MANAGING SHORT-TERM RELIABILITY RELATED RISKS

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Abstract: *In this paper we review criteria and methods for short-term reliability assessment and provision underlying current industry practices. The basic conclusion is that these approaches do not meet the quality of service requested by the regulators on behalf of the consumers. Reasons for this situation are complex, and result of both regulatory and technical limitations. In this paper we use simple examples to illustrate the rationale for this claim and its implications. Particular stress is on the criteria (standards) and tools used by a system operator. We illustrate on a small example what one can and cannot expect from specific approaches.*
In the later part of this paper we suggest possible changes in the paradigms governing the relationship between the provider(s) of reliable service and its users. Under the new paradigm, the reliability responsibilities are clearly decomposed into reliability provision by suppliers and wire companies, with verifiable reliability-related products seen by the customer. We furthermore conjecture that this framework can only be implemented in a regulatory setup that nurtures performance incentives.

Keywords: *Short-term reliability assessment; reserve requirement; reserve allocation; reliability related risks.*

I Introduction

The growing pains of the electric energy 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 [1].
Concerning continuity of service as seen by the customer, we describe major changes in fundamental principles underlying reliable electric energy 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 efficient use and reliability improvement of transmission grids. 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 powerfully technologies software tools in particular, for implementing a desired level of reliability.

Furthermore, we can see that most of the current discussions are related with long-term reliability issues [2], however in the short-term the market alone cannot solve the reliability problem.

If there is a shortage, as economic theory shows, the price increases to attract new suppliers [3]. It is true that enhanced prices attract new entrants in the long-run, however, in the electric energy industry there cannot be instantaneous new entrants. The "market" cannot produce additional resources immediately, consequently some load need to be curtailed and/or the prices increase rapidly.

The object of the above discussion is to stress the importance of guarding against insufficiencies in the short-time frame. Such situations can creep up on a system without notice.

Accordingly, the aim of this paper is to study how a System Operator and an ISO can ensure adequacy of supply in the short-term.

The paper is organized as follows: in Section II the practices usually used by System Operators in vertically integrated utility structure are presented, in Section III the current methods implemented by ISOs in a restructured electric energy industry are analyzed, in Section IV the general underlying principles for providing reliable service under industry unbundling are presented, and finally in Section V the main conclusions are summarized.

II Reliability management under vertically integrated utility structure

The operating and planning practices of a vertically integrated utility are defined and coordinated on the basis of reliability requirements defined by regulators. These requirements are implemented following "top-down" rules, expecting that meeting these criteria or technical standards will lead to the desired reliability at the customer side. The loss of load probability (LOLP) and the expected value of energy not served (EENS) are some of the typical indices used for measuring system-wide reliability. In this paper we use LOLP to compare the impact of

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operator actions on the reliability as seen by customers.

Considering the fact that independent multiple outages are very unlikely events in the short-term, a usual practice to guarantee short-term reliability is the operation on the basis of the so-called (N-1) security criterion. The system operator dispatches the available generation to minimize the total operating cost of supplying 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.
The critical issue to observe here, however, is that there is no direct relation between LOLP or any other probabilistic reliability index 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 transmission line outages.
As a consequence, like it or not, current industry practices are not designed to guarantee a pre-specified reliability level desired 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, while voltage and stability constraints are not accounted for.

II.1 What does a System Operator do to assess short-term reliability?

The composite problem of energy dispatch and reserve allocation for the electric energy industry can be formulated as a single optimal control problem, where the scarce resources need to be adjusted optimally in a period of time in order to supply the requirements and subject to a set of constraints[1].

For this optimization problem, the performance criterion is to minimize, over a period of time, the cost of the sum of generation and reserve allocation.

$$\underset{Pg,R}{Min} \sum_i \left(C_i(Pg_i) + C_i(R_i)\right) \qquad (1)$$

This minimization cost function is constrained by the following requirements:

a. Energy
The dispatched power must be equal to the customer demand[2].

$$\sum_i Pg_i = \sum_i Pd_i \qquad (2)$$

The generation must be within technical limits.

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \qquad (3)$$

The active power flow that responds to Kirchoff's law is function of the network topology, generation dispatch, and demand, is constrained to an upper limit, which can be defined by line thermal limits or by stability reasons for instance. In this work the DC power flow model is assumed [4].

$$F_l = \sum_i H_{l,i}(Pg_i - Pd_i) \le F_l^{\max} \qquad (4)$$

b. Reliability-reserve
Some variables are inherently random, especially the demand and the availability of the system components. Uncertainty in demand means that it changes continually in time. Uncertainty in equipment availability means that it is impossible to have a system without failures. So, on top of the basic energy problem, the system needs to have generation reserve to offset this randomness. On the one hand, short-term demand deviations are considered within the usually called frequency control problem [5]. On the other hand, equipment failures are considered into the reserve for contingency problem [6], which is deeply studied in this paper .

The amount of generation reserve must be enough to fulfill the system reserve requirement, which is generally defined as the maximum between a fixed percentage of the peak demand and the capacity of the largest generator dispatched. In large systems, where the peak demand is several times the capacity of the largest generator dispatched, the reliability requirement is simplified to a percentage of the peak demand; though in relatively small systems, this reserve requirement is simplified to the maximum generation dispatched.

$$\sum_i R_i \ge Rreq = \max\left\{x\%\sum_i Pd_i, \max\{Pg_i\}\right\} \qquad (5)$$

[1] The analysis is done for a specific snapshot "t". The time index "t" is not included in the mathematical formulation for simplicity only.

[2] For simplicity the ohmic losses are not included in this paper. However, this is not a limitation to understand the paper's message. It should be pointed out that any real study must take losses into account.

The maximum generation capacity reserve is limited by both unit excess capacities and their respective maximum pick up rates.

$$0 \le R_i \le R_i^{max} \qquad (6)$$

c. Link energy-reserve

Due to the fact that both dispatched capacity for energy supply and reserve are complementary products, it is fundamental to incorporate these coupling constraints in the optimization process in order to reach an optimal tradeoff between provision of energy and reserve by a resource.

$$Pg_i + R_i \le Pg_i^{max} \qquad (7)$$

II.2 Example 1

The main objective of this example is to illustrate criteria and methods underlying operating practices for providing reliable service by 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.

Here we consider a small fictitious electric power system shown in Figure 1 as a test system. The system in study has eight lines, three demands, and five generators. The generator production cost functions are linear or equivalently constant marginal cost of production. The units have both maximum and minimum capacity limits; and the reserve limit is defined as the difference between the unit capacity minus the generation dispatched. The demand is considered inelastic in the short-term and transmission lines have defined capacity limits in both directions.

The utility has knowledge of the availability of each transmission line connecting buses i and j. 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. The utility also knows the operating cost functions of its five generators.

By simple inspection of the system in Figure 1, it is easy to see that the demand located on bus 6 experiments 1 MW of deficit in case of outage of line 16, and the demand located on bus 8 experiments 10 MW of deficit in case of outage of line 48. Assuming only single line contingencies, the reliability benchmark is given by the probability of deficit LOLP = 2*0.01*(1-0.01)^7 = 0.0186.

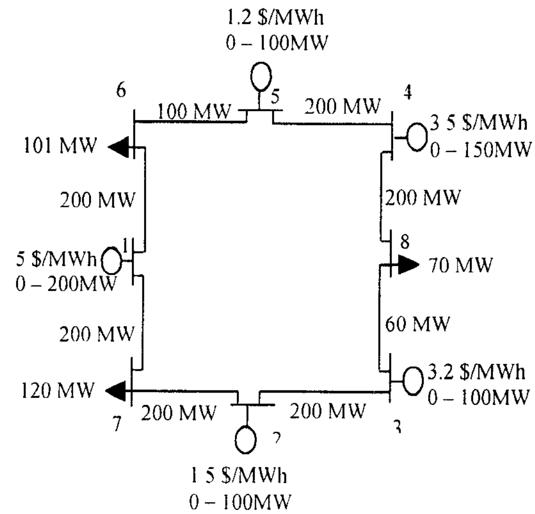

Figure 1: Power system example.

For this case, and using the formulation given in Section II.1 and the data in Figure 1, the dispatch that minimizes the generation costs results: Pg_1 = 0 MW, Pg_2 = 100 MW, Pg_3 = 82 MW, Pg_4 = 9 MW, and Pg_5 = 100 MW.

To define the reserve capacity limit for the units, is used the relation $R_i^{max} = P_{gi}^{max} - P_{gi}$. As a result, R_1^{max} = 200 MW, R_2^{max} = 0 MW, R_3^{max} = 18 MW, R_4^{max} = 141 MW, and R_5^{max} = 0 MW.

The reserve requirement is defined as in equation (5)[3]

Rreq = max {10% 291 MW, max{0 MW, 100 MW, 82 MW, 9 MW, 100 MW}} = 100 MW.

The reserve allocation that minimizes the reserve costs results: R_1 = 0 MW, R_2 = 0 MW, R_3 = 18 MW, R_4 = 82 MW, and R_5 = 0 MW.

Finally, it is necessary to simulate the operation of the system for different single contingency scenarios, and look for cases in which the system experiments deficit, calculating its amount and the probability of this event. The sum of the probabilities of all deficit states is the well-known reliability index LOLP.

Under this setup, and with the reserve allocation previously calculated the system experiments deficit when any of the following lines are out of service: L_{16}, L_{17}, L_{23}, L_{27}, L_{48}, or L_{56}.

The magnitude of the deficit is: 1 MW, 1 MW, (10.69 MW + 10.31 MW), (60.68 MW + 60.32 MW), 10 MW, or (10.54 MW + 10.46 MW) respectively.

[3] 10% is used only for purpose of the example, however it is in the range of the values usually used in real systems [7]

And the probability of having deficit is calculated as the sum of the probability of the scenarios with scarcity: LOLP = 6*0.01*(1-0.01)^7 = 0.0559.

If we compare the results with the reliability benchmark, it is easy to see that the reserve requirement and the reserve allocation procedure used by system operators leads to a lower reliability level than desired. Clearly this method does not guarantee a pre-specified reliability level. The only consideration of enough reserve capacity cannot guarantee its availability at the location where it is needed because transmission equations are not properly modeled in the reserve allocation procedure.

III Reliability management by Independent System Operators (ISOs)

Over the past several years we have witnessed a strong effort to enforce the existing industry practices for ensuring reliable operation by the Independent System Operators (ISOs) as these evolve. Some variations concerning the actual amount of reserve required, and the mechanisms for its implementation have been subject of major debates. The required reserve is implemented through so-called single settlement system, or through a multi settlement system. However, the entire debate misses the issues pointed out in our example, namely the conceptual impossibility of meeting a desired reliability level applying the criteria and calculation tools currently used.

We illustrate in the follow-up example that, much the same way as a system operator in a 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, the problem becomes more difficult as an ISO attempts to do the same. In addition to the problems illustrated above, 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.

III.1 What does an ISO do to assess short-term reliability?

In general, in a restructured electric energy industry both the energy supply and the system reliability are implemented on a market basis, energy market and reserve market respectively.

The energy market

In the markets for energy currently operating worldwide, generators explicitly bid prices at which they are willing to supply energy. The desire of privately owned generation companies to maintain and attract shareholders implies that they will attempt to exploit any potential profit-making opportunities through their bidding behavior. The ISO allocates the resources in order to supply the inelastic demand[4] while considering generation capacity limits and line capacity limits[5].

$$\underset{Pg_i}{Min}\sum_i C_i(Pg_i) \tag{8}$$

Subject to:

$$\sum_i Pg_i = \sum_i Pd_i \tag{9}$$

$$Pg_i^{min} \le Pg_i \le Pg_i^{max} \tag{10}$$

$$F_l = \sum_i H_{l,i}(Pg_i - Pd_i) \le F_l^{max} \tag{11}$$

The reliability-reserve market

In analogous way, the reserve market assesses the reliability of the electric energy industry, where participants explicitly bid prices at which they are willing to supply capacity reserve. The generators (or equivalently interruptible demand) will attempt to exploit any potential profit-making opportunities through their bidding behavior.

The reserve market is implemented in two steps: the first one is to define the system's reserve requirement, and the second one is to allocate the reserve. The ISO usually defines reserve requirement (MW) in a unilateral way [9], then allocates economically these requirements to participants that submit reserve bids subject to unit capacity limits.

$$\underset{R_i}{Min}\sum_i C_i(R_i) \tag{12}$$

Subject to:

$$\sum_i R_i \ge Rreq = \max\left\{x\%\sum_i Pd_i, \max\{Pg_i\}\right\} \tag{13}$$

$$0 \le R_i \le R_i^{max} \tag{14}$$

III.2 Example 2

The ISO in the current electric energy industry deals with two different markets, the first one is the energy market where the ISO's goal is to accommodate the energy transactions for normal operation conditions,

[4] There are some attempts to model the elasticity of the demand in terms of demand bids [8]

[5] The analysis is done for a specific snapshot "t" The time index "t" is not included in the mathematical formulation for simplicity.

and the second one is the reserve market where the ISO's goal is to asses system reliability buying reserve from generators that bid for this purpose as presented in the previous section.

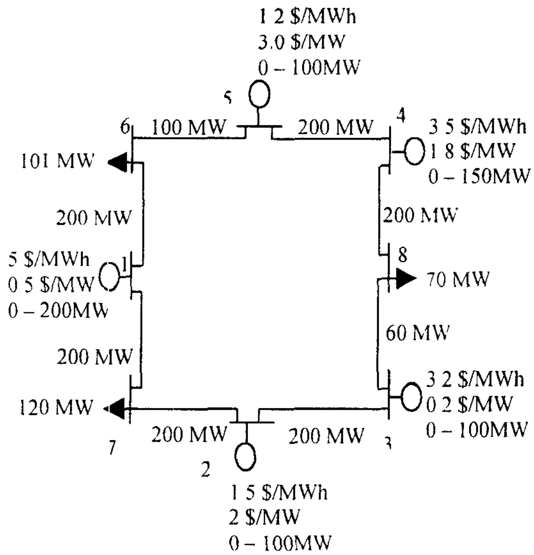

Figure 2: Test system.

For the same system in study, Figure 2, it is easy to see that the demand located on bus 6 experiments 1 MW of deficit in case of outage of line 16, and the demand located on bus 8 experiments 10 MW of deficit in case of outage of line 48. Assuming only single line contingencies, the reliability benchmark is given by the probability of deficit LOLP = 2*0.01*(1-0.01)^7 = 0.0186.

In this case, using the formulation given in Section III.1 and the data depicted in Figure 2, the energy market is cleared as follows: Pg_1 = 0 MW, Pg_2 = 100 MW, Pg_3 = 82 MW, Pg_4 = 9 MW, and Pg_5 = 100 MW.

In this example again is assumed that all generators participate in both energy and reserve markets, so to define the reserve capacity limit for the units is used the coupling equation $R_i^{max} = P_{gi}^{max} - P_{gi}$, and as a result we obtain R_1^{max} = 200 MW, R_2^{max} = 0 MW, R_3^{max} = 18 MW, R_4^{max} = 141 MW, and R_5^{max} = 0 MW.

The ISO defines reserve requirement as in equation (13)[6] Rreq = max {10% 291 MW, max{0 MW, 100 MW, 82 MW, 9 MW, 100 MW}} = 100 MW.

Then, the ISO receives reserve bids from generators and allocates the reserve such that the reserve requirement is satisfied at the minimum cost (bid-based), resulting: R_1 = 82 MW, R_2 = 0 MW, R_3 = 18 MW, R_4 = 0 MW, and R_5 = 0 MW.

Lastly, it is necessary to simulate the operation of the system for single contingency scenarios and look for cases in which the system experiments deficit, calculate its amount and its probability. The sum of the probabilities of all deficit states is the reliability index LOLP.

Under this framework, and with this reserve allocation, the system experiments deficit when any of the following lines are out of service: L_{16}, L_{27}, L_{45}, or L_{48}.

The amount of deficit is: 1 MW, (19.5 MW + 19.5 MW), 1 MW, or 10 MW in that order.

The probability of having deficit is calculated as the sum of the probability of the scenarios with scarcity: LOLP = 4*0.01*(1-0.01)^7 = 0.0373.

If we compare with the benchmark, it is easy to see that the procedure used by ISOs results in an inferior reliability situation. The only inclusion of reserve bids does not imply that the reliability problem of the electric energy industry is solved, because it is impossible to guarantee a desired reliability level with the criteria and methods currently used.

IV Underlying principles for providing reliable service under industry unbundling

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.

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

[6] 10% is used only for purpose of the example, however it is in the range of the values usually used in real systems [7]

process since one deals with the problem of ensuring uninterrupted service despite unexpected changes [10]. Accordingly, risk management is the quantification of potential failure and needs the answers to the following three issues:

#1 What can go wrong within a system?

#2 How likely is the failure to happen?

#3 What consequence will the failure cause?

The major point here is to understand that the assessment of risk involves both probability and consequences.

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 short-term operation planning for meeting a desired LOLP.

A 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 contractual agreements between entities. This requires first of all definition of reliability-related products for which there are sellers and buyers. In this environment technical "standards" are replaced by contractual expectations. In a rare case that the contracts are breached, there ought to be a well understood penalty mechanism.

V Conclusions

It can be concluded based on Examples 1 and 2 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 adequate amount of reliability reserve, and b) the adequate allocation of reserve, in order to guarantee the customers a specified service reliability according to a pre-agreed reliability index.

Moreover, the criteria and software tools for determining the 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 any arbitrary system. In this sense, none of the rules or technical "standards" could guarantee reliability as requested by a customer and/or regulator in the new industry. Utilities have made efforts to develop and apply rules most applicable to their particular systems, within the general guidelines of using type of criteria illustrated in this paper. The examples show that mere availability of generation reserve as calculated in well-know adequacy studies will not ensure that this reserve can be delivered to the customers 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 reserve requirement is viewed form the user's side depends strongly on the load level, the dispatch calculated to meet this load under normal operating conditions, the capacity of the transmission network, and the reliability of transmission lines. Technical standards, such as maintaining a generation reserve equal to the power of the largest generator dispatched, can at best guarantee the global adequacy of the generation system , but they do not give any clue about reliability as seen by the customers.

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 solve the 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.

Furthermore, based on the illustrations in Example 2, it seems 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.

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 in which risk taking is financially rewarded. 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 from 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 the most out of the existing (wire) resources.

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.

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 situations.

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VII Biographies

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