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ORIGINAL ARTICLE

Risk and reliability assessment for electrical distribution systems and impacts of regulations with examples from Sweden

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Abstract The introduction of performance based tariff regulations, and higher media and political pressure have increased the need for well-performed asset management in the operation and planning of electrical distribution systems. In this paper quantitative reliability assessment methods are proposed as a tool to meet these new incentives. Electrical distribution systems have compared to other technical systems several special characteristics which are important to take into consideration when introducing reliability analysis methods. Moreover, the paper gives a brief discussion on the effects and the importance of customer participation in improving system reliability by providing additional system operating reserve from the market perspective. Finally, the paper discusses the reliability analysis with the reliability test systems, and stresses the usefulness of generally known test systems for such assessments. The ideas of future work on development of these test systems to address the changing power systems are presented.

Keywords Electrical distribution systems · Reliability analysis · Risk management · Asset management · Regulation · Electricity markets · Customer participation

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1 Introduction

There are several risks connected with electrical distribution systems. This paper focuses on risks related to customer outages. Reliability analysis methods have been proposed in several studies as the primary tool to handle this category of risks (Billinton 2004; Janjic and Popovic 2007). Traditionally, the research and the development of reliability analysis methods have focused on generation and transmission (Kwok 1988). However, several studies have shown that most of the customer outages depend on failures at the distribution level (Billinton and Allan 1996; Billinton and Sankarakrishnan 1994; Bertling 2002). Furthermore, there is an international tendency towards adopt new performance-based tariff regulation methods (Billinton 2004; Mielczarski 2006; Mielczarski 2005). Hence, the focus on customer outages has increased and consequently the interest of introducing reliability assessment applied to power distribution. An increased fear of more extreme weather events in the future, following from the current climate-change debate, would give an additional focus on reliability and risk analysis in electrical distribution systems, which are often vulnerable to the weather conditions. An example of an event which had a large impact on the public opinion in Sweden is the severe storm named Gudrun. This storm struck the southern part of Sweden January 8–9, 2005 and caused the interruption of supply for approximately 450,000 customers (Wallnerström 2008). About 1 year after this event, a Swedish law on the compensation for power supply interruptions lasting longer than 12 h was established (The Swedish Law for the Electric Power System 1997). Other countries, e.g., UK, have also adopted new laws on customer compensation that work in parallel with the regulation of customer network tariffs (OPSI 2005).

To meet current and future requirements, new methods and tools to perform good risk analyses are needed (Nordgård 2010). Risk management is commonly used for example for studies of nuclear power plants, air pollution, dams etc. However, the use of quantitative approaches on electrical distribution systems is limited, if existing at all. A solution could be to introduce quantitative maintenance management and more comprehensive reliability analysis methods as input to the development of the risk management at the distribution system operators (DSOs). For all types of methods with underlying models, there is a need to balance the complexity of the details with needed input data, and the resources needed to put the models into practice. At the end there is always a need for the right incentive to make available needed resources in person-hours and data. Hence, experience both from the industry and from more theoretical academic methods could be valuable to coordinate within the development work. A first step is to examine possible risks and different incentives within the risk management (such as regulations). One specific reason in Sweden for developing risk methods within the electrical distribution industry is related to the new law which makes it compulsory for every DSO to report annually on performed risk and vulnerability analyses (The Swedish Law for the Electric Power System 1997). However, there are several strong incentives of developing good risk analysis, as mentioned above. Therefore, regardless of this obligation, there is still a strong motivation to develop quantitative and knowledge-based methods.

This paper provides a discussion on different reliability assessment methods with focus on electrical distribution systems, and also addresses the regulations of the electrical distribution system to ensure certain levels of reliability performance of distribution companies. The organization of the paper is as follows: The next section will introduce examples of reliability assessment of electric distribution systems. This section is followed by an inventory of increased incentives for the introduction of more comprehensive analysis methods applied to electric distribution, exemplified by the Swedish legislation in the section on "Regulation of Reliability—Examples from Sweden". While the previous section was about the regulatory model for ensuring reliability performance of the distribution companies, the section on "Customers' Involvement in Improving System Reliability" will discuss how the customers can actively contribute to improving the system reliability through the market mechanism. The paper will then discuss the benefits of using the common test systems and future directions for further development of such test systems in the Section on "Future Work on Reliability Assessment using Test Systems." Finally, concluding remarks are made in the last section.

2 Assessment of risk and reliability in electrical distribution systems

Risks associated with electrical distribution systems could typically be divided into three categories (1–3):

1. Risks of breaking any environmental or safety law.
2. Risks of customer outages which give repair costs, but also direct and indirect costs related to the outage such as customer compensation.
3. Risks of other events that imply a repair cost, but not any customer outages.

Compared with other technical systems, electrical distribution systems have special characteristics affecting the risk management to take into consideration when developing new methods:

- The entire society is dependent on reliable distribution of electricity.
- An event could affect a greater area of the system than the locally affected part, since failures have to be disconnected according to the safety aspect for humans and equipments (regulated by laws). However, if there are breakers, disconnecters etc., parts of the systems could be in function while other parts are not. The outage time could also differ between parts of the system.
- Some components such as overhead lines are significantly exposed and vulnerable to weather events (e.g., lightning, snow and wind), and this has effect along the system when failure occurs, and those effects need to be handled.
- Electrical distribution systems are operated as local regulated monopolies. The incentives for new investments in risk reduction could become different compared with non-monopolies, i.e., strongly dependent on the regulation.
- Electrical distribution systems are connected to other electrical systems such as the transmission system, supply points and load points (customers). Because there are dependences between these systems which could affect the operation and the risk of customer outages, this has to been taken into consideration within the risk management at DSOs.

There are large operational differences between different voltage levels of the electrical distribution systems, which in turn prompt different risk management policies. From a risk perspective, there are also significant differences between categories of systems, especially urban areas which have different characteristics compared with other power distribution systems at the same voltage level. This gives the incentive for the creation of several separate policies within the risk management as well as a policy to coordinate the risks at a central level at the company. The resulting classification is provided below as a list which includes some first proposals of risk policy approaches.

Characteristics of the different proposed parts of the risk management classification:

- *Risk of customer outages—low voltage* (0.4 kV) *electrical distribution*: (secondary substations included): Failures at this level seldom affect more customers than the affected area because of protection equipments in the secondary substations. Hence, the resulting risk value is often small. Therefore, it could be profitable to have another risk policy for this level, one which implies reallocating economic resources to other parts of the distribution system in order to maximize the cost effectiveness by doing less at this level.
- *Risk of customer outages—rural and semi-rural local electrical distribution*: Rural power distribution level often contributes to more than 80% of system average interruption duration index (SAIDI) (Wallnerström and Bertling 2009). Reliability analysis could therefore be an important part of the risk assessment. The consequences are however often less severe compared with higher voltage levels or urban systems. Nonetheless, an extreme event such as severe storms could cause several impairments at the same time, which could lead to long interruptions.
- *Risk of customer outages—urban local electrical distribution*: These systems have a high reliability compared with rural parts. The redundancy is often good, consisting exclusively of underground cables. However, the potential consequences are often more severe. Hence, the risk assessment should focus on how to handle and prevent extreme events with large consequences.
- *Risk of customer outages—regional electrical distribution*: These voltage levels are often operated with active redundancy, i.e., possibility to fulfill the N-1 criterion. The probability of customer outages caused by this voltage level is small, but the consequences can become significant. Like the urban systems, the risk assessment should focus more on extreme events with large consequences.
- *Other risks* (not reliability related): Within this category the most serious risks are included: such as risk of human injury and the breaking laws of safety and/or environment laws. Some of these risks could however be seen as absolute constraints (i.e., not permitted under any circumstances) as part ofin cost optimization analysis in other parts of the risk management.

2.1 Investment and maintenance planning for reliability improvement

Sweden has legislation regarding outages longer than 12 h and a functional requirement starting in 2011 that interruptions longer than 24 h are not tolerated. Consequently, 12 and 24 h are important limits for Swedish DSOs in maintenance and investment planning (Larsson 2005). Figure 1 presents results from an ongoing application study showing the expected number of outages longer than 12 h as a function of changed mean outage time. The current expected number of long outages (>12 h) per year is 136, affecting 1,000 customers. If an investment is estimated to reduce the average outage time with 1 h, this value will decrease to 121, while the opposite will increase the value to 151 long outages per year and 1,000 customers. The figure shows how the probability of long outages could be affected by investments (or savings). This could, for example, be a valuable input to asset management of investment and maintenance planning.

The results presented are based on failure statistics between 2001 and 2008 which occurred in a Swedish power distribution system with approximately 150,000 customers. Other results from this study are, for example, vulnerability analysis results based on hourly weather data from the eight years compared with detailed information of 62,000 outages during the period.

2.2 Details of reliability data

Good and comprehensive input data is expensive, and sophisticated analysis based on detailed data demands still further resources (Cigré Working Group 601 of Study Committee C4 2010). A common solution is to use mean values (of e.g., failure rates), which is the case in, for example, the calculation of well established indices such as SAIDI (Billinton and Allan 1996). However, there are significant disadvantages connected to the use of mean values in the analysis. For example: Using mean restoration time does not take into account the behavior of consequences.

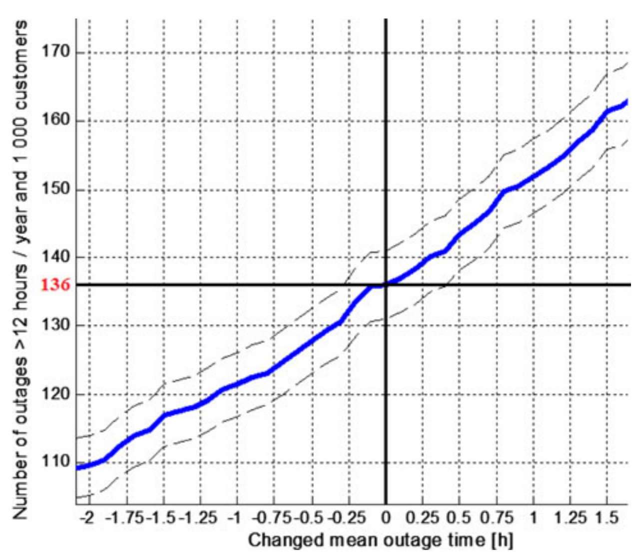

Fig. 1 Number of outages longer than 12 h as a function of changed average outage time including 95% confidence interval

Table 1 Approaches to handle mean values in reliability analyses

Strategy/approach	Advantages	Disadvantages
1. Only use one mean value	Easy manageable and well-established models	Discussed above
2. Estimate a statistical (e.g., exponential) distribution based on a single mean value	Capture all consequences, data easy available	More knowledge-intensive, the distribution is not always a suitable description of the real behavior
3. Dividing the failures into categories	Relatively simple, easy to adjust the complexity according to purpose	More work with data collection and processing, discrete model, not spanning all possible events
4. Estimate the real distribution	Gives results close to the reality	Complex, costly and time consuming

Table 2 Failure rates divided into short (0.05–12 h) and long interruptions (>12 h)

Component	Failure rate[a]	(%)[b]	Failure rate[c]	(%)[b]
Overhead line 0.4 kV	0.0668 ± 0.0025	0.8	0.0150 ± 0.0012	3.4
Overhead line 10 kV	0.1169 ± 0.0027	61.3	0.0086 ± 0.0008	92.2
Underground cable 0.4 kV	0.0395 ± 0.0014	1.1	0.0034 ± 0.0004	0.5
Underground cable 10 kV	0.0281 ± 0.0020	7.0	0.0002 ± 0.0002	0.4
Secondary sub station	0.0107 ± 0.0007	3.8	0.0006 ± 0.0002	0.2
Other/unknown	–	26.1	–	3.3

[a] Number of outage 0.05–12 h/year, km/station with 95% confident int

[b] Contribution to total outage time caused by the category of failure

[c] Number of customer outage ≥12 h/year, km/station with 95% conf. int

This will be shown in the following section. Four different approaches exist to handle mean values, with the advantages and disadvantages shown in Table 1.

Table 2 provides an example of the third approach dividing outages into two failure categories. The failure rates are based on over 50 000 historical outages over 8 years. The longer-than-12-h values stems from rare events, affecting system reliability indices to a small extent. The result is that the events causing these longer interruptions could be missed when the DSO works towards better reliability indices based on average values. When looking at average values at the 0.4 kV level, it might be assumed that underground cables cause more longer-than-12-h interruptions, but as can be seen in Table 2, the overhead lines are more problematic. This illustrates the value of applying the third approach, i.e., if our main concern is long interruptions, then we should focus on overhead lines.

3 Regulations of reliability in electrical distribution systems: examples from Sweden

3.1 New requirements for the DSOs on reliability performance

From the perspective of the DSOs, there are costs for operation and maintenance to balance against the requirements for the system reliability and the profit for the stakeholders. In a perfect market environment, a balance would be reached when customers select the DSO with the best price for the required customer value. However, the infrastructures are natural monopolies. It is the task of the authorities to judge if this tariff is reasonable.

3.2 Regulation of tariff levels for Swedish electrical distribution systems

3.2.1 Distribution tariffs after deregulation of the electricity market

Following the deregulation of the Swedish electricity market in 1996, a new regulating authority, the Swedish Energy Agency (STEM), was established in 1998. However the distribution was still operated as regional natural monopolies, with responsibilities as well as privileges (Bertling et al. 2005). Earlier, the DSOs were more or less allowed to compensate for all their costs by settling tariff levels regardless of the effectiveness and quality. Following the deregulation, STEM identified a problem of increasing tariff levels. Despite several attempts to keep the tariffs down, e.g., through price freezing, no solution was effective. It was therefore necessary to find a new regulation paradigm (Bertling et al. 2005). In 1998, a project was initiated by STEM to propose a new regulation model resulting in the Network Performance Assessment Model (NPAM) (Larsson 2005).

3.2.2 *Tariff regulation with the NPAM*

The NPAM was a unique and innovative regulatory tool. The model evaluated tariffs ex-post by entering several system data to a computer program which produces a fictive network, with the aim of having the same objective conditions as the real system (Larsson 2005; Wallnerström and Bertling 2008). Following the use of this regulatory tool, STEM demanded repayments from several DSOs each year from 2003, based on results from the NPAM. The Energy Markets Inspectorate (EI), a division of STEM, became an independent authority in 2008 with responsibility for, among others, regulating electric distribution system tariff levels (Wallnerström and Bertling 2010). The tariff regulation using the NPAM as the primary tool was, however, strongly criticized by stakeholders following the legal processes. For example, the NPAM was assailed for not taking historical circumstances into consideration (such as previous investments in areas with decreased need of electricity as a result of, e.g., abandoned industries) and for not being robust enough to fulfill the criteria of objectiveness (i.e., equal judgment between different companies) (Wallnerström and Bertling 2008; Wallnerström and Bertling 2007). In the later part of 2008, the parties made an agreement for 2003–2007, which included fewer DSOs and significantly lower levels of repayments compared with the original demand. In January 2009, the regulator decided to abandon the NPAM, although the model was working, (Wallnerström and Bertling 2010) partly motivated by the fact that it was not an ex-ante regulation (though theoretically it can be used in this way (Wallnerström 2008)).

3.2.3 *Introduction of an ex-ante regulation*

New regulation aims to offer more stable predictability of revenue, which in turn can facilitate investment- and maintenance-planning performed by the DSOs. Historical data from recent years gives a preliminary revenue framework for a period of 4 years. Changes in conditions compared with the forecast can then be adjusted (Wallnerström and Bertling 2010). The quality function in the new regulation could, unlike the NPAM, be both negative and positive. All costumers may collectively obtain revised tariff levels regardless of the individual reliability. In order to not "punish" a DSO twice, outages longer than 12 h are excluded (see Table 3). The quality function is limited to affecting the compensation for cost of restricted capital (Wallnerström and Bertling 2010). EI has, by law, the ability to integrate more quality aspects in upcoming regulation, but these will probably not be included in the first phase. The additional quality aspects that will be considered in the future include (Wallnerström and Bertling 2010):

- *Administrative deficiencies*: Customer service, which could for example get overloaded during large disturbances.
- *Voltage quality*: transients, waveform distortions, deviation from the nominal voltage value, *etc.*
- *Very short interruptions* (<0.05 h): These have traditionally not been included before. Short outages can cause large impacts on certain categories of customers.

Table 3 Consequences of outages longer than 12 h

Length of interruption (h)	Compensation to customer (SEK[a])	Minimum compensation[b] (SEK)
0–12	Input to the tariff regulation	–
12–24	12.5% of α[c]	2% of β[d]
24–48	37.5% of α	4% of β
Following 24 h periods	+25% of $\alpha + \gamma$[e]	+2% of β
…	…	…
Max	300% of $\alpha + \gamma$	–

[a] SEK = Swedish crowns, 100 SEK ≈ 11.0€ (EUR) or ≈14.5$ (USD)

[b] Set to even 100 SEK values, rounded up → 2% of β is rounded up to 900 SEK

[c] α = Individual customer's annual network tariff

[d] β = Yearly set base amount (42 400 SEK 2010)

[e] γ = Risk of additional consequences of breaking the law of 24 h functional requirement

3.3 Additional laws

3.3.1 *Compulsory risk and vulnerability analysis*

A law (The Swedish Law for the Electric Power System 1997) introduced in Sweden in 2006 dictates that every DSO has to annually report the results, from the risk and vulnerability analysis regarding the reliability of their systems. The risk analysis has to include an action plan of how the reliability shall be improved (Wallnerström 2008). An initial difficulty with this analysis was that Swedish law requires that the records of the Swedish authorities be open and available to the public. Hence, analysis results are potential "terrorist manuals", which subsequently led to a revision of the law. The regulator would receive the information that the analysis had been done, and if needed, read the results locally, at the DSO, without collecting the documents (Wallnerström and Bertling 2010).

3.3.2 Outage compensation and functional requirement

Sweden has legislation regarding outages above 12 h and a functional requirement starting in 2011 that interruptions above 24 h are not tolerated (The Swedish Law for the Electric Power System 1997). Consequently, 12 and 24 h are important limits for Swedish DSOs in maintenance and investment planning (Wallnerström and Bertling 2009). Table 3 summarizes the model for determining customer outage compensation and damages to effected customers (Setréus et al. 2007).

Note that outages longer than 24 h could both lead to compensation according to the customer compensation model and to additional consequences. The consequence of breaking the functional requirement will be examined after 2011, but EI has indicated that well-performed risk and vulnerability analysis could affect the consequences. That is to say, if the identified weakness that led to an outage longer than 24 h were included in the action plan for improvements (based on performed risk and vulnerability analysis), the outage would probably be tolerated to a greater extent than if the weakness had not been identified as important to handle.

4 Summary

The regulator has the role to provide incentives for cost efficient operation with acceptable reliability and reasonable tariff levels. Since the Swedish electrical distribution systems consist of many (~ 150) natural monopolies, with different operators, the regulation also has to be objective and fair, and not favor any particular DSO. The experiences from Sweden shows the importance of having a constructive dialogue with the DSOs without being to compliant, i.e., the regulator has to fulfill their task of ensuring reasonable tariff levels. Another difficult task for the regulator is to settle the issue of complexity, i.e., the balance between considering a great number of details and the manageability of such an undertaking.

5 Customers involvement in improving system reliability

In previous sections, different types of risks and reliability performance, as well as the evaluation methods of the electrical distribution system levels, have been discussed. In this section, the customers' (or the demand-side) participation in helping to improve the overall system reliability will be discussed.

The system reliability referred to here is related to the level of system operating reserve. For the secure operation of a power system, operating reserve is always required to account for changes in generation and/or load levels which lead to imbalance in supply and demand. It is rather obvious that the power system will be more reliable if a higher reserve level can be attained; being thus more reliable at the system level, this would also imply that the electrical distribution systems would have a higher level of reliability, since the main supply points from the transmission system would be more reliable. One of the most difficult tasks in power systems in many countries with deregulated power markets is to secure the level of peak capacity. In a regulated environment, sufficient capacity was more or less guaranteed from political decisions and priorities, and then carried out by a central entity. On the contrary, in a deregulated environment, the decision regarding investment in new generation capacity is at the hand of private generation companies (GENCOs), and driven by the profits that they make on the market. This could lead to problems in terms of the sufficiency of capacity in peak load situations, which happen during a small fraction of a year. The task of maintaining secure and reliable operation of the power system is handled by the independent system operator (ISO). Recent large-scale power system blackouts in the USA and Europe have given us a "wake-up call" on the vulnerability of our power systems, that they are being operated much closer to the limits than ever before (Mielczarski W et al. 2005).

The problem of keeping appropriate operating reserve is getting more difficult when many countries, e.g., in Europe, have chosen to develop extensive investment programs in renewable energy generation, especially wind power. Sweden has its own target for total wind power generation to reach 30 TWh (Nilsson and Bertling 2007) by 2020, which is equivalent to around 20% of total electricity generation today. This creates a new challenge: keeping the system balance in real time operation, since wind power is well-known for its intermittency.

Demand participation in providing additional system operating reserve capacity for the balancing of supply and demand is an alternative to investing in new capacity. If the customer is able to reduce its power consumption during the stressed condition, it is equivalent to having an additional reserve power of the same size. The larger demand peaks are, the more capacity is needed to maintain the reliability of the system during peak hours, which is costly. The cost of the provision of electricity can be reduced by smoothing the demand peaks, i.e., by making demand more responsive to price signals. Shortage of generating capacity would lead to price spikes in the spot market, which in turn will affect the customers at all voltage levels.

In deregulated electricity markets, different programs exist in which the demand-side can participate in providing additional reserve power to the power system. A comprehensive review of those demand response programs is provided in (Arnold and Tuan 2006). In Sweden, there are studies aimed at evaluating the potentials of demand responses from large customers to provide additional operating reserve (Fritz 2006). Several demonstration projects were recently carried out with very good results and active customer participation (Lindskoug 2006). In this program, the customers are compensated for reduction of the consumption for a total of 40 h per year, with advance notification as to when to reduce their power consumption. In the following sub-section, a brief description of a possible market model for optimal procurement of one type of demand-side participation in electricity markets and its effects on system operation will be presented (Tuan and Bhattacharya 2003).

5.1 Market-based model for customer participation

A market structure for interruptible loads based on a bidding framework for customers and pertaining to markets that have provision for both bilateral trades and a spot-market is proposed in this work. Based on the submitted offers, the ISO arrives at optimal contracts for interruptible load in real time (Tuan and Bhattacharya 2003). Ideally, the ISO's objective while formulating the optimal contracts would be to seek those customers offering the lowest price. However, such a selection, without taking into account the system and load flow pattern, may give rise to transmission congestion, increased system losses, increased reactive support requirements, etc. This may happen since choosing to interrupt a low-priced offer load located at a remote area may increase the system power flows in an undesirable manner. Thus, a location-dependent parameter to re-value the customer price offers is introduced. Based on the re-valuation of price offers, the ISO can obtain the optimal interruptible load contracts that satisfy all system constraints. An optimal power flow (OPF) based framework was used to model the above features of the interruptible load market, customer offers, geographical aspects in their offers, and the final optimal contracting decisions of the ISO. The OPF model is suitably modified to incorporate the above aspects, while also satisfying the usual system constraints such as bus voltage limits, reactive power support limits, reliability constraint which requires that the operating reserve level is greater than a pre-defined level, etc. A schematic diagram of the proposed interruptible load market structure operated by the ISO is shown in Fig. 2.

The ISO evaluates the offers and makes the optimal selection of interruptible loads as per its requirement; that is when the interruptible load market is cleared. The selected interruptible loads can expect to be called upon, when necessary, during the next hour. The market participants submit their offers specifying the price in $/MWh for energy to be interrupted and the quantity of interruptible load in MW. This model was applied to the Nordic 32-bus system (CIGRE TF 38-02-08 1995) to illustrate the working behaviors of the customers in the interruptible load markets. The results have shown that the customer's provisions of reserve power could very well help in relieving the system stress in the peak load condition, thereby helping to reduce the chances of system outages. Figure 3 shows one example result of the system load profile with and without interruptible loads during a contingency of losing one generating unit. The system functions well in this case with the peak load reduction from the participation of the demand-side when the contingency occurs.

6 Future work on reliability assessment using test systems

Preceding sections have discussed reliability assessment methods, and this section will discuss our future plan for further development and the use of different test systems for actual reliability calculations.

Using common test systems could be useful for valuable exchange and discussions of ideas and knowledge between countries, researchers and companies. There is a lot of work associated with creating good test systems satisfying many requirements. Hence, one obvious benefit is that the use of a pre-defined test system, if possible, saves time compared with creating a new model for each analysis or study. If no test system satisfies required aspects, it could still be easier to modify an existing system than to create a completely new one. Moreover, if a locally developed model is used instead, all used data must be published, since all academic studies must be replicable, while an internationally published test system could just be referred to. For academic projects, test systems provide the possibility to objectively compare research results, e.g., comparisons of different methods or different software.

One of the most well-known and most widely used test systems in power system engineering is the IEEE Reliability Test system (IEEE-RTS) which was developed in 1979 by IEEE Subcommittee on the Application of Probability Methods (Force 1979). This system was created to compare different reliability methods, but only at the generation and/or transmission level, in accordance with its earlier focus. The system was later enhanced in 1996 to reflect changes in evaluation methodologies and to overcome perceived deficiencies (Force 1999). Another well-known test system is the Roy Billinton Test System (RBTS), which was developed during the 90 s. It is smaller than the IEEE-RTS, but with every load bus defined at the distribution level (Allan et al. 1991; Billinton and Jonnavithula 1996).

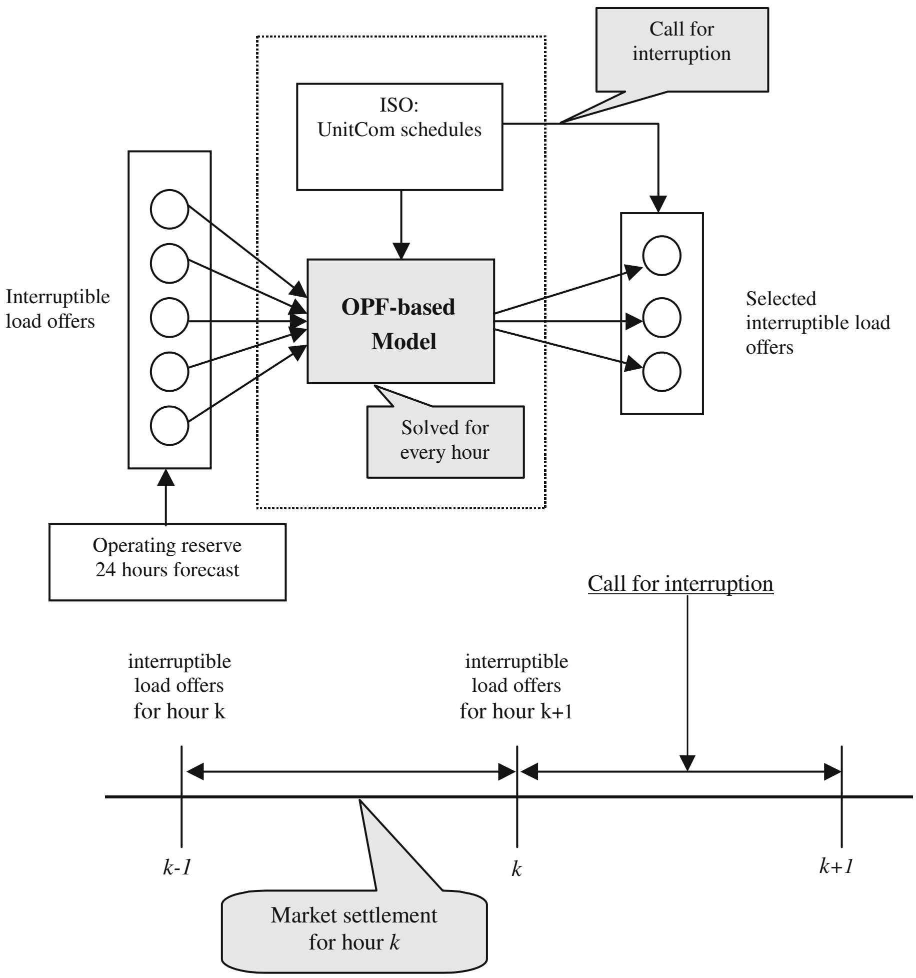

Fig. 2 Schematic representation of interruptible load market structure (Tuan and Bhattacharya 2003)

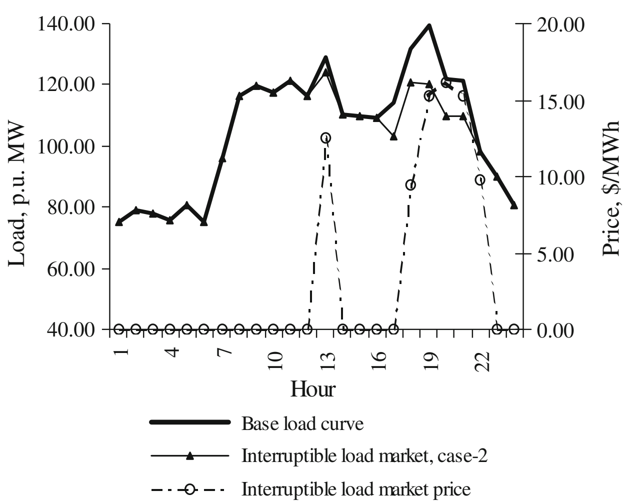

Fig. 3 Operation of the interruptible load market with one large generator on outage (Tuan and Bhattacharya 2003)

The future development of power systems is characterized by changes on both the supply and the demand side. On the supply side, the power system is integrating more and more power generation from renewable sources, in both small-scale and large-scale. On the demand-side, the load characteristics are changing with more non-linear loads, and the demand-side can also function as both consumers and as small producers, e.g., ideas of how future hybrid electric vehicles could be used as energy reserves based on the electricity price. The changes in the supply side and the demand side would definitely force changes in the transmission level. High voltage DC system (HVDC) development is among the most discussed topics in the field today. The whole power system is moving in the direction of what is referred to as the Smart Grid. With these changes, the requirements for the test system would also need to change. Our goal is to further develop the existing test systems mentioned above in order to address both the changes in the characteristics of the future power systems, as well as the evolutions of more advanced reliability evaluation methods.

7 Concluding remarks

This paper has discussed incentives to promote the development of more advanced analysis methods applied to electrical distribution systems. It is argued that the introduction of performance based tariff regulations and higher media and political pressure increases the need for well-performed asset management on the part of DSOs. Relevant Swedish legislation is presented as an example. The paper argues that the electrical distribution systems are different from a reliability standpoint as compared to other technical systems, and shows the effects of customer participation in providing additional operating reserve in the system from a market perspective. The relation between the system reliability and reliability of the lower voltage levels has been highlighted. Finally, the paper concludes by introducing reliability test systems as useful for the development of methods, and for reliability and risk management. Regarding future work, these test systems will be explored to meet the developments of the new electric distribution systems including the aspects discussed in this paper.

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