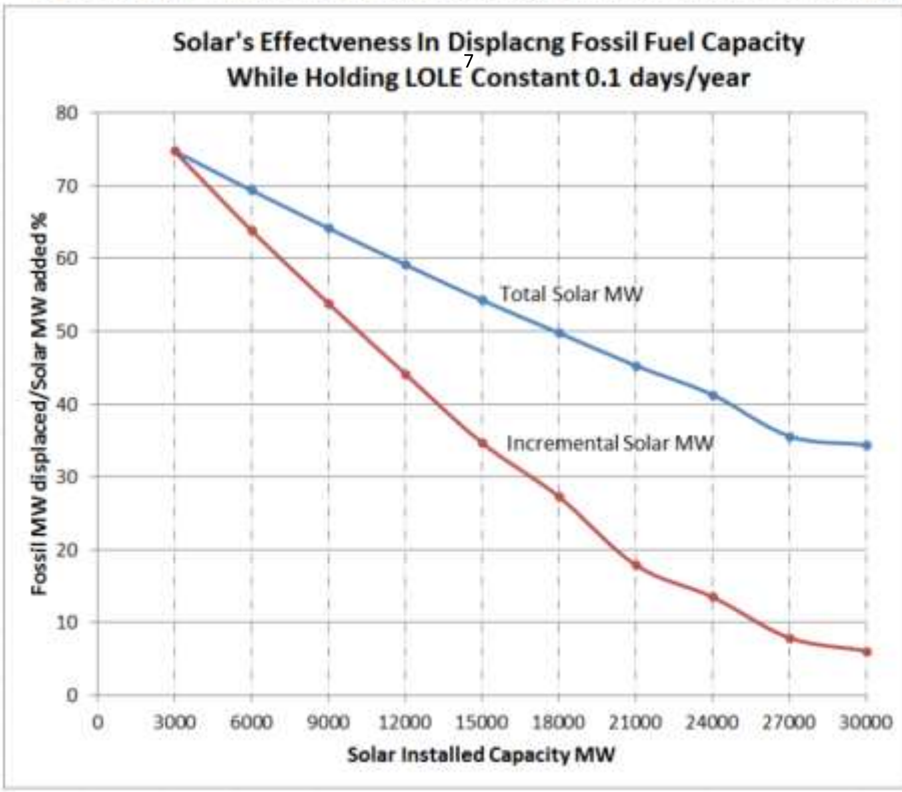
1. dba Eugene G Preston, LLC https://egpreston.com
2. Electric Reliability Council Of Texas http://www.ercot.com
3. CDR is the capacity demand reserve: https://www.ercot.com/files/docs/2021/05/06/CapacityDemandandReservesReport_May2021.pdf
4. SARA is the seasonal assessment of resource adequacy: https://www.ercot.com/files/docs/2021/05/06/SARA-FinalSummer2021.pdf
5. California ISO Duck Curve: https://www.bing.com/search?q=caiso+duck+curve
6. Peak firm load means load that is not classified as interruptible. Interruptible load has already been removed from the LOLE calculations.
7. LOLE is the loss of load expectation. LOLE = 0.1 days/year (or once in ten years the load is not served for a few hours) is a reliable system.
8. IEEE 2015 Denver Power Engineering Society Panel Session: https://www.egpreston.com/PanelSession.pdf
9. North American Electric Reliability Corporation: https://www.nerc.com
10. Variable Energy Resource Capacity Contributions: https://egpreston.com/17PESGM1850PaperFinal.pdf (reference Fig 5).
11. Poster Session of paper in ref 9 (above) https://egpreston.com/VER_RM.pdf (reference the last page for NERC recommendations).
12. RTS3 is the software program used to run the NERC studies and this study. The RTS3 program's speed and accuracy is unmatched.
13. Exact Indices Solution to the 1979 IEEE RTS http://ieeexplore.ieee.org/document/4335006/

NERC solar concerns from a 2015 presentation:

NERC saw my presentation in 2015 showing the decline in solar capacity value as more solar is added. The graph of interest shown at the IEEE meetings is labeled as Figure 1 below.

- **Can a reserve margin be a proxy for LOLE when renewables dominate?**
  - Not likely because of the moving target of renewable's capacity credit

Figure 1



NERC recommendations in the 2016 IEEE paper[11] and poster session[10]:

1) NERC regions should provide reliability evaluations of Variable Energy Resource impacts. Use of a reserve margin (RM) to measure adequacy can mask inadequate system reliability.

2) **It's very important to maintain chronology between different variable energy generation sources and load.** The easiest way to preserve correlations is at the historical hourly data level.

3) **It will be necessary to develop and maintain public databases of wind, solar, and hydro historical production.** This study could have used hourly regional wind data if it had been posted.

4) **VERs should be given capacity credits from the running of loss of load probability studies.** The reserve margins must be increased as VERs increase or VER capacity values need to be lowered. Reliability studies are necessary to make these evaluations. Monte Carlo simulations may require excessively long run times to obtain the accuracy needed to perform the ELCC[14] calculations.

14. ELCC is the effective load carrying capability; i.e. the increased load that can be served while holding the reliability at a constant level.

Study Cases and Results:

The RTS3 program was used to run the following nine cases to evaluate the capacity credits of wind and solar in ERCOT. The cases are quickly run with a high five digit accuracy and automatic load seeking to achieve an LOLE[7] of one day in ten years. Please watch this video to understand the Peak Demand MWs: https://egpreston.com/ERCOT_2022_Reliability.mp4

Table 1 - Test Cases with and without Wind and Solar in which each case has an LOLE = 0.1 d/y

	Peak Demand MW	Wind MW	Solar MW	Description
Case 1)	63753	0	0	gas coal and nuclear serves firm load
Case 2)	64000	1000	0	1000 MW wind serves 247 MW load
Case 3)	64400	0	1000	1000 MW solar serves 647 MW load
Case 4)	77299	36957	19682	all resources serves all the firm load
Case 5)	77499	37957	19682	1000 MW wind serves 200 MW load
Case 6)	77363	36957	20682	1000 MW solar serves 64 MW load
Case 7)	69920	36957	0	All the wind serves 6167 MW load
Case 8)	70641	36957	1000	1000 MW solar serves 721 MW load
Case 9)	84090	36957	19682	5700 MW 4 hour storage is added

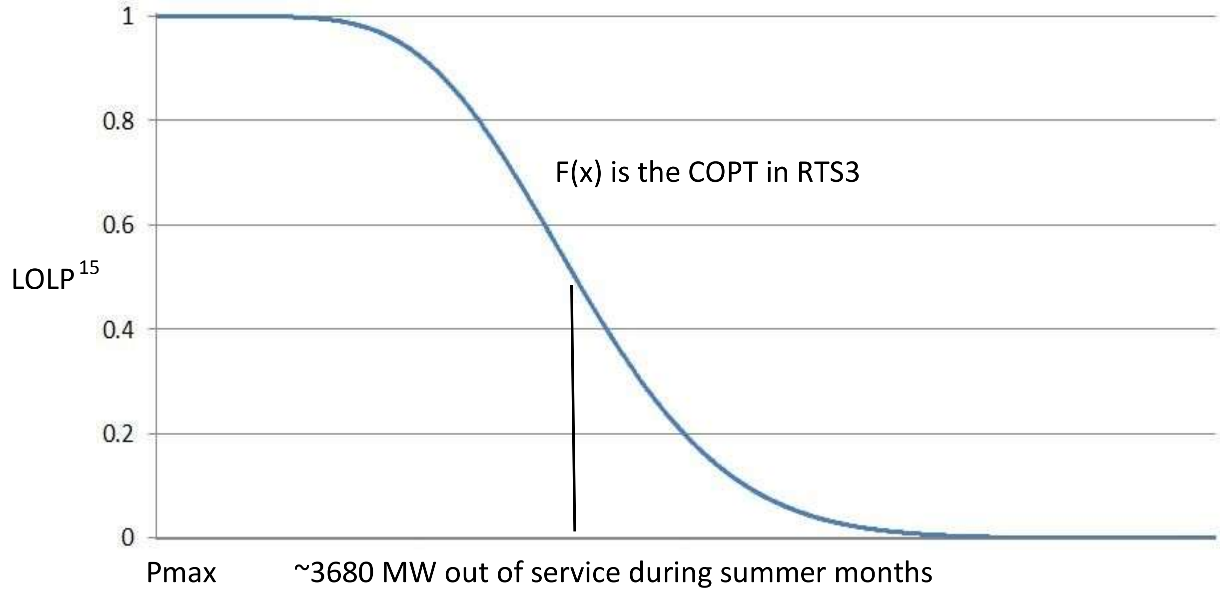
Cases 1 – 6 are used to estimate the capacity values for wind and solar without storage. Their ELCCs[14] are estimated by averaging the incremental values at low and high levels. The calculation of wind's effective load carrying capability from Table 1 is (0.247+0.200)/2 = 22.4%. The solar ELCC is (0.647+0.064)/2 = 35.6%. When these values are entered into the generator data file G2022A.txt the system reserve margin is slightly below 15%. Rounding up the wind and solar capacity credits to 23% and 36% respectively produces a 15% reserve margin.

Cases 7 – 9 study the benefit of adding battery storage. Case 8 finds that small 1000 MW solar has a 72% ELCC without storage. Adding wind first improves the solar ELCC. Large solar needs to pick up 0.72*19682 MW = 14170 MW load. Then the 14170 + 69920 is a total load of 84090 MW. In Case 9, storage is added until the load automatically reaches 84090 MW. This happens when 5700 MW 4 hours storage is added. However, the OP.txt file shows the maximum storage power is 11204 MW. In file G2022B.txt a battery of 11400 MW and 2 hours storage, with a total system load of 84090 MW, gives an identical result with an LOLE of 0.1 d/y. Solar is given a 72% capacity credit and wind is raised to 25% capacity credit to give an overall 15% reserve margin. The combination of wind, solar, and storage meets the same LOLE = 0.1 d/y and 15% reserve margin as the conventional generation in Case 1.

RTS3 COPT Methodology:

RTS3 reads a generator file and creates a capacity outage probability table or COPT. The specific COPT for ERCOT is graphed below in Figure 2. The actual table is listed in file COPT.txt.

Figure 2 - ERCOT Capacity Outage Probability Table



The COPT is created in a special manner to minimize errors. The generator Pmax is the MW level to the far left normally reserved for zero. In this instance, the left side of the ordinate axis is the sum of all generator nameplate capacities. As generators are convolved into the curve one by one, the graph grows and shifts to the right. Small probabilities are added to small probabilities so that their significant digits are maintained during summations. The convolution is straightforward. Suppose a generator of 100 MW with forced outage rate of 10% is to be added to the above graph. The above graph is scaled to a 90% of value curve and a 10% of value curve. The 90% curve is not shifted and remains in place. The 10% curve is shifted to the right by 100 MW. Now add the two curves together and you have a new COPT curve that represents an additional 100 MW of Pmax with the new generator outage probability in the curve. If all the generators have incremental MW nameplate capacities and the COPT is in one MW steps, then there is no convolution error except for numerical rounding, which is minimal. The COPT becomes a simple lookup table. For an x MW load level the LOLP(x) = F(Pmax-x). The COPT has six digits of accuracy for any large system using single precision in the program code.

15. LOLP is the loss of load probability. It is the probability of having enough capacity to serve that load level.

RTS3 Calculation of Indices:

RTS3 reads the hourly file HDATA.txt and calculates the hourly LOLPs as each line of data is read into the program. An hourly net MW load x is calculated and the LOLP for that x is looked up from the COPT. If x is not an integer, then a weighted LOLP is calculated from the two LOLPs on each side of real x.

The indices are calculated from the hourly LOLPs. The loss of load hours (LOLH) is the sum of all the hourly LOLPs in a year. The loss of load expectation (LOLE) is the sum of the daily maximum LOLP each day for a year. The expected unserved energy (EUE) is the sum of the hourly net MW times the LOLP each hour.

In the Monte Carlo simulations, the daily counts of loss of load events each day, when divided by the number of years iterated, will give the same daily LOLPs as the peak daily LOLP from the COPT if the VERs are treated as load reducers. This is the evidence that RTS3 is computationally consistent with Monte Carlo models that also treat VERs as load reducers. Treating wind and solar as load reducers is the gold standard that should be used to benchmark models that treat wind and solar as generators.

The NERC recommendations should have also mentioned that if VERs are modeled as generators, the results should be benchmarked against treating VERs as load reducers. Not performing this step can lead to modeling errors such as finding that wind over wide areas produces a reliable wind source. RTS3 using the actual historical data will capture the common mode events in which the wind is nearly zero everywhere. This may be a cause for some to think RTS3 is getting incorrect results when the problem is with the generator models throwing away valuable information. This is why we no longer use load duration curves (LDC) in reliability studies. Too much information is thrown away treating wind and solar as generation.

Next Steps in modeling ERCOT:

The next step will be to model Winter Storm Uri of February 2021 in RTS3 to see how much loss of load we can expect during these extreme cold weather events. My preliminary tests show the LOLE may be as high as 5 days per year with our current resources during the time the storm is in progress. How we deal with this is a challenge for all of us.