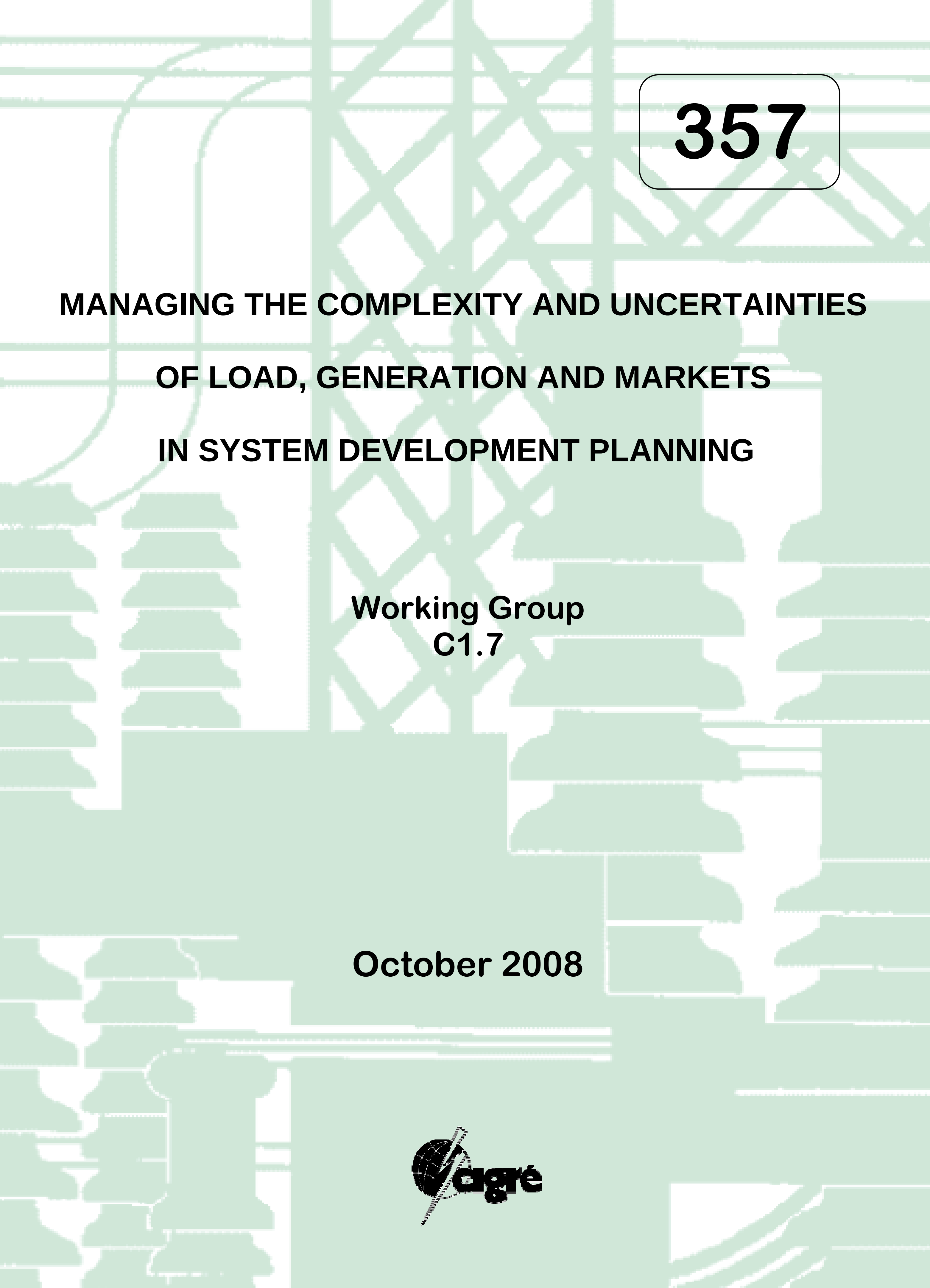


357

MANAGING THE COMPLEXITY AND UNCERTAINTIES OF LOAD, GENERATION AND MARKETS IN SYSTEM DEVELOPMENT PLANNING

Working Group
C1.7

October 2008

Working Group C1.7

Managing the complexity and uncertainties of load, generation and markets in system development planning

Members of WG C1.7

Richard Wakefield - Convenor	U.S.A.
Carlos Artaiz Wert	Spain
Tony Auditore	South Africa
Oyvind Bergvoll	Norway
Lian Chen	South Africa
Naoto Fujioka	Japan
Sebastien Henry	France
Christoph Maurer	Germany
Noel McGoldrick	U.K.
Hiroaki Nishigami	Japan

ISBN: 978- 2- 85873-045-2

Contents

List of Figures

Executive Summary

The issues investigated by earlier CIGRE working groups, and the results they reported, demonstrate the unique challenges faced by today's system planners. Working Group C1-7 was established to assess the methods that are now being used to accommodate the new uncertainties in markets, loads and generation and to develop system plans that balance reliability, economy and risk. A questionnaire was undertaken to survey the similarities and differences across countries and electrical systems in the nature of these uncertainties. The results of this survey are summarized in this report. In addition, case examples are provided to illustrate in more detail some of the specific methods being employed by planners around the world.

Market Uncertainties

In the context of this report the term "market" refers to the way in which the regional power system is structured and the way it operates. Most survey respondents felt that they were in a period of change or that they were working with new systems following the implementation of market changes. This reflects the point that within established markets, regulators are consistently seeking to increase competitive pressures within the market and produce efficiency gains for consumers. These market changes have increased system planning uncertainties. The survey results indicate that the two most significant uncertainties are those introduced by regulatory changes and the difficulties in accounting for cross-border flows. Both of these relate directly to investment levels. The next most significant uncertainty relates to the levels of future fuel prices. This stems from the planners' inability to predict future economic dispatch patterns for generation at different levels of system demand.

The most often cited single cause of these uncertainties was market restructuring, and this is consistent with the view of most respondents that they were experiencing a period of change within their markets. The most significant impacts of these uncertainties are decreases in the available transmission capacity, reduced system security, restricted maintenance outages, and the inevitable result, inadequate transmission capacity.

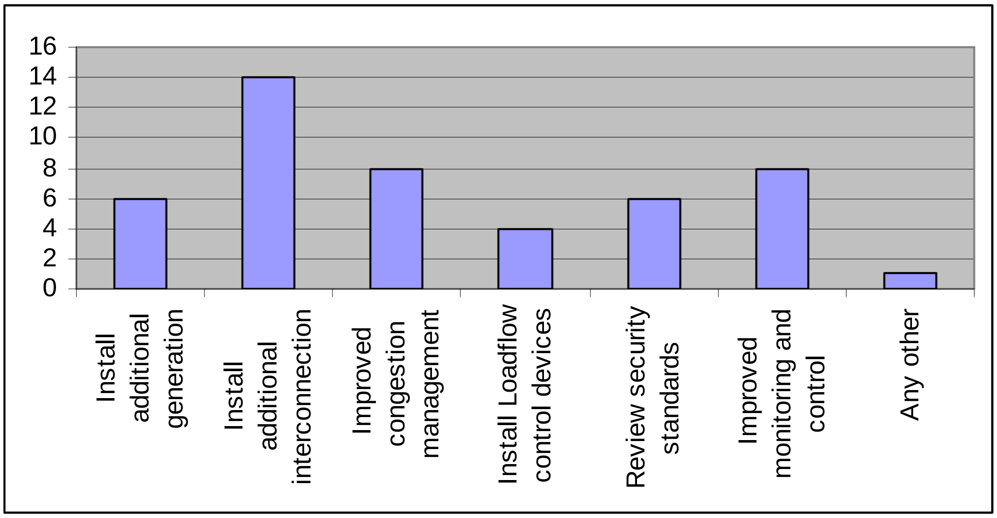


Figure S.1 - What options are available to minimize these uncertainties?

Figure S.1 shows the options that respondents believed would be most effective in reducing these uncertainties. Clearly, the option cited most frequently was to invest in additional interconnection capacity on the transmission system. However, the effect of the regulatory controls in most markets restricts the ability of planners to fully exercise this option. Other options that were cited include improvements in congestion management and monitoring and control.

Several case examples are provided to illustrate actual market uncertainties and methods for mitigating them. These include:

- Privatization of the British electricity system, and
- Two market interconnection examples, namely:
  - The NorNed Project in Europe
  - The Neptune Project in the U.S.

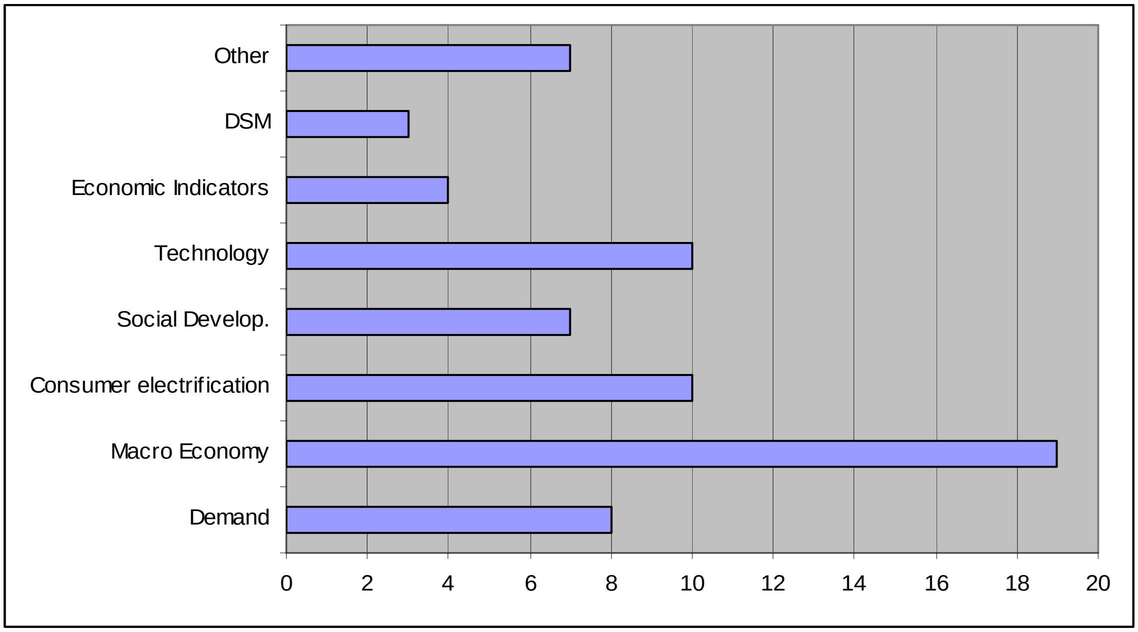
Load Uncertainties

Anticipating the growth in customer load is essential to ensuring that a reliable and economic supply of electricity will be available to meet future needs. However, load uncertainties were found to be less of a concern than market and generation uncertainties, due to 1) the lower load growths anticipated by most respondents, and 2) the availability of better tools for addressing these uncertainties.

Over the long term, more than half of the respondents expect to have low load growth, and only one expects high load growth. To some degree, this is a reflection of the mix of utilities responding to the survey, but it also indicates a changed situation for the many established utilities serving developed economies.

By far, the most frequently cited cause for load uncertainty was the region's future macro-economic performance. As Figure S.2 shows, the next most important causes were changes in technology and consumer electrification. Of course, these latter two causes are often linked to changes in the regional or national economy or to changes in energy policy.

Figure S.2 - Primary Causes of Uncertainty



Among the survey respondents, 60% indicated that the financial impacts associated with load uncertainties were either high or medium. Not surprisingly, these responses generally came from companies that expected high to medium load growth. The most commonly cited impacts were inadequate power delivery capability, inadequate transformation capability, and unacceptable system security. Another quite different impact, system under-utilization, was also reported by almost half of the respondents. Apparently, this reflects load shifts away from areas of historic growth.

Various methods are employed to mitigate load uncertainties and their effects on the power delivery system. These include the most obvious measure, system load forecasting, and various other methods used to assess the effects that load change will have on the system itself. Almost 80% of the survey respondents utilize annual system load forecasts and the remaining 20% utilize biannual forecasts. Almost 75% use some sort of macro-economic index to forecast future load growth. The other most common methods include peak load forecasts and extrapolations of historical load flows. Also of interest, approximately one-half of the respondents listed customer service agreements as an important input in assessing future loads.

Respondents also were asked to identify the method(s) they used to assess load uncertainties and to mitigate their effects. Over half of the respondents use probabilistic methods, and many of these also use scenario analysis. The two methods are quite compatible, especially when probability distributions are assigned to key model parameters. The associated probabilities can help defined the likelihood of certain scenarios that would require system additions and reinforcements.

Approximately 40% of respondents use some sort of collaborative process to mitigate load uncertainties. Such methods vary widely, but in most instances they include the development of a draft plan by the transmission owner and the subsequent review of that plan by various other stakeholders, often including regulators, customers, local government agencies, environmental organizations, and others.

Several case examples are offered to illustrate how certain companies are dealing with load uncertainties. These include:

- Kansai's use of a new scenario-based Master Plan
- The use of Demand-Side Measures (DSM) as a mitigation tool:
    - Japanese example
    - French example

Generation Uncertainties

As a consequence of the restructuring of the energy sector in a lot of countries and of rising green concerns transmission system planning has to face new types of uncertainties relating to generation of electrical energy.

First, the disintegration of formerly vertically integrated utilities means that planning of the transmission system and generation is no longer coordinated, with the common objective of the optimizing the whole power system, but rather takes place separately. This separation increases uncertainties for transmission system planners, who are no longer able to predict or even influence the size and location of new plants.

Second, environmental issues have motivated a trend towards new generation technologies, which often means decentralized generation units based on renewable sources or combined heat and power production.

With rapidly changing uncertainties often dependent on macro-economic trends or political considerations and long time periods needed for permitting and constructing transmission system assets, it is hard to meet the challenge of delivering a transmission system that is sufficient to satisfy the demands for system adequacy and system efficiency at the same time.

As a result of its study, WG C1-7 has identified five main uncertainties concerning generation which transmission system operators have to face today. These include:

- location and size of new generators,
- timing of new generators,
- development of renewable energy sources,
- future generation technologies and
- the retirement of existing plants.

Responses to the group's questionnaire clearly indicated that among these, location and size of new generators and development of renewable energy sources are the uncertainties with the highest impact and the most dynamic characteristics.

Overloadings of lines and voltage stability problems were identified as the most severe impacts on transmission systems due to these uncertainties. More detailed analyses showed that location and size of new generators were mainly blamed for overloading problems, whereas renewable energy generation and retirement of existing plants were the main drivers for voltage stability problems.

The working group investigated several approaches to mitigate the impacts of rising generation uncertainties. In general, it can be concluded that there does not exist any single measure to meet the challenges of generation uncertainties. System planning will have to include better forecasting methods with longer forecasting horizons and consideration of different scenarios. But it also is indispensable to adapt transmission systems to changing boundary conditions by means of network extension and reinforcement.

Besides more general approaches that also can be used for other types of uncertainties, in addressing generation uncertainties the WG C1-7 report focuses on special approaches that were used in different countries to mitigate the consequences of the rising share of renewable generation, especially wind energy generation.

Key Methods for Dealing with Uncertainties

Two key methods that are currently being used to deal with all kinds of uncertainties include 1) collaborative planning and 2) multi-scenario and probabilistic methods. Each is discussed and case examples are provided.

- **Collaborative processes for planning** - As described in the previous sections, many uncertainties are the consequences of the increased number of participants in the power systems and the lack of information available for the electrical utilities involved in transmission planning process. Taking into account only the point of view of a company in charge of transmission planning process, the ideal situation is to have information about and control of all the events that can influence its investments. One solution to this problem is to use a collaborative process for transmission planning. The objective is to associate the different companies involved in the system in order to increase the available information level and to take decisions that maximize the fulfillment of the needs and reduce the costs. With such a process, the responsibilities are shared among the different participants. Case examples include Central West Europe and the United States.

- **Multi-scenario and probabilistic methods** - A generic solution that allows the mitigation of uncertainties consists of using methods that take into account a huge number of future possible scenarios. The objective is to find, for each scenario, the efficiency of the proposed investments and the probability of occurrence of the scenario. Multi-scenario and probabilistic methods range from simple studies that take into account a limited number of scenarios to more complex studies, including Monte Carlo methods, with more or less sophisticated automatic generation of scenarios. A case example is provided for the French 400 kV grid development studies.

Conclusions

Based on questionnaire responses received from a large number of transmission companies with very different energy sector structures and on the individual experience of the working group members, the group concludes the following:

Load growth is not the dominant uncertainty

Considering uncertainties of markets, generation and loads, it is apparent that transmission system operators tend to be more concerned about market and generation uncertainties than they are about load uncertainties. There are different reasons for that. First, the results of our survey show that relatively few countries are experiencing high rates of load growth. Second, transmission system operators have gained a lot of experience with forecasting load and managing the uncertainties it causes.

In countries with no anticipated load growth or even a projected decrease of peak load, system planning uncertainties are not associated only with the extension of the existing system but also with the development of optimized replacement and refurbishment strategies. In such cases, system development planning therefore is closely linked to asset management tasks.

Market changes have created new uncertainties

Market uncertainties tend to have an ambiguous character. This is because the establishment of larger interconnected systems tends to increase the security of supply and, due to their higher flexibility and stability, makes it easier for the transmission system planners to cope with uncertain boundary conditions. Nevertheless, as market behavior is not controllable and predictable, the establishment of larger markets also produces new uncertainties, e.g. in terms of fluctuations in load flows or external flows caused by exchanges between surrounding countries. Development and evolution of market rules, grid codes and operational rules is widely used to reduce these uncertainties but will definitely not eliminate them.

The sizing and location of new generators cause major uncertainties

The break-up of formerly vertically-integrated utilities, together with the green movement and the political support for generators based on renewable energies, in addition to concerns about global warming and the resulting move away from conventional fossil fuel fired power plants, all cause major uncertainties especially in the locations and sizes of new generators that are being connected to the network. However, the technical characteristics of newer generation technologies like wind energy converters and their difficult-to-predict generation patterns, have caused new uncertainties that cannot be handled by TSOs on their own.

New planning methods are required

System planners have developed new methods that on the one hand consider new analytical and technical possibilities and on the other hand respect the more difficult structures in a sector in which the number of stakeholders have dramatically increased over the last two decades.

- <u>Multi-scenario analysis:</u> Multi-scenario analysis has gained significant importance in system planning studies, as the results of our survey clearly show. One cause for that surely is the sufficiently high computational power that is available today to cover all relevant scenarios. Another cause is the fact that multi-scenario analyses, because of their transparent and general approach, work well in convincing different groups of stakeholders of the needs for system development measures.
- <u>Probabilistic methods:</u> Another aspect is that rising uncertainties have lead to a situation where the worst-case analyses traditionally used by many transmission system operators no longer lead to either satisfying results or realistic system development plans. In such cases, the use of probabilistic methods has become an alternative. Considerable development work in this field is underway, and probabilistic methods may become an important tool for evaluating system development plans within a few years.

- Collaborative approaches: Collaborative approaches reduce uncertainties by 1) sharing information between neighboring systems and 2) facilitating the participation of various stakeholders in the planning process so as to share different views and come to mutually acceptable solutions. As a result, they can reduce risks for the transmission system planners.

1. Introduction

Several prior working groups have addressed the methods for planning power systems in light of the increased uncertainty caused by market restructuring. Specifically, WG 37-30 addressed the problems of planning with uncertainty in the sizing and location of generation. Subsequently, WG C1-2 addressed methods for developing plans that are responsive to market forces while also maintaining acceptable reliability.

The issues investigated by these earlier working groups, and the results they have achieved, demonstrate the unique challenges faced by modern system planners. In spite of these challenges, however, plans are being developed that recognize such uncertainties. Working Group C1-7 was established to assess the methods that are now being used to develop system plans that balance reliability, economy and risk. In doing so, the group has attempted to determine whether the results of earlier working groups are being used.

A questionnaire was undertaken to survey the similarities and differences across countries and electrical systems in the nature of these uncertainties. The results of this survey are summarized in this report. In addition, case examples are provided to illustrate in more detail some of the specific methods that are being employed to accommodate the increased uncertainty.

The following three sections address market, load and generation uncertainties, respectively, and discuss specific methods for dealing with them. Each of these sections includes case examples to illustrate the salient points. The final section describes tools and techniques that apply to more than one of the three categories of uncertainties. Terms of reference of the working group and structure of the questionnaire are included in Appendix A.

2. Questionnaire and Survey on System Planning Uncertainties

In order to document practices across a broad range of operating and planning entities, WG C1-7 developed and distributed a 14-page questionnaire on current planning practices and how uncertainties are being accommodated. The questionnaire is divided into three major parts addressing load uncertainties, generation uncertainties, and market uncertainties. In each of these sections, the questionnaire seeks information on:

1. Uncertainties and their severity
2. Causes of the associated uncertainties
3. Impacts on system plans
4. Responses to these impacts
5. Forecasting methods
6. Mitigation methods

The questionnaire format was designed with "check boxes" to reduce response times and to facilitate comparisons among countries/companies. A copy of the survey questionnaire is provided in Appendix B.

The working group received responses from 23 planning entities in 20 different countries. The survey participants are listed in Figure 1. Selected results and conclusions from the survey are provided and discussed in the following chapters that address market, load and generation uncertainties, respectively. A complete set of the questionnaire responses is voluminous. However, a copy of the responses will be posted on the Study Committee C1 website.

Figure 1 - Respondents to WG C1-7 Survey

Country	Company/Organization
Australia (Tasmania)	Transend Networks Pty Ltd
Austria	Verbund - Austrian Power Grid
Belgium	Elia System Operator
China	China power Engineering Consulting(Group) Corporation
Czech Republic	ČEPS, a.s.
Denmark	Energinet.dk
Finland	Fingrid Oyj
France	RTE (Reseau de Transport d'electricite)
Hungry	MAVIR Hungarian Transmission System Operator Company Ltd.
Ireland	EirGrid
Israel	Israel Electric
Japan	Kansai Electric Power Company
Korea	Korea Electric Power Company
Portugal	REN – Redes Energéticas Nacionais, SGPS, S.A. (Holding for Electricity and Gas) REN - Rede Eléctrica Nacional, S.A. (Electricity Transmission System Operator)
Romania	Romania Power Grid Company "Transelectrica" S.A
Russia	System Operator for UES
South Africa	ESKOM
Spain	Red Eléctrica de España, S.A. (REE)
United Kingdom	Scottish Power
United Kingdom	National Grid
United States	American Electric Power (AEP)
United States	Michigan Electric Transmission Company, LLC (METC)
United States	Public Service Company Of New Mexico (PNM)

3. Markets

In the context of this report, the term “market” refers to the way in which the regional power system is structured and the way it operates. As a general rule, there appear to be two basic models for electricity markets. These are the traditional vertically integrated utility model, and the competitive non-vertically integrated market model. In the vertically integrated utility model, the utility is responsible for all generation, transmission and distribution activities within a geographical area. This includes the operation of the existing network and generation stations and the planning of new developments to the system. As a result, the utility can implement a single planning process for generation and transmission with the purpose of developing fully co-coordinated plans for the commissioning of new generation onto the system and for the retirement of obsolete generating stations from the system. In addition, the utility can develop operating plans for the network based on a complete understanding of the operating regimes of the generating stations connected to the system.

However, there are perceived inefficiencies in this model resulting from the lack of competition. These include:

- lack of commercial pressure in operation of generating stations
- lack of incentives to introduce novel or non-technical solutions to technical problems
- a “one-size fits all” approach to meeting customer needs

With increasing development of markets and an increasing emphasis on the unit costs of delivered electricity, most market regulators seek to introduce greater transparency and competition into the electricity supply system. A typical example of this is the corporate separation of transmission and generation functions. (See Case Example 3.4.1)

With the formation of separate companies the planning of transmission and generation is no longer part of a single internal process. Instead, the processes for generation and transmission planning are driven by the market processes and procedures and may be impacted by many independent market participants.

There are enabling or structural elements of the market which must be defined in order that the market will function and that all participants know how to take part in the market. These structural elements include:

- connection rules
- charging rules
- ownership rules
- regulation

In addition, there are the trading rules that define how the market functions on a day to day basis and how power delivery capacity is shared when constraints occur.

Non-structural elements of the market include:

- the number of market participants
- interactions with other markets – fuel, emissions trading

The transmission system must now be planned to ensure there is adequate transmission capacity to operate the system within specified standards against a range of operating scenarios, not just those scenarios that were agreed to as part of a co-ordinated generation and transmission planning function.

When we refer to the effects of electricity markets on transmission system planning, we are referring to the effects of these market rules, processes and procedures on the plans that are developed. Specifically, we will address how these procedures cause there to be uncertainty, and how this uncertainty is dealt with.

3.1 Market Uncertainties

The following paragraphs describe the types of uncertainty our new markets create and their inevitable impacts on the transmission planning process.

3.1.1 Market structure

Regulation of investment

The basic structure of a market refers to the way that market is organised. Even among models that are based on similar principles there are variations within the precise implementation of those structures. Two questions that affect market investments include:

- Is the transmission system operated by a single company?
- Is a single regulator responsible for the approval of investment plans or are there several?

Where many external approvals are required there is increased uncertainty in the investment process because of the duration of the approval process. This increased uncertainty means greater effort is required to gain consensus on the right transmission reinforcement option, in part because of the time it takes to engage with external parties. Complex governance arrangements require time to follow the process. Planning across three states will require three separate sets of approvals in the planning process.

Number of market participants

Where there are many participants within the market then the range of scenarios increases greatly. For instance, if there are lots of independent generating companies there is greater uncertainty in the options that are open to individual generators. In such cases, there is more uncertainty about how they intend to operate their plants and consequently about the impacts on the operation of the transmission system.

Similarly, there is less uncertainty when transmission facilities are owned and operated by a single company than there is when transmission facilities are owned by one company but operated by a different company.

Other market uncertainties arise from:

- **Trading rules:** The structure of the market can also have an effect in terms of the range of solutions that the transmission owner/operator can provide.
- **Ancillary services:** A further significant impact on market uncertainty is which entity is responsible for dealing with constraint costs. It may be that the potential cost of dealing with the constraint justifies the construction of additional transmission capacity, even where the amount of transmission capacity satisfies reliability standards.
- **Options to overcome technical issues:** Some ISOs (such as the NYISO) consider a wide range of options to overcome technical issues. These options includes transmission reinforcement or expansion but also distributed generation and demand side measures.

3.1.2 Interconnection with external systems/markets

An interconnection to an external system may be either an AC or a DC connection. However, in both cases they are capacity-limited. That is, they are designed to carry a defined amount of power rather than the level of power that would flow across the boundary between the two networks if all generation within the two areas was dispatched on a single-system basis.

The level at which an interconnection will operate at any given time is difficult to predict. Among other factors, it will be based on the trading arrangements that are in use for the interconnector. In many systems, such trading arrangements include an auction element that may comprise auctions to purchase both long term and short term capacity. (See Case Examples 3.4.2 & 3.4.3)

Because interconnections operate between markets they cannot be characterized using directly equivalent generator characteristics. Rather, interconnector flows result from a combination of factors, e.g. relative generation prices, relative demand levels on each system. These uncertainties make it difficult to predict with accuracy the level of interconnector flow for a particular planning scenario. In addition, given that most interconnectors operate in both directions, the full range of flows is typically greater than the capacity of the interconnector e.g. the DC interconnector between Britain and France can flow at 2,000 MW in both directions.

When a system interconnects with a system that also has other interconnections, there is a further complication. In such cases, the levels of flows across the system with multiple interconnections may be driven by systems not directly connected to the newly-connecting system.

Hence, planning for the effect of interconnectors is difficult, and depending on the degree of interconnection, may require co-ordination across several systems both in planning and operational timescales. For example, the exploitation of the new interconnector between the Netherlands and Denmark will cause significant changes in terms of flows in other connected countries such as Belgium, Germany and France, while these countries' systems may not have been planned for the full range of scenarios that now may occur.

Where systems are directly connected through AC interconnectors, there is also the potential for incidents on one of the interconnected systems to affect the connected systems through voltage sags, or loss of system stability, or cascade-tripping of circuits. Hence, although interconnecting systems can result in advantages, such as sharing reserves, providing access to cheap generation, and increasing a generator's access to markets, it also introduces uncertainties. The potential for these effects can be reduced through the use of DC interconnections.

3.1.3 Enlargement of Markets/Systems

A recent trend in transmission system planning and operation has been the enlargement of a transmission system so that it includes transmission networks which previously were treated as interconnected systems. This has the advantage of reducing some complexity in that:

1. All access to the transmission system is allocated on a consistent basis;
2. Generation is dispatched on a consistent basis across the system so that it is more straightforward to define consistent planning scenarios;
3. What was previously an interconnection boundary is now treated the same as any other internal system boundary, i.e. security standards are applied uniformly across the whole network; and
4. Sharing operating reserves is possible over the larger network

When the boundary between two separate but connected systems is internalized within a single larger combined network there is the potential for unrestricted flows across the boundary. Typically this will lead to increased flows as cheaper generation to one side of the boundary will now have unfettered access to demand on the other side of the boundary. Typically this requires the building of additional transmission capacity to cope with the prospective range of flows. However, the cost of providing that additional infrastructure is usually more than offset by the cost savings from being able to run the most competitive generation to supply demand.

The uncertainties introduced by system enlargement are associated with the fact that you are now dealing with a larger network with more unknowns and a greater range of flows across the network. In addition, during the initial period after market merging there is an amount of time required for planners to become familiar with the key issues that are pertinent to the new enlarged system.

3.2 Variations among systems - Questionnaire results

The following bar charts summarize how survey respondents felt about the nature of market uncertainties, their causes, and methods for minimizing the effects of such uncertainties.

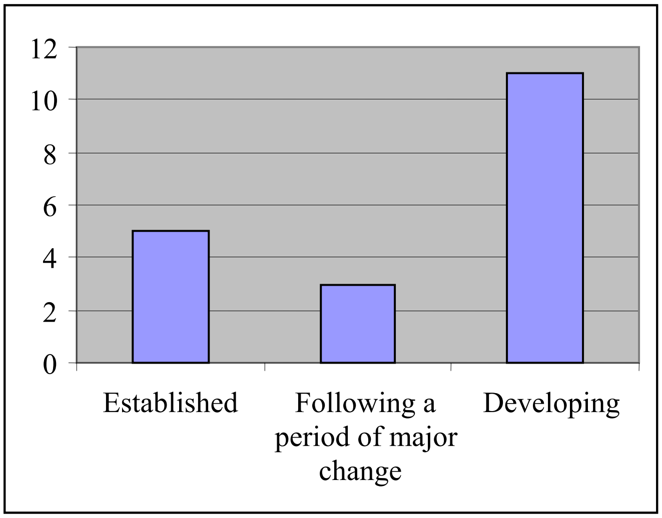


Figure 2 - How would you define the level of market change currently taking place in your market?

As Figure 2 illustrates, most respondents felt that they were in a period of change or that they were working with new systems following the implementation of market changes. This reflects the point that within established markets, regulators are consistently seeking to increase competitive pressures within the market and produce efficiency gains for consumers.

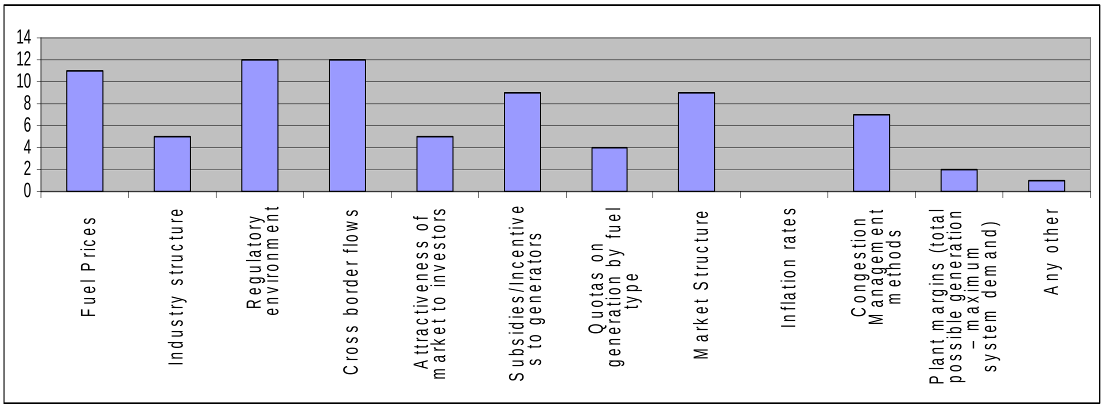


Figure 3 - Which of the following introduce major uncertainties into your planning processes?

These market changes have greatly increased system planning uncertainties, and Figure 3 indicates there are diverse contributing factors. The top two factors were the uncertainties introduced by regulatory changes and accounting for cross border flows. Both of these relate directly to investment levels. From a the regulatory perspective, a key uncertainty arises in setting the level of capital investment allowances, i.e. getting agreement to invest to meet planned scenarios. The uncertainties introduced by cross border flows relate to predicting the appropriate level of flows on which to base an investment program. The next most significant contributing factor was future fuel prices. This stems from the planners inability' to predict future economic dispatch patterns for generation at different levels of system demand.

The most often cited single cause of these uncertainties was market restructuring, and this is consistent with the view of most respondents that they were experiencing a period of change within their markets.

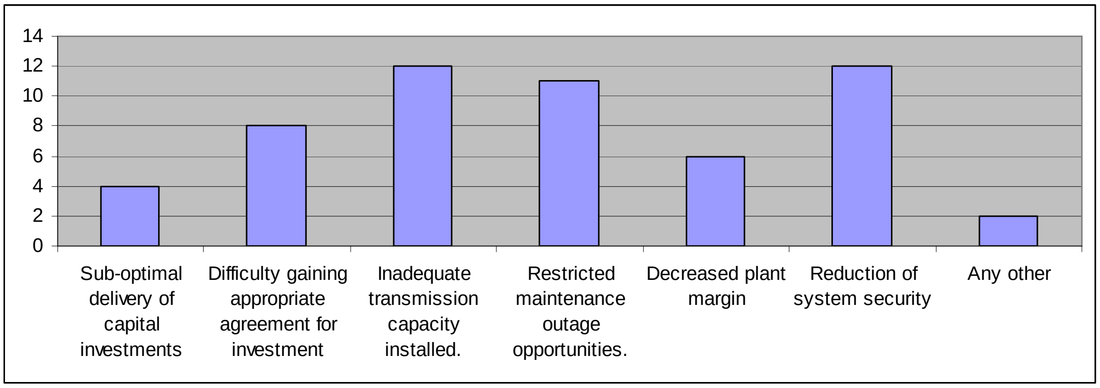


Figure 4 -What are the impacts (consequences) that these uncertainties will have on the transmission system?

As Figure 4 shows, the most significant impacts of these uncertainties are decreases in the available transmission capacity, reduced system security, restricted maintenance outages, and the inevitable result, inadequate transmission capacity.

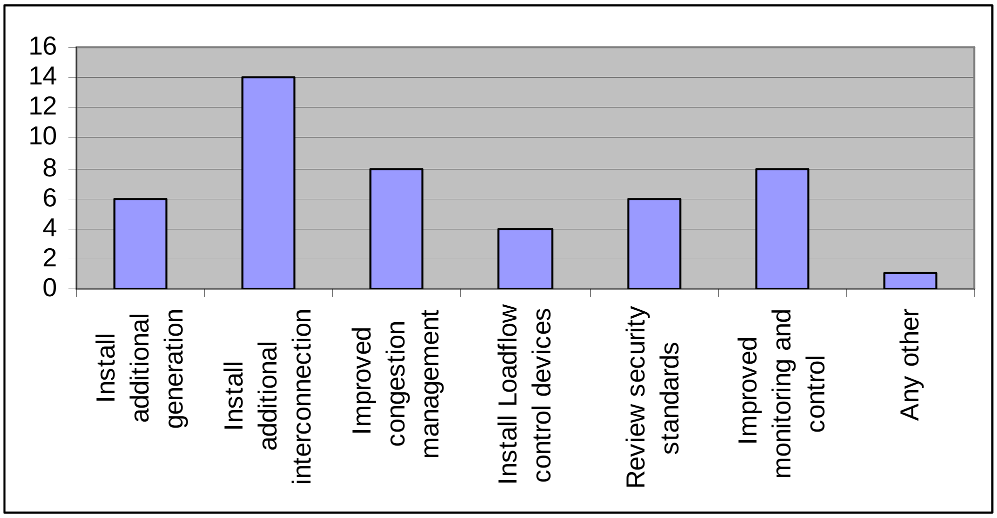


Figure 5 - What options are available to minimize these uncertainties?

Figure 5 shows the options that respondents believed would be most effective in reducing these uncertainties. Clearly, the option cited most frequently was to invest in additional interconnection capacity on the transmission system. However the effect of the regulatory controls in most markets restricts the ability of planners to fully exercise this option. Other options that were cited include improvements in congestion management and monitoring and control.

Figure 6 indicates that the most popular method for dealing with market-related uncertainty in the planning process is the use of scenario planning techniques. Other results indicate that the two most significant ingredients to the development of scenarios are macro-economic indicators (e.g. inflation, gross domestic product) and fuel prices.

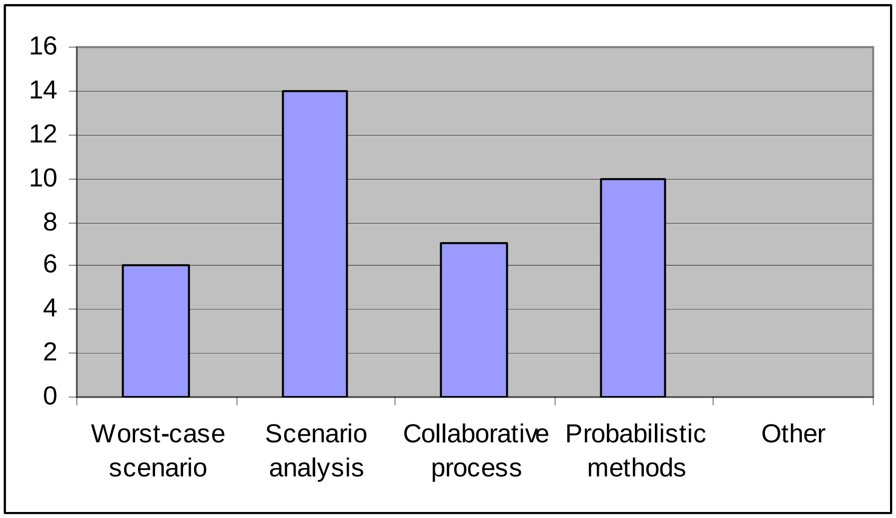


Figure 6 - Which methods are used for assessing the impacts of market-related uncertainties?

3.3 Tools/Techniques for mitigation

3.3.1 Market Rules/Grid Codes

One of the most effective methods for addressing market uncertainties introduced through markets is ensuring that the rules and procedures that govern the functioning of the market are well thought-out, robust and clearly-specified.

Most markets are designed with a Grid Code that defines the minimum technical requirements that generators and demand customers connected to the transmission system must meet, e.g. the minimum reactive capability that a generator must provide.

In addition, the transmission system is typically designed to an established set of security standards. These standards define the levels of transmission capacity that the market requires. These standards are, however, based on assumptions about the technical performance of the connections that are made to the transmission system.

Such market rules must be kept up-to-date and should be the subject of an ongoing review so they remain up-to-date in the face of changing demands on the market, such as the connection of increasing amounts of renewable generation.

3.4 Case Examples

3.4.1 Privatization of the British electricity system

In 1990 the electricity system in England and Wales was privatized. The Central Electricity Generating Board, which up until that point was responsible for generation and transmission, was split into independent companies. The National Grid Company took on sole responsibility for the ownership, operation and planning of the transmission system. Separate generating companies assumed control of all the generation stations. Twelve regional electricity companies were made responsible for supply and distribution at voltages of 132kV and below.

Centralized planning of generation and transmission facilities ceased. In its place was a codified system for managing connections and making applications for connection to the transmission system. The transmission system planners put together plans for developing the transmission system and for the connecting competing generation projects based upon contractual arrangements with the independent generating companies.

The balancing of supply and demand was provided through a pool arrangement. Through the pool generators bid in their price per MW hour and were scheduled to run for half hourly periods based on a lowest bid price first arrangement. The System Marginal Price for any half hour was set by the bid price of the marginal generator and all generators that ran during the half hour period were paid at that system marginal price.

Over the period from 1990 to 2007, the regulation and operation of the market and the new connection process has continued to evolve. The original power pooling system for dispatching generation has been replaced with a bilateral balancing market that now includes Scotland.

The connection of new generation has continued apace. From the initial push to connect gas-fired power stations in the early 1990s to the drive to connect onshore and offshore wind powered generation now. In each case, the connection of the new generation requires the system to be reconfigured to accommodate large flows of energy from parts of the network not traditionally planned and constructed to facilitate those flows.

Initially, the regular Price Control Review determined a capital allowance fixed for the three year duration of the price control which has since been revised to a six year period. One of the shortcomings with a longer price control period is that there is a greater risk of actual outturns being different from planning expectations at the start of the review period. As a consequence, National Grid could be under or over funded during the review period. In its 2007 price control review the industry regulator Ofgem introduced Revenue Drivers to address this issue. The drivers reduce uncertainty associated with funding by varying National Grid’s allowed revenue depending on the actual level of new connections to the transmission system without resorting to a full price review process.

3.4.2 The NorNed project

The NorNed-cable is an HVDC subsea interconnector between The Netherlands and Norway. The two national Transmission System Operators, TenneT and Statnett are currently executing the project, as equal partners.

The decision to build the interconnector was made in December 2004, and it will be completed in October 2007. Commercial operation is scheduled to start late November 2007. NorNed will be the longest subsea HVDC cable in the world. NorNed is a prioritized infrastructure project under the EU Trans European Networks (TEN) programme.

Cable length: 580 km
Total project costs: Approx. EUR 495 million
Cable capacity: 700 MW
Land terminals will be Feda (Norway) and Eemshaven (The Netherlands)
Weight: Single-core cable = 37,5 kg per m; two-core cable = 85 kg per m
Voltage level: +/- 450 kV
Maximum sea depth: 410 m

NorNed will be an open interconnection, that will be utilised via market coupling of the Dutch and Nordic markets. Temporarily, until the 01.01.2009, the cable capacity will be sold on an explicit auction. The long-term solution will be market coupling based on implicit auction. This market coupling will be handled by the power exchanges APX (in the Netherlands) and NordPool in Norway (Nordic countries). The capacity utilization will then be determined by price differences in the day ahead markets.

NorNed will connect the thermal power system of the Netherlands with the hydro-dominated power system of Norway. The two markets have very different characteristics and hence price structures (day/season/year). Figure 7 below shows how the power prices in the two systems vary during a typical week. Even though the average price might be almost equal on a daily/weekly basis we can see that the price difference per hour is significant. These price differences lead to high trade income, estimated to give an acceptable rate of return on the investment. The interconnection will be regulated, meaning that costs and revenues related to the project will be attributed to the grid customers.

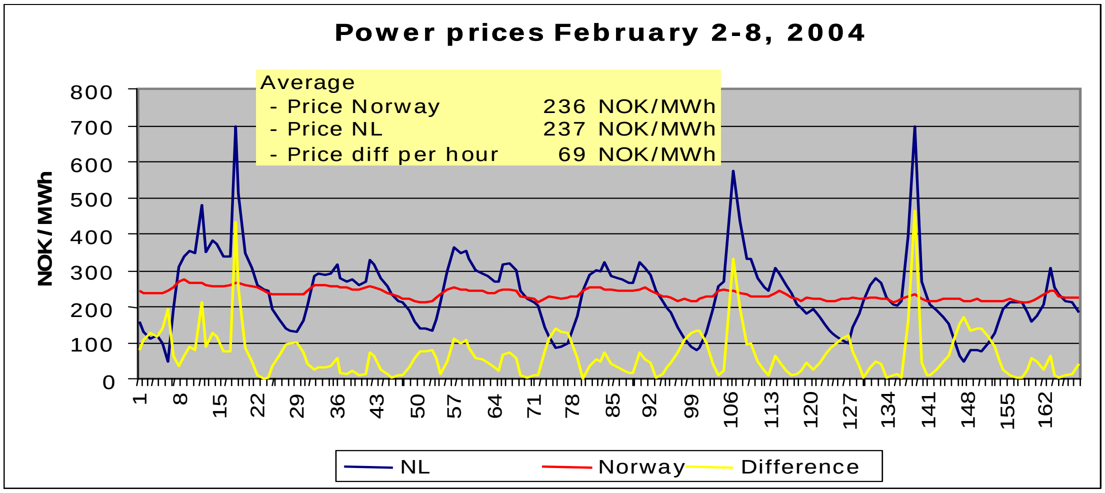


Figure 7 – Power Prices February 2-8, 2004

Improvement in market functionality by increasing competition on both sides, security of supply by enabling higher exports to Norway during dry years and giving extra capacity in the Netherlands during peak loads, are other important benefits.

3.4.3 Interconnection Case Example – Neptune Cable

New HVDC interconnections between markets that previously were not connected, or were only weakly connected, provide a low-risk way of mitigating the uncertainties associated with market access and generation availability. DC connections are controllable and allow system operators to use discretion in setting interchange levels. Diversity of loads and outages in adjacent markets make it quite likely that, in an emergency, the market at one end of the cable can provide support to the market at the other end of the cable.

One such interconnection in the U.S. is the Neptune Cable that now connects Northeast New Jersey with Long Island, New York. Because there already is an existing underwater DC connection between Long Island and New England, the new Neptune cable actually helps to connect three separate markets, namely the PJM RTO, the NYISO, and ISO-New England.

In describing the new 500 kV Neptune transmission line, the Long Island Power Authority (LIPA) states [1]:

> "The over $600 million, 65-mile long Neptune Regional Transmission System is an undersea and underground High voltage Direct Current (HVDC) system that includes a cable that runs from Sayreville, New Jersey to New Cassel in the Town of North Hempstead in Nassau County. It carries 660 megawatts (MW) of energy, which is enough to meet the electricity demands of about 600,000 average-sized homes."

The Neptune cable was granted a Certificate of Environmental Compatibility and Public Need by the N.Y. Public Service Commission on January 23, 2004. The project was subsequently completed ahead of schedule and energized in June 2007 in time for the summer peak load period.

When Neptune's 660 MW capacity is combined with the existing 330 MW "Cross-Sound" DC cable linking Long Island and Connecticut, LIPA now has 990 MW of DC interconnect capacity with adjacent markets. This is a welcome change from the past when Long Island loads were served only from "on-island" generation and two small cables linking the island to the NYISO to the north. Given that existing Long Island generating capacity is approximately 5,000 MW, its new ties to PJM and New England provide the ability to import almost 1,000 MW of additional capacity when island resources are more costly or are not available.

According to LIPA's Chairman Kevin Law, "Long Island enters a new era with the Neptune cable. The Neptune cable provides LIPA with the opportunity to acquire lower-cost energy to meet customer needs while providing more flexibility in selecting the markets from which we acquire that energy. It is a significant win-win for Long Island."

4. Load Uncertainties

4.1 Types of Load Uncertainties

4.1.1 Predicting customer load growth

Anticipating the growth in customer load is essential to ensuring that a reliable and economic supply of electricity will be available to meet future needs. If the rate of load growth is low to moderate and uniformly distributed geographically, a stable and predicable network expansion plan can usually be developed and implemented. Where high load growth is expected, the "optimal" network expansion may take too long and various types of mitigation may be required. Where either flat or negative load growth is anticipated, other problems may result, such as the lack of a compelling need to replace or update aging transmission facilities.

Changes in overall national or system load growth may result from either:

- A change in the average use per customer,
- A change in the number of customers, or
- Both factors.

As examples, rapid economic development and/or increased customer wealth are almost always accompanied by a significant increase in electricity use.

Such load growth can be predicted using statistical, economic, governmental, and physical information. Statistical models have long been used to correlate electricity growth to past time series of data. In such studies, the economic growth of a country or region is always a key independent variable. Major national initiatives, such as the location of new government facilities, or military bases, can also influence the future need for power in certain regions. For any specific location, of course, physical limits such as steep mountains, bodies of water, or adverse terrain may limit the ability to relay on a simple extrapolation of past load growth trends.

As the following sections discuss, average total system load growth alone generally does not provide an adequate indicator of the load uncertainties that affect transmission needs. The reason is that transmission needs are affected by any significant changes in where power is generated and where it is consumed. Generation uncertainties are discussed in the next chapter. Locational uncertainties are discussed in the following sections.

4.1.2 Location of load growth

Next to the total amount of customer load to be served, the load's location presents the greatest uncertainty in planning transmission facilities. Even with zero overall load growth, a large shift of load from Location A to Location B can create major challenges for transmission planners. Anticipating such changes requires the same types of tools and information as used for the system as a whole, but sometimes there is no prior infrastructure for collecting data for the specific geographic area(s) where such rapid growth occurs. In those instances where adequate transmission facilities cannot be constructed rapidly enough, other demand-side measures may be required, as discussed in the following sections.

4.1.3 Predicting distributed generation

If significant distributed generation is available close to the customer load, the need for transmission can be significantly reduced or even eliminated entirely. The physical presence and operation of such generation can effectively "cancel" the local load's effects on the regional transmission system. For such a load to be reliable, however, the local generators must be committed to the service of that load. This usually requires adequate reserve capacity and a legal or contractual service agreement. When the generation is owned and operated by a utility, such a commitment is assured. When it is privately owned, a contractual commitment is advised.

4.2 Variations among systems

4.2.1 Load growth expectations

The results of our survey show diversity in the situations of many respondents, but they also show striking similarity in the effects they are experiencing. To illustrate, Figure 8 shows the expected load growth of the 22 responding utilities. Over the short-term, half of the respondents expect a medium load growth (2 to 4%). Of the other half, two expect high load growth and the other nine expect low-load growth.

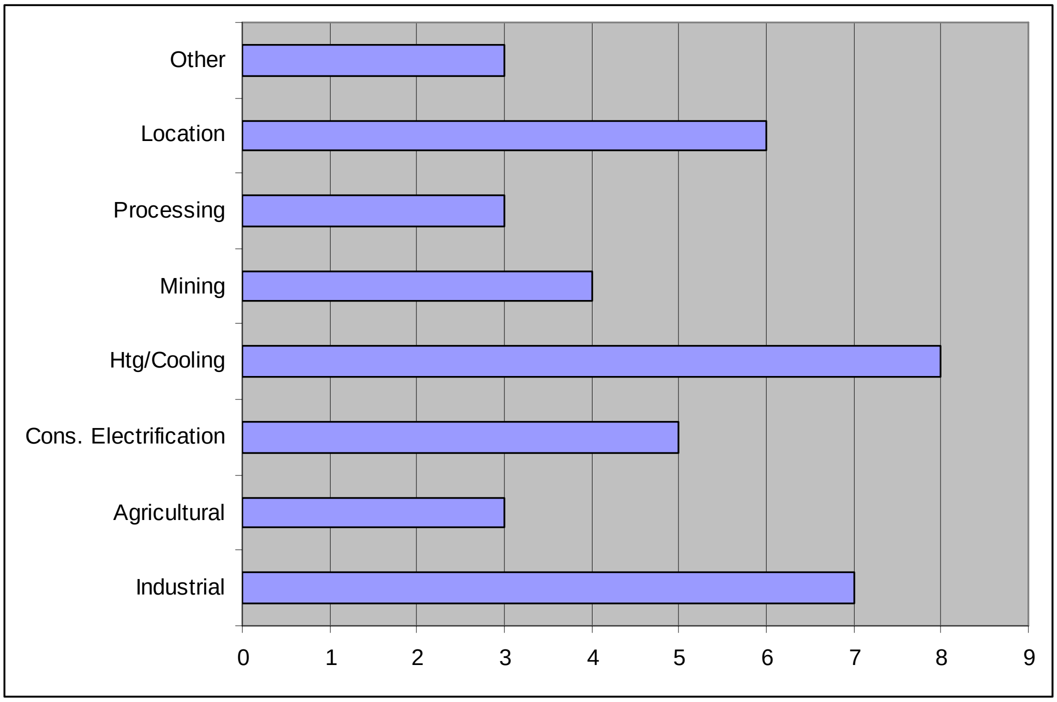
Figure 8 - Load Growth Expectation

Load Growth	**Time Horizon**	
	Short Term	*Long Term*
High (> 4%)	2	1
Medium (2 to 4%)	11	8
Low (< 2%)	9	13

Over the long term, over half of the respondents expect to have low load growth, and only one is expecting high load growth. To some degree, these results are a reflection of the mix of utilities responding to the survey, but they also indicate a changed situation on the many established utilities serving developed economies.

The effects of load uncertainty are reduced for these entities when compared with utilities that must plan for high load growth. However, as established earlier, even utilities with moderate or low overall load growth can experience great uncertainty in dealing with load shifts among demand sectors or between geographic locations. Almost half of the surveyed utilities expect such shifts, and Figure 9 shows the demand sectors where significant changes are expected. Heating/cooling loads and industrial demands were the two sectors most frequently cited, and changes in demand location were the third most common reason for load changes.

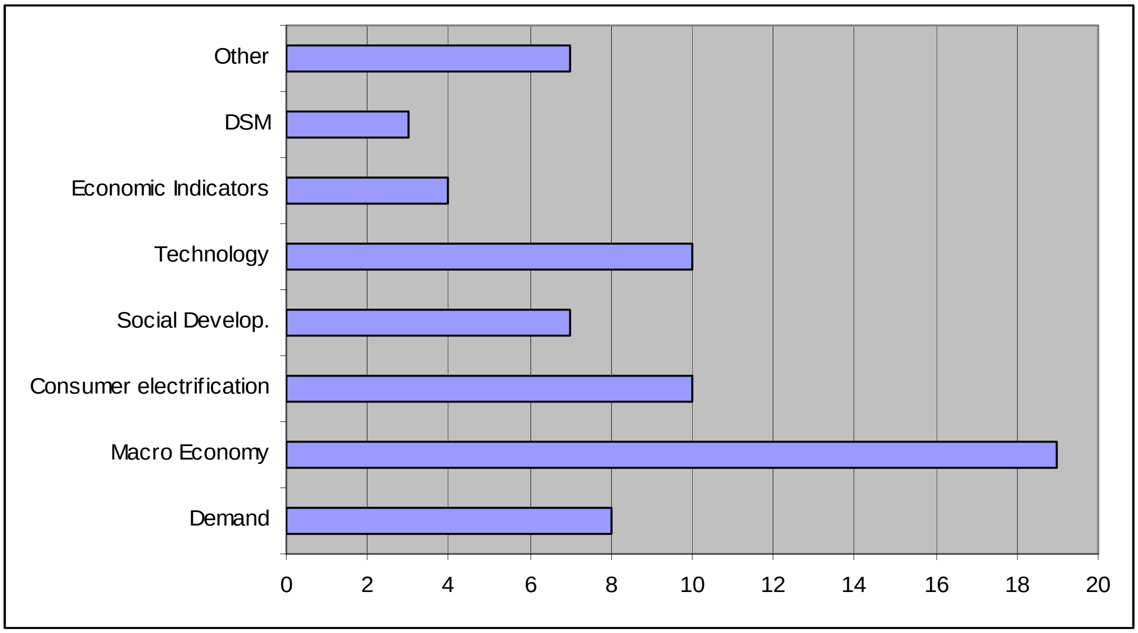
Figure 9 - Sectors Where Demand is Expected to Change



4.2.2 Causes of Uncertainty

By far, the most frequently cited cause for load uncertainty was the region's future macro-economic performance. As Figure 10 shows, the next most important causes were changes in technology and consumer electrification. Of course, these latter two causes are often linked to changes in the regional or national economy or to changes in energy policy.

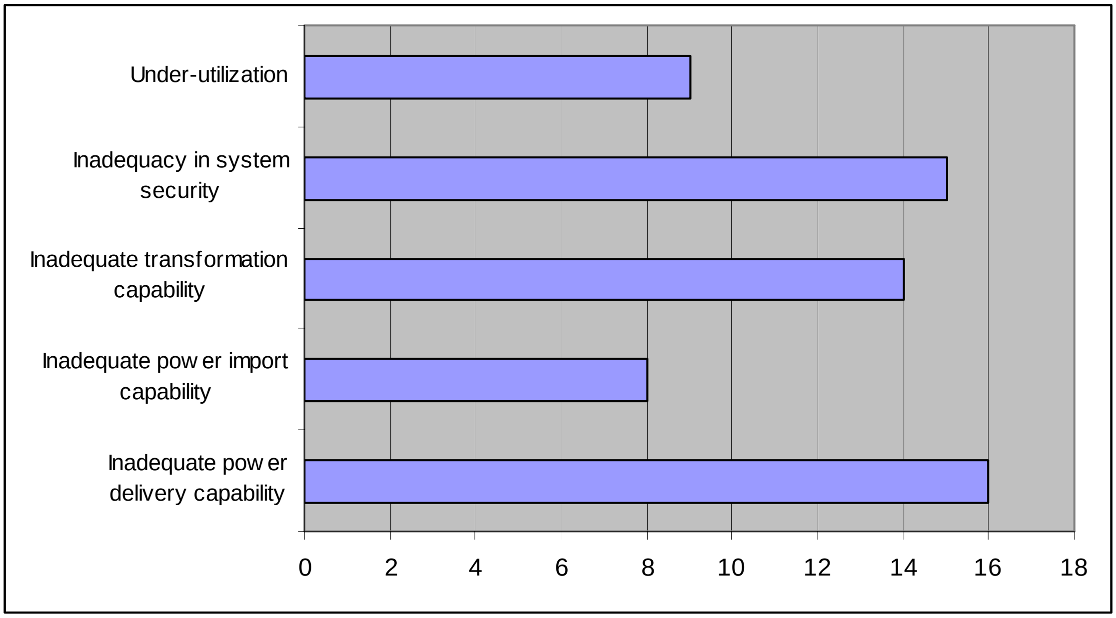
Figure 10 - Primary Causes of Uncertainty



4.2.3 System Impacts and Responses

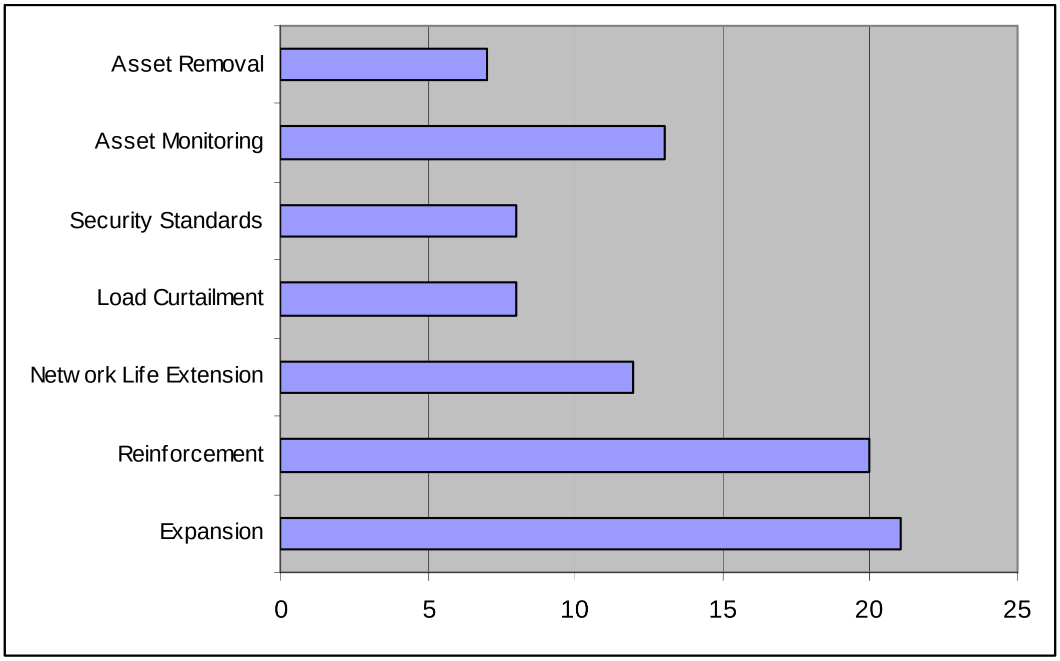
Among the survey respondents, 60% indicated that the financial impacts associated with load uncertainties were either high or medium. Not surprisingly, these responses generally came from companies that expected high to medium load growth. As Figure 11 shows, the most commonly cited impacts were inadequate power delivery capability, inadequate transformation capability, and unacceptable system security. Another quite different impact, system under-utilization, was also reported by almost half of the respondents. Apparently, this reflects load shifts away from areas of historic growth.

Figure 11 – Key Impacts of Load Uncertainty



Approximately two-thirds of the survey respondents felt that system modifications would be required to address the impacts identified in Figure 11. Such modifications include both system expansion and reinforcement, which were cited by almost all respondents as likely responses. Other responses, as illustrated by Figure 12, include network life extension, asset monitoring, revised security standards, and load curtailment. Where negative load growth was expected, asset removal was also mentioned by seven respondents. Of all these responses, system reinforcement and expansion often require long lead times, and so there is a clear need for methods to reduce load-related uncertainties. The methods that are currently being used to reduce load uncertainty are discussed in the following section.

Figure 12 – Responses to Load Uncertainty



4.3 Methods of Handling Uncertainties

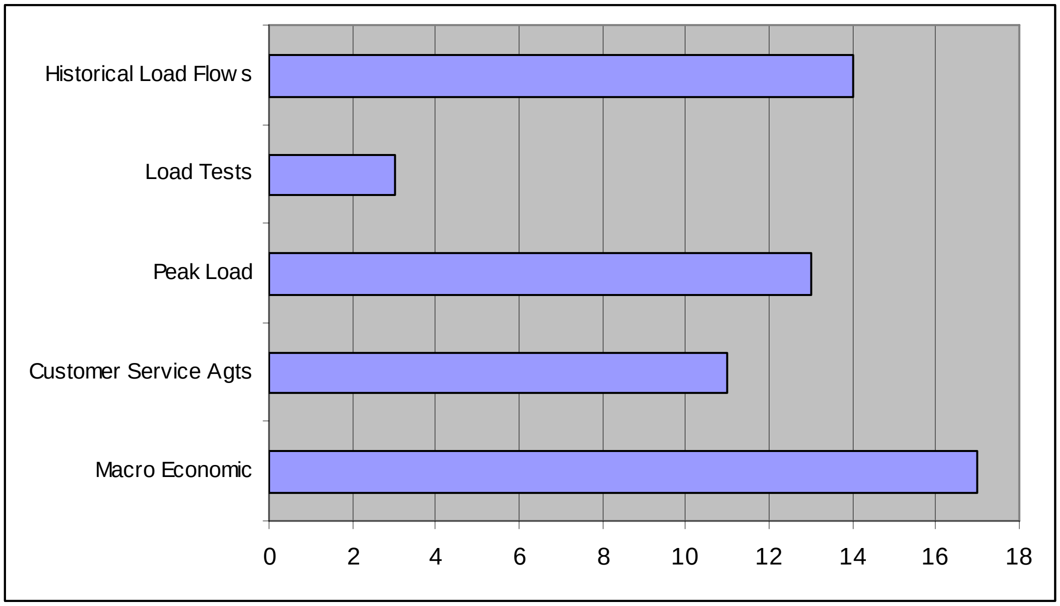
This section addresses the methods that are employed to mitigate load uncertainties and their effects on the power delivery system. These include the most obvious measure, system load forecasting, and various other methods used to assess the effects that load change will have on the system itself.

Almost 80% of the survey respondents utilize annual system load forecasts, and the remaining 20% utilize biannual forecasts. Over half of these forecasts cover a 10-year period, and another one-third cover a 15-year period. Some companies also forecast for 5-year and 20-year time horizons.

The sources of the load forecasts are similar for many (but not all) respondents. Almost 80% use forecasts from their distribution groups, and approximately 35% get forecasts from their bulk supply organizations. Half of those surveyed also utilized forecasts produced by government organizations. Other sources included market operators, customer surveys, economic institutes and industry research.

Figure 13 shows the load forecast methods reported by the survey respondents. Almost 75% use some sort of macro-economic index to forecast future load growth. The other most common methods include peak load forecasts and extrapolations of historical load flows. Also of interest, approximately one-half of the respondents listed customer service agreements as an important input in assessing future loads.

Figure 13 - Load Forecasting Methods Used by Respondents



Respondents also were asked to identify the method(s) they used to assess load uncertainties and to mitigate their effects. Almost all respondents used some form of scenario analysis. Seventeen reported using the general practice, which involves studying the system effects of experiencing a wide range of plausible scenarios defined by credible combinations of assumptions for key parameters, such as economic growth, full prices, generator locations, DSM implementations, and feeder loads. Eight respondents claimed that they identified the "worst case" scenarios and designed their systems accordingly. For larger system serving areas with very different economic profiles, it is difficult to define any single worst case scenario. Instead, there may be multiple worst cases, each for a different portion of the system where load growth uncertainties are significant.

Over half of the respondents use probabilistic methods, and many of these also use scenario analysis. The two methods are quite compatible, especially when numerical probabilities are assigned to key model parameters. These probabilities can help to assign a likelihood to certain scenarios would merit system additions and reinforcement.

Approximately 40% of respondents use some sort of collaborative process to mitigate load uncertainties. Such methods vary widely, but in most instances they include the development of a draft plan by the transmission owner and the subsequent review of that plan by various other stakeholders, often including regulators, customers, local government agencies, environmental organizations, and others. Comments by these are then filed and discussed, and the original plan may then be revised. After one or two iterations, there usually is a feeling of shared ownership and responsibility for the final plan. Because so many views are included, this approach provides an increased likelihood that divergent views will be heard and accommodated.

4.4 Case Examples

Possible case examples include:

- Scenario-based master plans that balance demand growth fluctuations among substations.
- Demand-side measures to shift customer use away from peak load periods.

4.4.1 Kansai's Approach to Demand Uncertainties

1 Concepts of Kansai's Master Plan

In order to deal with uncertainties of demand growth properly, Kansai started to develop new master plan on a base of scenarios. The objectives were:

- A system flexible to future demand fluctuations, considering not only high and low but also negative demand growth
- A system flexible to unpredictable emerging demand
- Improving customer services by maintaining high reliability without raising transmission tariffs in the long run

2 Current Situations and Future Trends

The population of Japan started decreasing due to a declining birthrate after peaking in 2005, and the number of households, which shows strong correlation with electricity demand, is predicted to decrease after peaking in 2015. Additionally, concerns for costs and the global environment have been accelerating the shift energy-saving technologies. On the other hand, electrification has been advancing because it is very convenient in terms of energy use. And, as a recent trend, customers who possess their own generation systems have tended to stop using them and returned to receiving power from provider transmission systems due to the skyrocketing fuel prices. We have also experienced large amounts of spot demand increases as a result of the development of large-scale factories.

From these perspectives, we foresee very mild or negative growth in our future demand as a whole system with uncertainties in and around emerging spot large-scale demand, which is difficult to predict.

3 Methodology of Making a Master Plan

(a) Demand forecasting

To achieve the above-mentioned objectives, it is necessary to minimize the risks of demand increases and decreases as much as possible. Therefore, Kansai's total supply area is divided into smaller areas (See Fig.14) so that development in each smaller area is closely analyzed and directly reflected in demand forecasts.

For each such area several load growth scenarios are defined. The most likely scenario of future demand trend is the middle case or base case. Considering factors such as those in shown in Figure 15 that reflect the individual circumstances of the region, the high case that demand increases and the low case that demand decreases are defined as “risk scenarios.”

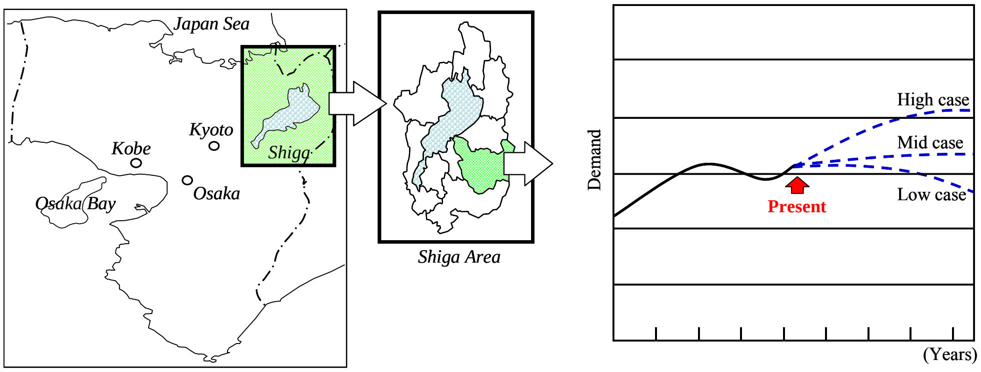


Figure 14 - Demand forecasting in Shiga Supply Area

Figure 15 - Examples of Assumed Factors

Assumed factor	High Case	Middle Case	Low Case
Population	+5%	Forecasted Value by local Governments	-5%
Energy-saving improvement	not-improving	National Target value	+5%
Increase in distributed generation		Past trend	National Target value
Large-scale development	Uncertain development	Almost certain development	

(b) Approach to formulating a master plan

Kansai then develops additional scenarios by combining individual demand forecast scenarios and the individual generation development scenarios for each transmission line, transformer and so on. Though each generation scenario is sometimes evaluated by a probabilistic approach, the final plans are based on the following approach of using scenarios to deal with load uncertainty.

(1) Middle case (Base scenario)

The situation of the highest possibility is assumed, and the scenario is applied to the capacity of each installed equipment, including transmission line size, transformer capacity and so on. And, it is made the base case of the plan.

(2) High case (Risk scenario)

Once constructed, a substation and tower cannot be easily changed. Therefore, the high case scenario applies to them.

Because when demand increases more than the base case or when a large-scale generation plant is connected to the transmission system, the high case scenario applies to them to secure the capacity in the future. How high a load case we prepare for is a very important factor in achieving secure and efficient planning.

(3) Low case (Risk scenario)

Asset efficiency will decrease if demand growth is lower than the base case. Therefore, it must be evaluated whether asset efficiency can be maintained by replacing equipment.

Example of Applying New Methodology

Kansai is examining various approaches to handling future uncertainties and improving customer service. One typical case is introduced below from a recent study.

(1) Transformer installation plan in local transmission system

Secondary substations A and B (A SUBSTATION and B SUBSTATION) supply to distribution substations in the same area. The transformer capacity is determined as follows.

(a) Examination of the base plan

Following the middle case demand forecast, the least costly plans for A SUBSTATION and B SUBSTATION are plan a-3 and plan b-2, respectively (See Figures 16, 17 and 18).

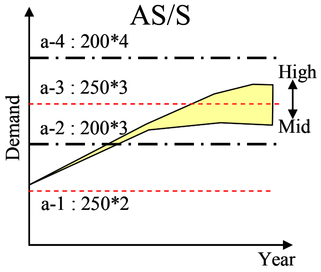


Figure 16 - A SUBSTATION demand forecast

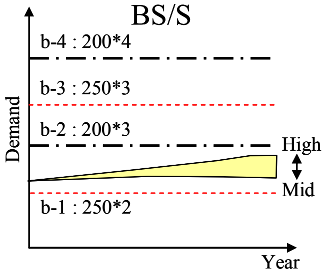


Figure 17 - B SUBSTATION demand forecast

Figure 18 - Transformer capacity plan

Transformer capacity	Cost	A SUBSTATION			B SUBSTATION		
		Plan	High case	Middle case	Plan	High case	Middle case
250MVA*2	1 : low	a-1	No	No	b-1	No	No
200MVA*3	2	a-2	No	No	b-2	Yes	Yes
250MVA*3	3	a-3	No	Yes	b-3	Yes	Yes
200MVA*4	4 : high	a-4	Yes	Yes	b-4	Yes	Yes

(b) Risk examination

B SUBSTATION can supply high case demand by plan b-2 because the B SUBSTATION demand fluctuation risk is small. However, A SUBSTATION cannot supply high case demand by plan a-3, and the supply plan for high case demand is examined for two cases:

Case I - A SUBSTATION plan is plan a-4.

Case II - The load that exceeds the A SUBSTATION supply capacity of plan a-3 is switched to B SUBSTATION.

The cost of each plan and the associated risk need to be evaluated overall. For high risk, additional space for the transformer will be secured. Once B SUBSTATION is constructed based on plan b-2, there may be some difficulty in changing the substation configuration to plan b-3. Therefore, case and risk need to be thoroughly examined before construction.

(c) Long-term asset replacement plan

Based on these results, Kansai designed a long term replacement plan for the base case and the high case considering the expected life of each transformer.

(d) Confirmation of property efficiency in the low growth case

In the low case, studies were made to determine whether asset efficiency could be maintained by replacing aged transformers to smaller capacity units and sharing load among substations. A long-term plan for the low demand case was developed in this way. In summary, Kansai's use of its "Master Plan" methodology provides a structural and consistent process for evaluating the risk associated with its power delivery alternatives in the face of wide variations in demand growth among its substations.

4.4.2 Case Example – Demand-Side Management (DSM)

Demand-side management (DSM) programs involve actions taken on the customer side of the meter that have the intention and effect of reducing the customers' requirements during peak times. DSM programs typically involve utility incentives provided to consumers to reduce or curtail their demands at specific times (usually system peak times, but also can be used to address locational peak times). Load management and demand response incentives are most often provided and renewed to program participants annually.

Some utilities use DSM resources as part of their integrated resource plans. The largest portion of the potential benefits from DSM comes from avoided generation costs. Other avoided costs, such as transmission and distribution costs, are usually much smaller. It is typically difficult to justify a DSM resource based solely on avoided transmission/distribution costs.

The short term magnitudes of DSM capacity reductions are not extremely large. For example, the first year of Texas' DSM program targeted only 10% of expected load growth. In another case, legislation in Illinois is awaiting the Governor's signature that establishes an annual DSM goal at 0.2% of energy deliveries, escalating up to 2% of energy deliveries in the eighth year. Over a period of years, however, there is no question that DSM can make an important contribution to reducing the need for transmission system expansion.

The typical process for assessing the potential impact of demand side resources involves an extensive market potential study that examines the customer make-up (e.g. residential, commercial, and industrial) and end-use energy profiles (e.g. lighting, HVAC, motors, refrigeration), and potential curtailable load. These studies identify opportunities to achieve demand-side savings. Based upon the market potential study, the most attractive end uses and the most attractive customer segments are identified as targets for program development. Next, programs are identified and designed, including the theory, incentives, channels, and marketing plans. Programs may be tested prior to implementation. Delivery may be accomplished through the utility's own staff or outsourced to qualified vendors. Depending upon the risk tolerance, urgency, and external involvement, program development can take 3 to 15 months from management approval of a budget until the program is launched in the marketplace. In the United States, large scale programs are most often funded and managed by and through utilities, state government agencies, or third parties accountable to state government.

4.4.2.1 Case Example – Demand-Side Management (DSM) measures to shift peak load times

For almost 20 years, Kansai Electric Power Company has provided strategic pricing system for middle and large customers aim at achieving a peak shift. Figure 19 is an example of Kansai's price menu.

Figure 19 - One example of Kansai's electricity rates (April 1, 2006)

B-TOU	20KV or 30kV Supply	Base Rate	1774.5	Yen/kW
		During the period July 1 through September 30, 10AM - 5PM	13.22	Yen/kWh
		Except for the above, 8AM - 10PM	9.11	Yen/kWh
		Except for the above	6.91	Yen/kWh

Figure 20 shows demand curves for 22KV or higher customers on the peak days load 1998 and 2007. We can see the increase of the peak load is milder than the increase night time. The smaller peak can also be seen around 10PM.

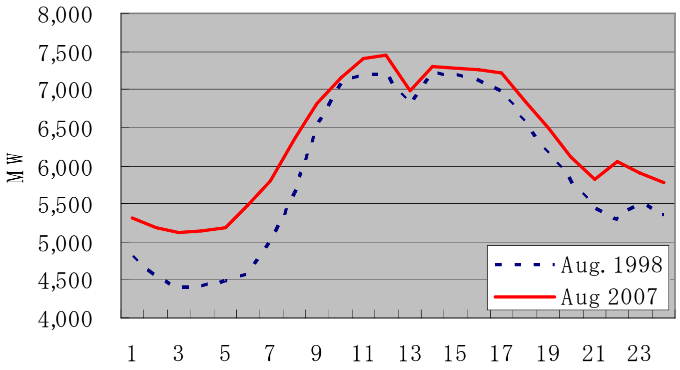


Figure 20 - Duration comparison between 1998 and 2007

4.4.2.2 French system example of using high peak time prices to avoid voltage collapse in Brittany

In France, some customers have access to a Peak Day Shading contract. With this kind of contract, the prices are reduced for 343 days/year and increased for 22 days/year. These 22 days are selected, among the days between 1st of November and 31th of March, using load forecast and generally correspond to very high load period or periods with unavailabilities of transmission devices or generation units. For the

Peak Day Shading contracts, France is divided into four zones in which the Peak Days can be selected independently.

The consumption reductions possible under Peak Day Shading contracts for the winter 2007, in the various geographical zones concerned, are estimated as follows. For information, the historical peak load demand was established on Friday 27th January 2006 at 6:58 pm with 86,280 MW.

Zone	Average load shedding in MW
France North	889
PACA (Provence-Alpes-Côte d'Azur)	170
West	450
France South	816
Total France	2325

5. Generation Uncertainties

The traditional planning of transmission systems did not have to address the types of generation uncertainties that exist today.

There are two principal causes that make the uncertainties associated with the connection of generation stations to the transmission system such a challenge for system planners [2].

- For the first, starting from the United States and Western Europe, especially UK and the Scandinavian countries, a major restructuring of the whole sector has taken place and led to the disintegration of formerly vertically integrated utilities into independent transmission and generation companies. As a result of that unbundling process, network planning today is carried out by independent system operators or grid companies that must ensure a non-discriminating network access for all interested parties and therefore must not have any special relationship or exchange of insider information with regard to new plant projects or similar aspects.
- Second, rising green concerns and the increased awareness of environmental issues all over the world have created a drive towards the construction of decentralized and distributed generation units with high efficiencies and a move away from large centralized power plants. Examples include the development of combined heat and power production and the increased use of generation based on renewable energy sources.

In addition to this uncertainty associated with the connection of new generation, there is the uncertainty associated with predicting the day to day operation of existing generation plants in the face of competition from new generating stations. The regulation policy in many countries aims to intensify competition in power generation and supply by giving incentives to new market participants to build new power plants and augment the number of competitors in the energy market.

Such incentives assume the obligations of transmission system owners to extend their networks in a way that makes congestion unlikely or even to grant priority access to newly constructed power plants. But even without such rules or incentives, a functioning energy market depends on the ability of network operators to connect generation in acceptable timescales, as the costs of congestion usually are significantly higher than the costs of network extension.

5.1 Types of Generation Uncertainty

During its investigation of influences of uncertain developments on the system development process, the working group identified five different types of generation uncertainties that are relevant in this context.

5.1.1 Location and size

Most apparently, the location and size of new generation units will influence the system planning process. In the past, the decision for the site of a new power plant of course was largely driven by economic reasons but also took into account network aspects. That meant that power plants were preferentially built near load centers, in areas with highly meshed networks or with sufficient transmission capacity nearby. Today the generation companies do not take into account any network constraints but decide to construct their plants at sites that seem to be economically favorable, e.g. due to direct access to the sea which means low transportation costs for fuels. As a consequence, a relatively high concentration of power plants at advantaged sites can be observed though these sites may be far away from load centers, or even if load centers are nearby, the total amount of installed capacity may exceed the regional peak load by far.

The location of new generators becomes a severe problem due to the typical rated power of units connected to the transmission grids in the range from some 100 MW to 1600 MW per generator (new nuclear plant currently built in Finland) or even some 1000 MW (grid connection of offshore wind farms). The typical size can necessitate major grid reinforcements as the typical power injections of new plant are in the range of typical capacities of transmission lines. But the effective and efficient execution of these reinforcements depends on early knowledge of grid connection points for future plants.

5.1.2 Timing

Transmission system operators more and more are obliged to guarantee a network extension appropriate to the market participants' needs. A relevant obstacle for the fulfillment of this obligation is the different lead time needed to construct new plants and new transmission lines. Whereas modern CCGT plants may be ready for operation within two years after the start of their construction, typical time horizons for planning and installation of a new transmission line (at least in Western Europe) are about ten years. This is due to difficulties in getting over the resistance of environmentalists, approvals for the right-of-ways, the compensation of land owners and the expropriation processes necessary in many cases. Thus, a grid reinforcement that starts with the decision on building a new power plant will most likely not be completed at the time when this plant goes into operation.

On the other hand, a purposeful and efficient preventive grid reinforcement appears to be very difficult because of the uncertainties in location and timing of new units. Moreover, in a regulated environment the motivation for grid operators to bear the risk of potentially inefficient investments is very low.

5.1.3 Renewable Energy Sources

Rising green concerns and discussions about the global warming potential have led to a higher share of energy generation based on renewable energy sources. This development is mostly politically driven as today most renewable based generation units could not withstand the competition of thermal and nuclear units in a totally liberal energy market. But with the help of different political incentive mechanisms, like guaranteed injection fees and priority access to grids, investment in renewable generation has become very attractive for more than a decade now.

Energy generation with renewables does not have major influences on transmission systems as long as the totally installed capacity in a region or area is small compared to the load in that region. But the installed capacities of wind generation in some regions (e.g. in Denmark, Spain and Germany) have reached levels which are much higher than the regional load and are causing severe problems in transmission systems and network planning.

CIGRE WG C1-3 especially addressed the problems connected with wind energy generation in its recent report [3]. Other technologies, like photovoltaics, solar thermal or biomass plants, up to now have had little or no impact on transmission systems. However, with the rising need to substitute conventional generation by carbon-free technologies, they could also cause problems for transmission system planning in the future.

5.1.4 Technologies of future plants

The technologies that future conventional plants will utilize introduce additional uncertainty that is closely connected to the location and timing of new generators.

After some years with only small investments in nuclear power plants, many countries all over the world have announced their intent to increase the share of nuclear energy generation. On the other hand, countries like Germany have decided to phase out nuclear energy generation.

There also is uncertainty about the future importance of combined heat and power plants for energy generation. These plants are typically connected to regional transmission and distribution networks. If their share in total energy generation gets very high, this could mean that the provision of ancillary services for the transmission grid will become problematic.

5.1.5 Dispatch and retirement of existing generators

The uncertainties described above are primarily related to unknown future developments of the generation system. But existing generation units can also impose uncertainties for network planning.

- As the dispatch of generation units depends on various rapidly changing factors that are out of control of transmission system operators and difficult to forecast, a precise nodal prognosis of injected energy in the situations that are critical for the grid becomes more and more unrealistic.
- Additionally, due to economic reasons plants may be taken out of operation even before reaching the end of their technical lifetime. This might even get worse with the rising importance of emission certificates that could make the operation of older plants economically or environmentally unattractive.

Thus, even the behavior of existing generation units becomes a major uncertainty for system operators.

5.1.6 Challenges for network operators

The described uncertainties for transmission system operators mean technical as well as economic and organizational uncertainties that affect system planning in many ways.

- Prediction of the future need of transmission capacity and identification of sufficient and sensible network extension projects gets difficult.
- Therefore, from an ex-post point of view, the efficiency of extension measures is not sure, and this can impose economic risks in a regulated environment.
- As structural changes in the field of power generation may occur within time intervals that are much shorter than the times typically needed for planning and construction of transmission assets, a network reinforcement according to the needs at any time is unrealistic. This means that transmission system operators more than today will have to face the problems of congestion and increased network security risks.
- Additionally, the provision of ancillary services could become more and more critical if the share of conventional power plants sinks below certain thresholds.

5.2 Variations among systems - Questionnaire results

The objective of this section is to give an overview as to how relevant the different uncertainties are in different countries. This analysis is based on the results of the questionnaire sent out by this working group.

The parties that answered the questionnaire (23 in total) on the one hand could evaluate the importance of the aforementioned uncertainties for their systems on the basis of a three level scheme (low, medium, high). They could additionally provide information about the current development of these uncertainties (decreasing, no change, increasing).

Analysis of the answers clearly indicates that the uncertainties connected with location and timing of new generators, as well as the problems of generation based on renewable energy sources, have the highest impact on system development planning. Figures 21 and 22 show that these two uncertainties as well are considered to have high impact (86 % and 81 %, respectively) but also are expected to increase in the future (67% and 71%, respectively). The other uncertainties seem to be of lower importance in general, though increasing (conventional distributed generation and future plant technologies), or at least are not expected to increase in the near future (plant retirement). This latter case makes it probable that the usual methods to deal with these uncertainties will continue to be sufficient for the future.

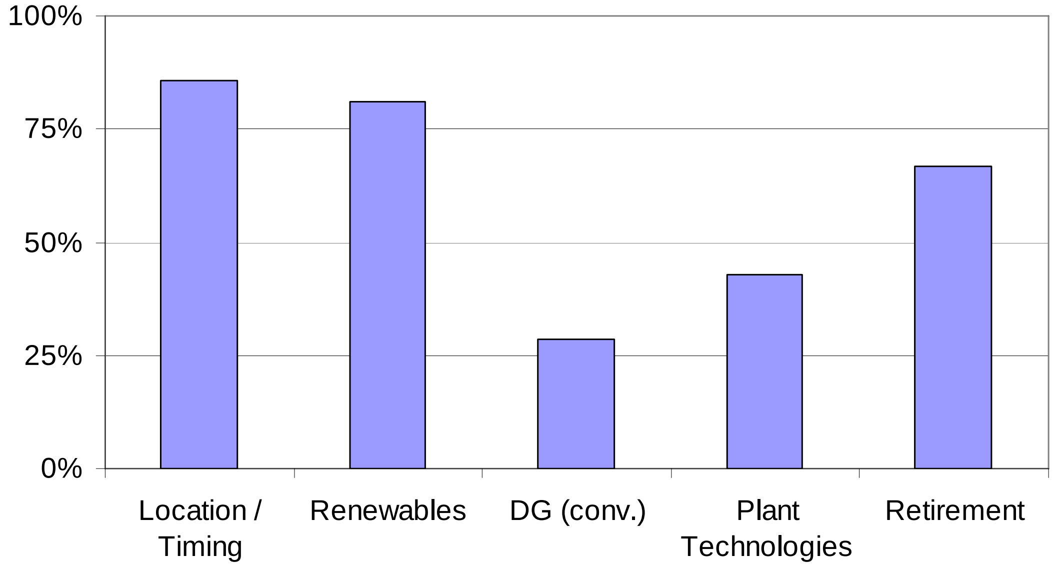


Figure 21 - Share of answers that assigned the uncertainties a high or medium impact

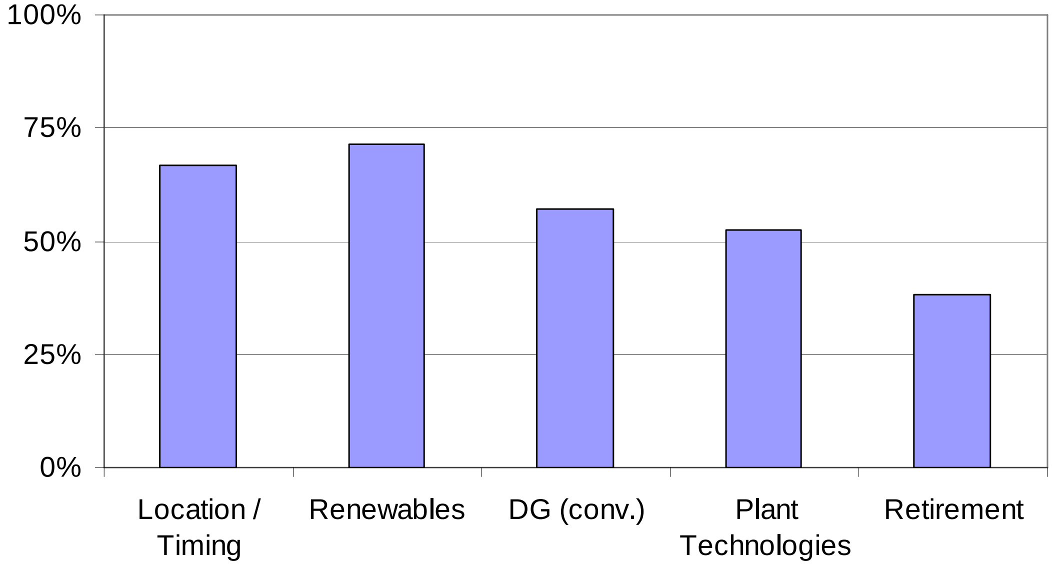


Figure 22 - Share of answers that considered an uncertainty as increasing

Additionally, it is remarkable that none of the uncertainties was considered as decreasing by any of the respondents.

Also, the respondents mentioned further uncertainties that they claimed were at least as relevant, or even more relevant, than the ones referred to in the questionnaire. e. g., one transmission system operator cited its dependence on a special HVDC line. The availability of this line dominates the system security in that special case.

Another system operator expressed worries about capacity problems due to an inadequate replacement of generators reaching their useful lifetime.

Finally, uncertainties relevant for generation of electricity may also be influenced by neighboring commodity markets. Several respondents mentioned the uncertain development of natural gas markets as relevant for their system planning.

A deeper analysis of the questionnaire answers gave only few indications for different developments in different parts of the world. Especially the uncertainties in the field of location and size of generation units and the development of renewable power generation were considered to have high relevance in industrialized as well as in developing countries and in Europe and the US, as well as in Asia. Only the question of a retirement of existing generators evidently seems to be more important, especially in European countries where key elements of the generation infrastructure are expected to reach the end of their technical lifetimes within a few years.

Besides the information about relevant uncertainties the working group attempted to determine the causes behind these developments. Respondents to the questionnaire therefore could allocate the uncertainties to six different causes:

- Changes of generation technology
- Green concerns
- Increase of fuel prices
- Government policies
- Sector restructuring
- Prices of alternative primary energy sources

Of course these causes are in some ways overlapping, but, especially as multiple allocations were possible, the answers provide an overview of the relevant drivers in the field of generation uncertainties.

Looking at the two uncertainties with the highest impact on system planning, location and timing of new generators and grid integration of renewables, (Figure 23) several conclusions can be drawn.

- First the field of generation uncertainties seems to be heavily influenced by governmental decisions as government policies were identified as the most relevant cause for both uncertainties considered here. This result is not too surprising, as the economic boundary conditions are especially important for a competitive Industry branch like power generation and trading on the one hand and because the rising share of renewable power generation is based on politically given incentives, as described before.
- Secondly, for the uncertainties of renewable generation, the relevant causes can be identified unambiguously. Besides the aforementioned government policies, rising green

concerns are especially relevant here. These green concerns were not only nominated by developed western countries but also were claimed as a relevant uncertainty, e.g. by South Korea and China. This shows that these impacts seem to be of global significance.

- Third, the causes that drive the uncertainty of location and timing of new generators cannot be identified in such a clear manner. Different developments seem to overlap here, though government policies and sector restructuring are certainly very important. But the causes do not seem to be as obvious as in the field of renewable power generation. This is also affirmed by the fact that more companies (90% of respondents) could allocate this uncertainty to any of the six possible causes given in the questionnaire than they could for the location and timing uncertainty (62%). The respondents also had the opportunity to suggest other causes, but there was relatively little additional information provided.

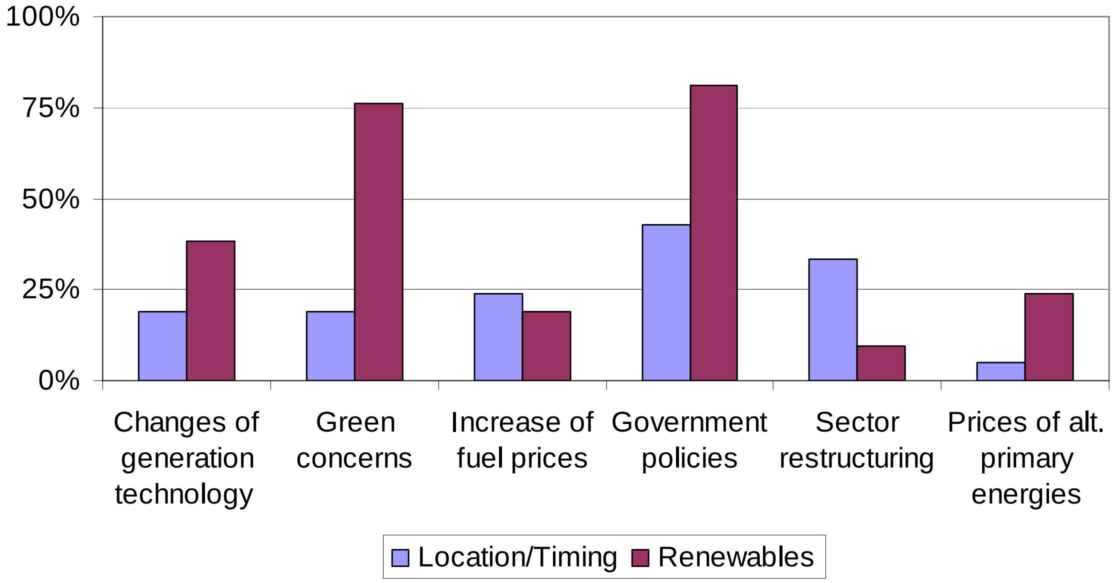


Figure 23 - Causes for the development of relevant uncertainties in the field of generation

To be able to give advice on how to manage generation uncertainty in system development planning it is also important to know which impacts on the grid are caused by this uncertainties in detail. The questionnaire submitted by this working group focused on six possible impacts.

- Overloading of equipment
- Voltage stability problems
- Angle stability problems
- Problems of load-frequency control
- Under-utilization of assets
- Reduction of system security

Figure 24 shows the impacts that were found to cause problems by the respondents. Besides the high share of the rather general and not clearly defined impact "system security reduction" that might be seen as a general description for most of the possible impacts, the main problems identified by the respondents were overloading of equipment and voltage stability problems, which together make up more than 50% of all nominated impacts.

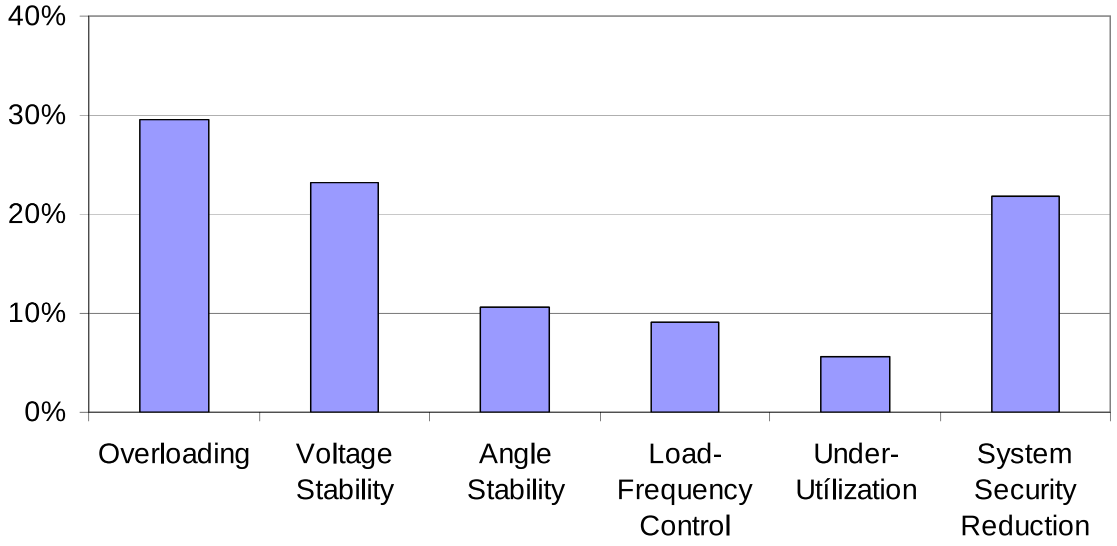


Figure 24 - Grid impacts of uncertainties in the field of generation

It shall be investigated whether these two impacts in some way can be linked to the different types of generation uncertainty. Figure 25 therefore shows which uncertainties believed to cause overloading on the one hand and voltage stability problems on the other hand.

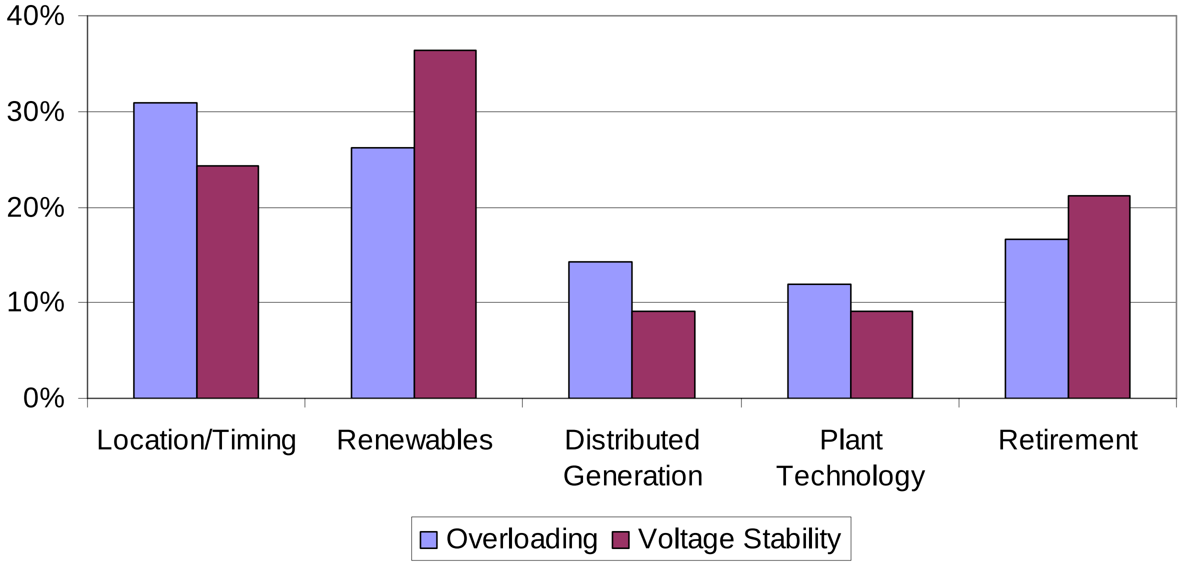


Figure 25 - Uncertainties behind overloading and voltage stability problems

The diagram clearly identifies the two uncertainties blamed by the respondents as the most severe ones (see above) and also as the ones which drive the most severe impacts. This confirms the consistency of the answers given by the respondents.

The influence of uncertain location and timing for new generators on line loading is obvious as well as the fact that overloading also might be caused by locally concentrated renewable power generation (like offshore wind generation with power injections of up to 10 GW at one node of the transmission grid). What seems to be of special interest are the causes for voltage stability problems, mainly renewables but also retirement of existing plants. Taking into account that renewable generation currently does not provide any reactive power and that retiring plants often are not replaced by newer ones at the same place, a local absence of sources for reactive power is the expected cause of these voltage stability problems. This shows that sufficient provision of ancillary services, though not broadly discussed today, may become a major problem in the future.

5.3 Tools/techniques for mitigation

5.3.1 Forecasting

Given the fact that different types of uncertainties influence network planning and that these uncertainties are continuously increasing, it is necessary to develop tools and methods to handle them within the planning process. The first important measure in handling the uncertainties is to become aware of all possible developments that could influence the planning process. This mostly means that it is important to make a forecast of the uncertain developments. The relevance of forecasting generation uncertainties is proven by the fact that 90% of the respondents to the WG C1-7 questionnaire indicated that they carry out forecasts for generation uncertainties. Nevertheless, forecast horizons and types of forecast used differ largely among the respondents.

The first difference relates to who carries out such a forecast. As the field of power generation is not necessarily in the competence area of transmission system operators, it might be sensible to outsource at least the forecasting of special aspects of generation uncertainty. According to the questionnaire answers, this is done by 28% of the respondents, all located in Western Europe or the US. External knowledge especially is used from governmental agencies or similar institutions and mainly affects questions of general interest, like the development of renewable energy generation. Thus, most of the companies combine external forecasts with internal prognoses to achieve relevant scenarios for system planning. Only one system operator claimed reliance on external forecasts alone, whereas about 50% of respondents said they did not use external forecasts at all.

Besides the question of who carries out the forecasts, it seems to be of importance which types of forecasts are used. There are several possibilities to consider:

- The simplest method to do a prognosis is to forecast the typical or expected value of a development. In favor of this method is the easy way to achieve such a forecast and the possibility to compare it with other forecasts. On the other hand, it does not consider all other possible developments and therefore limits flexibility in system planning.
- The second possibility is to forecast the upper and lower limits for an uncertain development, i.e. the extreme values. The disadvantage of a system plan that relies on extreme values is that it tends to be over-dimensioned, because the system layout is oriented towards one possibly very unlikely development and therefore is likely to be much more expensive than if it assigned the more likely developments a higher weighting.
- Rather popular in system development planning are scenario analyses which means a comparison of different system expansion strategies and its sufficiency for possible developments of the uncertain boundary conditions. One realization of all uncertain boundary conditions is called a scenario. Scenario analyses require an appropriate forecasting not only of typical or extreme values but also of some possible developments and the relationships between the different boundary conditions. With no further information on the probability of occurrence of the different scenarios, however, scenario analysis mainly validates a decision based on other forecasting methods, like typical or expected values, but gives little basis for a decision without additional data.

- To solve this problem probability based scenario analysis can be used, which allows a system operator to do its system planning considering probabilities of different developments and finally come to a stochastic optimization of the planning process. This approach seems to be optimal from a theoretical point of view but bears the problem of often not being able to allocate probabilities to uncertain developments, which is a prerequisite here.

The respondents to the WG C1-7 questionnaire indicated which of these forecasting types are used within their companies. The results show that up to now none of the different types of forecasts has proven to be preferable in general. Specifically, 53% of the companies do a forecast of typical and expected values, 38% use extreme values, 48% consider different scenarios with probabilities, and 43% use such scenarios without probabilities of occurrence. There was no clear trend as to which types of forecasts are used for which types of uncertainties.

The next issue with forecasting is the forecast horizon, where one has to face the problem that the development planning of transmission systems, due to long technical lifetimes and long planning and construction periods, requires a planning horizon of from several years to a few decades. The forecast of uncertainties, however, loses accuracy with longer forecast horizon. This results in about 55% of the respondents to the questionnaire carrying out a forecast with a horizon of one year and therefore possibly little effect on system development planning. Other typical forecast horizons are five years and ten years (both used by 47% of respondents). Longer forecast periods of 15 or 20 years are rather unusual and only carried out by 29% of the respondents. Although such long horizons are favorable from the system planning point of view, most transmission system operators do not seem to consider them as useful or even manageable for the field of generation developments. However, it can be discussed whether a long term plan based on inaccurate assumptions is not better than no long term planning due to no assumptions on long term developments.

Finally, it is important to consider which uncertainties are forecasted. Consistent with the attribution of importance for system planning, most companies do forecasts on location and timing of new generators (71%), retirement of existing generators (62%) and development of renewable energy generation (53%).

5.3.2 Planning measures

To manage or mitigate the consequences of generation uncertainties besides improving the knowledge of the future developments, planning measures are indispensable.

The working group found seven relevant measures that could be used here:

First, networks can be adapted to new challenges and usage by a suitable network expansion. This means primarily the installation of new assets. This measure should work in most cases but tends to be more expensive than alternative measures.

Alternatively, where appropriate, existing equipment could be reinforced. Often also a combination of reinforcement and network expansion is necessary.

As network expansion and reinforcement often take some years of time, a faster reaction on a change in boundary conditions might be helpful. In some cases this can be given by a life extension of existing assets. Such life extensions have proven to be possible for some years but bear the risk of an excessive asset age if used regularly.

As network operation does not only rely on the assets themselves but also on ancillary services, it might also be necessary to contract additional auxiliary services. Examples for that could be the acquisition of additional reserve power.

As flexibility in network operation can be necessary in the current, rapidly-changing environment, installation of special devices to control the load flows like phase-shifting transformers or FACTS might be a successful mitigation method.

Some of the problems with generation uncertainty might also be managed by improvements in system monitoring and control, like wide area measurement systems, which are able to measure e.g. phase angles of currents at distant places at exactly the same time.

Lastly, some new types of uncertainties require that the system security standards be updated and adapted.

Normally, not one of these measures, but a combination of several or even all of them, will be sufficient to deal with the different uncertainties.

Figure 26 therefore also shows that in practice transmission system operators use several of the measures mentioned above. Network expansion and reinforcement are the most often used measures, as could be expected. But nearly half of the respondents to the WG questionnaire also expressed their need for additional ancillary services or improved system monitoring and control. Typically, the measures are used to mitigate the consequences of all types of generation uncertainties. The only significant exception is the provision of additional ancillary services that is closely correlated with problems of renewable energy generation. That seems to be plausible, considering the problems for example with wind energy generation that is: not exactly predictable (need for more reserve power), causes high line loadings (need for more reactive power) and replaces thermal generation, the traditional source for reactive power in network operation.

Regarding the use of improved monitoring and control, it seems likely that at least some of the respondents are making increased use of Wide Area Monitoring Systems (WAMS). WAMS monitor real-time electrical conditions from locations at great distances from each other but on the same interconnected system. Such information can provide advance warning of a rapid deterioration in system performance. Timely monitoring of this data also may provide an opportunity to reconfigure or isolate portions of a system that represent a threat to the entire system's security. Recently, the technology underlying WAMS has advanced with the development of Phasor Measurement Units (PMUs). PMUs permit time-synchronized voltages and currents at distant buses to be recorded and shared using a navigational satellite system. Measurements are synchronized to within 1 microsecond [4]. In North America, PMU applications are being pursued by the North American SynchroPhasor Initiative (NASPI) Working Group (www.naspi.org). Among NASPI's ambitious research goals are: improved state estimation, real-time control & protection, dynamic ratings, and automatic smart-switchable networks [5]. If these goals are achieved, some of the uncertainties associated with new generating sources may be substantially off-set.

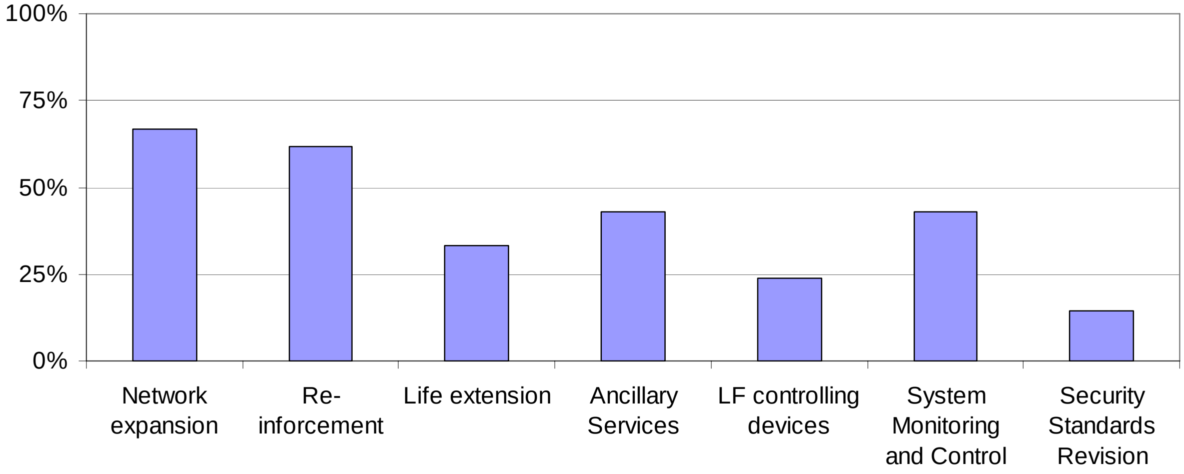


Figure 26 - Measures to mitigate generation uncertainty

5.4 Case examples

In discussions among working group members and industry representatives there were different methods identified which are used to mitigate the special types of uncertainties related to generation, especially with regard to generation based on renewable energy sources and to location of new generation units. We present some of the most interesting approaches as case examples in the following.

5.4.1 Connection Rules for Wind Energy Converters in Germany

Energy production with wind energy converters has gained significant importance all over the world, but especially in European countries like Denmark, Spain and Germany since the beginning of 1990s. Currently, with a total installed capacity of 22.4 GW in December 2007 Germany is the country with the highest installed capacity of wind energy converters worldwide. Figure 27 shows the rapid increase of that installed capacity during only a few years.

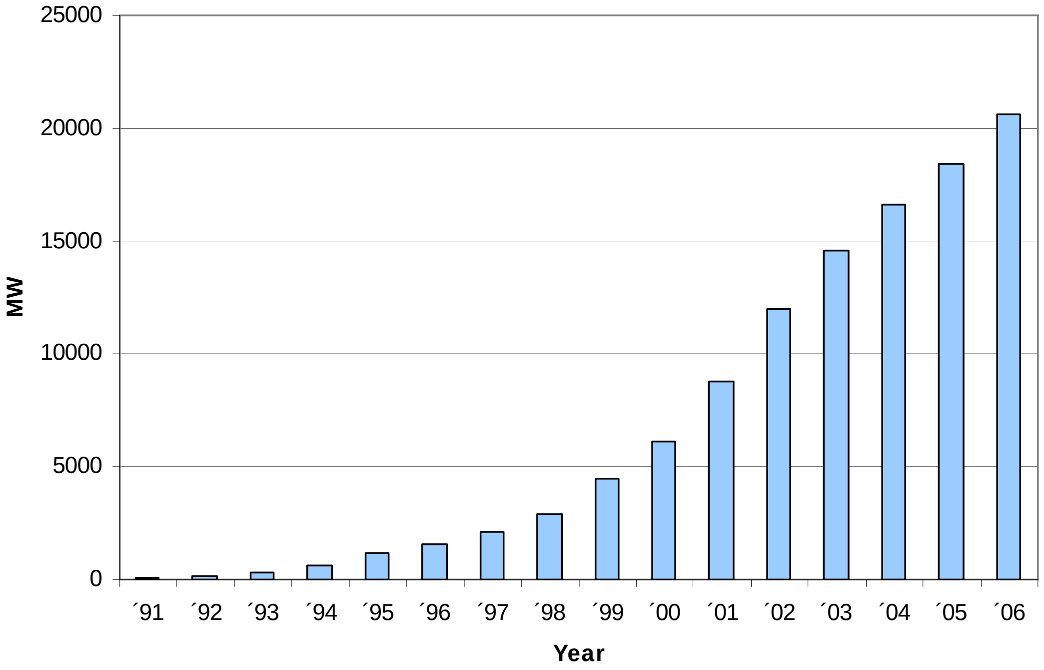


Figure 27 - Development of the installed wind energy capacity in Germany since 1990 (Data source: German WindEnergy Association, www.wind-energie.de), [6].

During this period, with the rising share of wind energy generation, the problems with the Gerrman grid integration changed. At the beginning of the described development, the influence on transmission systems was more or less negligible. Wind energy converters were being connected to distribution networks. Thus connection rules and operating practice were determined mainly from the viewpoint of distribution system operators who wanted to avoid having trouble with generation devices connected to their networks, especially in the case of unforeseeable events and failures.

With this motivation, connection rules forced wind energy converters to disconnect from the grid for example after a short-circuit with voltage dips below 80% of the nominal voltage. These rules were established to simplify network operation and to protect the wind energy converters themselves from possible damage due to extraordinary operating conditions.

Though in principle helpful for the operation of distribution systems, these rules began to cause serious problems when the total power of wind energy converters became so high that serious influences on the transmission systems were possible.

As one can see from regionally disaggregated statistics[1] wind energy converters in Germany are not distributed equally over the country but largely concentrated in the northern parts, especially near the coasts, where the average wind speeds are significantly higher than in the South.

With this local concentration of wind energy converters after a short-circuit in the extra high-voltage network, the unavoidable voltage sag in the underlying voltage levels in the area could, due to the disconnection obligation given by distribution system operators at voltages of 80% or below of the nominal voltage, lead to an unselective network disconnection of wind energy converters with a total power in-feed of several thousand MW. This could be a serious danger for network security as the total primary reserve in the European continental system UCTE is 3000 MW. A loss of wind energy converters with a power injection of more than 3000 MW would therefore lead to a frequency drop that could possibly only be handled by the shedding of load.

In 2004, within the dena Grid Study [7] [2], a joint investigation by German TSOs, research institutions, wind energy industry and governmental institutions on grid integration of wind energy, calculations were carried out that showed that even at this time under special, but realistic conditions (high wind power injection, short-circuit on special EHV lines in the North of Germany) a tripping of up to 4,000 MW wind power infeed could occur. As such behavior would not comply with guidelines in the UCTE Operation Handbook (the grid code for all members of the UCTE interconnected system.), connection rules for wind energy converters were changed some years ago.

The new rules adopted in the German grid codes specified that network failures that are cleared by protection devices in the conventional way may not lead to disconnection of generating devices. Within an amendment to the then valid grid code, called "Renewable Energy Based Generating Devices connected to HV and EHV grids [8] [3], these rules were defined more precisely in 2003 and overhauled again in 2007 [9] [4]. Figure 28 shows the newly-adopted tripping characteristic of undervoltage and overvoltage protection for generating devices under the rules of Germany's Renewable Energy Law (EEG) (for converters not coupled to the grid directly via synchronous generators, but e.g. via frequency converters like nearly all modern wind energy converters).

---

[1] See e. g. http://reisi.iset.uni-kassel.de/pls/w3reisiwebdad/www_reisi_page_new.show_page?page_nr=13&lang=ger&owa=

[2] dena-Grid Study I, 2005, available as an English short summary at http://www.dena.de/en/topics/thema-kraftwerke/projects/projekt/grid-study-i/ (03.09.07),
complete German version at
http://www.dena.de/de/themen/thema-kraftwerke/projekte/projekt/netzstudie-i/ (03.09.07)

[3] VDN (German Association of Network Operators) directive: EEG Erzeugungsanlagen am Hoch- und Höchstspannungsnetz (Renewable Energy Based Generating Devices connected to HV and EHV grids), 2004, http://www.vdn-berlin.de/global/downloads/Publikationen/Fachberichte/RL_EEG_HH_2004-08.pdf (03.09.07)

[4] VDN (German Association of Network Operators), TransmissionCode 2007: Netz- und Systemregeln der deutschen Übertragungsnetzbetreiber (Grid and system rules of German transmission system operators), 2007, http://www.vdn-berlin.de/global/downloads/publikationen/TransmissionCode2007.pdf (03.09.07)

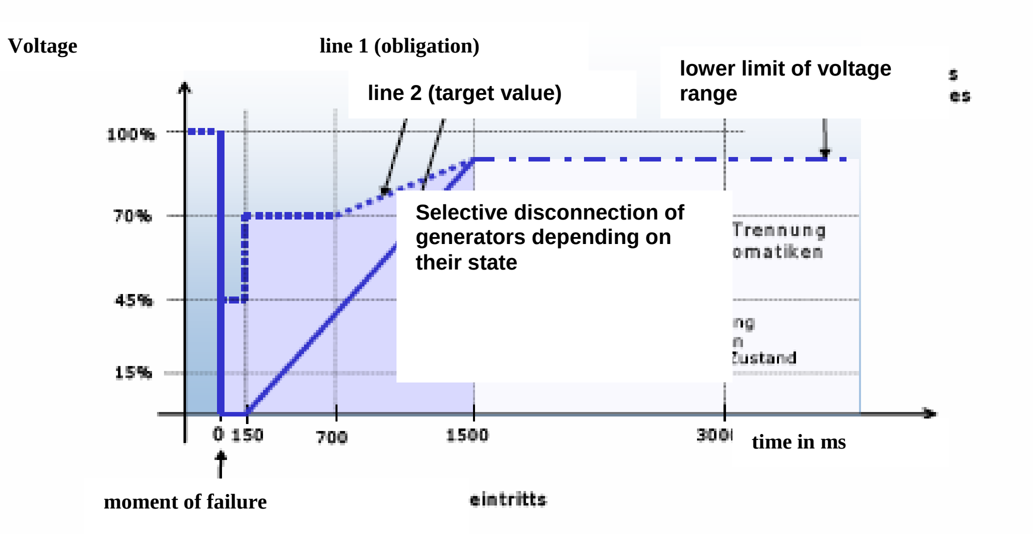


Figure 28 - Allowed tripping characteristic of undervoltage protection for generating devices based on renewable energies according to German Transmission Code 2007 (Source: German Transmission Code 20074 [9] , with translations of German descriptions)

One can see that a disconnection at voltages below 80% of the nominal voltage is now only allowed with break times of 1.5 seconds and more, whereas in the range of the normal clearing time of failures in transmission systems a fault-ride-through must be possible even at voltages of 45% of the nominal voltage until fault clearance and shall be possible down to voltages of 15% of the nominal voltage.

Additionally, it was defined that generating devices based on renewable energy also have to contribute to voltage control in the case of failures by activating a specified voltage control scheme and infeed of an additional reactive current of up to 100% of the nominal current.

With this adaptation of rules, problems of grid integration of large amounts of wind energy converters can be reduced. But it has to be mentioned that these rules are only valid for newly constructed or repowered converters. However, because a lot of old converters, to which these new grid connection rules cannot be applied easily, are still in the grid, the situation is expected to improve only slowly. Nevertheless, this example proves that new developments can make it necessary to completely revise common rules for grid connection of generating devices.

5.4.2 Requests for proposals for new generating capacity

In the United States, numerous utilities and some Regional Transmission Organizations (RTOs) issue Requests for Proposals (RFPs) for new generating resources to meet projected future loads. This practice, which originated in the 1990s to encourage the use of both demand-side and supply-side resources, continues to be used to stimulate a more open and competitive resource planning process. Using RFPs can reduce generation uncertainty by educating potential suppliers about local area needs and by communicating other system constraints, such as transmission limitations, that may be a factor in selecting resources to meet those needs.

As one example, Tri-State Generation and Transmission Association (Tri-State) released an RFP in early 2007 requesting "…up to 250 MW of intermediate power supply to serve its growing Colorado loads [10]." In describing the need, Tri-State's Senior Vice President of Generation, Ken Anderson, stated, "Tri-State is in need of additional resources that can be called upon to meet our members' near-term power requirements and facilitate the integration of renewable energy into our system…We will issue an additional solicitation specifically for renewable resources later this year, and we need to begin developing resources that can cost effectively manage the intermittent power produced from renewable energy."

As the Tri-State example illustrates, RFPs offer planners an opportunity to encourage certain types of generation, and when a responding supplier is selected, power purchase contracts may be offered that significantly reduce the financial risk to generation investors.

In another example, the City of Seattle, City Light Department (City Light) issued an RFP in July 2000 [11], stating, "City Light is interested in purchasing up to 100 MW of capacity and energy from Renewable Resources for a term of 1 – 20 years under a purchase power contract or partial ownership arrangement. City Light will consider a broad range of proposals and technologies."

As stated previously, RFPs can communicate important technical information that encourages bidders to consider the effects of their proposed resources on the regional electric system. To illustrate, City Light's RFP states, "All proposals must meet the requirements set forth in this RFP. Selection will be based on responsiveness to the requirements and benefits to City Light…" Bidders must respond to these requirements in their technical proposals and provide a wide range of information, including resource type, location, output characteristics, outage information, financial arrangements, and emissions. Further, City Light's RFP specifically requests transmission information, as follows:

- Describe interconnection to BPA Grid or to City Light system.
- Describe Point of Delivery for delivery of energy.
- Describe assumptions for transmission and provide information to support respondent's ability to deliver on the assumptions. Are there new facilities required for interconnection? Does pricing include all transmission costs?

Clearly, RFPs can take many forms. In the U.S. they are often overseen by state regulators and/or regional planning authorities. Where they are used, generation uncertainties are reduced for state and local planners, transmission network planners, and resource investors.

6. Key methods for reducing uncertainties

This section addresses general solutions which can be applied to mitigate nearly any kind of uncertainty. Therefore, these solutions are not covered in detail in any of the earlier sections, although they can be applied to the previously described uncertainties.

Two generic key methods are addressed:

(1) Collaborative processes for planning

(2) Multi-scenario and Probabilistic methods

6.1 Collaborative processes for planning

As described in the previous sections, many uncertainties are the consequences of the increased number of participants in the power systems and the lack of information available for the electrical utilities involved in transmission planning process. We can recall some of the causes:

- the development of electricity markets,
- the increase of power exchanges on interconnections between systems, and
- the disintegration of formerly vertically integrated utilities into independent transmission and generation companies.

Taking into account only the point of view of a company in charge of the transmission planning process, the ideal (and very theoretical) situation is to have information about and control of all the events that can influence its investments. One solution to this problem is to use a collaborative process for transmission planning.

The objective is to associate different companies involved in the system in order to increase the available information level and to take decisions maximizing the fulfillment of the needs and reducing the costs. With such a process the responsibilities are shared between the different participants.

6.1.1 Case Example: Central West Europe collaboration

On June 6th 2007, the Ministers of the Pentalateral Forum and the High representatives of the Regulatory Authorities, Transmission System Operators (TSOs), Power Exchanges (PXs) and the Market Parties Platform of the Central Western Europe (CWE) region (that is France, Belgium, Germany, Luxembourg and the Netherlands) signed a Memorandum of Understanding that reaffirms the need to improve the collaboration between the five countries.

One of the purposes of the collaboration is to assess the security of supply in CWE, i.e. elaborate an improved regional system adequacy forecast (SAF) for 2008-2015. One very interesting point about this

SAF is that it will take into account network extension planning, generation planning and forecast of load based on commonly defined scenarios. Therefore, this collaborative study will give access to information to all the parties including the different TSOs.

Results of the study should be known by June 2008. Let's notice that every European Country already has to make a National SAF Study every two years. But that kind of study makes of course assumptions about the way other countries will evolve in the future and how exchanges and market conditions can be. It also makes assumptions about the future new interconnections.

The fact that these assumptions are not validated by the other countries is not satisfying in some cases.

Required Data for the CWE SAF Study:

Basically, we intend to represent load, generation and interconnections. We don't take into account internal networks. We'll need good precision on the data, for example for loads description:

- Annual domestic demand (TWh)
- Share of domestic demand sensitive to outdoor temperature (TWh)
- Estimated maximum peak-power under normal temperature(MW)
- Estimated minimum power under normal temperature (MW)

The following items are sets of 8760 hourly values:

- Power demand (MW)
- Outdoor average temperature in °C
- Outdoor temperature above which there is no electric heating (a)
- Outdoor temperature under which there is no air-conditioning (b)
- Power gradient in MW / °C for temperatures below (a)
- Power gradient in MW / °C for temperatures above (b)

The same kind of precision will be asked for thermal generation, hydro generation, wind generation, demand side management, operational reserves, net transfer capacities…

Expected Benefits of the Study

We think that the adequacy computed in this study will be more accurate than the aggregated adequacy indices computed separately by each country. Scenarios are more realistic and give a better idea on how countries can help each other when there is a lack of power in one of them during the year.

Possible Extension of the Study

In order to compute the adequacy, we have to do some kind of market simulation to obtain the generation pattern. As a consequence, we should be able to see how interconnection limitations prevent this market from being "perfect," and we should get technical and economical indices:

- How many MW of transfer capacity do I need to get a single market?
- Knowing the different market prices, what should I gain with an interconnection reinforcement?

As a conclusion, we expect this pentalateral study to give a good idea of adequacy on a five-country basis, and probably, an idea on the best (technically and economically speaking) interconnection projects. The point we'd like to highlight with this example is not the realization of the SAF study for itself but the rising importance of collaboration between European TSOs at least in terms of information sharing.

6.1.2 Case example: Collaborative Planning in the U.S.A.

On February 16, 2007, the Federal Energy Regulatory Commission (FERC) issued Order No. 890 [12], requiring that "…transmission providers implement a coordinated, transparent and participatory transmission planning process as a means to alleviate perceived opportunities for undue discrimination." FERC considers these rules to be an amendment to its prior regulations and pro form open access transmission tariff (OATT) adopted in earlier Order Nos. 888 and 889 [13]. According to FERC, these orders "…encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. However, the prior orders…"did not, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region."

Where ISOs and RTOs exist, they are required to participate in these processes, as well, but FERC explicitly stipulates that "…transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process." This point was clearly stated by FERC because it felt RTO planning processes tended to emphasize regional, rather than local, problems and solutions. Further, FERC noted that some commenters in the rulemaking process felt that RTOs and ISOs did not carefully scrutinize individual transmission owner's plans before including them in the regional plan.

The new collaborative transmission planning process mandated by FERC in Order No. 890 will reduce uncertainty in several ways. Specifically, if active participation actually materializes, the process should lead to:

- A larger constituency supporting the plan and its rationale
- Broader understanding of the need, costs and benefits of transmission alternatives
- Advance knowledge of potential timing and occurrence of new generators
- Clear accessible documentation on the associated assumptions and criteria

Finally, FERC's order encourages direct participation by state regulatory staff members. Hopefully, this participation will facilitate subsequent certification processes for any required new facilities.

Figure 29 shows the "strawman" transmission planning process developed by the California ISO (CAISO) and its Participating Transmission Owners (PTOs) in response to FERC's new planning requirements [14]. It envisions a repeating annual cycle with three to four stakeholder meetings, leading to a Final Transmission Plan. As illustrated, the CAISO and the PTOs "initiate and organize" the meetings with continuing comments and input from interested stakeholders.

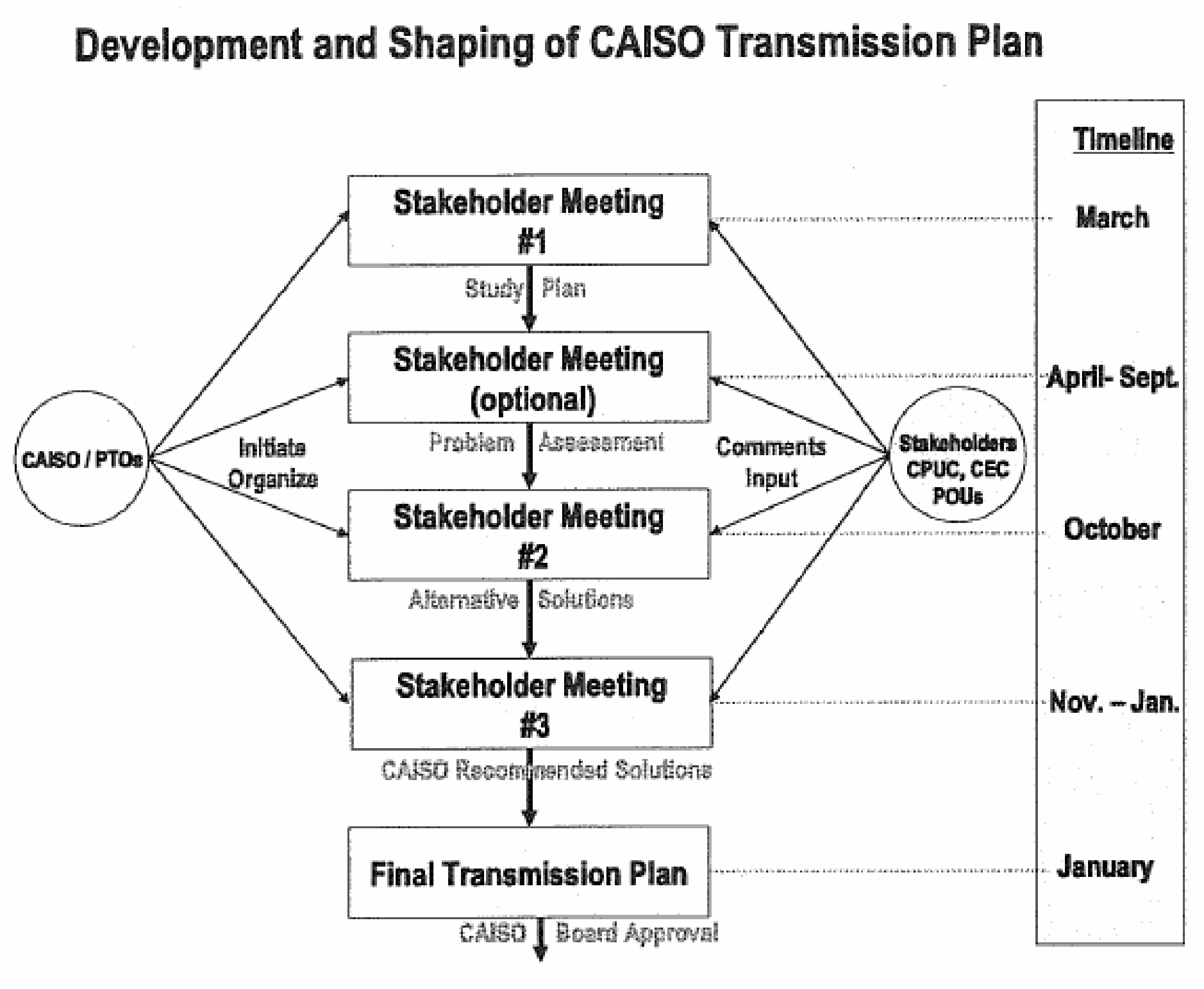


Figure 29 - Overview of CAISO's Transmission Plan Development

6.2 Multi-scenario and Probabilistic methods

A generic solution allowing the mitigation of uncertainties consists of using methods that take into account a huge number of future possible scenarios. The objective is to find, for each scenario, the efficiency of the proposed investments and the probability of occurrence of the scenario. In theory, investment risk can be minimized if all the possible scenarios are analyzed. In practice, electric utilities involved in transmission planning process study as many probable scenarios as possible before taking their investment decisions.

Multi-scenario and probabilistic methods range from simple studies that take into account a limited number of scenarios to more complex studies, including Monte Carlo methods, with more or less sophisticated automatic generation of scenarios. Some typically modeled uncertainties include:

- variations of individual generation unit production (modeling of markets, unavailabilities...),
- variations of load level,
- variations of flows on interconnections,
- variations of the network state (unavailability of devices for maintenance, substation configuration...).

6.2.1 Case example: French 400 kV grid development studies

With the growth of uncertainties (on prices, on localization of production…), the assessment of power system security is an increasingly complex problem. Moreover, in the context of more market oriented industries, system security limits are seen as constraints preventing the market from being operated according only to economic rules. Therefore, it is now necessary to analyze a sufficiently large number of scenarios in order to take into account the uncertainties, assess security levels with sufficient confidence and devise robust and understandable results.

In the context of system planning (i.e. investment and reinforcement planning), alternative system configurations must be screened for a wide range of generation and load patterns and a large number of contingencies in order that investments can be well-targeted and risks quantified. The necessity for investment in network reinforcement and the real value obtained from it can be determined

RTE has carried out probabilistic studies for the development of the French 400 kV grid (Figure 30) since the 1970s. The method has been improved in the recent years thanks to an initial work with the Université de Liège followed by a collaboration with NGT.

Figure 30 - French 400 kV network

The method is divided into three steps (See Figure 31):

Step 1. Creation of thousands of situations modeling the future states of the network

Using random sampling laws, the objective is to get, on one side, the rare but dangerous situations that can appear, and on the other side, to get a vision of the more probable situations. Hence the constraints of the network and the efficiency of the various possible modifications of the network structure can be appreciated from these two points of views. This implies the generation and analysis of several thousand situations.

For the French 400 kV network studies, the following uncertainties are modeled:

- The production pattern in France (production of thermal units, hydraulic units, wind turbines…playing on availabilities of these units, costs with representation of market rules, weather conditions),
- The load level in France,
- production patterns and loads in other UCTE countries directly influencing interconnection flows.

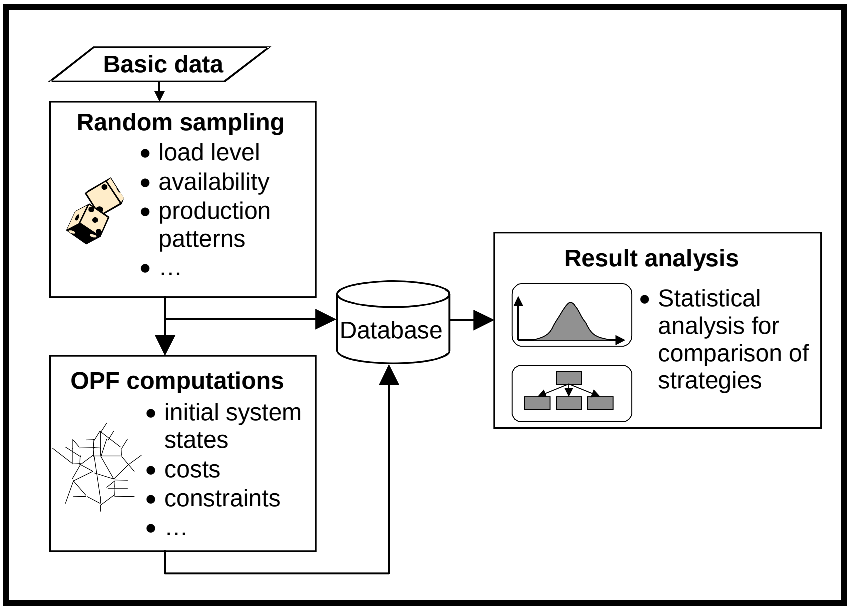


Figure 31 - Methodology overview

Step 2. Simulation of each situation

For each sampled situation, we carry out a static simulation using an Optimal Power Flow in order to obtain, if any, the constraints appearing in the situation and their associated costs for the system (in terms of re-dispatching and interruption costs).

Step 3. Results analysis

The final analysis consists of comparing the different strategies of 400 kV grid reinforcement/development (including a strategy that includes doing nothing) in terms of costs for the project compared to the estimation of avoided costs for the system. All these costs are estimated for the entire set of situations and this permits the ranking of the proposed investments.

In complement, useful results on the behavior and constraints of the system are extracted using classical statistical and data-mining functions. Figure 32 illustrates the comparison between two reinforcement strategies in terms of possibilities for exchanges.

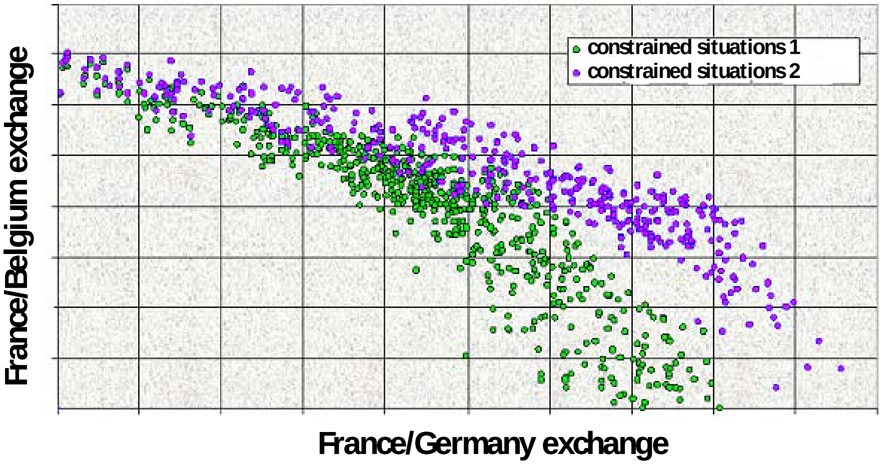


Figure 32 - Comparison of two reinforcement strategies

Faced with exploitation conditions that are increasingly variable, uncertain and sometimes surprising, even in the short-term, RTE is trying to improve its techniques, methods, processes in order to strengthen the system and then to operate the network with safety. In that scope, statistical/probabilistic methods are relevant in order to mitigate uncertainties by providing a way to evaluate investment decisions on the basis of a more exhaustive evaluation of potential situations.

These decisions are based on a process that includes risk analysis and a weighting of the costs and associated risks. This process can evolve with changes in the economical, technical or political environments of the network operator. Multi-scenario analyses are effective in strengthening the robustness of the investment process and in producing more understandable results for both stakeholders and regulatory authorities.

7. Conclusions

The global energy industry is constantly changing and evolving. Some of these changes are a result of industry reforms, while others are a response to wider societal changes, such as economic development or increasing trends towards the development of renewable energy sources. These changes in the energy industry all over the world are leading to completely new uncertainties for the planning of transmission systems. CIGRE has tried to stay abreast of these changing demands on the energy industry and has initiated several working groups in recent years to review their impacts. Each of the working groups builds on the results of earlier working groups while carrying out detailed analyses on additional aspects.

Working Group C1-7 was established to assess the methods that are now being used to develop system plans that balance reliability, economy and risk caused by uncertainties in load, generation and markets.

Based on questionnaire responses received from a large number of transmission companies with very different energy sector structures and on the individual experience of the working group members, the group concludes the following:

Load growth is not the dominant uncertainty

Considering uncertainties of markets, generation and loads it is apparent that transmission system operators tend to be more concerned about market and generation uncertainties than they are about load uncertainties.

There are different reasons for that. First, the results of our survey show that relatively few countries are experiencing high rates of load growth.

Second, transmission system operators have gained a lot of experience with forecasting load and managing the uncertainties it causes. The questionnaire responses clearly proved that there are highly sophisticated methods being used, and forecast horizons tend to be much longer than for market and generation uncertainties. These latter ones are relatively new and therefore new approaches are still under development.

In countries with no anticipated load growth or even a projected decrease of peak load, system planning uncertainties are not associated only with the extension of the existing system but also with the development of optimized replacement and refurbishment strategies. In such cases, system development planning therefore is closely linked to asset management tasks.

Market changes have created new uncertainties

Market uncertainties tend to have an ambiguous character. This is because the establishment of larger interconnected systems tends to increase the security of supply and, due to their higher flexibility and stability, makes it easier for the transmission system planners to cope with the development of uncertain boundary conditions. Nevertheless, as market behavior is not controllable and predictable, the establishment of larger markets also produces new uncertainties e.g. in terms of fluctuations in load flows or external flows caused by exchanges between surrounding countries.

Development and evolution of market rules, grid codes and operational rules by or under the participation of transmission system operators is widely used to reduce these uncertainties but will definitely not eliminate them.

The sizing and location of new generators cause major uncertainties

The break-up of formerly vertically-integrated utilities, together with the green movement and the political support for generators based on renewable energies, together with the concerns about global warming and the resulting move away from conventional fossil fuel fired power plants, all cause major uncertainties especially in the locations and sizes of new generators that are being connected to the network. However, the technical characteristics of newer generation technologies like wind energy converters and their difficult-to-predict generation patterns, have caused completely new types of uncertainties that cannot be handled by TSOs on their own.

New planning methods are required

TSOs are faced with the objectives of offering requested transmission capabilities, fulfilling their responsibilities for security of supply, and at the same time, limiting the risk of not getting sufficient revenues to refinance investments in transmission system extension. In doing so, system planners have developed new methods that on the one hand consider new analytical and technical possibilities and on the other hand respect the more difficult structures in a sector in which the number of stakeholders have dramatically increased over the last two decades.

Multi-scenario analysis

Multi-scenario analysis has gained significant importance in system planning studies, as the results of our survey clearly show. One cause for that surely is the sufficiently high computational power that is available today to cover all relevant scenarios. Another cause is the fact that multi-scenario analyses, because of their transparent and general approach, work well in convincing different groups of stakeholders of the needs for system development measures.

Probabilistic methods

Another aspect is that rising uncertainties have lead to a situation where the worst-case analyses traditionally used by many transmission system operators no longer lead to either satisfying results or realistic system development plans. In such cases, the use of probabilistic methods, has become an alternative. Today's applications are limited, due to problems in describing the stochastic characteristics of input data for network analyses, as well as a lack of experience in interpretation of probabilistic results. However, as pilot applications show, a lot of development work in this field is underway, and probabilistic methods may become an important tool for evaluating system development plans within a few years.

Collaborative approaches

Finally, responses to our questionnaire and the experience of the working group members have shown that collaborative approaches are becoming more popular in managing these uncertainties that cannot be handled by a transmission system operator on its own. These collaborative approaches reduce uncertainties by 1) sharing information between neighboring systems and 2) facilitating the participation of various stakeholders in the planning process so as to share different views and come to mutually acceptable solutions. As a result, they can reduce risks for the transmission system operators, for example if regulatory agencies approve investment plans and guarantee cost recovery, investment uncertainty is greatly reduced. Such approaches will, as a consequence, make it more probable that sufficient transmission capacities are available when needed.

8. Bibliography

[1] Long Island Power Authority, News Release, “New Neptune Cable Delivers 660 Megawatts to LIPA System, Opens Electric Transmission Corridor from Mid-Atlantic to New England,” New Cassel, NY – June 28, 2007.

[2] Maurer, Ch et al.; “Planning of High Voltage Networks under Special Consideration of Uncertainties of Load and Generation,” Cigre 2006, Contribution C1-204.

[3] CIGRE WG C1.3, “Electric Power System Planning with the Uncertainty of Wind Generation,” (CIGRE Technical Brochure No. 293, April 2006).

[4] Burnett, R.O., Jr.; Butts, M.M.; Sterlina, P.S.; “Power system applications for phasor measurement units,” *Computer Applications in Power, IEEE,* Volume 7, Issue 1, Jan 1994.

[5] U.S. Department of Energy, “DOE Update – NASPI Working Group,” presentation by Phil Overholt at NASPI Meeting, New Orleans, Louisiana, March 6, 2008.

[6] German Wind Energy Association (bwe), A clean issue - Wind Energy in Germany, Brochure, 2006.

[7] dena[5], dena-Grid Study I, 2005, available as an English short summary at http://www.dena.de/en/topics/thema-kraftwerke/projects/projekt/grid-study-i/ (03.09.07), complete German version at http://www.dena.de/de/themen/thema-kraftwerke/projekte/projekt/netzstudie-i/ (03.09.07)

[8] VDN directive: EEG Erzeugungsanlagen am Hoch-und Höchstspannungsnetz (Renewable Energy Based Generating Devices connected to HV and EHV grids), 2004, http://www.vdn-berlin.de/global/downloads/Publikationen/Fachberichte/RL_EEG_HH_2004-08.pdf (03.09.07)

[9] VDN[6], TransmissionCode 2007: Netz-und Systemregeln der deutschen Übertragungsnetzbetreiber (Grid and system rules of German transmission system operators), 2007, http://www.vdn-berlin.de/global/downloads/publikationen/TransmissionCode2007.pdf (03.09.07)

[10] Tri-State Generation and Transmission Association, Inc., News Release, “Tri-State seeks proposals for new resources,“ Westminster, Colorado, July 2007.

[11] The City of Seattle, Seattle City Light Department, “Request for Proposal (RFP) for Renewable Resources,” Seattle, Washington, July 10, 2000.

[12] Federal Energy Regulatory Commission, “Order No. 890: Final Rule: Preventing Undue Discrimination and Preference in Transmission Service,” Washington, D.C. 20426, February 16, 2007.

[13] Federal Energy Regulatory Commission, “Order No. 888, “Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,” and Order No. 889, “ Open-Access Same Time Information System and Standards of Conduct,” issued April 24, 1996.

[14] California Independent System Operator, “FERC Order 890: Strawman Proposal – In Compliance with the Nine Planning Principles of the Final Rule,” Folsom, California, May 29, 2007.

---

[5] Abbreviation for Deutsche Energie-Agentur (German Energy Agency)

[6] Abbreviation for Verband der Netzbetreiber (Association of German Network Operators)

Appendix A – Terms of Reference of CIGRE WG C1 -7

CIGRE Study Committee N° C1

TERMS OF REFERENCE FOR A NEW WORKING GROUP

WG C1.7	**Name of Convenor:** Richard Wakefield (USA)

Title of the Group: Managing the complexity and uncertainties of load, generation and markets in system development planning.

Background:

Three prior working groups have addressed the methods for planning power systems in light of the increased uncertainty caused by market restructuring. Specifically, WG 37-30 addressed the problems of planning with uncertainty in the sizing and location of generation. Subsequently, WG C1-2 addressed methods for maintaining acceptable reliability; WG C1-5 addressed how uncertainty is accounted for in the economic analysis of transmission/distribution/generation plans and C1-3 is the major recent WG in this area.

The issues raised by these earlier working groups, and the results they have achieved, demonstrate the difficult challenges faced by modern system planners. In spite of these challenges, however, plans are being developed that recognize such uncertainties. This working group will assess the methods now being used to develop system plans that balance reliability, economy and risk. In doing so, the group will also attempt to determine whether the results of earlier working groups are being fully utilized.

Scope:

In Part 1, the group will address the following tasks:

1. How to estimate uncertain parameters based on the best available information and methods.
2. What factors to consider in defining the network planning boundaries.
3. How to define acceptable plans that meet reliability requirements specified in WG C1-2
4. How to utilize the results of WG C1-5 in evaluating the economics of proposed plans.
5. How to manage the complexity of these uncertainties in specifying plans that are most economic while maintaining reliability.

In Part 2, the group will address the following tasks:

1. How to describe these uncertainties for system planning purposes.
2. How to define investment risk and incorporate such risk when making investment decisions.

Deliverables:

1. Ongoing progress to be reported on the C1 Website.
2. Report to be published in Electra or technical brochure with summary in Electra.

Target Groups: Power Transmission System Managers, Planners, Operators and Owners

Time Schedule:

Part 1:

Start	November 2004
Progress Report	Athens 2005
Draft Report	Paris 2006
Final Report	July 2007
Tutorial material	July 2007

Part 2: Timetable to be prepared at conclusion of Part 1.

Comments from Chairmen of SCs concerned:

Approval by Technical Committee Chairman: **Aldo Bolza** **Date**: **November 18, 2004**

Appendix B – Survey Questionnaire

Managing the Complexity and Uncertainties of Load, Generation and Markets in System Development Planning.

This questionnaire has been prepared by the CIGRE Working Group C1.7 and it is addressed to electrical utilities involved in transmission planning process. The purpose of the questionnaire is to identify and address new and recent changes of previously identified planning uncertainties.

The issues raised by earlier working groups, and the results they have achieved, demonstrate the difficult challenges faced by modern system planners. In spite of the challenges, however, plans are being developed that recognize such uncertainties. This working group will assess the methods now being used to develop system plans that balance reliability, economy and risk. In doing so, the group will also attempt to determine whether the results of earlier CIGRE working groups are being fully utilized.

This work has been requested by CIGRE Study Committee C1 and it has been sanctioned by the Technical Committee. Our assignment requires the Working Group to consider the effects of economic regulation on transmission system planning arising from the need to ensure adequate investment in the transmission network while taking into account the expectations and regulations set by Governments and Regulators.

The final results of the Working Group will form the basis of a report designed to assist utilities in improving their transmission planning activities.

Please attempt to answer all questions and return the completed questionnaire to the authors by **August 18, 2006.** If you are unable to answer any of the questions, please leave it blank.

All information supplied by respondents will be treated with professionalism and discretion. Upon completion of the study all respondents will be sent a summary report of the results. Any report that is published will contain the names of the utilities and/or countries that responded but will not disclose any information that you designate as proprietary or confidential.

If you have any questions or concerns, please address them to the working group member who forwarded this questionnaire to you.

We thank you for your cooperation.

Sincerely,

Richard A. Wakefield
Convener, CIGRE WG C1.7

Sender's Information

Country:
Or if applicable Region or State ____________________

Is your organization the system operator for the entire country ____________________

Name of your organization: ____________________

Role of your organization in transmission planning process: ____________________

Web address of your organization: ____________________

Name of sender: ____________________

Your position/ function within the organization: ____________________

Email address: ____________________

Respondent's Information

This is the person who has filled in the questionnaire so that we can contact the individual in the event that clarification is needed.

Name of Respondent: ____________________

Your position/ function within the organization: ____________________

Email address: ____________________

The questionnaire to be returned to:	*Working Group Memeber*
Email:	*Workinggroupmember@address.com*

GENERAL INFORMATION

1. Is your company the system operator for the entire country?
   ☐ Yes ☐ No

   If No, which part of your country do you cover?
   ____

This questionnaire is divided into the following general areas:

Section A: Uncertainties associated with Load

Section B: Uncertainties associated with Generation

Section C: Uncertainties associated with Markets

Each of the three sections is split into 6 minor sections:

1. The questionnaire seeks to identify the general areas of uncertainty.
2. What are the causes behind these uncertainties?
3. What are the potential impacts of these uncertainties?
4. How are uncertainties managed, what responses are used to cope with their impacts?
5. What is the role of forecasts in assessing the uncertainties?
6. What methods are used to develop those forecasts?

SECTION A: LOAD

A.1 Uncertainties & their severity.

Electricity utilities continually identify uncertainties in the planning of transmission networks. This question relates to the review of these previously identified uncertainties, and the identification of modern day uncertainties facing electricity utilities.

A.1.1 What is your expectation regarding the future annual rate of change in demand?

Short/Mid-term (less than 10 yrs):	**Long-term (more than 10 yrs):**
☐ Low growth (≤ 2%)	☐ Low growth (≤ 2%)
☐ Medium growth (2-5%)	☐ Medium growth (2-5%)
☐ High growth (≥ 5%)	☐ High growth (≥ 5%)
☐ Saturation (0%)	☐ Saturation (0%)

A.2 Causes

This section investigates the causes of the revised and newly identified uncertainties identified in A.1.

What do you account as the main causes for these uncertainties? Check each cause you believe is relevant. Then, assign a contributing weight factor (CWF) to each of the causes you deem relevant. High = H, Medium = M, and Low = L.

		CWF
☐	Demand for commodities (raw materials)	☐
☐	Macro economic (growth or recession)	☐
☐	Energy conservation	☐
☐	Social development (e.g. rural electrification)	☐
☐	Technology	☐
☐	Economic indicators (please specify)____	☐
☐	Other Demand side measures	☐
☐	Other	☐

A.4 Responses to impact

This section relates to the modifications envisaged to be carried out on the transmission network following the previously identified uncertainties.

A.4.2 Which of the following would be your utility's response(s) to the impact of uncertainties? Please check each response that is relevant. Then, assign a contributing weight factor (CWF) to each of the responses you deem appropriate. High = H, Medium = M, and Low = L.

	CWF
☐ Expansion of the existing network	☐
☐ Reinforcement (refurbishment)	☐
☐ Network life extension	☐
☐ Load curtailment	☐
☐ Revision of security standards	☐
☐ Asset monitoring and control	☐
☐ Asset removal (if load decreases)	☐
☐ Other____	☐

A.5 Forecasts

This section investigates forecasting parameters used in assessing future network loads.

A.5.1 What load forecasting methods are used?

☐ Macro economic indicators (growth or recession)
☐ Assessments for each customer class
☐ Peak load extrapolation
☐ Load tests
☐ Historical load forecasts
☐ Other____

SECTION B: GENERATION

B.1 Please evaluate the level of uncertainties with regard to system development planning.

A. Location and timing of new generators (All sizes, including thermal and hydro)

1) Influence:

☐ weak
☐ medium
☐ strong

B. Renewable Energy Sources (Wind, small hydro, solar)

1) Influence:

☐ weak
☐ medium
☐ strong

C. Distributed Generation (Conventional technologies)

1) Influence:

☐ weak
☐ medium
☐ strong

D. Generation technologies of future plants

1) Influence:

☐ weak
☐ medium
☐ strong

E. Retirement of existing plants

1) Influence:

☐ weak
☐ medium
☐ strong

B.2 For all uncertainties in Section B.1 that you marked as increasing or completely new, please give your impression as to what has caused these developments?

Check all that apply:	Enter relevant letters (A, B…F):
☐ Changes of generation technology	______________
☐ Green concerns/Green movement	______________
☐ Increase of fuel prices	______________
☐ Government policies	______________
☐ Restructuring of energy sector	______________
☐ Prices of alternative primary energies	______________
☐ Mergers and acquisitions in energy sector	______________

☐ Others (please specify) ____

B.5 Forecasting of Uncertainties (distinguish your answers between uncertainties, if necessary)

a. Which type of forecasts are used?

Check all that apply:	Enter relevant letters (A, B…F):
☐ Typical values	______________
☐ Extreme values	______________
☐ Different scenarios without probabilities of occurrence	______________
☐ Different scenarios with probabilities of occurrence	______________
☐ Scenario trees	______________

SECTION C: MARKETS

C.1 Uncertainties & their severity.

The aim of this section is to identify where wider market uncertainties, not addressed by load or generation, introduce uncertainty in the planning and timing of investments on the transmission system.

C.1.2 Which of the following introduce major uncertainties into your planning?

☐ Fuel Prices
☐ Industry structure
☐ Regulatory environment
☐ Cross border flows
☐ Attractiveness of market to investors
☐ Subsidies/Incentives to generators
☐ Quotas on generation by fuel type
☐ Market Structure
☐ Inflation rates
☐ Congestion Management methods
☐ Plant margins
☐ Any other

C.2 Causes

This section aims to clarify the causes of the uncertainties identified in C.1.2. What is it that specifically causes these uncertainties? For the major sources of uncertainty that you have identified please rank the following in the order of their importance (i.e. 1,2,3,...).

☐ Introduction of new laws

☐ The demand for commodities

☐ Increasing fuel prices

☐ Enlargement of interconnected systems

☐ Market restructuring, e.g. energy trading rules

☐ Any other

C.3 Impacts

The section relates to the technical impacts (consequences) that these uncertainties will have on the transmission system. Please check all impacts that apply:

☐ Sub-optimal delivery of capital investments

☐ Difficulty gaining appropriate agreement for investment

☐ Inadequate transmission capacity installed.

☐ Restricted maintenance outage opportunities.

☐ Decreased plant margin

☐ Reduction of system security

☐ Any other

C.5 Forecasts

This section investigates forecasting parameters used to evaluate the causes of market-related uncertainties (listed in C.2). Please check or specify those that you use.

☐ Macro economic indicators (growth or recession)

☐ Consumer price indices

☐ Fuel price indices

☐ Currency exchange rates

☐ Commodity prices

☐ Other (please specify)____