MIT EL 00-008 WP

Energy Laboratory

Massachusetts Institute
of Technology

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November 2000

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Energy Laboratory Publication #
MIT EL 00-008 WP

Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139-4307

November 2000

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Abstract

In this paper we first review criteria and methods for reliability assessment and provision underlying current industry practices. The basic conclusion is that these approaches do not directly provide quality of service requested by the regulators on behalf of the consumers. Reasons for this situation are complex, and are results of both regulatory and technical limitations. In this paper we use simple examples to illustrate rationale for this claim and its implications. A particular stress is on the criteria (standards) and tools used by a system operator. We illustrate on a small power system example what one can and cannot expect from specific approaches.

These startling findings are critical as we attempt to assess and provide reliable service under competition primarily because the current practices for ensuring reliability are often implied as the technical basis while encouraging competitive power supply.

In the later part of this paper we suggest possible changes in criteria and methods fundamental for avoiding the broken links between the provider(s) of reliable service and its users. We suggest that this is doable under any industry structure currently under consideration. However, the regulatory incentives for reliable service differ drastically depending on the industry structure. This indicates that a new paradigm appears to be necessary, in which reliability responsibilities are clearly decomposed into reliability provision by suppliers and wire companies, with understanding of verifiable reliability-related products seen by the customer. We furthermore conjecture that this framework can only be implemented in a regulatory setup which nurtures performance incentives in one form or the other. We again illustrate this paradigm on the same small example.

Introduction

The growing pains of the electric power industry restructuring are becoming quite visible to the general public. These are reflected either through undesired service interruptions and/or through highly volatile wholesale electricity prices. In this paper we only consider issues related to the continuity of service, and do not analyze the electricity price dynamics. The second subject deserves a separate treatment that is outside the scope of this paper; however, we do emphasize that volatile prices under high demand should not come as a surprise to the users, and are not necessarily bad. This is true as long as the users see relatively low prices at times of low demand. A meaningful study here would be to compare the evolving electricity prices to the prices under regulation over prolonged periods of time.

Concerning continuity of service as seen by the customer, we describe major changes in fundamental principles underlying reliable electric power service as the industry restructures. We suggest in this paper that the service interruptions are to a large extent the result of a significant lack of regulatory incentives for maintaining and improving reliability of a grid and its efficient use. While this is true even in the regulated industry, the situation becomes critical, as the evolving electricity markets require the transmission service beyond the conditions for which it was originally designed. The implications are weak relations between current operating and planning practices and the reliability seen by the customers, as well as inadequate use of potentially powerful technologies, software tools in particular, for implementing a desired level of reliability.

Reliability management under vertically integrated utility structure

The operating and planning practices of a vertically integrated utility are defined and coordinated based on the reliability requirements, or criteria, defined by the regulators. Here we proceed by reviewing and assessing the reliability criteria currently used first. We also assess the effectiveness of the current industry practices (decision making "technical standards" and supporting software) for meeting reliability requirements set by the regulators. We analyze the relation of the electricity tariffs in place and the incentives to meet the reliability requirements by analyzing technical standards used.
To start with, the regulatory requirements for reliable service are typically set at each state level since they are relevant for customers directly connected to a distribution network. The utilities are required to serve customers beyond certain minimum interruption threshold; the customer average interruption index (CAIDI) and the customer average interruption frequency index (CAIFI) are typical of current regulatory requirements on behalf of customer.
In a vertically integrated utility these requirements are implemented using "top-down", or system type criteria (technical "standards") with the expectation that if these system type criteria are met, the indices measured at a customer side would be also met. The loss of load probability (LOLP) and the expected value of energy not served (EENS) are the

typical indices used for measuring system-wide reliability level. The LOLP computes the probability that the entire system load is higher than the generation supply available in the system for a period of interest by comparing the generation capacity with peak demand subject to possible equipment outages. Although the index provides the information on service interruptions, the severity of the interruptions is not measured. The EENS calculates the expected value of the energy not being served by looking at the magnitude and the duration of load exceeding the available generation with possible generator and transmission line outages in a simulation. The severity of interruption is captured in terms of the magnitude and duration through this index.
In this paper we use LOLP as one single index to compare the results of operators actions to their effect on the reliability as seen by the customers.

Industry practices for meeting reliability requirements

Based on the required LOLP, a vertically integrated utility determines the amount of generation capacity required to meet this requirement. This capacity has historically been differentiated into generation needed for compensating small random fluctuations in demand around the forecasted load (AGC), and, into reserve generation for supplying customers under severe unpredictable equipment outages for the projected load demand. Long-term changes in projected demand are met by building new power plants, and by designing enough transmission to deliver the power. In this paper we do not discuss the AGC-related criteria and the need for their changes under the new industry[i]. Moreover, most of the discussion in this paper, except for an illustrative example, concerns reliability methods for the EHV transmission grid[ii]. Here we only study operations planning criteria and methods.

The short-term operating practices for meeting the LOLP for the anticipated (known) load are generally based on so called (N-1) security criteria. The system operator dispatches available generation to minimize the total operating cost of providing the load in such a way that in case any single large equipment outage (generator or transmission line) takes place the load remains unaffected at least for certain duration of time. Many powerful software tools exist to assist system operators with this task. This criterion is entirely deterministic.

The critical issue to observe here, however, is that there is no direct relation between the LOLP and the deterministic (N-1) security criterion as currently practiced. We show in the follow-up example that the amount of reserve needed to meet a pre-specified LOLP depends on the actual energy dispatch, even when there is sufficient generation reserve because the ability of the transmission system to deliver these reserves heavily depends on the likely status of the system. The inability to deliver could be caused either by so-called "congestion", i.e. inability to deliver power even when the transmission system is intact, or by the transmission line outages.

As a consequence, like it or not, current industry practices are not designed to guarantee a pre-specified LOLP needed on the customer side. This is true even in the simplest technical setup when "congestion" refers to the steady state problems in delivering real power (MWs), while voltage and stability constraints are not accounted for[iii].

In the follow-up examples we suggest that it is indeed possible to define the optimum (least cost) amount of reserve to ensure a pre-specified LOLP index as the energy dispatch changes. Unfortunately, as it will be shown, the computational methods for doing this are quite involved and are not currently used by the system operators even in the most advanced control centers. It is our suggestion that only with the right regulatory incentives, tools of this type would develop.

Example 1: What is a system operator doing to meet reliability?

The main objective of this example is to illustrate criteria and methods underlying operating practices for providing reliable service by the vertically integrated utilities. This example concerns methods used by the system operators of the EHV transmission system. As such it is relevant only for reliability assessment at the wholesale level. The reliability issues as seen by the small users at the distribution system level and the relations between the two are illustrated briefly in the later part of this paper.

Here we consider a small fictitious electric power system shown in Figure 1 owned and operated by a vertically integrated LightCo.

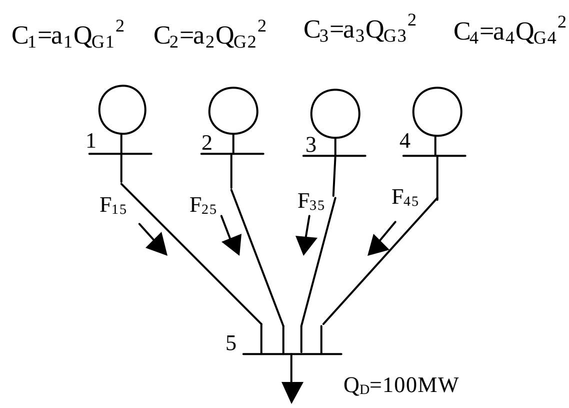

Figure 1: A small power system example

The company has knowledge on availability of each transmission line ij. For purposes of numerical illustrations, say that each line has availability v_{ij} =0.99, or probability of failure 1 - v_{ij} = $Pr(F)_{ij}$=0.01. LightCo also knows the operating cost functions C_i $(Q_{Gi})=a_iQ_{Gi}^2$ of its four generators.

A typical approach to ensuring the (N-1) security criteria is to provide a reserve requirement determined as R(MW) = max $\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4})$ which corresponds to the capacity of the largest power plant. For the (radial) transmission topology of this example and assuming that all generators are always functional, we analyze the role of transmission grid reliability. In this case the reliability requirement is equivalent to having generation reserve which corresponds to the R(MW)=max $\{F_{15}, F_{25}, F_{35}, F_{45}\}$

where F_{ij} is a real power line flow between nodes i and j. Then based on this requirement, this reserve R is allocated to different generators (R_1, R_2, R_3, R_4). The reserve determined this way results in some (not pre-specified) LOLP as seen by the load at bus 5.

To illustrate numerically the issues of interest in the increased order of complexity, consider first the simplest scenario when transmission lines have sufficient capacity, i.e. there is no congestion problem. In this case, the only scenario in which load does not get served is if a transmission line does not deliver because it is not there to make a connection between the supply and demand points. Two cases are analyzed, first when the cost of all generators are the same and, second, when the power plants are vastly different in costs.

If the operating cost of all generators is the same, i.e. $a_1=a_2=a_3=a_4=1\$/MW^2$ per hour the simple minimal total cost dispatch problem results in equal energy dispatch $Q_{G1}= Q_{G2}= Q_{G3}=Q_{G4}=25MW$ necessary to meet the given load of 100MW. In order to meet the reserve requirement $R(MW) = \max \{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 25MW$ typical heuristic-based practice is to allocate reserve in the same proportion as energy dispatch subject to the constraint that the sum of reserve for three units be equal to 25MW. This results in reserve allocation $R_1= R_2= R_3= R_4=8.33MW$.

A simple analysis of the implications of this reserve allocation shows that if one transmission line is out, the system has 3*8.33MW reserve to replace the output of 25MW that was affected, so load deficit is zero for any single contingency. Therefore, the corresponding probability that some deficit, or loss of load, occurs is computed by looking at the probability that two or more lines are out in which case deficit is no longer zero. This probability is computed based on the probability of line availability as LOLP = Pr(def > 0) = 1 – Pr(all lines operational) – Pr(any single line out). Given the specified line availabilities v_{ij} this results in LOLP $= 1 - 0.99^4 - 4*0.01*0.99^3 = 5.9203e-004$. For purposes of further illustrations in this paper we assume that this LOLP is at the same time the value desired by the customers and set by the regulators.

Consider next the situation when LightCo owns very different power plants, so that their costs are mutually different. This is seen in the values $a_1=1$, $a_2=2$, $a_3=3$, $a_4=4$ $\$/MW^2$ per hour in the operating cost function. In this case the result of least cost energy dispatch to meet the desired 100MW load results in energy schedules of $Q_{G1}= 48MW$, $Q_{G2}= 24MW$, $Q_{G3}= 16MW$ and $Q_{G4}= 12MW$. In this case the corresponding reserve requirement $R(MW) = \max \{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 48MW$ could be allocated proportionally to the energy schedules subject to the constraint that the sum of reserve for three units be grater or than equal to the Q_{Gi} affected. This leads to the reserve allocation of $R_1= 0MW$, $R_2= 22.15MW$, $R_3= 14.77MW$ and $R_4= 11.08MW$.

The implications of this energy schedule and reserve allocation are that if one line is not operational the system still has enough reserve available. The criteria that under the most severe contingency to load still does not see any deficiency leads to LOLP = Pr(def > 0) = 1 – Pr(all lines operational) – Pr(any single line one out) $= 1 - 0.99^4 - 4*0.01*0.99^3 =$

5.9203e-004. This is the same as in the case when all power plants are the same cost plants.

Consider next a more complicated scenario on the same system, assuming congestion capacity of each line to be 30MW. In this case for equal energy cost, $a_1=a_2=a_3=a_4=1\$/MW^2$ per hour, the optimal dispatch subject to the transmission line flow limits still results in the same least cost energy dispatch $Q_{G1}= Q_{G2}= Q_{G3}=Q_{G4}=25MW$. If the reserve requirement R(MW) = max $\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}$ = 25MW gets allocated in proportion to the energy dispatch subject to the sum of reserve for three units be equal to 25MW, this results in the same reserve allocation $R_1= R_2= R_3= R_4=8.33MW$ as when the transmission flow constraints did not exist.

However, in this case an analysis of the resulting reliability as seen by the load shows that if one transmission line is not in service the system would have sufficient generation reserve of 3*8.33MW to replace the 25MW not delivered from one generator via transmission line which has failed, but the transmission lines are now congested at 30 MW implying that deficit is different from zero for any single contingency. Therefore, in this case the reliability seen by the load is significantly reduced to LOLP = Pr(def > 0) = 1 – Pr(all lines operational) = $1 - 0.99^4 = 0.0394$.

We observe that even though the system has enough generation capacity reserve to support the single output of any of the generators (line outage-generation affected) the transmission system is not able to transfer the reliability related redispatched power and the load has less reliability than desired (LOLP of 0.0344 > LOLP of 5.9203e-004).

If the company owns power plants whose operating costs are different, characterized by $a_1=1$, $a_2=2$, $a_3=3$, $a_4=4$ $\$/MW^2$ per hour and assuming that the transmission capacity limits are $F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW, respectively, this results in the least cost dispatch of Q_{G1}= 48MW, Q_{G2}= 24MW, Q_{G3}= 16M and Q_{G4}= 12MW. Following the same current practice the reserve requirement R(MW) = max $\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}$ = 48MW and its allocation in proportion to the energy schedules subject to the constraint that the sum of reserve for three units be grater than or equal to the Q_{Gi} affected, we obtain R_1= 0MW, R_2= 22.15MW, R_3= 14.77MW and R_4= 11.08MW. However now line 25 has a capacity limit of 30 MW and for the case where line 15 is out, the system cannot supply completely the demand (deficit = 48 – 6 – 14.77 – 11.08 =16.15MW). Consequently, LOLP = Pr(def > 0) = [1 – Pr(all lines operational) – Pr(any line out except line 15)] = $1 - 0.99^4 - 3*0.01*0.99^3 = 0.0103$.

This scenario shows that even though the system has enough generation capacity reserve to support the single output of any of the generators (line outage-generation affected) the transmission system is not able to transmit the redispatch for the case that line 15 is out; consequently, the system is less reliable than desired (LOLP of 0.0103 > LOLP of 5.9203e-004).

Reliability management by the Independent System Operators (ISOs)

Over the past several years we have witnessed a strong effort particularly by the North American Electric Reliability Council (NERC) to enforce the existing industry practices for ensuring reliable operation by the Independent System Operators (ISOs) as these evolve. These efforts are possibly best illustrated in NERC documents concerning interconnected operating services (IOS)[iv]. Some variations concerning the actual amount of reserve required, and the mechanisms for its implementation have been subject of major debates. For instance, the New England ISO does not have a separate market for reserve, while California ISO does. The implementation of the required reserve is through so-called single settlement system, or through a multi settlement system[v]. The entire debate misses the issues pointed out in our example, namely the conceptual impossibility of meeting a reliability level desired when using types of criteria and software methods currently used.

We illustrate in the follow-up example that, much the same way as a system operator in today's vertically integrated utility is not capable of delivering a pre-specified reliable service to a user, because of the limitations of criteria and methods used, this problem only gets enhanced as an ISO attempts to do the same. The problem becomes more difficult in addition to the problems illustrated above, by the fact that the reliability reserve gets dispatched through a market, without adjusting the amount of reserve needed to the conditions of the energy market and the transmission status.

Example 2: What is an ISO doing to meet reliability?

One of the qualitative changes in applying current operating practices for reliable service under competition is the fact that the reliability reserves are offered in some ISO structures in a way that the generators bid separately into a reserve market according to some bid function for providing reserve. If the cost of reserve is considered to be different than the energy cost, this reserve is sometimes allocated at least (reserve) cost subject to the constraints on available reserve (R_i^{min}, R_i^{max}). Assume this bid curve to be linear for simplicity, i.e. $C_i(R_i) = b_i R_i$. This is used just as an illustration of the issues of interest, and therefore any other bid function could be chosen. In this case, energy market is cleared first, and then the reserves are provided through a separate market so that the total cost of reserve bids purchased is minimized, and also observing that each reserve bid has a reserve capacity limits (R_i^{min}, R_i^{max}).

To recognize the sensitivity of the reliability outcome as seen by the customer on the amount of reserve chosen, we recognize here that this generally heuristic (operating conditions independent standard) could vary with a market design. A slightly different heuristic standard for the total reserve required could be something like $R(MW) = \max\{20\%\ Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\} = \max\{20MW, 25MW\} = 25MW$. The amount 20% Q_D is used as an example only. Assume for purpose of illustration that b_i=0.5 \$/MW and R_i^{max} = 15MW for all four generators. This problem has no unique solution (because of the linear cost function chosen); one possible solution is again to allocate reserve equally among all four generators. Numerically, $R_1= R_2= R_3= R_4=6.25MW$. If one line is out, the system has 3*6.25MW redispatched to replace the output of 25MW that was affected, so the demand sees 6.25MW of deficit for any single contingency, having a LOLP = Pr(def > 0) = 1 – Pr(all lines operational) = $1 - 0.99^4 = 0.0394$, which is worse reliability than the desired (LOLP = 5.9203e-004).

Another scenario is when power plants have different cost functions. This is translated into different bids for both energy and reserve. If we consider values $a_1=1$, $a_2=2$, $a_3=3$, $a_4=4$ \$/MW^2 per hour in the operating cost function. In this case the least cost energy dispatch to meet the desired 100MW load results in energy schedules of $Q_{G1}= 48MW$, $Q_{G2}= 24MW$, $Q_{G3}= 16MW$ and $Q_{G4}= 12MW$. The reserve requirement R(MW) = max $\{20\%Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\}$ = max{20MW, 48MW} =48MW is often implemented by minimizing the total cost of reserve and subject to the limits of available reserve of each generator (R_i^{min}, R_i^{max}). For the reserve cost of $b_1=0.5$ $b_2=1$, $b_3=1.5$, $b_4=2$ \$/MW and the reserve limits of R_i^{max} = 15MW, the least cost reserve allocation results in $R_1= 15MW$, $R_2= 15MW$, $R_3= 15MW$ and $R_4= 3MW$. With this allocation the system has enough reserve for any single contingency except for the case when line 15 is out. The system LOLP is equal to [1 – Pr(all lines operational) – Pr (any single contingency except line 15)] = $1 - 0.99^4 - 3*0.99^3 *0.01 = 0.0103$ that is worse reliability than the desired (LOLP = 5.9203e-004).

Consider next a more interesting scenario on the same system, assuming congestion capacity of each line to be 30MW. In this case for equal energy cost, $a_1=a_2=a_3=a_4=1$\$/MW^2 per hour, the optimal dispatch subject to the transmission line flow limits still results in the same least cost energy dispatch $Q_{G1}= Q_{G2}= Q_{G3}=Q_{G4}=25MW$. If the reserve requirement R(MW) = max $\{20\% Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\}$ = max{20MW, 25MW} =25MW gets allocated based on the reserve bids subject to the reserve requirement and to the technical constraints R_i^{max} = 15MW. Due to the fact that $b_i=0.5$ \$/MW, the problem has no unique solution, a criterion is to allocate equally $R_i=6.25MW$. If one line is out, the system has 3*6.25MW ready to be used, but the transmission system allows only 3*(30MW-25MW), implying that deficit not only is different from zero but also greater that the first case for any single contingency. For this scenario the LOLP is [1 – Pr(all lines operational)] = $1 - 0.99^4 = 0.0394$, which means worse reliability than the desired (LOLP = 5.9203e-004).

Other scenario is when power plants are different, characterized by $a_1=1$, $a_2=2$, $a_3=3$, $a_4=4$\$/MW^2 per hour and assuming that the transmission capacity limits are $F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW, respectively, results in the least cost dispatch of $Q_{G1}= 48MW$, $Q_{G2}= 24MW$, $Q_{G3}= 16M$ and $Q_{G4}= 12MW$. Following the same current practice, the reserve requirement R(MW) = max $\{20\%Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\}$ = max{20MW, 48MW} =48MW and its allocation is implemented based on minimization of the cost of providing reserve subject to the reserve requirement (MW) and the technical constraints (R_i^{min}, R_i^{max}). The result of the reserve dispatch is $R_1= 15MW$, $R_2= 15MW$, $R_3= 15MW$, and $R_4= 3MW$. Even though the system has enough reserve to fulfill the reserve requirement, the transmission capacity limits introduce other issue with the result of having only reserve to support the single contingency of line 45. Consequently, LOLP = Pr(def > 0) = 1 – Pr(all lines operational) – Pr (contingency line 45), or LOLP = $1 - 0.99^4 - 0.99^3 * 0.01 = 0.0297$, which value is worse than the desired (LOLP = 5.9203e-004).

Possible criteria and methods for ensuring reliability at a customer level

It can be concluded based on Examples 1 and 2 above that in order to define the amount and the allocation of reserve for ensuring a pre-specified level of reliability, it is necessary to consider explicitly the transmission capacity equations such that the reliability requirement is fulfilled. Solving this problem requires determining a) the amount of adequate reliability reserve, and b) the allocation of adequate reserve, in order for the users to obtain reliable reserve as specified according to a pre-agreed reliability index.

The next example shows how could a pre-specified LOLP be determined by an ISO, given the right software. A very similar version of this example could be worked out to illustrate the same for a system operator in a vertically integrated utility. The next example shows the need for more adaptive methods for determining the amount of reserve and its allocation for the pre-specified reliability product. In terms of methods, this is by order of magnitude harder to do than what is currently practiced.

Example 3: What can an ISO do with right software?

A tentative proposal to deal with both reserve requirement and reserve allocation problems are to consider explicitly transmission capacity equations for each scenario, as a result, the reliability requirement is fulfilled.

To illustrate this idea, consider first the case when lines have 30 MW as a transmission capacity, and power plants have equal costs, $a_1=a_2=a_3=a_4=1\$/MW^2$ per hour. The optimal dispatch subject to the transmission line flow limits still results in the same least cost energy dispatch $Q_{G1}= Q_{G2}= Q_{G3}=Q_{G4}=25MW$ as in Example 1 above.

For the reserve market, we assume that reserve bids are equal for generators and are characterized by $b_i=0.5\$/MW$ in the bid function subject to technical constraint R_i^{max} = 15MW. The objective is to have at least the same or better reliability level than the pre-specified (LOLP = 5.9203e-004), and allocate reserve considering the transmission limits[vi]. As a result, the optimal reserve allocation is $R_1= R_2= R_3= R_4=5MW$. For any single contingency the system is only able to redispatch up to the line capacity, so it cannot allocate more than 5MW to each unit, this is the most economic of the possibilities. The system has now LOLP = Pr(def > 0) = 1 – Pr(all lines operational) = $1 - 0.99^4 = 0.0394$, which is worse reliability level than the pre-specified in Example 1.

To meet the pre-specified LOLP of supporting any single contingency with zero deficit, the transmission system needs to be enhanced. Due to the symmetry of the example, with equal energy and reserve costs, enhancing any of the four lines is the same.

Let us assume first that the investment is in line 15 such that $F_{15} \leq 60$ MW. The energy dispatch does not change, but the reserve dispatch changes to R_1=15MW, and R_2= R_3=R_4=5MW. Now the system has enough reserve to support any single contingency except when the line 15 is out. Consequently, LOLP = Pr(def > 0) = 1 – Pr(all lines operational) – Pr(any single contingency except line 15 out), or LOLP = 1 – 0.99^4 – $3*0.99^3 *0.01$= 0.0103.

If additionally line 25 is improved to $F_{25} \leq 60$ MW, the reserve dispatch is R_1= R_2= 15MW, and R_3=R_4=5MW, and the system finally supports any single contingency having a LOLP of 5.9203e-004.

A second more interesting case is when both energy and reserve costs are different for different generators and transmission capacity limits are considered ($F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW). With a_1=1, a_2=2, a_3=3, a_4=4 \$/MW^2 per hour, the dispatch results Q_{G1}= 48MW, Q_{G2}= 24MW, Q_{G3}= 16MW, and Q_{G4}= 12MW.

For the reserve part of the problem, let us assume that each generator has different reserve bids b_1=0.5, b_2= 1, b_3=1.5, b_4=2 \$/MW, and the same technical constraint R_i^{max} = 15MW. The objective is to have at least the same or better reliability level than the requirement (LOLP = 5.9203e-004) and allocate reserve considering transmission limits $F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW. In order to illustrate the necessary procedure, each scenario will be considered explicitly and then the final reserve dispatch will be defined such that R_i = max {R_i for each scenario}.

When line 15 is out, the system needs to have enough reserve to substitute the output of generator located at bus 1, so R_2+R_3+R_4=48MW, and at the same time the transmission capacity limits need to be considered, resulting in

$Q_{G2} + R_2 \leq 30\text{MW} \rightarrow R_2 \leq 6\text{MW}$

$Q_{G3} + R_3 \leq 50\text{MW} \rightarrow R_3 \leq 34\text{MW}$

$Q_{G4} + R_4 \leq 50\text{MW} \rightarrow R_4 \leq 38\text{MW}$

Finally, the reserve is allocated economically based on the reserve bids and technical constraints, resulting in R_2=6MW, R_3=34MW, and R_4=8MW.

In a similar way, when line 25 is out, the system needs to have reserve R_1+R_3+R_4=24MW and each transmission capacity limit needs to be considered explicitly.

$Q_{G1} + R_1 \leq 50\text{MW} \rightarrow R_1 \leq 2\text{MW}$

$Q_{G3} + R_3 \leq 50\text{MW} \rightarrow R_3 \leq 34\text{MW}$

$Q_{G4} + R_4 \leq 50\text{MW} \rightarrow R_4 \leq 38\text{MW}$

The optimal result for this scenario is R_2=2MW, R_3=22MW, and R_4=0MW.

Similar analysis is needed for scenarios of line 35 and line 45 are out of service. For line 35, we have R_1+R_2+R_4=16MW

$Q_{G1} + R_1 \leq 50\text{MW} \rightarrow R_1 \leq 2\text{MW}$

$Q_{G2} + R_2 \leq 30\text{MW} \rightarrow R_2 \leq 6\text{MW}$

$Q_{G4} + R_4 \leq 50\text{MW} \rightarrow R_4 \leq 38\text{MW}$

i.e., R_1=2MW, R_2=6MW, and R_4=8MW

Finally, for line 45 out, it is necessary to have $R_1+R_2+R_3=12MW$ and
$Q_{G1} + R_1 \leq 50MW \rightarrow R_1 \leq 2MW$
$Q_{G2} + R_2 \leq 30MW \rightarrow R_2 \leq 6MW$
$Q_{G3} + R_3 \leq 50MW \rightarrow R_3 \leq 34MW$
i.e., $R_1=2MW$, $R_2=6MW$, and $R_4=4MW$.

The optimum reserve allocation considering R_i = max {R_i for each scenario} is therefore, $R_1=2MW$, $R_2=6MW$, $R_3=34MW$, and $R_4=8MW$.

With this formulation, the system has for any single contingency not only enough generation reserve but also transmission capacity. This is possible as a result of the correct consideration of the transmission equations. The reliability level is measured by the LOLP = [Pr(def > 0) = 1 – Pr(all lines operational) – Pr(any single line out)] = $1 - 0.99^4 - 4*0.01*0.99^3 = 5.9203e\text{-}004$, which means that the system fulfils the desired reliability level.

Underlying principles for providing reliable service under industry unbundling

Finally it is important to recognize that the entire industry is undergoing functional and corporate unbundling and that it is no longer realistic to expect that risks associated with reliable service would necessarily be borne by one entity, and not by the other.
In order to address this important turning point, it would help to assess the approach on the reliability services by different business, ranging from power suppliers, through wire (transmission and/or distribution) providers and, finally, the customers.

Decentralized approach to reliability

As the industry restructures, it has become imminent that each entity will have its own business objectives, both short-term as well as long-term. Not all of these decentralized objectives will be consistent with the objectives of the vertically integrated utility in which decisions are made in a coordinated way under the assumption that generation, transmission and distribution are all owned and managed by the single entity.

We point out that it is extremely helpful to think of reliability primarily as a risk taking and management process since one deals with the problem of ensuring uninterrupted service despite unexpected changes[vii]. In the vertically integrated utilities these uncertainties are caused by the unpredictable demand deviations and by the equipment outages. In an unbundled industry the uncertainties come from incomplete information about other parts of the industry also. For example, it is well known that it is very difficult to plan a new power plant without knowing plans for transmission enhancements, and the other way around. Similar concerns arise in light of shorter-term operations planning for meeting a desired LOLP.

Particularly difficult aspect of the industry unbundling concerns dependence of risk management on the industry structure in place. For example, in a vertically integrated industry the risk is seen by the customer, who is not guaranteed to be delivered a pre-specified service quality, as shown in the above examples.

In an industry structure characterized by a full corporate unbundling of generation, transmission and distribution, responsibilities for risk taking have to be clearly defined through a type of contractual agreements between entities. This requires first of all definition of reliability-related products for which there are sellers and buyers. In this environment the technical "standards" are replaced by the contractual expectations. In a rare case that the contracts are breached, there ought to be a well understood penalty mechanism.

Approach of generation serving entities to reliability

Much literature exists on the objectives of competitive power suppliers and their methods[viii]. Without getting into specifics, their major objective is to sell the product (power) in order to make most profit without too much risk taking that the profit would not materialize.

The power suppliers see reliability as an issue of their risk that they would not be able to sell their product. This could happen either because their power plant fails, or because it is not possible to deliver physically power to the buyer. Power suppliers are developing a variety of methods for managing risk created by their failure to produce. They are hedging their risk by having a contract with some other producer to send power in case of failure. Hedging against generation failures remains a difficult problem, because it is best done when all generators share their risks, namely through a separate market for reserve. As it is well known, these markets are at their rudimentary stages.

The other even more difficult aspect of risk taking as seen by the power suppliers concerns transmission problem when an agreed upon contract cannot be executed because it is not physically deliverable. Currently this step requires permission to use the transmission at the desired time and location, as well as paying for its use. Depending on the type of methods used by the ISOs and/or system operators in charge of the system that is being used, and also depending on the type of transmission tariffs this risk could be very different. The tariffs could range from just paying an access charge, through paying for congestion, various types of transmission rights, etc. It could be seen from the methods illustrated in the above examples that a system operator and/or ISO do not differentiate between methods for congestion, when the status of all equipment is normal, from the methods for what would amount to transmission reliability in case a line fails and system users still wish to use the system.
Seen by a generator, there is no difference between not being served because congestion occurred or not being served because a transmission line failed. To him, this is one single risk. Therefore, generators wish to have well defined market mechanisms for hedging against the transmission status uncertainties.

The risks described here apply to both short-term as well as to long-term horizons relevant for building new plants. It is for this reason that it is necessary that transmission providers offer a range of transmission products, provided on a daily basis through seasons and even years.

Approach of transmission providers to reliability

To start with, transmission providers are obligated by law to provide “open access” to all users, directly connected to their grid on an equal basis. In this setting they are generally being paid as much as they are used. Given the fact that transmission remains to be viewed by most as a fully regulated monopoly with a guaranteed rate of return on all capital investments, this only determines how are the transmission charges of local users affected; if the system once built only for them is being used by others, they end up contributing less. Transmission provider, on its side, is indifferent in many ways with regard to who is being served. The only real effort on the transmission side is to do this at the minimum possible cost.

Given very uncertain regulatory changes, transmission providers have not considered any significant investment into enhancing their systems. Under strict environmental constraints it is very difficult to make the case for transmission upgrades given that there is much small-scale (distributed) generation on its way to be built, which partly offsets the need for enhanced transmission. This situation has all together left transmission providers completely out of having any serious impact on system reliability, except for the requirements to maintain their existing equipment (cut trees, in particular).

It appears that, instead, the main system burden is placed on the evolving ISOs to provide system reliability and to manage the associated system risks. As shown in the above examples, there is only so much that ISOs could do under current operation practices and with their typical software. Given the fact that an ISO does not own generation, this could be done in some way by creating reserve markets for both generation and transmission reliability. This is unlikely to be carried out by the ISOs whose function is not risk taking nor profit making. (This is true except for the idea of forming for profit performance-based ISOs, in which case these entities would be genuinely interested in coming up with the most adequate criteria and software for their performance).

Another possible approach is to create performance-based transmission providers, whose products and incentives for risk management would be defined through market rules, rights and responsibilities[ix]. In this setup a transmission provider would quickly learn that it requires a different contract for serving a generator for energy than a generator who has a hedging contract for power in case this generator fails. It is quite plausible for a transmission provider of the future to offer an unbundled transmission product, one for congestion management and a second one when a generator participates in a reserve market. On the other hand, it is possible that a transmission provider offers a single product of delivering transactions under well-defined terms, but at a different price. It is of critical importance that a transmission provider offers only products over which he has control such as the improved reliability related only to the transmission line failures.

Based on the demand for these products, a transmission provider would over time dare to invest at the right places, without any guarantee that the investment would fully return. Creating a market of this type, together with the right tariffs and the right objectives of providing reliable transmission is a difficult subject[x].

Approach of distribution providers to reliability and customer choice

It is important not to forget that generation and transmission reliabilities are only a part of the total picture. The ultimate test of reliability is seen by the consumers. The reliability seen by the users will be a combination of reliability at the *interface* between transmission (EHV) and distribution (HV/MV) grid and the *distribution* reliability within a distribution network. Before one even considers notion of *distribution* reliability, the fact that consumers might request an improved (above minimum reliability) and a differential reliability (different for different loads) needs to be taken into account. First of all, one could show that consumers should play an active role in the setting of a reliability level at the *interface*, and not take it as simply a given input. Second, one needs to recognize that the reliability at the *interface* could be provided in various ways and at different levels from the minimum reliability. The following example illustrates these ideas.

Example 4: Improved and differential reliability at a consumer level

In the example shown in Figure 2 we added to bus 5 of Figure 1, which becomes the interface bus, a MV network with 3 loads, (one of which, load 1, demands reliability above minimum) and one distributed generator (DG). The improved reliability requested by load 1 is such that for all double line contingencies at the transmission level, load 1 needs to be supplied.

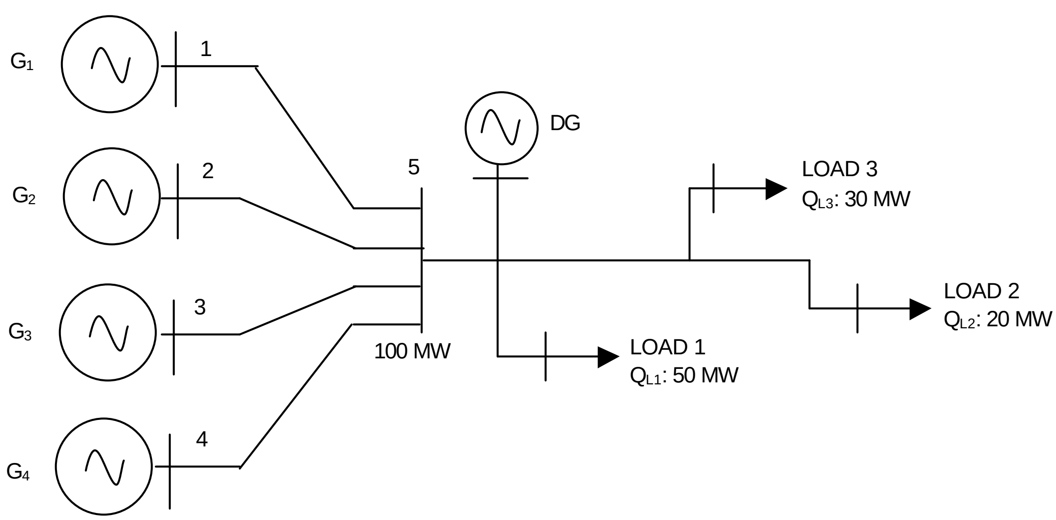

Figure 2: Customer choice of reliability

As stated, let us assume that load 1 demands N-2 reliability and that it would be curtailed according to its demand in case of deficit at bus 5. In fact, any double contingency on the transmission side results in a deficit at the interface (bus 5), which needs to be redistributed based on the curtailment criterion of the distribution company. This means that, according to the needs of load 1, the reserve requirement at bus 5 changes.

Various alternatives exist to provide load 1 with the reliability he asked for, i.e. to reduce the value of the deficit at load 1 to zero even in case of double contingencies. We consider four.

A first way to improve reliability at the *interface* is to change the reserve requirement at the transmission side: A transmission provider has to provide additional reserve. We calculated the necessary amount and allocation of this additional reserve with the same assumptions as in Example 1 for the cases a) equal energy and reserve costs (no congestion) and for the case b) different energy and reserve costs (no congestion).

In case a) generator operating costs are $a_1=a_2=a_3=a_4=1\$/MW^2$ per hour. The simple minimal total cost dispatch problem results in equal energy dispatch $Q_{G1}= Q_{G2}= Q_{G3}=Q_{G4}=25MW$ to meet the load of 100MW at bus 5. According to this, the system needs to have enough reserve to perform the reserve requirement of R(MW) = max $\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}$ = 25MW. As a result, the optimal allocation of reserve is $R_1= R_2= R_3= R_4=8.33MW$.
For any double contingency, the 100MW load at bus 5 cannot be supplied, resulting in the system deficit of 33.34MW, which needs to be redistributed based on the curtailment criterion of the distribution company. If we assume that the curtailment is proportional to the demand, for load 1 this means a curtailment of 16.67MW.

Therefore, in order to serve load 1, even in the case of a double contingency, a transmission provider needs to allocate additional 16.67MW at the transmission level. Following a similar procedure as in Example 1, the system reserves for the second contingency $R''_1= R''_2= R''_3= R''_4=8.33MW$ just for load 1, which has now a reliability level of LOLP = Pr(def > 0) = Pr(three lines out) + Pr(four lines out of service) = $4*0.99*0.01^3+0.01^4$ = 3.9700e-006.

In case b) the system power plants have mutually different operating costs $a_1=1$, $a_2=2$, $a_3=3$, $a_4=4$ $\$/MW^2$ per hour. In this case the result of least cost energy dispatch to meet the desired 100MW load results in Q_{G1}= 48MW, Q_{G2}= 24MW, Q_{G3}= 16MW and Q_{G4}= 12MW and the corresponding reserve requirement R(MW) = max $\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}$ = 48MW could be allocated proportionally to the energy schedules subject to the constraint that the sum of reserve for three units be grater or than equal to the Q_{Gi} affected. This leads to the reserve allocation of R_1= 0MW, R_2= 22.15MW, R_3= 14.77MW and R_4= 11.08MW.

For any double contingency, the 100 MW load at bus 5 can no longer be fully supplied. In this case, the amount of deficit depends on the lines that are out of services. In order to calculate the optimal reserve allocation, it is necessary to simulate each scenario, calculate the deficit at bus 5, and then redistribute this deficit to each load based on the curtailment criteria of the distribution company. The reserve requirement for the second contingency is just the amount of reserve that makes curtailment at load 1 for each scenario equal to zero.

A transmission provider needs to allocate additionally reserve defined as the maximum of the reserve allocation for each scenario such that the curtailment for any second contingency at load 1 is zero. As a result, the goal is satisfied with R_1= 11.57 MW, R_2 = 10.19 MW, R_3= 13.19 MW, and R_4 = 9.889 MW, and load 1 sees a LOLP equal to Pr(def > 0) = Pr(three lines out) + Pr(four lines out of service) = $4*0.99*0.01^3+0.01^4$ = 3.9700e-006.

A second way to improve reliability at the *interface* is by obtaining additional generation from a generator on the MV side (DG). The additional amount of reserve needed from the DG will be 16.67 MW in case a). Load 1 has in this case a reliability of LOLP = 3.9700e-006. In case b), the amount of reserve needed from the DG will be defined for the worst scenario (lines 15 and 25 out of service), which is R(MW) = deficit at bus 5 seen by load 1 = 46.15 MW/2= 23.08 MW. As a result, load 1 has a LOLP of 3.9700e-006.

A third way to provide a certain level of reliability at the *interface*, again, through the transmission network is with a bilateral contract for reserve between a load 1 and a generator at the wholesale level. A consumer pays directly the generator to be available for providing reserve. Therefore, a transmission provider, when purchasing reserve, can count on an already available generator, and will allocate the remaining reserve requirement accordingly. On the other hand, the consumer will receive a discount from a transmission provider for the reliability service. It is worthwhile observing that it is probably the most efficient way to do this is by a transmission provider calculating reserve requirement in the optimal way as in shown in the examples above – for the entire network- and for the consumer to pay directly one of the generators.

Finally, a different way to provide improved, differential reliability at the consumer's site is the following: Let us consider a particular agreement between load 1 and a distribution provider. If the load requests N-2 reliability, this can be achieved through different curtailment criteria: in case of deficit at bus 5 Load 1 will be the last one to be interrupted. This means that load 1 will not see any curtailment, while the other two loads absorb this deficit. As a result, in case a) for any double line contingency, at bus 5 the system sees a deficit of 33.34MW, which is distributed to the loads as 0 MW curtailment for load 1, 13.4 MW curtailment for load 2, and 20 MW curtailment for load 3.
In case b) for any double line contingency, at bus 5 the system sees a deficit at bus 5 (the magnitude depends on the scenario), which is absorbed by both load 2 and load 3 proportionally to their demands. This means that load 1 will not see any curtailment while the other two loads absorb this deficit having a reliability of LOLP = 3.9700e-006.

It is important to emphasize that all the analysis, except for the last case, was done considering the reliability at the interface. The last case opened the door for a further analysis. In fact the analysis is valid only if the distribution system is completely available, which is a very hard assumption[2].

Conclusions

To summarize, the criteria and software methods for determining total amount of reliability reserve by a system operator in the vertically integrated utilities were never designed to be universal and to apply unconditionally to an arbitrary system. In this sense, none of the rules, or technical “standards’’, could be used for guaranteed reliability as requested by a customer and/or regulator in the new industry. Utilities have made efforts over time to do their best and develop rules most applicable to their particular systems, within the general guidelines of using type of criteria illustrated in this paper. In particular it is illustrated here that the availability of generation reserve (adequacy) will not ensure that this reserve gets delivered to the users under certain contingencies. This is mainly because often when an attempt is made to deliver reserve under transmission contingency, a transmission grid becomes a bottleneck, often at some other path.

Generally, the ability to meet a required reserve at a user side strongly depends on the level of load, energy dispatch made to meet this load under normal operations, capacity of the transmission grid and the reliability of the transmission lines. Technical standards, such as maintaining maximum capacity of the largest power plant and alike are only capable of guaranteeing adequacy of total supply, at best.

We stress that the regulatory rules for vertically integrated utilities have always been biased toward capital investments and not toward the most effective technology choice. Today’s industry tariffs based on guaranteed rate of return on capital investment offer effectively no incentives for advanced software developments of the type needed to overcome reliability issues illustrated in this paper. This has been a major obstacle to progress in the electric power industry when compared to many other industries.

In the later part of this paper we show how a system operator and/or independent system operator could overcome the issue raised here. The fact that it has not been done is attributable to the lack of incentives to do this.

Furthermore, based on the illustrations in Example 2, we suggest that there is no real reason to believe that an ISO could do any better or worse than a system operator as seen by the customers. Both a system operator and an ISO are using similar criteria for determining amounts of reserve required and the software tools for their allocation. While there are some differences depending on the type of reserve implementation (bundled with energy vs. unbundled, separate reserve market) and on the type of settlement systems in place, we suggest that tools that account explicitly for transmission constraints and line failures are not used by either system operators or ISOs. Because of this, an ISO does not deal with the basic problem pointed in this paper either.

Unfortunately, the real reasons for this lack of most effective software go back to the regulatory disincentives. Everything said earlier about the disincentives for adequate technologies in the vertically integrated industry continues to hold.

Finally, the current operating practices (both in the vertically integrated utilities and by the ISOs) for determining the total amount of reliability reserve and its allocation to different power plants are contrasted on the same example power system with an alternative proposal suggested here in which the reserve is computed in order to meet a pre-specified LOLP, or some other reliability criteria verifiable at the customer locations.

We suggest that the regulators need to take the leading role in supporting new paradigms for implementing reliability under competition. It is no longer prudent to expect the remnants of utilities of the past to take all the risks created by energy markets. Reliability goes hand in hand with risk and needs business and regulatory structures which reward risk taking financially. The imbalance with respect to risk taking among competitive suppliers, system providers and consumers cannot co-exist in a sustainable way. As long as suppliers willing to take risks can make profit on this, the system providers ought to be encouraged to be the same and, in addition, be rewarded for doing it. Only then will system providers engage into developing technological tools necessary for making most out of the existing (wire) resources.

On a consumer side, in a country like this, one must ensure at least minimum level of reliability and understand who is providing it and at which price. It is essential to understand the basis for how is this minimal reliability level provided and the meaning of technical standards for supporting its implementation. The differentiated reliability at higher price is also plausible as indicated in one of the examples in this paper. In order to achieve this, it is essential to have well-defined regulatory setup that encourages performance by means of most effective technologies.

We point out that it is extremely helpful as one goes through this assessment exercise to think of reliability primarily as a risk taking and management process since one deals with the problem of ensuring reliable service despite unexpected changes in demand and equipment conditions. This is generally helpful when assessing modeling, analysis and decision making tools used by the utilities in order to meet the regulatory requirements. It is furthermore helpful for understanding the shift in risk taking responsibilities and opportunities brought about by the willingness to take the risk on behalf of the others, particularly its dependence on the regulatory structure in place.

We finally recommend possible framework for assessing and providing reliable service in accordance with the industry restructuring. The basic idea is to introduce verifiable measures of reliable service under functional industry unbundling. This calls for separable and verifiable reliability criteria for transmission, distribution and power suppliers.

It is, furthermore, suggested that the reliability provision by different entities ought to have financial incentives, much in the same way as supply and demand currently have in the electricity markets. We further suggest that market-based provision of reliable service may be the only guarantee that reliability related risks would be handled adequately. This calls for careful development of markets for this purpose. Performance-based regulation is a must for reliable service in the future.

It is worthwhile mentioning that some utilities with advanced R&D departments, such as Electricité de France have developed software tools that are more adequate for what is needed. However, most of these tools are primarily employed for planning rather than for the purpose described here, in which the operator must guarantee reliable service to the users as energy dispatch varies. Much of the fundamental research on dynamic security assessment, in particular, can also be related to the need in place. The right tariff incentives would provide a solid basis for much of technology transfer of these methods. In this paper we restrict our analysis to the basic issues of steady state problems in delivering available generation to the users without considering voltage related problems and assuming no dynamic problems. All data used in the examples are hypothetical and do not reflect industry practices.

Acknowledgements

The authors greatly appreciate the financial support by the MIT Energy Lab Consortium on "New Concepts and Software for Deregulated Power Industry", the EPRI/ARO Contract number EPRI-W08333-03, the FOMEC fellowship from Ministry of Education of Argentina, and the doctoral fellowship from the Italian 'Ministry of University and Scientific and Technological Research'.

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Endnotes

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