Reliability Modeling Best Practices
and Annotated Bibliography


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Reliability Modeling Best Practices

The following is an abbreviated summary of 16 best practices for reliability modeling:

1. **Accounting for All Drivers of Supply Shortfall Risk:** Supply shortfalls can have many drivers, including: high load, low conventional generator availability, low variable resource output, low water inflows to energy-limited hydro, insufficient flexibility, and intertie/transmission outages. Developing robust results requires accurately characterizing the magnitude of uncertainties associated with each driver, preferably by calibrating model inputs and outputs against historical data whenever possible. Also important is reviewing the underlying drivers of historical reliability events and ensuring that each driver is represented in the reliability model. For example, in Alberta a likely risk is the possibility of BC intertie failure and hot weather causing multiple outages at the same time. Many reliability models will not necessarily account for the representation of such idiosyncratic events as a default.

2. **Load, Economic Uncertainty and Weather Modeling:** Some reliability models use a simplified approach with one load profile and a normal distribution to characterize load uncertainty. This approach will understate the likelihood of reliability events because of the failure to represent: (a) the non-normal skew of weather uncertainty (i.e. more likely to drive extreme high load than extreme low load), and (b) the potential for protracted high-load periods (e.g. reliability events driven by ERCOT’s 2011 extended heatwave, and an unusually hot September in PJM that coincided with planned outage season). To address these concerns, we recommend developing load shapes based on as many years of historical weather data as possible (e.g., 30) to robustly account for the effect of weather uncertainty. We also recommend isolating and separately modeling the effects of weather-driven load variability and economic/non-weather load forecast uncertainty. Weather-driven uncertainty is relatively constant with the forward period in question, while the effect of economic uncertainty grows with a longer forecast horizon.

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1 This paper was prepared for the Alberta Electricity System Operator.
3. **Conventional Generator Outage Modeling (planned, forced, seasonal de-rate and random partial de-rate):** All reliability models simulate unavailability of conventional generators based on forced outage rates partial and full outage events. More sophisticated models account for: the possibility of partial unavailability (i.e. seasonal de-rates), the time-sequence and duration of outages, correlation of outages with extreme hot or cold temperature conditions, and differences in forced/planned/maintenance outages. Regardless of the underlying model capabilities, best practice is to compare the modeled distribution of aggregate fleet-wide outages to specific historical years to ensure the distribution of fleet-wide availability is captured accurately. Many reliability modeling efforts fail to capture the likelihood of multiple outages being driven by a single underlying cause (such as hot weather, cold weather, gas pipe shortages, or day-ahead forecast error causing under-commitment of supply or demand response). Many models ignore correlations among generator outages and are agnostic about the underlying causes of outage events, and so understate the likelihood of multiple simultaneous plant outages. By comparing and calibrating model outputs to historical fleet-wide outage rates it becomes possible to more accurately represent the likelihood of “tail events”.

4. **Cogeneration and Self-Supply:** Cogeneration and self-supply can be most accurately modeled on a gross supply and gross demand basis (though truly accurate modeling is likely to require the collection of more accurate cogeneration resource data in Alberta over time). Representation of net supply to the grid is a less accurate characterization, though if done should still be compared and calibrated to historical performance data.

5. **Wind and Solar Profiles:** Historical hourly (or sub-hourly) wind and solar profiles should be used to characterize the variability of these sources over an annual time series. We recommend incorporating as many annual profiles as possible into the modeling, consistent with different historical weather, wind, and solar conditions. Using actual historical wind and solar output data is less desirable than using historical weather data to simulate output profiles, in order to incorporate more weather years and account for technological advancements. Profiles can be plant-level or be the aggregate RTO-wide or zonal generation from each resource type, but should not scaled up generation from an individual plant. As a first-best practice, we recommend mapping these profiles to the same weather year used in each load profile in order to capture the correlation between load and intermittent generation profiles.

6. **Hydro Modeling:** Hydro modeling should distinguish between different hydro types, potentially including: run-of-river hydro (modeled similar to wind and solar profile), pumped hydro, and hydro with daily/monthly/seasonal storage capacity. In Alberta, we expect that accurate characterization of the BC hydro system will be important, including storage capability, hydro operating constraints (such as maintaining water levels), and the hydro cycle. Historical hydro output and other operating data should be used to characterize this availability and to guide calibration of model outputs.

7. **Intertie and Transmission Modeling:** Transmission interties between modeled regions should be modeled at two levels to characterize their reliability value: (a) estimate the availability of net supply from other regions that can be imported to support internal
reliability needs, and (b) account for possible intertie outages. If internal transmission congestion or outages has the potential to make some resources unavailable in some conditions then we also recommend modeling these as internal zones (for example to enable Alberta to assign a lower capacity value to wind located in generation pockets where they may be curtailed more often). We recommend that Alberta model external regions “at criterion”, i.e. meeting their own reliability criteria, rather than projecting whether neighboring regions may have excess supply. A best practice is to estimate an appropriate capacity benefit margin (CBM) that should not be awarded to support firm capacity imports. The CBM is the portion of the intertie capacity that is reserved for non-firm energy imports that are probabilistically expected to be available during Alberta reliability events due to the diversity of supply and demand across regions.

8. **Gas Supply Availability:** Most reliability models do not specifically model the availability of gas supply, gas pipeline constraints, or pipeline disruptions. To the extent that gas availability is likely to be a material driver of outages (e.g., as in the Northeastern U.S.), best practice is to either explicitly model gas infrastructure if the reliability model has that capability or to identify an alternative approach for characterizing gas-driven outage events such as developing outage correlations among gas plants.

9. **Characterizing Each Level of Emergency Event (load shed events, reserve ancillary service shortages, etc.):** Most reliability models trigger load shedding emergency events based on reserves falling below a predetermined level. More sophisticated models also characterize other types of emergency event that do not involve load shedding, but may trigger system operator actions such as deploying demand resources, running short of operating reserves, voltage reductions, and curtailing exports. Characterizing the frequency of lower-level shortage events can provide a richer understanding of the range of hours that are important for reliability and associated market design decisions.

10. **Estimating Effective Load Carrying Capability (for wind, solar, hydro, storage, use-limited, DR):** Reliability models originally designed for conventional generators may not easily characterize the load carrying capability of variable renewable resources, storage, hydro, and demand response. This is especially problematic if the model cannot represent characteristics that significantly reduce the load carrying capability of some resource types, such as DR call limits or advance notification hours and storage energy limitations. If the relevant resource characteristics are represented, the ELCC can be calculated using an approach such as: (a) adding one traditional generating plant and observing the reduction to EUE (or the relevant reliability metric), and then (b) removing that traditional plant and adding the non-traditional resource until EUE drops by the same amount. This approach determines the translation between 1 UCAP of traditional supply and 1 UCAP MW of non-traditional supply with certain characteristics. More advanced models may be able to calculate ELCC automatically.

11. **Identifying High-EUE Periods for Use in Setting Availability Requirements, Must-Offer, Penalty Mechanisms, and Cost Allocation:** It is possible to review reliability study results to identify the pattern of days, hours of day, and months when reliability events (either load shed or other emergency events) are more common. These patterns can be used to
help determine key market design decisions including the time windows that are most important to impose must offer requirements and penalties; the coincident peak hours most relevant for determining cost allocation; the availability and call event/hour requirements placed on demand response; and the potential need for a seasonal resource adequacy construct.

12. Economic Modeling: Some reliability models also provide insight into system economics, including production costs, customer costs, and generator revenues. These insights can be valuable when selecting between physical reliability standards or for developing a reliability standard based on economics, e.g. the economical optimal reserve margin. Another valuable result is how customer costs and generator revenues may vary across years due to drivers such as extreme weather years and the timing of plant outages. The accuracy with which the economics can be modeled depends on how accurately the model represents supplier costs and commitment/dispatch parameters, e.g. at the unit level or aggregated by generator type. Having some representation of costs is important in many market design and other study contexts if decision makers view it as important to weigh reliability against system costs, customer costs, price volatility, and/or supplier revenues.

13. Demand-Side Resource Modeling: Models should accurately represent a variety of different demand-side resource types, including representing the primary characteristics that affect their reliability contribution to the system. For example, modeling emergency demand response requires reviewing the guidelines for calling emergency events and translating those guidelines into a forecast of emergency demand response participation. Modeling economic demand response requires reviewing at what price thresholds demand response has historically offered into the market and a model that can determine market clearing prices. Demand response modeling may require capturing other idiosyncratic factors such as call event limits, hour limits, and advance notification hours. For example, a demand response resource with a 10-hour annual call limit will contribute only a portion of the reliability value of a resource with unlimited calls (and the value will degrade quickly as the aggregate penetration of demand response in the system grows). Energy efficiency is typically included within the load forecast, which ideally would account for variations in energy efficiency supply across the year (e.g. air conditioner efficiency would only modify load in the summer).

14. Storage Modeling: Best practice is to model storage with an accurate representation of resource characteristics including considering maximum generation and charge levels, discharge hours, round trip efficiency, and likely usage patterns. These usage patterns are more accurately represented by an economic model that considers how the resource would be operated within a market context. Many reliability models do not have the capability to accurately model storage, but the deficiency is only a concern if storage has a significant market share.

15. Operational Flexibility Modeling: Most models used for reliability assessments do not consider sub-hourly behavior and reliability events. However, sub-hourly modeling may be necessary to identify flexibility needs for systems with high levels of variable renewable generation, and to evaluate how flexible resources can improve reliability. Best practice is
to account for load forecast uncertainty at multiple forward timeframes to so that forecast error can be used to drive behavior in cycles such as 5-minute ahead, 10-minute ahead, 1-hour ahead, multi-hour ahead, and day-ahead. Accurately capturing resources’ technical parameters that determine flexibility, such as ramp rates, start times, and ancillary service capability is also important.

16. **Model Run Times and Iterations:** Best practice is to identify the number of model draws needed to achieve convergence (i.e. until further draws do not materially change model results). This number of draws will be different for every model in each market, but may be approximately 5,000 draws per reserve margin tested. Best practice is for runs to take no longer than overnight to run, and for the team to develop infrastructure to enable multiple runs in parallel. Faster runtimes and parallelization allow for faster interpretation and refinement of model results on a daily business cycle.

**Annotated Bibliography and Additional Resources**

Below we provide links to other sources that discuss the best practices listed above in more detail.

**INDUSTRY STUDIES**


NERC requires regional reliability entities to conduct probabilistic modeling to inform biannual Probabilistic Assessment (ProbA) reports. This document guides those analyses, by identifying “the practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments”. **Best Practices Discussed:** 1, 2, 3, 5, 7, 9, 10, 13, 14, 15.


Report prepared for the European Commission that introduces resource adequacy concepts, compares modeling methods and adequacy metrics, and provides a set of best practices for evaluating resource adequacy across EU member states. See Chapters 5 and 6 for best practices and recommendations. Includes an empirical analysis surveying resource adequacy policies in E.U. member countries. **Best Practices Discussed:** 1, 2, 3, 5, 7, 10, 12, 13, 16.

Report prepared for the European Commission that compares resource adequacy methodologies used across Europe, highlights the best practices and proposes methodology recommendations. Focused on maintaining reliability under high renewables. **Best Practices Discussed: 1, 2, 3, 5, 6, 7, 10, 13, 14, 15.**


Brattle report prepared for Federal Energy Regulatory Commission (FERC) assessing the economic and reliability implications of the common 1-in-10 resource adequacy standard and how it compares to alternative approaches; includes probabilistic simulations of reliability achieved and economic costs for a study RTO. A survey of resource adequacy criteria and reliability modeling software used across U.S. and Canadian power systems included in appendices. **Best Practices Discussed: 1, 2, 3, 5, 6, 7, 9, 10, 12, 13, 14, 16.**


Brattle report prepared for the Public Utility Commission of Texas estimating the economically optimal reserve margin (EORM) that would minimize system costs in ERCOT, and comparing the EORM to the reserve margin that ERCOT’s current energy-only market design would likely support and to standard physical reliability standards (LOLE, LOLH, EUE). Analyzed the associated economic costs. **Best Practices Discussed: 1, 2, 3, 5, 6, 7, 9, 10, 12, 13, 14, 16.**


Report prepared for the European Commission assessing savings from a coordinated European capacity market to meet resource adequacy and flexibility needs compared to individual, country-specific capacity markets to meet needs, particularly with respect to weather-driven variability under high renewable scenarios. **Best Practices Discussed: 2, 3, 5.**


**ACADEMIC PAPERS**


Analyzes the risk posed by correlated failures among generators. The paper illustrates that three types of correlated failures may increase outage risks: natural gas supply disruptions, reduced reliability among generators during winter months, and the simultaneous shutdown of multiple nuclear generators for regulatory reasons. Best Practices Discussed: 2, 3, 8, 12.

Madaeni, S.H., Ramteen Sioshansi, and Paul Denholm. “Comparison of capacity value methods for photovoltaics in the Western United States.” July 2012. Posted at:
https://www.nrel.gov/docs/fy12osti/54704.pdf

“This report compares different capacity value estimation techniques applied to solar photovoltaics (PV). It compares more robust data and computationally intense reliability-based capacity valuation techniques to simpler approximation techniques at 14 different locations in the western United States. […] Overall, under the assumptions used in the analysis, we find that some approximation techniques can yield similar results to reliability-based methods such as effective load carrying capability.” Best Practices Discussed: 5, 10.


This paper examines the various methods used to estimate the capacity value of wind. Best Practices Discussed: 5, 10/

Sioshansi, Ramteen, S. H. Madaeni, and Paul Denholm. "A dynamic programming approach to estimate the capacity value of energy storage." 2014. Posted at:

The paper presents a method to estimate the capacity value of storage. Best Practices Discussed: 10, 14.