A Probabilistic Security Criterion for Determination of Power Transfer Limits in a Deregulated Environment

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SUMMARY

This paper presents a novel approach to on-line security control and operation of power transmission systems. The approach is based on a probabilistic criterion aiming at on-line minimisation of the total grid operating costs, defined as the sum of expected interruption costs and congestion costs in a specified period of operation. The probabilistic criterion is described and illustrated by a case study example. The approach currently applied by the Norwegian transmission system operator, enables flexible power transfer limits by taking into account various criteria, such as cost of redispatching, weather conditions and system protection. This is a practical approach in order to meet the increasing demand for flexible and efficient utilisation of the transmission grid in a changing environment, and can be seen as a first step towards implementing probabilistic security standards.

Keywords: Power system security, Probabilistic criterion, Transfer limits, Congestion costs, Interruption costs.

1. INTRODUCTION

Deregulation of the electric power markets in the Nordic countries and elsewhere impose new challenges for the power system operators responsible for the overall system security. The competitive environment has led to increasing focus on efficient and flexible utilisation of the main transmission grid. As a result the question has been raised whether the deterministic (N-1) criterion, applied by most transmission grid operators for security assessment, in some respects is too conservative.

The (N-1) criterion implies that transmission line capability is not always fully utilised. As a consequence unnecessary high congestion costs may be imposed on power producers and grid operators. Hence, one is looking for a more flexible criterion, which takes into account probabilistic failure models, expected power interruption costs and constraint (congestion) costs.

A lot of research work has been reported, recently, on dynamic security assessment and emergency control. See e.g. [1] for an overview. This paper has two main objectives. The first is to present a probabilistic criterion for determination of power transfer limits based on on-line minimisation of expected interruption costs and congestion costs. The second objective is to describe current practice and experiences with respect to security control and congestion management in the Norwegian transmission system.

The paper is organised in four main sections. Chapter 2 describes the background and main challenges with respect to operation of the Norwegian transmission system. The emphasis is on congestion management and determination and control of power transfer limits from a security point of view. In this context, the probabilistic operational criterion is described, and various aspects related to risk and uncertainty are discussed. Chapter 3 illustrates the proposed methodology through a case study. The chosen example illustrates the determination of transfer limits on a specific interface in the Nordic transmission system. Chapter 4 describes the practical approach applied by the Norwegian transmission system operator, which enable the use of flexible power transfer limits by taking into account various criteria, such as cost of redispatching, weather conditions and system protection. Implementation aspects and practical approaches towards further use of probabilistic security standards are discussed in chapter 5.

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2. POWER SYSTEM OPERATION AND SECURITY CONTROL

2.1 Power System Operation

Norway has had a deregulated power system since 1991. Deregulation implies that there is a competitive and free market in production and trade of electrical power. Network operation, however, is still a monopoly, and the transmission grid is operated and mainly owned by Statnett SF - The Norwegian Power Grid Company.

As system operator, Statnett SF is responsible for operation of the entire Norwegian power transmission system, and subjected to national regulatory directives. The directives involve specific requirements with respect to cost effective operation of the power system, and imply that the system operator must aim to minimize the total costs of transmission reinforcements, operation and maintenance of the system.

As the actual short term scheduling in this competitive environment is determined from the balance of supply and demand in the power markets, this has lead to larger variations in load flow patterns. In this context, bottlenecks and transfer limits in the transmission grid represent a constraint to the free power market. This has in turn led to increasing focus on efficient and flexible utilization of the main transmission grid.

2.2 Deterministic Security Criterion (N-1)

As most transmission operators, Statnett has traditionally applied the deterministic (N-1) criterion for operational security assessment. A main task in daily operation planning is the determination of *interface flow limits*. An *interface* is defined as a set of circuits (transmission lines) separating two portions of the power system (closed interface), or a subset of circuits exposed to a substantial portion of the transmission exchange between two parts of the system (open interface). Thus, the *interface flow* represents the net power flow from a sending end area to a receiving end area. The determination of interface flow limits using the (N-1) criterion is an established part of the operating procedures at Statnett's National Control Centre.

The (N-1) is a simple, technical criterion which states that the system should be designed and operated in such a way that it is able to withstand any single contingency, e.g. outage of a line or generator, without resulting in unacceptable consequences. This criterion has shown to provide sufficient security. It does, however, not include any economical aspects, and it does not necessarily lead to the most cost effective operation. It is, for example, not sensitive to varying outage probabilities for circuits exposed to changing weather conditions.

2.3 Probabilistic Security Criterion

An important part of the operational control procedures involves monitoring and control of interface flows in order to maintain the transfer limits. The actions may be either corrective when flow limits are exceeded during normal operation, or preventive when bottlenecks are predicted from the initial power balance in the spot market.

Corrective and preventive actions in order to maintain interface flow limits imply congestion costs. These costs increase as the power transfer demand exceeds the transfer limits. On the other hand, if a higher transfer flow is accepted in order to reduce the congestion costs, this would reduce the security level and increase the risk of collapse associated with a system failure. Thus, the expected interruption costs will increase as the power transfer level increases.

The main idea of the probabilistic operational security criterion, as described below, is to enforce flexible interface flow limits in a way that minimises the sum of congestion costs and expected interruption costs. Thus, the interface flow limits will vary with time, as a function of weather conditions, power prices and other factors affecting the grid operating costs. The criterion can be formulated as an optimisation problem with the objective to minimise the total grid operating cost, $C_T(F)$, in the specified period of operation, where F is the interface flow:

$$\min_F \left[C_T(F) \right] \tag{1}$$

where

$$C_T(F) = C_C(F, m) + C_{EIC}(F, w) \tag{2}$$

The variables, m, and, w, indicate that the costs are depending on market and weather conditions, respectively. The total grid operating cost is defined in (2) as the sum of constraint costs and expected interruption costs. The cost of transmission losses should in principle also be included in (2), but this term is neclected since the variation in losses as function of the interface flow limits is assumed to be small. The two remaining cost terms are briefly described below.

<u>Congestion costs, C_C</u>

These costs arise when a congestion occurs in the transmission grid, i.e. when the power transfer demand, given by the market, exceeds the interface flow limit set by the grid operator. In the Norwegian system congestions are presently treated in two different ways:

When a bottleneck is predicted prior to price setting in the spot market, the market is split into two separate bid areas on each side of the critical interface in order to maintain the power transfer limit. Thus a higher price is established in the receiving end area than in the sending end area, and the consequence is that the actors in the market may either gain or lose revenue depending on their particular obligations. This is called the price area model, and the congestion costs are defined as the net loss of revenue for all market participants compared to the unconstrained case.

The second case is when a bottleneck occurs in on-line operation. Then, corrective actions are taken in terms of redispatch of selected power plants on each side of the bottleneck, or through tripping of interruptible loads. This is called the "buy-back" model. The buy-back model can be described as follows. Consider two areas (A and B) with a transfer path (interface) between them. Let the transfer flow for a market settlement in the unconstrained case be F_u, and let the transfer limit be F_{lim}. Then the generation in each area must be adjusted to reduce the transfer from A to B from F_u to F_{lim}.

$$\Delta F = F_u - F_{\lim} \tag{3}$$

The adjustment must be made by the grid operator (i.e. Statnett) through a purchase of power (increased generation) in area B, and a sale (decreased generation) in area A. The price in each area is given by a generation cost (bid) curve in a separate regulating market. The purchase will be made at a price π_{hi} which is higher than the unconstrained price, and the sale at a price π_{lo} which is less than the unconstrained price. Then the total congestion cost for this transaction is

$$C_C(F,m) = \Delta F \cdot (\pi_{hi} - \pi_{lo}) \tag{4}$$

The reduction in flow is linear with a reduction in flow limit, but the price difference is increasing due to the non-linear generator cost curves. Hence the cost curve is a non-linear function of the flow limit.

The congestion cost is primarily a function of the interface flow *(F)* and the market situation *(m)*. Presented as a function of interface flow, the congestion cost will typically be a piecewise linear decreasing function as depicted in Fig.1, reaching zero cost at the interface flow level which satisfy the initial market demand.

Other aspects related to congestion management are described in [4].

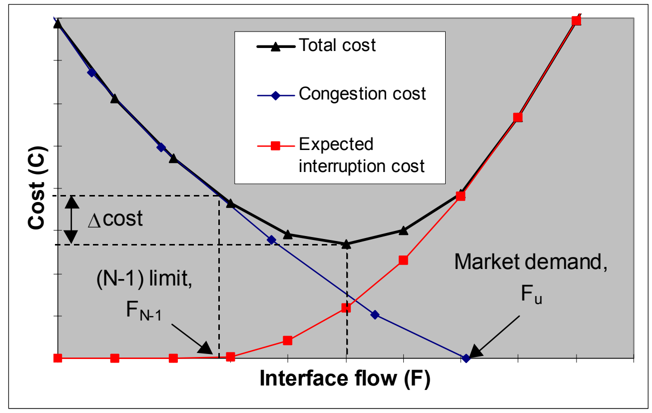

Figure 1. Interface flow limit determined from minimization of total grid operating costs.

Expected interruption costs, C_{EIC}

These are the total expected customers' cost of energy not supplied resulting from a transmission grid failure. The cost increases with increasing transfer flow as a consequence of the increased probability of a system collapse. The computation of expected interruption costs involves contingency analysis combined with statistical information about failure rates and interruption scenarios determining the amount of energy not supplied. Mathematically, this can be formulated as:

$$C_{EIC} = \frac{1}{8760} \sum_{i=1}^{n} \left[\lambda_i(w) \cdot \sum_{j=1}^{m(i)} \left(p_{ij}(F) \cdot P_{ij} \cdot c_{ij} \cdot r_{ij} \right) \right] \tag{5}$$

where

- $\lambda_i\ (w)$ *[failure/year]* is the weather dependent annual failure rate associated with contingency *i* (e.g. outage of a line).
- $p_{ij}(F)$ *[0,1]* is the probability of interruption scenario *j* following the contingency *i*.
- P_{ij} *[MW]* is the average power interrupted in scenario *j*.
- c_{ij} *[NOK/MWh]* is the average specific customer interruption cost in scenario *j*.
- r_{ij} *[h]* is the average time to restoration of supply in scenario *j*.

The expected interruption cost is primarily a function of the interface flow (*F*) and the weather conditions (*w*), since the failure rates are known to be highly weather dependent. The cost functions are shown in Fig 1. Using (1) as an operational security criterion, the figure illustrates how the interface flow limit is determined from minimisation of total grid operating costs. Implementation aspects and computational procedures involved in the determination of transfer limits are discussed in the following chapters.

2.4 Risk Assessment

The computation of cost functions relies on both market information and system descriptions (load flow and dynamic models). While the computation of congestion costs is relatively simple and straight forward, the determination of expected interruption costs require extensive computations, which involve various degrees of uncertainty. Both contingency analysis and dynamic simulations, incorporating system protection models, are generally needed in order to assess the amount of interrupted power resulting from a contingency. The uncertainties include the following aspects:

- Uncertainty or lack of required data.
- Uncertainty related to the choice and use of models.
- Uncertainty related to the choice of interruption scenarios and the risk of disaster scenarios.

In order to make the probabilistic criterion reliable in practical use, the operator must be able to assess the risk and uncertainty in a simple and understandable manner. These aspects represent important challenges for practical implementation of the proposed method. Several approaches have been studied, and these are summarised in [2].

3. APPLICATION OF THE PROBABILISTIC SECURITY CRITERION

An example from a case study [5] is included to illustrate the use of the probabilistic security criterion for determination of operating transfer limits.

The chosen network case, illustrated in Fig. 2, represents the major interface for power transfer between Norway and Sweden. This interface is known to represent a bottleneck in the Nordic system, since the power transfer demand in the market frequently exceeds the established transfer limits.

The basic load flow case and market data used in this example represent a snapshot from operation of the Nordic power system on a morning hour in January 1997. Key figures describing the case are:

-Total power production in Norway:	14700 MW
-Total consumption in Norway:	17000 MW
-Total power production in Sweden:	21900 MW
-Total consumption in Sweden:	18900 MW
-Total power import demand:	2100 MW
-Transfer limit set by the (N-1)criterion:	1650 MW

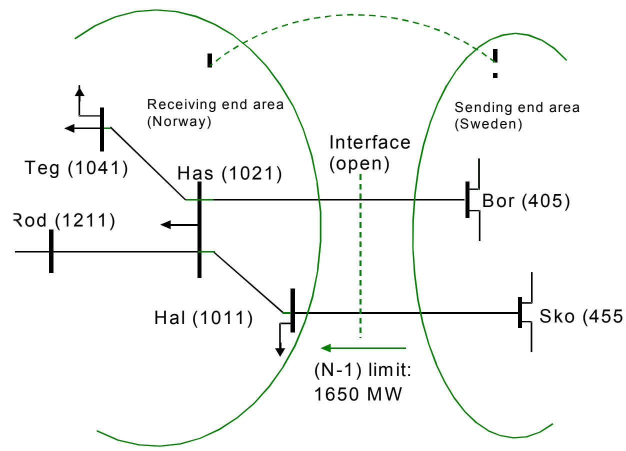

Figure 2. Case study network.

3.1 Constraint costs:

The congestion cost is computed as a function of the interface flow by assuming that corrective redispatch (the buy-back model) is used. Redispatch is enforced in order to reduce the actual interface flow from 2100 MW to the desired value, *F*. The cost is determined from the actual prices in the regulating power market [3]. The resulting cost function is shown in Fig. 3. This indicates that the hourly cost of reducing the power transfer to the (N-1) level (1650 MW) is in the order of NOK 40.000,- (USD 5.500,-).

3.2 Expected interruption costs:

These costs are estimated from contingency analysis and interruption scenarios. Four different contingencies are regarded as critical, namely outages of the following lines: *Hal-Sko*, *Has-Hal*, *Has-Bor* and *Teg-Has*. Each of these lines has failure rates, λ_i, that is weather dependent. Three different weather conditions, termed *fair*, *uncertain* and *adverse*, have been considered in this case study.

Five different interruption scenarios are defined as likely consequences of an outage. The interruption scenarios are associated with probabilities of occurrence, $p_{i1}(F),..,p_{i5}(F)$, that are mainly functions of interface flow and the initiating outage, *i* (see eqn. 5). The scenarios are briefly described below (j = 1..5):

1. *The outage does not lead to problems. The system is stable and no load is interrupted.*
2. *The outage leads to overload on certain critical lines at lower voltage levels in the south-east part of Norway. This results in a local collapse and interruption of 3.700 MW load.*
3. *The outage leads to undamped power oscillations or overload on the interface. This leads to cascading outages and separation of southern Norway from the*

rest of the Nordel grid. The separation initiates frequency controlled load shedding. The amount of load shed depends on the initial interface flow level, and is determined from dynamic simulations.

4. *Same as scenario 3, but the separation leads to a total collapse in southern Norway. The amount of power to be interrupted is 12.200 MW.*
5. *The outage leads to undamped power oscillations between the areas. This results in a collapse that affects the entire southern parts of Norway and Sweden. The amount of power to be interrupted is 27.250 MW.*

3.3 Optimisation and risk assessment:

Using statistical information about failure rates, and preliminary (but credible) values on probabilities, repair times and specific interruption costs, the resulting cost function for the fair weather case is shown in Fig. 3.

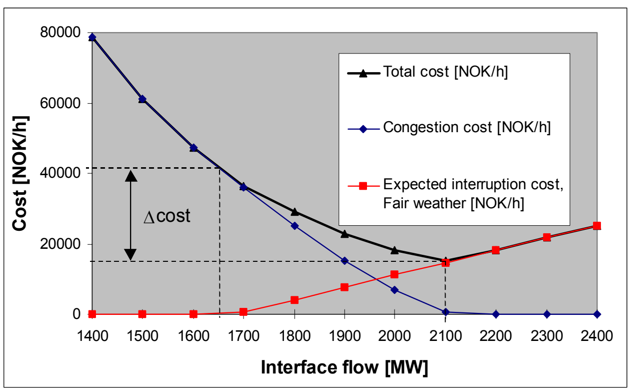

Figure 3. Congestion cost, expected interruption cost and total cost as function of interface flow in fair weather.

The results show that by increasing existing transfer limits in periods of fair weather, considerable economic savings and increased efficiency can be achieved without significant reduction of security. The interface flow limits determined from minimisation of total costs can vary from 1600 MW in the adverse weather case, and up to 2100 MW in the fair weather case. The potential benefit of this approach is clearly demonstrated in the fair weather case (Fig. 3), where the total expected cost reduction (∆cost) of increasing the transfer limit is nearly NOK 30.000,- per hour.

Similarly, during adverse weather conditions, it is shown that the transfer limit should not exceed the present (N-1) limit. The study has also shown that uncertainties with respect to data or interruption scenarios can significantly affect the optimal transfer limit. A special case is shown in [5] where the total cost has its minimum at 2000 MW, but within a wide interval of interface flow levels (between 1700 and 2100 MW) the cost function varies little. In such cases the risk assessment approach in [2] is especially interesting in order to verify or assess if it is worthwhile to increase the transfer limit and thereby the associated risk, considering the rather low reduction in expected total costs.

4. CURRENT PRACTICE IN THE NORWEGIAN TRANSMISSION SYSTEM

The Norwegian transmission system operator, Statnett, is currently investigating several approaches in order to increase transmission capacity on their existing network. Probabilistic security criteria and on-line determination of transfer limits can be seen as an ultimate goal in this respect. However, as illustrated above, there are still fundamental uncertainties and computational difficulties associated with this approach which suggest some practical adaptations. The purpose of this chapter is to present possible adaptations and current practice with respect to determination of power transfer limits in the Norwegian transmission system.

Statnett uses the deterministic (N-1) criterion as the main operational security criterion. It is, however, recognised that this criterion under certain conditions, and in some parts of the network, imposes unnecessary high congestion costs for both power producers and grid operators. On the other hand, e.g. during adverse weather conditions, the (N-1) constraint may not provide sufficient security. Thus, in order to minimise the congestion costs while maintaining an acceptable level of security, a number of practical efforts are taken to enforce more flexibility in determination of transfer limits. These efforts are summarised below.

- Weather dependent relaxations of the (N-1) criterion. In some parts of the network, especially in less densely populated areas, the cost of maintaining the (N-1) limit may be very high. In such cases the thermal capacity of transmission lines may be fully utilised (N-0) if the probability of an outage is regarded as low. Weather reports (mainly windspeed and thunder storm predictions) are then used as a formal criterion for enabling increased transfer limits.
- Extensive use of system protection schemes. A number of overload initiated (or breaker initiated) generator tripping and load shedding schemes are implemented to act on certain interfaces. These schemes are implemented primarily to enable increased transfer limits and not only to reduce consequences of disturbances or interruptions.
- Interruptible loads. Some large consumers have a special tariff for interruptible loads. In a high load / high power transfer demand case, Statnett may disconnect loads in order to allow increased power transfer on certain interfaces. The cost of interrupting loads is then

weighted against other congestion costs in order to obtain the least cost alternative.

- Corrective redispatch. An efficient way of dealing with congestions is of course to redispatch generators. This possibility is utilised by Statnett primarily when unpredicted bottlenecks occur during operations. The cost of redispatch is based on the generators' bids on the balancing (regulating) power market [3].

5. IMPLEMENTATION ASPECTS

The practical approach described above can be seen as a first step towards implementing probabilistic security standards in power system operation. Implementation aspects are further discussed below based on the layout suggested in Fig. 4.

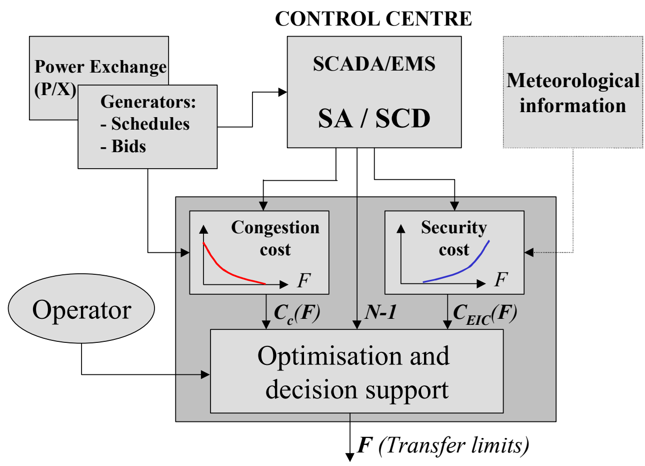

Figure 4. Layout of a practical implementation.

A main goal for this work has been to develop a practical tool for assessing the trade off between congestions costs and security aspects (risk) in transmission system operation. This trade off is explicitly formulated in the probabilistic security criterion (1) and illustrated in Fig. 4.

Computation of congestion costs as a function of interface flow can be performed in the pre-operational phase, after clearing of the Elspot (24 hour) market, and when the generator production plans (schedules) have been reported to the system operator. The amount of redispatch is determined based on a SCD (Security Constrained Dispatch) type of algorithm.

The computation of expected interruption costs can in principle be based on security analysis (SA), combining contingency analysis and dynamic simulations, and the use of time and weather dependent probabilities of incidents. There are, however, fundamental uncertainties and difficulties related to the computation of interruption costs. Thus, there is a need for investigating alternative methods for assessing the security costs. This is a topic for current research, and from an operator point of view, this is an important condition for implementing new criteria for determination of power transfer limits.

6. CONCLUDING REMARKS

The purpose of this paper is to present a novel approach to on-line power system security control. The main objective of the work is to assess possible methods to enable the use of more flexible transfer limits in the transmission system.

The possibility of increasing the transfer limits in periods of fair weather conditions, and when the market transfer demand is high, could lead to significant savings in total grid operating costs, as demonstrated by the case example. In a long term perspective, such a practise may result in more effective utilisation of the transmission grid, and thereby avoid or postpone the construction of new lines.

Preliminary conclusions indicate that the probabilistic method presented in this paper is a feasible solution to the objective. Two issues are found to be important for further development and practical implementation. The first relates to computational problems and uncertainties involved in the determination of expected interruption costs. Secondly, effective use of system protection schemes is found to be particularly important, not only as a means to reduce the actual interruption costs, but also for reducing the uncertainty related to determination of expected interruption costs.

7. ACKNOWLEDGEMENTS

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