Incorporating Resource Dynamics to Determine Generation Adequacy Levels in Restructured Bulk Power Systems

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Abstract - Installed capacity markets in the northeast of the United States ensure that adequate generation exists to satisfy regional loss of load probability (LOLP) criterion. LOLP studies are conducted to determine the amount of capacity that is needed, but they do not consider several factors that substantially affect the calculated distribution of available capacity. These studies do not account for the fact that generation availability increases during periods of high demand and therefore prices, common-cause failures that result in multiple generation units being unavailable at the same time, and the negative correlation between load and available capacity due to temperature and humidity. A categorization of incidents in an existing bulk power reliability database is proposed to analyze the existence and frequency of independent failures and those associated with resource dynamics. Findings are augmented with other empirical findings. Monte Carlo methods are proposed to model these resource dynamics. Using the IEEE Reliability Test System as a single-bus case study, the LOLP results change substantially when these factors are considered. Better data collection is necessary to support the more comprehensive modeling of resource adequacy that is proposed. In addition, a parallel processing method is used to offset the increase in computational times required to model these dynamics.

Keywords: electric power industry restructuring, installed capacity, loss of load probability (LOLP), Monte Carlo, power system reliability

1. Introduction

The introduction of competition in the electric industry has created a new environment in which to ensure the reliability of the bulk power system. Installed capacity markets are one mechanism being used in the northeast of the United States to guarantee adequate generation to meet load, and specifically to make sure that the applicable loss of load probability (LOLP) criterion is satisfied [1]. The amount of required capacity to satisfy the LOLP criterion is determined by generation adequacy models (GAMs). In brief, these models assume that the availability of generation is independent of the availability of other generation units, system conditions such as demand, and other external events such as temperature and humidity.

This paper is organized as follows. Section 2 briefly summarizes the LOLP calculations used to establish installed capacity requirements and presents the empirical evidence for the types of dependencies that affect the amount of available generation. Section 3 is a single-bus case study using the IEEE Reliability Test System (RTS) to compare LOLP results as currently calculated versus those incorporating the factors heretofore ignored. Section 4 concludes the paper and proposes avenues for additional research.

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2. LOLP Modeling in Capacity Markets: Assumptions Versus Empirical Evidence

2.1 Summary of LOLP Calculations Used to Determine Capacity Requirements

The LOLP is the probability that demand exceeds supply within a period of time, for example within a year under a specified set of assumptions, and is described in many references [1,2]. The fundamental set of assumptions in these LOLP calculations used to establish capacity requirements in the northeast of the United States is independence ([2] and [3]), even though some of these independence assumptions have been relaxed in the power system reliability literature. For example, two weaknesses of traditional common cause outage models were recently addressed [4]. A standard textbook on power system reliability addresses common-cause failures and common-mode failures in distribution systems [5].

Despite the importance of common-cause failures in contributing to the unreliability of high-reliability systems in general [6] and bulk power systems in particular (see

Section 2.2 and [5]), GAMs currently fail to account for several important common-cause failures and dynamics [3]. The relevant omissions are: 1) during periods of high demand and correspondingly high prices, generation availability improves because of the higher revenues, as do profit margins that can be earned during these periods compared to periods of low demand; 2) high temperatures and humidity during summer periods of high demand reduce generation capacity; and 3) some common-cause failures remove from service two or more generation units. For brevity, we refer collectively to these items and other similar ones as "resource dynamics."

2.2 Empirical Evidence Supporting Common-cause Failures and System Dependencies

We examine a database and other empirical studies to document the types and prevalence of resource dynamics. To do so systematically, we propose a categorization scheme to identify and quantify resource dynamics.

2.2.1 North American Electricity Council Disturbance Analysis Working Group Database

The Disturbance Analysis Working Group (DAWG) database is a publicly available database that summarizes 451 major disturbances in generation, transmission, and distribution that have occurred on the bulk electric systems of North American electric utilities, as reported to the U.S. Department of Energy (DOE), from 1984 to 1999 inclusive [7]. The reporting criteria consist of five elements: electric service interruptions, voltage reductions, acts of sabotage, unusual occurrences that can affect the reliability of the bulk electric systems, and fuel problems.

To analyze the database, we categorized the 451 entries based on the initiating event of the report. Classifying reportable events in this way is a logical starting place to describe and evaluate the types of events that threatened or actually reduced bulk power system reliability. The five major categories of initiating events used are internal events, external events, human error, sabotage/vandalism, and other. Internal initiating events refer to events whose proximate cause is due to a failure of a system component. External initiating events refer to situations in which a cause external to the system, such as severe weather, is the proximate cause.

We assigned each of the 451 events to one of these categories based on the description of the event provided in the comment section. The database comments are almost always sufficient to determine, at least for our classification scheme, the type of initiating event. In those cases where the comments are insufficient to assign the event to one of the first four categories, we used the "Other" category.

Subcategories of internal and external initiating events were determined based upon a review of all of the events in the database. Internal initiating events are categorized as being caused by generation outage/high demand or transmission outages. A combination category of generation outage/high demand is necessary because insufficient detail is provided in many of the reportable events' comments to identify which of these two factors is the proximate cause. External initiating events were divided into four subcategories based on the types of external initiating events reported: severe weather/lightning, earthquakes, external fires, and other. Events initiated by human error were divided into two subcategories based the error was operational or maintenance.

The other major classification applied to the DAWG database is determining whether the initiating event resulted in an independent or dependent failure. The independent failure classification refers to initiating events that did not result in other system component failures. For example, if a large generation unit trips off-line, resulting in a reportable event but not resulting in other system components failing, that event is classified as an independent failure. Note that this classification scheme may overestimate the number of independent failures. For example, assume that two generation units are unavailable due to a common system component failure, perhaps of a transformer. If a third generation unit that is online trips, resulting in loss of load because sufficient generation is not available, this type of event would be classified as an independent failure because, even if such information is known, the tripped generation unit is not the proximate cause of the two non-operating generation units. On the other hand, initiating events that resulted in other component failures, such as a transmission line failing resulting in three generation units tripping off–line, are classified as dependent failures.

Table 1 presents the classification of the 451 reported DAWG events we examined. The assignment of each reportable event to a particular category that results in Table 1 is provided in [2]. Limitations of the DAWG database are described in [2].

Two conclusions are readily apparent from Table 1. First, independent generation outage/high demand initiating events constitute a small percentage (14%) of the total reported events. This is the only type of initiating events that is considered in determining resource adequacy requirements in the northeast United States. Second, dependent failures of all types constitute 69% of the initiating events. Dependent events are approximately 2.5 times more likely to result in a reportable event (69%) than are independent events (27%).

Table 1 considers only the frequency of reported events. It could be the case that the average magnitude (e.g., number of customers curtailed or amount of energy not consumed due to a curtailment) of the less frequent independent, internal events is greater than that of dependent and external events. Although the DAWG database cannot be used to obtain estimates of these magnitudes, it is clear from reviewing the database that the dependent and external events have a larger negative impact on the reliability of bulk power systems than do independent, internal events. This should not be surprising since dependent initiating events result in multiple component failures, which is likely to raise more severe reliability issues than would a single component failure.

Table 1 Categorization of Initiating Events in the DAWG Database and Whether Dependent Failures Occurred [2]

Initiating Event	Total %	Independent Failure	Dependent Failure %
Internal Event	47%	22%	25%
Generation Outage/High Demand	16%	14%	2%
Transmission Outage	32%	8%	23%
External Event	37%	1%	35%
Severe Weather/Lightning	30%	2%	29%
Earthquake	1%	0%	1%
External fire	3%	0%	3%
Other	3%	1%	3%
Human Error	9%	1%	8%
Maintenance	8%	0%	7%
Operations	1%	0%	1%
Sabotage/Vandalism	3%	2%	0%
Other (insufficient information)	4%	?	?
Total	100%	27%	69%

Note: Percentages may not sum to subtotals due to rounding. The percentage of single failure and dependent failures do not sum to 100% because insufficient information exists for those events in the "Other" category to subcategorize these events into single or dependent failures.

2.2.2 Other Empirical Results Relating System Conditions and Generation Unit Availabilities

We augment our database findings with other available empirical research that shows that several important factors affect the availability of multiple generation units. They include severe weather that results in generation outages, season of the year, fuel supply infrastructure, intentional shutdown of nuclear units due to anticipated severe weather, and regulatory evaluations of owners of nuclear power plants.

Ambient and cooling water temperatures have an important effect on the capacity of generation units. Higher temperatures reduce the efficiency of generation units, thereby reducing their maximum output by raising the average temperature of water used to condense steam in steam units and by raising ambient air temperatures. This, in turn, reduces the efficiency of turbine units. The former temperature effect is seasonal and is commonly accounted for in generation adequacy models by using summer and winter capacities for generation units. The latter effect varies daily. High temperatures result in high load levels but low capacities, particularly for gas turbines and combined cycle units, which are not usually considered in generation adequacy studies. The DOE reported that during periods of high temperatures, capacity ratings for generating units could overstate the units' capabilities [8]. This overstatement resulted in the equivalent of an outage of a moderate-sized fossil unit (500 MW) on July 23, 2000 in the south-central region of the United States [9].

GAMs also fail to account for the limitation of fuel availability due to extreme weather. For instance, during the week of January 16, 1994, a major cold wave swept across the U.S. Midwest and into the Mid-Atlantic States [9]. This cold wave followed a week in which much of the same area was blanketed by ice storms. As a result of this cold weather, demand for electricity exceeded expectations, and cold weather-related problems with generators and fuel supplies resulted in two control areas in the Eastern Interconnection — Pennsylvania, Jersey, and Maryland Interconnection (PJM) and Virginia Power — having to resort to rotating blackouts. Frozen coal piles, frozen conveyer belts, and frozen mine equipment incapacitated some coal burning plants. Oil deliveries were delayed to some oil-fired units or dual-fired units that were started up on oil instead of natural gas, which had interruptible contracts curtailed, resulting in generation units being shut down. In addition, some oil gelled in its tanks.

The fuel supply infrastructure is another common factor that can affect the availability of multiple generation facilities. With the increase in the use of natural gas to fuel generation units, natural gas transportation disruptions (e.g., high consumer gas demand, a break in a major pipeline) could result in multiple natural-gas fired units being unavailable. In New England, this possibility has compelled the New England Independent System Operator (ISO-NE) to evaluate the reliability implications [10]. During one generation capacity shortage situation in New England that occurred after the introduction of competitive wholesale markets, 1,000 MW of the 5,000 MW of available generation was unavailable due to natural gas supply curtailments [11].

Ordered shutdowns by regulators of several nuclear units owned by the same company, in response to safety issues, are another type of fuel disruption that has adversely affected bulk power system reliability. For example, the North American Electric Reliability Council (NERC) — in its 1997 Summer Assessment [12] — stated that the Mid-America Interconnected Network (MAIN) region, particularly Northern Illinois, would face significant challenges in meeting customer demand due mainly to the expected unavailability of 4,700 to 6,500 MW of nuclear generation capacity in Northern Illinois and Wisconsin. Nuclear Regulatory Commission (NRC) regulatory issues were one of the causes of this large amount of unavailable nuclear capacity. In the summer assessment from the previous year, the NERC cites the fact that three Millstone nuclear units, totaling 2,630 MW, were out of service because the NRC had requested that Northeast Utilities verify that each unit's Updated Final Safety Analysis Report and other license documents were in accordance with design specifications before those units could be returned to service [13]. Another example involves American Electric Power (AEP). Two of AEP's nuclear units at its D.C. Cook nuclear power plant in Bridgman, Michigan were shut down due to safety concerns over ice condenser containment equipment, which is used to condense steam resulting from a break in a primary system pipe [14]. A similar situation occurred in Ontario, Canada [15].

Historically, generation units' availabilities increase during peak seasons. This was true even prior to restructuring. The NERC [16] reviewed fossil-steam units for the years 1982-1988 and divided these units into two groups based on the number of service hours per year. Group A units operated 2,000 or more hours per year, whereas Group B units operated less than 2,000 hours. For both groups, the peak season average equivalent forced outage rate (EFOR) was less than the annual average EFOR. For Group A, the peak average EFOR decreased by 8.6%; for Group B it decreased by 31.6%. In both groups, the decrease is statistically significant at 99.9% or greater confidence. This NERC report notes that winter peaking units do not show as much improvement in peak season EFORs as summer peaking units, and postulates that this is due to extreme cold conditions that present greater equipment and personnel difficulties than does extreme heat. With restructuring, the relative value of a unit being available during the peak versus non-peak season increases dramatically compared to the situation prior to restructuring.

ISO-NE in August of 2000 commissioned a study of the availability of the region's power plants. The aim, in part, was to determine whether plant availability changed between 1995 and 2000, particularly after new wholesale electricity markets were introduced in May 1999 [17]. ISO-NE concluded that "unit availability had changed for the better in New England" and that plant owners were "responding to economic incentives to keep their plants running when demand was the highest" [18].

3. Case Study

We use a single-bus version of the IEEE Reliability Test System (RTS) to investigate the effect on LOLP calculations of the dependencies discussed above [19]. We use Monte Carlo analysis to calculate the LOLP under several different scenarios for daily peak hours. Our base case is the RTS as given, including the planned maintenance schedule provided. The LOLP is 2.73 days per year with a standard deviation of 1.74 days per year. We use the software program @Risk and its Latin Hypercube algorithm. The convergence criteria, all of which must be satisfied, are less than a 1.5% for the average percent change in percentile values (0% to 100% in 5% increments), the percent change in the mean, and the percent change in the standard deviation. We use an Intel Pentium III processor at 894 MHz and 256 MB of RAM.

We model four cases in addition to the Base Case: reductions in forced outage rates (FOR) as a result of actions generation unit owners take to improve each of their unit's availability during peak hours (FOR Case); reductions in available capacity with a simultaneous increase in load due to high temperature and humidity (Temperature Case); common-cause failure due to an input fuel distribution pipeline failure (Common Cause Case); and a case that combines all of the previous cases (Combined Case).

In the FOR Case, we assume that during the peak hour of the year the FOR decreases 8.6% for baseload units and 31.6% for peaking units [16]. The LOLP decreases to 2.46 days per year, a 9.9% reduction from the base case, with a standard deviation of 1.60 days per year. This FOR case, unlike the other non-Base cases, is based on reported numerical values. For the remaining cases, we selected the values of parameters that exemplify the relationship of the dependency that we are trying to model but do not claim that the associate results are empirically valid because the necessary numerical inputs are not available. By using parameters to model these dependencies, however, we demonstrate that they can be modeled, determine the overall direction of each dependency, and discover the additional calculational times needed to incorporate them in generation resource adequacy modeling.

In the Temperature Adjusted Case, we adjust the summer daily peak loads by a factor drawn from a normal distribution whose mean is 0 with a 2.5% standard deviation. In addition, the maximum output of all of the units is divided by this factor. This factor is intended to represent the reduction in capacity due to the higher temperature and humidity, which would also increase peak load. In the Common Cause Case, we assume that there is a 0.001 probability of both 400 MW nuclear units being unavailable due to a common-cause failure. Finally, in the Combined Case, we calculate the peak hour LOLP, accounting for all four cases simultaneously.

In addition, to reduce computational time, we also split the simulations of the Combined Case into two parts. In part one, we assume that there was no common-cause failure; in part two, we assume that the common-cause failure always occurred. We then calculate the daily LOLP using the Theorem of Total Probability, as applied to our analysis in the following form:

$$\begin{aligned}&\text{LOLP(Combined Case)} = \\ &(\text{LOLP} \mid \text{Probability of common cause failure} = 0) \quad (1)\\ &+ (\text{LOLP} \mid \text{Probability of}\\ &\text{common cause failure} = 1)\end{aligned}$$

Table 2 summarizes the results.

Table 2 Daily Peak LOLP Results

Case	LOLP (days/yr)	Standard Deviation & Min to Max	# Iter-ations	Computer Run Time (minutes: seconds)
Base	2.73	1.74 0 to 11	900	5:44
FOR	2.46	1.60 0 to 8	600	3:22
Temperature	3.19	2.68 0 to 20	1,300	8:21
Common Cause	2.79	2.95 0 to 92	2,500	17:56
Combined	3.07	4.53 0 to 147	2,600	14:34
Combined (Prob. common cause = 1)	3.00	2.68	800	4:53
Combined (Prob. common cause = 0)	86.01	33.91	500	3:26
Combined Results	3.08			8:19

4. Conclusions and Areas for Future Research

We find that there are several important dynamics that affect generation adequacy analysis, in particular daily LOLP calculations. A review of a database of reliability incidents in the United States reveals that independent generation outages account for only a small percentage of incidents that may lead to reliability problems (16%) in bulk power systems, based on our proposed categorization scheme. Moreover, a review of a variety of empirical reports identifies several resource dynamics that current generation adequacy calculations used for the purpose of determining installed capacity requirements do not consider: market dynamics, temperature dynamics, and common-cause failures. Only in the case of improved FOR during peak periods are numbers available to model the contribution of this dynamic to LOLP results. We find that this FOR dynamic reduces the daily peak LOLP by 9.9% for the IEEE RTS. We also find that other dynamics can easily be incorporated into standard Monte Carlo models, and we demonstrate this finding in several simulations runs. In addition, we used a method to split the analysis of common-cause failures into two parts in order to reduce computational time.

Additional research is needed in several areas. First, better data are needed to quantify the effects of these various dynamics on LOLP calculations. As our research indicates, some dynamics improve reliability (e.g., increases in FORs) whereas others decrease reliability (e.g., common-cause failures). Second, these dynamics need to be incorporated into larger-scale models than the IEEE RTS. Third, policy changes to installed capacity markets need to be considered in light of dynamics that substantially alter the LOLP calculations. Finally, incorporating dynamics can substantially increase the run-time of calculations. Alternative means of reducing run-time need to be investigated, along the lines of parallel calculations that we employ.

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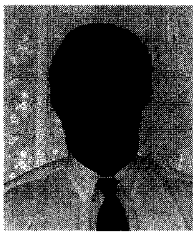

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