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Enhanced Method for Reliability of Supply Assessment – An Integrated Approach

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***Abstract*— A comprehensive analysis of reliability of electricity supply to end users requires a unique set of models, methods and tools. Of special significance are long term power market models for predicting future operating states (generation and load patterns) and more detailed network simulation models for analysing consequences of contingencies. This paper describes an integrated approach for reliability of supply analysis, assessing reliability and interruption costs down to the specifics of different kinds of end users at different delivery points in the network model. Furthermore, the effects of power system protection, temporal variation of parameters, and corrective actions as part of the consequence analysis, are taken into account in the presented integrated approach. The results are illustrated through a case study on a realistic hydro dominated four-area meshed test system.**

***Index Terms*-- Contingency analysis, interruption cost, protection system, reliability, temporal variation, transmission system.**

I. Introduction

The power system is under change for a number of reasons such as the integration of considerable amounts of renewable energy, a drive towards efficiency and higher utilization of the existing network, the transition to smart energy networks, and at the same time climate changes impose increased climatic stress. In this environment of complexity and uncertainty, it is a challenge to maintain reliability of supply to the end users, in particular taking into account the increasing dependency of electricity throughout the entire society. This calls for tools to aid the assessment of power system reliability for planning purposes.

Reliability analysis of power systems traditionally attempts to answer three fundamental questions (analogous to risk analysis [1]):

- What may go wrong?
- How likely can it happen that something may go wrong?
- What are the consequences?

This paper presents a discussion on important aspects to be taken into consideration when answering the two last questions. In particular, it will discuss the importance of the following aspects for the reliability assessment:

- Selecting the operating state of the system.
- Protection system misoperations.
- Temporal variation in interruption costs and reliability data.
- Strategy for corrective actions in the contingency analysis.

To obtain the results presented in this paper, a previously postulated framework of the integrated methodology for reliability of supply analysis [2] has been used, with extensions. In essence, the approach provided in this paper is an integration of methods and tools that can provide a conceptual and methodological link between power market simulations and power system reliability analysis.

The methods behind the inclusion of the above mentioned aspects in the reliability assessment have been individually presented in separate papers [3]–[6]. However, in those papers the focus was on the methods themselves rather than on the importance of integrating them together. The significance of these aspects relative to each other not only gives valuable input on which factors should be definitely included in a comprehensive reliability analysis, but also valuable information on where the highest potential for improvement in the reliability lies.

The paper is organised as follows: Section II provides a summary of the integrated methodological framework used in this paper. Section III, IV and V give an account of the various unique aspects considered in the reliability assessment using the underlying integrated framework – protection system failures, temporal variations, and modelling of corrective actions. Section VI uses a realistic case study to illustrate the results of the proposed integrated methodology, followed by discussion of the results and conclusions.

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II. INTEGRATED METHODOLOGY

The previously suggested methodology for reliability of supply analysis involves three distinct phases [2], [7], [8]: Power market analysis (phase 1), contingency analysis (phase 2) and reliability analysis (phase 3). This integration as illustrated in Figure 1 enables a better information exchange and interaction between the different actors of the chain of analysis.

Phase 1: In the security constrained power market analysis phase, generation and power market scenarios are combined to produce a set of 'operating states' (OS). The definition of operating state as postulated by the EPRI report on transmission system reliability methods [9] is as follows: '*a system state valid for a period of time, characterized by its load and generation composition including the electrical topological state (breaker positions etc.) and import/export to neighbouring areas.*' These operating states can be further grouped using different clustering functions to obtain representative scenarios that can significantly reduce the computational requirements [10].

Phase 2: Analytical contingency simulation of component failures due to random events is carried out using AC power flow models. Minimal cut sets (MCs) are then obtained for each operating state and delivery point, representing the critical contingencies leading to potential interruptions or reduced supply at various delivery points in the power system.

Phase 3: The reliability analysis is based on the MCs for each delivery point. Relying on the approximate methods of system reliability evaluation [11], a simple yet efficient way to obtain the various reliability indices for each delivery point is then put in place –number of interruptions per year λ, annual expected interruption duration U, and expected average interruption duration r. Subsequently, the annual power interrupted ($P_{\text{interrupted}}$), annual energy not supplied (ENS) and annual interruption costs (cost of energy not supplied, CENS) are computed for each delivery point.

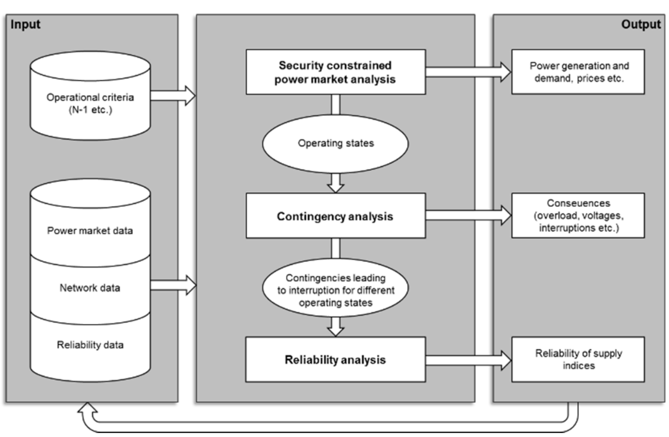

Figure 1. Integrated methodology for reliability of supply assessment.

The MCs obtained by the contingency simulation may represent a single component failure or an event of independent or dependent failures. An interruption occurs in a delivery point when the available capacity after a specific contingency j is unable to match the load. The available capacity is the sum of the available capacity in hour h, on weekday d, and in month m ($SAC_{j,h,d,m}$) for the specific contingency and the local generation (LG) at the delivery point (if available). A negative margin implies that load has to be partially or totally disconnected:

$$P_{\text{interrupted},j,h,d,m} = P_{h,d,m} - SAC_{j,h,d,m} - LG \tag{1}$$

Energy not supplied $ENS_{j,h,d,m}$ for a specific interruption, i.e., resulting from the minimal cut j, is found as the product of the corresponding interrupted power given by (1) and the interruption duration found from the equivalent outage time $r_{j,h,d,m}$ for the minimal cut:

$$ENS_{j,h,d,m} = P_{\text{interrupted},j,h,d,m} \cdot r_{j,h,d,m} \tag{2}$$

In the same way, the cost of energy not supplied $CENS_{j,h,d,m}$ is calculated introducing the unit interruption cost c_t at a specific time:

$$CENS_{j,h,d,m} = ENS_{j,h,d,m} \cdot c_t \tag{3}$$

III. PROTECTION SYSTEM RELIABILITY

The reliability of protection systems has a considerable effect on the reliability of supply, and hence appropriate protection system reliability models must be incorporated in power system reliability studies. The embedded approach circumvents the need for complex Markov models to include the effects of protection system reliability by enhancing the minimal cut set approach presented in the previous section [4], [12].

A. Basic Approach

Protection systems are characterized by two attributes: the ability to trip when called for (dependability), and the ability to restrain from tripping when not called for (security) [13]. Failure of a transmission line (i.e., isolation from the network) can be thought of as a result of different protection system response scenarios, governed by the parameters describing the dependability and security attributes of the transmission protection systems. Accordingly, equivalent failure rates of transmission lines can be obtained from appropriate mathematical modelling of the identified failure scenarios. Four mutually exclusive failure modes, denoted as fault types (FTs) were identified and modelled in our previous works [4], [12], [14]. A brief generic description of such fault types is presented below.

Fault Type 1 (FT1): A fault occurs on the transmission line i, upon which there could be two consequent scenarios: Consequent Scenario 1 - The fault is successfully cleared by the line's primary protection system; Consequent Scenario 2 - The fault could not be cleared because of the unreadiness of the line's primary protection system. The failure rate of FT1 is merely the failure rate of the transmission line.

Fault Type 2 (FT2): The transmission line i is fault-free, but because of faulty operation of the line's primary protection system, unwanted spontaneous tripping of the circuit breaker(s) occurs. This results in isolation of the healthy line i. The failure rate of FT2 is the summation of unwanted spontaneous tripping rates of circuit breakers of line i.

Fault Type 3 (FT3): A fault occurs on one of the neighbouring transmission lines, but the faulty operation of the primary protection system of the neighbouring line results in the missing operation of a circuit breaker, because of which the faulted neighbouring line cannot be isolated by its own circuit breakers. In such a case, the protection system of line i acts as back-up to isolate the faulted neighbouring line. This also results in isolation of the healthy line i.

Fault Type 4 (FT4): A fault occurs on one of the neighbouring transmission lines, upon which the neighbouring line's primary protection system clears the fault correctly. However, because of faulty operation of either of the protection system units of line i or both protection system units of line i, unwanted non-selective tripping of line i's circuit breaker(s) occurs. This results in healthy line i's isolation.

In reliability parlance, a system with a component consisting of four mutually exclusive failure modes is analogous to a four component series system. Hence, the usage of approximate methods of system reliability evaluation in obtaining the equivalent failure rate of a transmission line on account of the protection system response scenarios is a valid approach.

B. *Equivalent Failure Rates*

The equivalent failure rate of a transmission line (i.e., its original failure rate augmented by incorporating additional failure rates that pertain to dependability and security attributes of the protection systems) is not constant, but varying depending upon the composition of the MC that it is a part of. This is on account of dependencies among the elements of MC. For every MC of transmission lines, dependent mode failure rates as mandated by backup protection coordination among the neighbouring elements if any are computed, and all the MCs are duly combined using the approximate series system reliability logic [4], [12]. An overview of the basic formulae used in [12] is presented below:

$$\lambda_{FT1(i)} = \lambda_i \tag{4}$$

$$\lambda_{FT2(i)} = [\lambda_{BE_{A[i]}} + \lambda_{BE_{B[i]}}] \tag{5}$$

$$\lambda_{FT3(i)} = \lambda_j * P_{M(PT_{A[j]})} + \lambda_k * P_{M(PT_{B[k]})} \tag{6}$$

$$\lambda_{FT4(i)} = \left([\lambda_j * P(PT_{A-j})] + [\lambda_k * P(PT_{B-k})]\right) * \left(P_{U-Ns.(PT_{A[i]})} + P_{U-Ns.(PT_{B[i]})} - P_{U-Ns.(PT_{A[i]})} * P_{U-Ns.(PT_{B[i]})}\right) \tag{7}$$

$$\lambda_{Eq.(i)} = \lambda_{FT1(i)} + \lambda_{FT2(i)} + \lambda_{FT3(i)} + \lambda_{FT4(i)} \tag{8}$$

The nomenclature used in the above formulae (with respect to line i) is listed below.

λ_i : Failure rate of transmission line i.

r_i : Outage/repair time of transmission line i.

$\mathrm{PT}_{\mathrm{A[i]}}, \mathrm{PT}_{\mathrm{B[i]}}$: Protection system units at each of the ends A and B of transmission line i.

$\lambda_{BE_{A[i]}}$: Failure rate of unwanted spontaneous tripping of the circuit breakers of protection system unit at the A-end of line i. Similar interpretation for $\lambda_{BE_{B[i]}}$.

$P_{U-Ns.(PT_{A[i]})}$: Probability of unwanted non-spontaneous operation of protection system unit at the A-end of transmission line i. Similar interpretation for $P_{U-Ns.(PT_{B[i]})}$.

$P_{M(PT_{A[i]})}$: Probability of missing operation of protection system unit at the A-end of transmission line i. Similar interpretation for $P_{M(PT_{B[i]})}$.

$P(PT_{A-i})$: Successful fault clearance rate of protection system unit at the A-end of transmission line i, which is the sum of missing and unwanted probabilities of the unit subtracted from 1. Similar interpretation for $P(PT_{B-i})$.

$\lambda_{Eq.(\mathrm{i})}$: Equivalent failure rate of line i taking all FTs into account.

The impact of substation configuration arrangement on transmission protection system failure dependency propagation can also be included, based on the combinatorial analysis of all possible backup coordination related interaction scenarios arising due to the substation structure [14]. However, in this paper the impact of substations has not been considered for this phase of research.

IV. Temporal Variation

There are temporal variations such as those encountered in load, generation, failures, and consequences of interruptions [5]. To capture these effects, the presented methodology uses correction factors for monthly, daily, and hourly variations. A brief summary of the implementation is provided below. Reference [5] gives a detailed explanation.

A. *Temporal variation in cost functions*

The cost of a single interruption in monetary terms should be calculated using (9), taking into account interruption duration and time of occurrence [15], [16]:

$$C_t = c_{ref}(r) \cdot P_{ref} \cdot f_{Ch} \cdot f_{Cd} \cdot f_{Cm} \ \ (NOK) \tag{9}$$

Where

C_t	=	Interruption cost for an interruption at time t (NOK[1])
$c_{ref}(r)$	=	Sector customer damage function in NOK/kW for duration r, at reference time
P_{ref}	=	Interrupted power in kW at reference time
f_{Ct}	=	Correction factors for the cost (in NOK) at time t (in hour h, on weekday d and in month m) [16]

[1] NOK = Norwegian Krone (currency)

The correction factors in (9) describe the deviation in costs from the cost at the reference time. The factors are e.g., given in the regulations [16]. They are based on information of variation in interruption costs by season, weekdays, and time of day from the survey [17].

The customer damage functions used in this paper are presented in Figure 2. It can be clearly seen that the rate of change in the customer damage functions vary significantly between the sectors[2]. Consequently, one needs to distinguish the sectors to obtain a more precise estimate for the interruption costs.

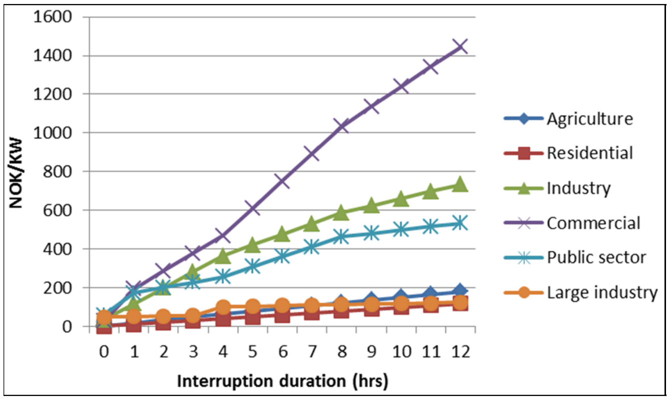

Figure 2. Customer damage functions (cost level 2012) [5].

B. Temporal variation in reliability data

A time-varying failure rate is traditionally explained using a two-state weather model [11], and time-sequential Monte Carlo simulation is used to represent the chronological variation in reliability data and loads [18]. Methods for representing time variation in input parameters are discussed in [19]-[22]. Two different approaches are presented in [19]; the black box approach and an approach based on representing underlying factors [21]. Examples of underlying factors are weather-related data such as lightning and temperature, and activity data [19]. The method presented in [20] belongs to the first approach. In this method, the time variation in the input parameters is represented using statistically based patterns for component failures, restoration times, load curves and relative factors as those in (9) for the time variation in interruption costs.

The methodology presented in this paper uses the method from [19], with the same time resolution as in (9). This gives the following equations for the time variation in repair times and failure rates.

$$\lambda_{h,d,m} = \frac{\lambda_h}{\lambda_{av}} \frac{\lambda_d}{\lambda_{av}} \frac{\lambda_m}{\lambda_{av}} \lambda_{av} \tag{10}$$

$$r_{h,d,m} = \frac{r_h}{r_{av}} \frac{r_d}{r_{av}} \frac{r_m}{r_{av}} r_{av} \tag{11}$$

[2] It can be noted that the customer damage function (in NOK/kW) for Large Industry is much lower than for Industry and Commercial. The main reason is that this category comprises the power intensive industries with a very high load (in kW).

In equations (10) and (11) the subscripts *h, d, m* represent hour, day, and month, respectively. The subscript *av* represents the annual average. These correction factors have to be calculated for each component type in the system.

The correction factors used for failure rates and repair times are shown in Figure 2. It is worth noting that the repair times and failure rates for the most months rise and fall in opposite directions. In this paper, we have only included seasonal variation in the reliability data for the sake of illustration, although the daily and weekly variation might be considerably higher [5].

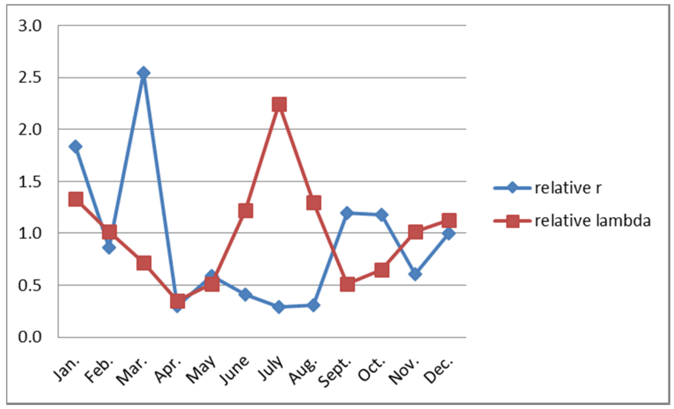

Figure 3. Correction factors for reliability data for transmission line.

C. Time resolution in the market model and the correction factors

Time variation is considered for hours, days, and months. This results in 2016 different factors that have to be used for each operating state in the case study presented in Section VI. The market model used to generate the operating states uses a different time resolution. Here, each year is represented by 52 weeks, and each week is divided into load segments that consist of several hours [23]. This means that there is ambiguity about the correction factor to be used for a load segment.

The ambiguity is solved by taking the average of correction factors for the hours that make up a load segment. For instance, consider that we have a load segment that is Monday from 08:00 to 12:00. This load segment will occur 52 times, since we simulate the year as consisting of 52 weeks. The correction factor for repair time for a component during a load segment *s* occurring at month *m* and day *d* will be:

$$r_s = \frac{r_8 + r_9 + r_{10} + r_{11} + r_{12}}{5 r_{av}} \frac{r_d}{r_{av}} \frac{r_m}{r_{av}} r_{av} \tag{12}$$

V. MODELLING OF CORRECTIVE ACTIONS

Power system contingency analysis is an important part of reliability assessment of electric power systems. For every contingency that is to be considered in a reliability analysis, one needs to somehow evaluate the consequences for the power system. Typically, a contingency analysis involves power flow calculations to estimate the power supplied to each delivery point. This output is then used as input to the reliability analysis to estimate reliability indices for the system, such as the total annual expected energy not supplied.

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For an accurate assessment of the reliability of a real power system, the models used in the contingency analysis need to capture the features of the real system that have the most substantial impacts on the results. Previous work has shown that power system operation, including the corrective actions taken by the operator, is essential in determining the consequences of contingencies [6]. In this paper, two different strategies for corrective actions are simulated, namely, trip next and generation rescheduling using heuristics. The strategies are briefly described below Results and comparisons on more strategies are presented in [6].

A. *Trip next*

In this strategy, it is assumed that the only actions available to the operator are to trip the most overloaded line of the system and to operate the system as separate islands. When creating islands, the algorithm assumes that a generator bus can act as a swing bus.

B. *Generation rescheduling using heuristics*

In this strategy, the operator has more actions to choose from in addition to the ones in the trip next strategy in the following order:

1. Reschedule generation
2. Trip component
3. Reduce generation
4. Shed load.

In this implementation, it is assumed that the operator can shed just the amount of load needed to relieve overloads. This may in many cases be too optimistic; the implementation also allows for choosing other options.

The strategies are implemented as heuristics-based algorithms in MATLAB. A very simple time representation is implemented allowing the operator to attempt 10 corrective actions to solve problems. If the problems are not solved within these attempts, a blackout is assumed. The contingency analysis also distributes the slack to all generators according to the maximum capacity of the generators. This is a way of representing frequency control in a power flow study.

VI. CASE STUDY

There are several different test systems for reliability studies described in the literature, e.g., the IEEE RTS [24] and the RBTS [25]. As described in previous sections, this study requires a test system with corresponding market and network models. This is not available for any of the well-known test systems. It was therefore chosen to carry out the study on the four area test system depicted in Figure 4, which is further described in [7]. The system is a hydro dominated system with four distinct areas with corresponding market and network models used for the case study. Actual generation and demand for the different units and bus bars vary with the different operating states, and is a result from the power market simulations. In the original case 10400 operating states distributed over 50 years were simulated. In this paper, the median year in terms of ENS from [7] was used. The reason for not using all of the 10400 operating states was merely due to computational time. For the reliability data, statistics from the Norwegian system were used.

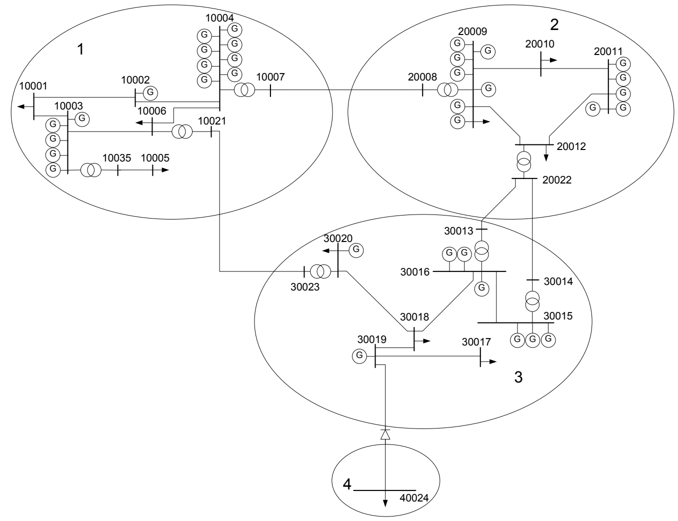

Figure 4. Four area network [7].

Reliability assessment can be very dependent on the modelling and simulation choices made. To demonstrate how much the results can vary depending on the choices made, six different cases were simulated. One of the cases is what we call the *Base case*. It is named such, since all the other cases only differ from it by one modelling choice. The cases are presented in Table I. It is worth noting that for the case without temporal variation (*Constant reliability data*) this only applies to the reliability data, meaning that the interruption cost still depends on the interruption's time of occurrence.

TABLE I. SIMULATED CASES.

Case name	**Corrective actions strategy**	**Temporal variation**	**Protection and control**	**One OS**
Base case	Generation resch.	Yes	No	No
Trip next	Trip next	Yes	No	No
Constant reliability data	Generation resch.	No	No	No
Protection and control	Generation resch.	Yes	Yes	No
Worst OS	Generation resch.	Yes	No	Yes
Best OS	Generation resch.	Yes	No	Yes

VII. RESULTS AND DISCUSSION

Only the reliability of supply for buses where loads are modelled as firm power will be presented. The reason for this is that the market model models some buses as preference functions making it difficult to separate load and generation at the bus [7].

The total interruption costs for all the cases are depicted in Figure 5. From the figure it is evident that the interruption costs vary significantly from case to case. In particular, the choice of corrective actions strategy, the choice of operating state, and the inclusion of protection and control is important. The most important aspect seems to be the choice of the operating states, a finding that is well in line with results presented in [3, 10].

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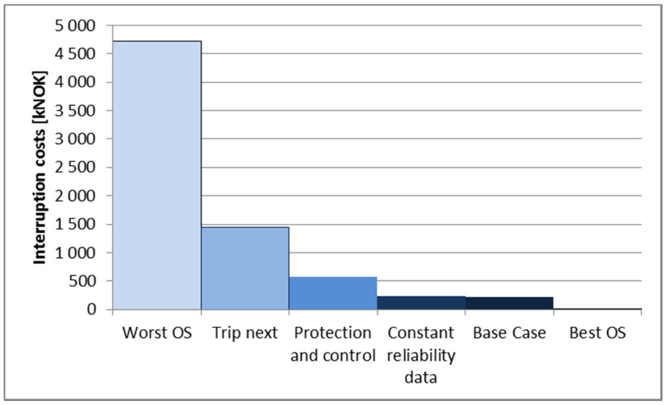

Figure 5. Total interruption costs for all cases.

To better understand the results presented in Figure 5, it is useful to investigate the interruption costs for all the buses in the network. The most noticeable observation from Figure 6 is that the case *Trip next* is clearly the worst case for all buses except 40024. Furthermore, bus 40024 is the least reliable of all buses in all cases, except for *Trip next*. This indicates that the network is vulnerable to cascading overloads if overloads are not mitigated using generation rescheduling or load shedding. It is in other words, important to understand and model correctly the network's response to contingencies. Not only to obtain an estimate for the reliability as close as possible to reality, but more importantly to ensure that the reliability of the load points in relation to each other are correct. Reliability assessments can be used for expansion planning, and depending on how corrective actions are modelled one may end up with different answers on where it is most important to invest in the network.

The interruption cost for bus 40024 remains the same for *Trip next*, compared to the *Base case*. This may at first sight seem somewhat counterintuitive since one may expect cascades to increase the number of interruptions at the bus. However, since this bus is importing, cascading line tripping in other parts of the network will not affect the reliability of this bus as long as the generator at bus 30019 can supply the load at 40024.

The highest interruption cost that can be seen in Figure 6 is for the *Protection and control* case at bus 40024. Although the interruption costs are higher for all buses, in this case it is remarkably high at 40024. This is because the reliability of this bus is entirely dependent on the failure of the line connecting it to bus 30019. With protection and control included, its reliability is also dependent on the security of the protection on the line between buses 30019 and 40024, and the dependability of the protection on the adjacent lines. This means that two more first order contingencies will influence the reliability of bus 40024. The numbers presented in Table II clearly demonstrate this effect. One can see that the increase in the number of interruptions with protection and control included is much greater than the reduction of the interruption duration.

TABLE II. NUMBER OF INTERRUPTIONS AND INTERRUPTION DURATION FOR THE BUS 40024.

Base case		**Protection and control**	
λ (/yr)	*r (h)*	*λ (/yr)*	*r (h)*
0.00452	14.308	0.05539	2.982

The results are dominated by the *Trip next* case and bus 40024 making it difficult to read Figure 6. Figure 7 shows the results with the *Trip next* case and bus 40024 removed. One can now clearly see that *Constant reliability data* results in an overestimation of the reliability compared to the *Base case*, which also corresponds with Figure 5.

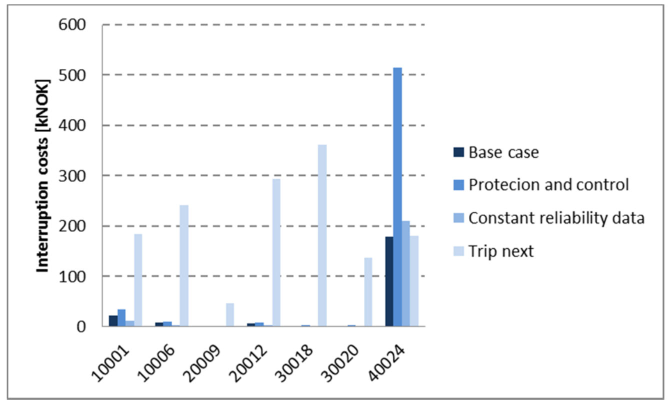

Figure 6. Interruption costs for cases with multiple operating states.

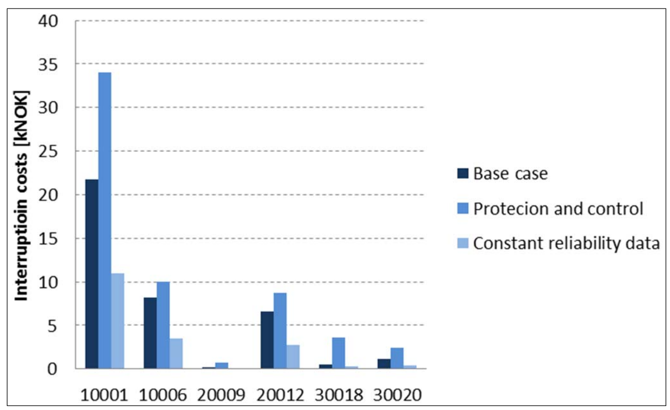

Figure 7. Interruption cost for areas 1, 2, and 3.

VIII. CONCLUSIONS

This paper has described an enhanced methodology for reliability of supply assessment, integrating methods and tools that provide a conceptual and methodological link between power market simulations and power system reliability analysis.

The main contribution of this paper is to show how the previously presented methodologies can be integrated to take into account protection system misoperations, temporal variation in interruption costs and reliability data, as well as alternative strategies for corrective actions in the contingency analysis. These additions have previously been implemented and tested separately; here the different parts are implemented all together to provide an enhanced methodology for reliability of supply assessment.

Further, this paper shows that it is possible to run integrated analyses in a prototype consisting of a power market simulator, a power system simulator and a reliability analysis tool, while taking protection system misoperations, temporal variation in interruption costs and reliability data, as well as alternative strategies for corrective actions in the contingency analysis into account. The impact of the integration is demonstrated by applying a realistic test case studied with respect to reliability of supply indices.

A first conclusion is that the choice of operating state(s) for the assessment is of vital importance for the reliability results. The test case also shows that the enhanced modelling options of protection system reliability, time dependency, and corrective actions have considerable influence on the results in terms of aggregated indices for the entire network. It is shown that they may affect the reliability differently for single load points. Including corrective actions, as well as protection and control may be of vital importance for the results, while there is less, but still negative, effect from the temporal variation of reliability data in this particular case. This is mainly due to the choice of only including seasonal variation in the reliability data in the case study presented this paper.

Altogether, this implies that care has to be taken when utilising the results, e.g., in network expansion studies. What is identified as the best candidate for expansion will depend on the modelling choices, underlining the importance of knowledge of the network under study.

The significance of the individual aspects relative to each other not only gives valuable input on which factors should be definitely included in a comprehensive reliability analysis, but also valuable information on where the highest potential for improvement in the reliability lies. For instance for the test network studied in this paper it is clear that the ability to reschedule generation quickly increases the reliability significantly.

IX. Acknowledgment

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