International Review of Transmission Reliability Standards

Summary Report
prepared for the

Australian Energy Market Commission Reliability Panel

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Executive summary

The work described in this report is in response to a ministerial directive to developing a consistent national framework for network security and reliability. It is part of a review of jurisdictional transmission reliability standards. In response to these actions the AEMC on behalf of the Reliability Panel engaged KEMA, Inc. to provide a report on transmission planning reliability standards or criteria used in different electricity markets around the world.[1]

The purpose of transmission planning is to identify a flexible, robust, and implementable transmission system that reliably facilitates commerce and serves all loads in a cost-effective manner. Meeting this planning goal requires both technical (electrical engineering) analysis of different transmission-system configurations and economic analysis of different transmission projects. Planning standards set the balance between reliability and cost. In general, higher reliability standards will result in additional investment in transmission facilities and higher investment costs.

This report compares the frameworks for establishing consistent transmission planning standards across multiple transmission network owners. A selection of six international power systems has been chosen, all of which support wholesale electricity markets. The six power systems are: Germany, Great Britain (GB), Nordel (Norway, Sweden, Finland, and Denmark), Alberta, PJM, and California. In North America, the North American Electric Reliability Corporation (NERC) plays a critical role in setting minimum national standards, which are the basis of standards set by regional reliability councils, such as the Western Electricity Council (WECC). The relationship between the NERC standards and regional standards is also explored.

Key findings for the markets studied include:

- All the international power systems studied use a deterministic form of standard together with a deterministic planning methodology.

- The level of standards:
  - Is generally n-1 (or higher);
  - The overall minimum standards do not diverge across connection points (or groups of connection points) in the power system though regions and individual systems are allowed to have more stringent criteria;
  - Is set by a body independent from the transmission owners (TOs) in the North American markets, GB, and Germany. In Nordel and Germany the TOs play a role in setting transmission standards.

1. In this report 'criteria' and 'standards' are used interchangeably. Both define the tests performed and acceptable performance of the transmission system in evaluating and developing the transmission system.

- The degree of decentralized planning differs:
  - A national transmission plan exists only in the Great Britain market;
  - A regional transmission plan exists in the three North American markets; and
  - In Germany and Nordel, there is no national transmission plan.
  - TOs are obligated to comply with regional/national plans where they exist.
- The distinction between the transmission and sub-transmission network does not exist in the systems sampled so there is no difference in the standards and arrangements for joint-planning and operation of transmission and sub-transmission networks.
- These selected markets, while different from the Australian National Energy market (NEM) in some ways, are similar to the NEM in many ways such as:
  - They are economically developed nations that depend on affordable and reliable electric supply;
  - They have developed high-voltage transmission networks;
  - They serve types of customers that range from central business districts to rural farming areas;
  - They have multiple TOs providing service within a single market structure; and
  - They have separated the generation and transmission functions and ownership, and have a variety of independent power providers.
- The frameworks used in other countries for setting consistent standards nationally (or regionally in the case of the North America, where "regionally" spans several state jurisdictions) show, to varying degrees, what we consider to be the principles for a successful framework. In our experience these principles should be:
  - **Transparent**—the transmission reliability standards and process should be published and consistently applied by TOs in evaluating the transmission system and evaluating expansion plans;
  - **Consistent**—the evaluations developed using the transmission reliability standards should produce consistent results such that independent parties can reproduce the results obtained by the TOs or other parties;
  - **Independent**—the transmission reliability standards should be set by a body that is independent of the TOs;
  - **Economic**—the transmission reliability standards must strike a reasonable balance between transmission system cost and customer reliability;
  - **Specific**—the transmission reliability standards should be clearly specified on a readily-understandable basis;
    - Identify the starting condition for the transmission studies
    - Define the test that will be performed on the system; and

- State what constitutes acceptable system performance

- **Amendable**—the specific requirements and many of the processes should be able to be amended without requiring legislative approval either through approval by the various regulatory bodies involved or an open stakeholder process;
- **Open**—the process should be open to stakeholders to the extent possible by making committee meetings open, publishing data and results on the internet, and by generally involving stakeholders in the process;
- **Flexible (upward)**—the transmission reliability standards should allow for reliability standards to be more stringent or add detailed specifics where appropriate—e.g. for central business districts (CBD), or according to explicit customer needs at their connection point; and
- **Accountable**—the consequences of not following the transmission reliability standards must be clearly defined along with the processes for enforcing the standards and reviewing or appealing any enforcement action.

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1. Background

The AEMC Reliability Panel (the Panel) engaged KEMA, Inc. to provide a report on:[2]

- The transmission reliability standards (relating to the planning horizon) used in different electricity markets around the world; and
- The frameworks used in foreign electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple jurisdictions and/or separately owned transmission networks.

The Panel developed ten questions to use in making the necessary comparison. The ten questions were:

1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?
2. What instruments are used in those frameworks to give effect to such consistency:
   a. Grid Codes?
   b. Transmission licenses?
   c. Market Rules?
   d. Legislation?
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?
   a. What form (deterministic, probabilistic, or variants) of standards are used?
   b. What levels of standards (e.g. n-0, n-1, n-2) are applied?
   c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. metropolitan, urban, and rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?
   d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?
   e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?
4. What institutional/governance models are used to support such frameworks?

2. The Reliability Panel is a specialist body within the AEMC and comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on the safety, security and reliability of the national electricity system and advising the AEMC in respect of such matters.

a. Regulatory institutions

b. National planner or Regional Transmission Organization (RTO) planner

c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?

d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.

e. Accountabilities

5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?

6. Governance issues with framework:

    a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?

    b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.

7. To what degree does the framework specify the actual level of standards:

    a. By connection point?

    b. By voltage level?

8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?

9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?

10. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.

This report is to assist the Panel in developing a framework for nationally consistent transmission reliability standards for the NEM. The Panel has been asked by the AEMC to provide advice of on such a framework, which will inform AEMC in formulating advice to the Ministerial Council on Energy (MCE).

2. KEMA's approach

In consultation with the Reliability Panel,, KEMA selected six electric systems to use in the required comparison. KEMA based its comparison on published documents and prior experience in working with the selected systems.

The systems considered suitable for comparison must have been in market environments where there were multiple transmission owners (TOs). In North America we found that there were many TOs but only a few market environments. In contrast, each nation in Europe is part of a market but few had multiple TOs. In addition, only utilities from advanced industrial countries in Europe and North America were considered.

These six selected systems were:

In North America

1. The California Independent System Operator (CAISO)—which includes the three large investor-owned utilities in California.
2. The PJM Interconnection—is a regional organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM operates the world's largest competitive wholesale electricity market and ensures the reliability of the largest centrally dispatched grid in the world.
3. The Alberta Electric System Operator (AESO)—is responsible for the safe, reliable and economic planning and operation of the Alberta (Canada) Interconnected Electric System. They provide open and non-discriminatory access to Alberta's interconnected power grid for generation and distribution companies and large industrial consumers of electricity. In doing so, the AESO contracts with transmission facility owners to acquire transmission services and, with other parties to provide fair and timely access to the system. They also develop and administer transmission tariffs, procure ancillary services to ensure system reliability and manage settlement of the hourly wholesale market and transmission system services.

In Europe,

4. Great Britain—includes the transmission facilities of the National Grid owner of the transmission in England and Wales, Scottish Hydro Electric owner of the northern Scotland network, and Scottish Power transmission owner of the southern Scotland network.
5. Germany—Four companies operate Germany's national transmission grid, as there is no unified operator for the entire country: RWE/VEW; E.ON, Energie Baden-Wuerttemburg (EnBW), and Sweden-based Vattenfall. Germany enacted a new energy law in July 2005 that vested regulatory oversight of the industry with the newly created Bundesnetzagentur (BNA).
6. The Nordel Market countries—Norway, Sweden, Finland, and Denmark have co-operated for many years to provide their collective populations of about 24 million with an efficient and reliable supply of electric power, and optimal use of total system resources.

In addition information was also developed for

7. The North American Electric Reliability Organization (NERC)—its mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. NERC is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.
8. The Western Electricity Coordinating Council (WECC)—-is responsible for coordinating and promoting electric system reliability and for promoting a reliable electric power system in the Western Interconnection of North America. The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the eight regional councils of NERC. The WECC territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western U.S. states in between.

These systems present a variety of governance/political environments—Single and multiple political jurisdiction; and while all have multiple Transcos they may have a single or multiple control areas managed by a single or multiple system operators. There are also multiple transmission regulatory environments. A comparison of political and regulatory environment of the selected systems is shown in Table 1.

Table 1: Political and regulatory environments of the selected systems

System	Political jurisdictions	Transcos	Control areas	Transmission regulatory regime		
					Incentive-based	
				Regulated rate of return	CPI-X price cap	Revenue cap
CAISO	1	10	1	√		
PJM	14	16	1	√		
AESO	1	3	1	√		
GB	1	3	1		√	
Germany	1	4	4		√	
Nordel	5	6	6	Sweden, Iceland		Norway, Finland, & Denmark

3. Summary of responses to specific questions

The sample systems include a fairly wide range of experience and practice. From Alberta with strong central control for all utilities in a single province; to Great Britain and PJM with strong control over multiple countries/states; to Germany, the Nordic countries, and NERC that have varying levels standards and control over integrated plans. The sample includes utility systems with liberalized markets with unbundled generation and transmission, and with vertically-integrated utilities.

A summary of the individual responses of the systems is provided in Appendix A at the end of this document. More detailed summaries are also provided for each of the eight systems in a separate volume 2 to this report. Volume 2 also includes supplemental information that provides selected additional detail about the systems.

This chapter and the summary tables are organized to correspond to the ten questions posed by the Panel. So, section 3.1 corresponds to question 1, *et cetera*.

3.1 Frameworks used to assure consistent standards

The frameworks for transmission planning standards include the underlying set of principles and their context. These principles are found in the enabling legislation or contracts that establish the relationships among the participating TOs, the system operator, and the other entities that are involved in setting, applying, and monitoring transmission reliability. The issue addressed here is what framework is used to assure consistent standards are applied across multiple TOs.

All the sample systems have standards that are applied based on legislative authority. The following sections add details concerning:

- The form of standards and the planning methodology used to implement those standards (See sections 3.2, 3.3);
- The institutional arrangements for setting, implementing, and enforcing the standards (See section 3.4);
- The process for setting the standards (See sections 3.5, 3.6.); and
- The scope of the standards (See sections 3.7, 3.8, 3.9).

Each framework is given effect through a range of legal, regulatory and other instruments.

3.2 Legal instruments used

There are a variety of legal instruments used around the world and in the six selected systems. The main legal instruments may include:

- **Grid codes**—established by the government set overall requirements affecting the operation and planning of the entire network, including grid access arrangements;

- **Transmission licenses**—granted by the government set requirements for TOs who own and/or operate the transmission system within a jurisdiction;
- **Connection (or interconnection) agreements**—established by the system operator set requirements and obligations of the TOs to the system operator and to comply with technical, market and whatever other rules may be applicable;

  The TOs, in turn, enter into connection agreements with network users to ensure conformance with planning, operating, security, and reliability requirements; and
- **Market rules**—established by the market operator with government or regulatory approval that guide the operation of the power market.

In North America, Great Britain, and Germany national legislation provides the basis for the standards. The Nordic countries have each individually passed compatible legislation to provide the authority for the standards.

In North America the standards generally arise out of the interconnection agreements that allow the TOs to participate in the market. This is true for PJM and CAISO. Federal legislation is the source for reliability standards that apply to all utilities in North America regardless as to whether they are in a market environment or operate as independent vertically-integrated utilities.

In most North American states (but not all) TOs have a legal franchise to exclusively build transmission facilities in their assigned area. This is given to them by their state legislatures. In return they must meet environmental and siting requirements. Very few states have any kind of reliability standards that they apply. Many utilities have established planning practices that have been informally accepted by their state regulatory agencies, but there is no official endorsement of the standards.

Connection agreements in North America—the agreements to connect new generators or major new load—also have no set standards that are approved by the state or federal governments. The TOs apply the NERC and local criteria so that such connections "cause no harm." Different markets have different rules regarding how much transmission improvements—deep or shallow—the generator may have to pay for, but the criteria used is only the standard NERC and local ones. The cause-no-harm aspect often adds special requirements for a generator interconnection—such as high-speed relaying, special protection schemes, or special communication requirements.

In Alberta, restructuring arose out of provincial legislation that reformed all the pre-existing utilities in Alberta. This legislation unbundled the utilities and set requirements for them to own and operate their facilities. In this regard it is more like a grid code that was established in provincial legislation. The legislation empowers the AESO to set the reliability standards.

In GB, Germany and the Nordel countries the reliability standards are established in national (or transnational) grid codes or the transmission system codes of each TO.

3.3 Standards applied

All the systems have a minimum set of standards that are applied universally. These standards allow individual ISO areas and utilities to set specific standards that exceed these minimums. While, in theory, there are two broad types of standards—deterministic and probabilistic—only deterministic criteria are used by the sample systems.

3.3.1 Deterministic and probabilistic standards

The purpose of transmission planning is to identify a flexible, robust, and operable transmission system that reliably facilitates commerce and serves all loads in a cost-effective manner. Meeting this planning goal requires both economic and technical (electrical engineering) analysis of alternative different transmission-system configurations and projects. Planning standards set the balance between reliability and cost. In general, higher reliability standards will result in additional investment in transmission facilities and higher investment costs.

Reliability criteria are somewhat subjective. Attempts to quantitatively base them on a balance between the utility's costs of providing reliability and the consumers' benefits of uninterrupted service have limited success. One particularly challenging problem has been determining the true cost of service interruptions, which depends on when they occur, how long individual interruptions last, who is interrupted, and a number of other considerations, some of them rather subjective. As a result, evaluating transmission system performance and expansion planning requires balancing economics, reliability, engineering, and policy.

Developing meaningful estimates of transmission system’s capability to serve load requires considerable engineering expertise, data, and analytic tools. This challenge arises because this capability is not merely the rating of a single line or of a few lines. Rather, the transmission system’s capability is a function of the strength of the integrated system as a whole, including not only the transmission facilities but the physical interaction with generating facilities as well.

The transmission system’s capability also varies over time, further complicating any assessment of the adequacy, limitations, or opportunities for expanding capabilities. It varies as switching operations occur and as demand, generation, and transmission flow patterns change. Fluctuating patterns of demand, changing availability of generators and transmission lines, and even weather, can all affect capability.

Reliability evaluations require an examination of the system’s responses to many likely (and some not so likely) contingencies. These contingencies act as proxies for the hundreds of other contingencies and unexpected events that also may occur on the system. Certain types of system conditions are studied in accordance with accepted national utility practice. Studying these conditions indicate the “health” and robustness of the system. A power system that fails one of these tests is considered “unhealthy” and steps must be taken so that the system will respond successfully under the tested conditions. System failure and equipment overloads, particularly under single contingencies, are serious problems that must be addressed by the system operators.

Furthermore, historical design practices and established planning traditions within individual utilities may affect the choice of reliability standards across a market, since implementing a market-wide change in planning criteria may have a significant effect on utility investment requirements and customer reliability over a period of years. This can be particularly true if a deterministic planning approach is replaced with a probabilistic one.

3.3.1.1 Deterministic planning standards

Deterministic transmission planning standards are often referred to in the familiar n-1, n-2 style. The system is modeled under a variety of expected future initial conditions, and then failures of individual (n-1) and multiple (n-2) components are evaluated. Equipment loadings and voltages that violate acceptable ranges indicate a need for system improvements.

When violations occur, they prompt development of alternate plans to solve the identified problem. Each proposed plan is evaluated in turn to see that it will meet the criteria. The plans that meet the criteria are usually then ranked based on cost and the long-term benefits to the system.

Deterministic transmission planning criteria are similar to the kinds of tests a physician might make. A doctor might ask a patient to step up and down on a platform for five minutes as a stress test. This test is not intended to see what happens if the patient were to climb a flight of stairs for five minutes. It is, rather, a test to see how the patient's heart and lungs perform based on some standard conditions. Many of the deterministic power system planning criteria are similar—they test the system to see that it is robust enough that it can survive the many other events that are not actually being studied.

There are various reasons why utilities prefer deterministic over probabilistic criteria for transmission planning. Deterministic criteria are:

- Easier to explain to the public,
- Easier to reproduce,
- More transparent, and
- Familiar because of past use.

The big disadvantage of deterministic criteria is that the balance between cost and reliability is somewhat subjective. With deterministic criteria it is not easy to demonstrate that a given solution costs less than the associated reliability benefit. It is also difficult to incorporate the deterministic results into economic comparisons of different alternative plans.

3.3.1.2 Probabilistic planning standards

Probabilistic transmission planning standards are intended to consider many of the same types of event as deterministic standards, but they measure the performance of the system in a different way. Rather than applying a pass/fail tests as with deterministic standards, probabilistic standards estimate/assess various measures of reliability—frequency of interruption, average length of interruption, maximum load interrupted, or average annual interrupted energy (expected unserved energy (EUE)).

A probabilistic analysis evaluates the system under a variety of expected future initial conditions, and then failures of individual components, but not multiple, are evaluated. Each combination of condition and failure must be evaluated to determine the impact on the transmission system to see if customer load will be affected. The failures are based on actual failure rates for specific transmission and generation elements. Equipment loadings and voltages that violate acceptable ranges are resolved first by redispatching generation and, if this is not adequate to relieve the violation, by disconnecting customer load. These results can be used to estimate the technical performance of the system such as the EUE.

A probabilistic standard can be specified either as limiting the absolute amount of a technical measure such as the EUE or as an expected customer value (ECV). The ECV is determined from the EUE and an estimate of the cost to customers of interrupting their load, plus any cost for generation redispatch.[3] The reliability standard would then require action should the EUE or ECV exceed certain levels.

When the EUE or ECV exceeds their specified levels, they prompt development of alternate plans to reduce the EUE or ECV. Each proposed plan is evaluated in turn to determine its EUE or ECV. The EUE or ECV of the plans can then be combined with the annual cost of system improvements each plan would require to rank them based on their cost/benefit ratios and their absolute benefit.

The big advantage of probabilistic standards is that they can easily be used to make this type of economic comparisons between alternative expansion plans. They also make it easier to present the economic justification for selecting a particular expansion plan.

The disadvantages of a probabilistic approach are that they:

- Are very computer intensive requiring hundreds of thousands of system evaluations for each year studied;[4]
- Tend to be less transparent than deterministic methods because replicating the analysis is very complex;
- The database of failure rates for specific transmission element outages is difficult to develop and very complex to maintain;

3. In Victoria the cost of customer interruption is the value of customer reliability (VCR), the economic value VENCorp has determined is applicable for the Victorian market.

4 Generally it is necessary to study at least a thousand hours during the year. For each hour multiple generation dispatches must be considered, and for each of these all credible contingencies must be evaluated. So a modest analysis of 2,000 hours, with 5 dispatches/hour, and 100 contingencies would require 1,000,000 simulations.

- Often do not clearly identify where in the transmission system the problem lies, only that there is excessive EUE or ECV (it is possible that multiple smaller transmission problems combine to cause excessive EUE or ECV); and
- Multiple, extreme or unusual contingencies are hard to evaluate.

There have been many methods developed to probabilistically evaluate transmission system reliability. So far their limitations have prevented their use except for demonstration purposes.

In Victoria, VENCorp uses a combination of deterministic and probabilistic criteria. It is our understanding that they use deterministic criteria to establish the need for any network improvements and identify the best solution. VENCorp then use probabilistic techniques to justify the specific timing of any needed improvements. This is different from using fully probabilistic planning criteria to evaluate the system and develop plans as discussed above.

3.3.2 Standards used in the sample system

All of the sample systems use a deterministic form of their standards and analyses. North America has a hierarchy that includes n-0, n-1, n-2 and extreme contingencies. Great Britain uses n-2 for the main transmission system (≥275 kV). Germany and the Nordic countries use n-1.

In North America, NERC has a fairly extensive set of standards that must be met by all utilities in the US and Canada. Regions or individual utilities may have additional or more specific standards. The NERC standards also allow some room for interpretation.

In Europe, Great Britain and the Nordic countries apply the standards to all transmission. In Germany the 220 kV and 380 kV system must meet a higher standard than the 100 kV system. Germany also provides for different connection standards for renewable generation. Great Britain also allows variation based on the size of load connected.

A word of caution regarding the terminology of 'n-1', 'n-2', *et cetera* is useful here. This shorthand for criteria involving the loss of one or two elements from the system is commonly used. By themselves n-1 and n-2 deterministic standards are rather simplistic and will almost always have a variety of additional considerations attached to their use. Some of these considerations are:

- What constitutes 'n'—normally it is assumed that this means the system is in its normal operating state, but this is not universally applied.
- There also is a clear distinction between the 'n' used in planning and the 'n' used in operation. In operation it means whatever state the system is actually from hour-to-hour or minute-to-minute during operation.
- Are any preconditions allowed, is the system to be stressed before the making an n-1 analysis?
- Are various combinations of generation dispatch evaluated?

- Are special, but important, conditions to also be considered?

Because of this potential confusion, the NERC standards do not use the n-1 or n-2 terminology. In the other markets there are also additional conditions applied.

3.3.3 Transmission and subtransmission

There is a difference between Europe and North America in regard to subtransmission. In Europe there is a different design—the transmission systems includes all facilities that area typically above 100 kV. All the facilities below 100 kV are distribution.

In Europe, the transmission system includes all facilities that are typically above 100 kV. All the facilities below 100 kV are distribution. This differs from North America.

In North America the main interconnected grid is also greater than 100 kV but there is lower-voltage subtransmission that form sub-networks underneath the main transmission network. These subtransmission systems are, in many cases, networks (not just radial), but they are not connected together and do not span large areas. They support the distribution system in an area. The subtransmission system is generally composed of transmission between 60 and 100 kV. In North America both transmission and subtransmission must meet the same standards.

3.4 Institutional/governance models

There are three significant aspects to governance and institutional arrangements across the samples systems:

1. The institutions enforcing the standards;
2. The responsibility for developing national (or multi-TO regional) transmission plans; and
3. The responsibility for enforcing transmission network development plan across multiple TOs.

3.4.1 Institutions enforcing the standards

Each system has a regulator that wields legal power to enforce the standards. In practice there is some variation in the efficacy of that enforcement power.

In North America FERC provides the legal back-stop and oversight of NERC. FERC is able to enforce the rules by imposing fines if, for some reason, a member does not otherwise comply. FERC also provides oversight to see that the rules are fair.

In Great Britain OFGEM has the enforcement power. In Germany the Federal Network Agency (FNA) enforces the standards. In the Nordic countries each legislature has the regulatory power, but the legislatures have taken a rather light hand in this role.

3.4.2 Responsibility for developing transmission plans

Most of these systems do not have any form of central planning. Most have some form of bottom-up planning where the TOs develop their own plans which are the subject to either review or coordination through the central body. The two exceptions are PJM and Alberta.

In PJM a single plan is developed jointly by the stakeholders in an open process. The PJM staff and individual TOs identify criteria violations and offer plans to resolve those problems. These plans are then scrutinized by stakeholders through a standing committee. Once approved the TOs move forward with these plans.

In Alberta criteria violations are identified and plans are developed by the AESO staff. The staff also identifies feasible alternative plans. These plans are then reviewed as part of an open stakeholder consultation process. The AESO makes the final determination of the facilities that are needed.

3.4.3 Responsibility for enforcing transmission network development plans

The enforcement of plans follows the same pattern as centralized planning. Most markets have no enforcement of the plans. The planning standards are met if plans are developed that will resolve the identified problems.[5] As above, the two exceptions are PJM and Alberta.

In Alberta and PJM, where the ISO plays a key role in transmission planning, the ISO also has some enforcement powers:

- The AESO has the authority to enforce its plans, though this is not really necessary in Alberta's transmission regulatory environment, which has strong incentives for transmission augmentation.
- PJM also has the authority to enforce its plans. If a TO is unwilling to move forward with a plan, then PJM can ask another party to build the facilities. PJM, as an alternative, can go to FERC to threaten fines for inaction.

In Great Britain, the GBSO and OFGEM also have the authority to require action on the plans. The TOs develop their transmission plans in accordance with the requirements of the GB Security & Quality Standards of Supply (GBSQSS) and based on the a data set including generation and demand forecasts provided to them by the GB System Operator (GBSO) under the SO/TO code. These are subject to scrutiny by the GBSO. The GBSO can request amendment and/or addition to these transmission investment plans if the GBSO feels they do not comply with GBSQSS. If the GBSO and TOs fail to mutually agree on finalized transmission investment plans, the matter is referred to OFGEM for a determination; which is then binding on all parties.

5. This relates to regulatory jurisdiction and authority. Utility plans must often be approved by various land-use, environmental, and siting bodies. These bodies may delay, modify, or prevent planned facilities from be built. The TOs are not held accountable if these other bodies prevent timely completion of the approved plans.

3.5 Who sets the standards

There is a clearly identified body that sets the standards in each market. In most of the sample systems there is a single entity that sets the standards. In North America there is a hierarchy of entities and standards—NERC sets minimum standards that must be met, the regional councils under NERC may have additional or more specific standards, and individual utilities may have even more specific or additional standards. An example is the additional voltage standards related to power-voltage and power-reactive standards that the WECC (covering western North America) requires. In addition, individual utilities in WECC will often have additional criteria that apply to central business districts or to other critical load centers, for example.

3.6 Governance/independence

All the sample systems have independent standard-setting bodies; at least in theory:

- In North America, NERC is clearly independent of any TO, is governed by an independent Board and has many active, open stakeholder groups.
- In Great Britain, the situation is similar to that in North America in that GBSO and OFGEM are independent of the TOs.
- In the Nordic countries, there is a mix—Nordel only advises concerning the standards but it is composed of the TOs.
- In Germany, the VDM sets the standards but it is dominated by the TOs.

3.7 Standards setting

The level of transmission reliability standards is fairly clear and specific for all the sample systems:

- North America has several levels of standards—as the tests become more severe there is more leeway in what is needed to pass the test.
- In Great Britain there is a single standard for the main transmission system.
- In Germany there are the distinctions as mentioned above for voltage levels and renewable generation.

In most cases there is no distinction in the level of standards applied by voltage level. This assumes, however, a fairly clear definition as to what is transmission and what is distribution. (The transmission standards do not apply to the distribution system.)

3.8 Allowed variations in standards

In all cases there is a standard that is applied universally. In North America regions and individual utilities are allowed to have standards that are more restrictive or more specific than the NERC standards which are minimum standards.

In all the sample systems there are also variations in design standards among the TOs. Generally each faces different weather conditions that will affect thermal ratings and other design practices. In Alberta the AESO is even developing a single consistent standard for these rating and design matters.

3.9 Issues with divergent standards

At the highest levels there are no significant issues with divergence of standards in any of the sample systems. Each system has minimum standards that apply across all TOs in the system. Some form of divergence does exist on a location-specific basis, however. This location-specific divergence is managed in at least three ways:

1. **There is a transition period** allowed for compliance with new levels of standards. Transitions are allowed whenever a new connection/ interconnection is established where the newly connecting party does not initially meet all the criteria. The transition period for compliance can be as long as five years.
2. **There is an approved exception** (i.e. derogation) to standards which may be granted for the remaining life of a specific asset. There are a few, very rare, cases where compliance may be prohibitively expensive or, even impossible. An example might be an older power plant built along a steep rocky coast. The plant may not have the physical space to modify its bus/breaker design to meet the new national standards. Exceptions can be granted for such situations on a case-by-case basis. It should be noted that such exceptions are very specific and are not broad exemptions from compliance with the standards.
3. **There are local standards** that exceed the mandated minimum standards. Some utilities apply additional criteria. These additional criteria are almost always based on past experience, special technical conditions, or long-standing historical practices that have been widely accepted. Special criteria used in the WECC and requirements for service to central business districts are two examples mentioned above. Other examples include evaluating conditions where high amounts of imports or exports occur, or when a critical transmission line or generator is out of service.

3.10 Transmission owner compensation

The means of recovering transmission network costs differs between systems depending on the transmission regulatory regime.

Transmission costs in North America are generally allowed to pass-through to the customers. There is an approval process so that TOs must demonstrate that their facilities are necessary. But once this hurdle is met the costs are passed on to customers. These costs will be assessed in energy ($/kWh) charges and, in may cases, also through demand charges ($/kW).

All three examples in Europe have some form of rate incentive approaches. Costs are reviewed typically every five years, but the TOs are expected to control their costs during these periods in order to generate any profits.

In North America the compensation system tends to encourage transmission investment as new facilities will increase the TO's asset base and thus increase their profitability. In Europe, the compensation system tends to be a disincentive for the TOs to build new facilities.

3.11 Differences with NEM

There were four aspects of planning standards where the practices of NEM were different from the sample systems considered here. These were:

1. In NEM there are significant regional differences in the standards whereas all the sample systems had universal minimum standards.
2. The form of the standards in NEM is a mixture of deterministic and probabilistic approaches whereas the sample systems all used the deterministic form of standards.
3. The form and level of standards in NEM are set by individual jurisdictions whereas the sample systems all have a trans-jurisdictional body that sets the form of the standards and a common minimum level of standards. .
4. In NEM there are different levels of standards depending on the type of customer and area. In the sample systems this is not generally the practice, though there was some variation among them.

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Appendix A: Summary findings

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
Basic facts Transmission owners Peak load (GW) States and Provinces Countries	 100s 800 59 US & Canada	 17 140 14 US	 68 160 20 US, Mexico & Canada	 10 50 1 US	 4 12 1 Canada	 3 62 n/a England, Scotland, Wales	 4 78 n/a Germany	 6 70 n/a Norway, Sweden, Finland, Denmark (E & W), and Iceland
1. What frameworks are used to ensure consistent reliability standards across multiple political jurisdictions and/or separately owned transmission networks?	The NERC standards are minimum requirements applicable to all utilities in the United States and Canada. There is a hierarchy of standards—national, regional, and local—to which TOs must to comply. A few regions and localities have standards in addition to or more specific than the NERC minimum standards.					Within GB's BETTA market framework; transmission reliability standards specified within GB Security & Quality of supply Standards (GBSQSS) document	VDN (association of all German industry stake-holders) sets transmission reliability standards that apply to all German TOs.	Nordel (association of all Nordic TSOs) sets transmission reliability standards to apply to all utilities within Nordic market region
2. What instruments are used: Grid Codes? Transmission licenses? Market Rules? Legislation?	Federal legislation in US. Provincial legislation in Canada (currently in process). Portion of Mexico within WECC (voluntary compliance only at this time). There are no standards included in transmission licenses tough there are usually specific requirements associated with generator connection agreements.				Provincial legislation	National legislation; Transmission Licenses; GB	National legislation and the German Transmission Code	See above - Nordel's issued standards document

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<tr><td rowspan="2">3. What transmission reliability standards are applied in these markets?</td><td colspan="5">All areas must meet the NERC standards as a minimum</td><td rowspan="2">A single national transmission reliability standard</td><td rowspan="2">A single national transmission reliability standard</td><td rowspan="2">A single transmission reliability standard</td></tr>
<tr><td></td><td colspan="3">More stringent or more specific standards may also be established by regions or individual utilities.</td><td>AESO may set specific standards</td></tr>
<tr><td>a. What form (deterministic, probabilistic, or variants) of standards are used?</td><td colspan="5">Deterministic</td><td>Deterministic, with probabilistic scenarios</td><td colspan="2">Deterministic</td></tr>
<tr><td>b. What levels of standards (e.g. n-0, n-1, n-2) are applied?</td><td colspan="5">All are applied to different degrees—n-0, n-1, n-1-1, n-2, and more.</td><td>N-2 standard to the Main Interconnected Transmission system</td><td>n-1</td><td>n-1</td></tr>
<tr><td rowspan="2">c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?</td><td colspan="5">The NERC minimum standards are applied universally</td><td rowspan="2">The standards are applied universally. There is varying provision for demand based on the size of the demand being supplied at a connection point</td><td rowspan="2">The facilities at 380 kV and 220 kV must meet a higher standard than those at 100 kV. There are also varying standards for connection of conventional versus renewable generator</td><td rowspan="2">The standards are applied universally to transmission</td></tr>
<tr><td></td><td colspan="3">Individual transmission owners may have more stringent standards or more specific tests than NERC's minimum standards</td><td>AESO sets all transmission criteria</td></tr>
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Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
d. Consistency of standards for transmission and sub-transmission networks	NERC's minimum planning criteria are universally applied, though regions and individual utilities may apply more specific or stringent criteria.					There is no subtransmission distinction		
e. Extent transmission and sub-transmission networks are jointly planned and developed	Applies to all transmission ≥ 100 kV	Applies to all transmission ≥ 69 kV	Applies to all transmission ≥ 100 kV	Applies to all transmission ≥ 100 kV & most 69 kV	Applies to all transmission ≥ 100 kV	Applies to all transmission		
4. Institutional/governance models used to support such frameworks			Board elected by WECC members	Governing Board appointed by CA Governor				
a. Regulatory institutions	FERC backs-up NERC which requires compliance					OFGEM enforces compliance	The Federal Network Agency (FNA) enforces compliance	Nordreg is the coopera-tive organization for the Nordic regulatory authorities – it has no enforcement power. The individual national regulators enforce national requirements within each country.
		PJM has contractual authority over its members	FERC regulates WECC processes	FERC regulates CAISO tariff	FERC has no authority in Canada			

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
b. National planner or Regional Transmission Organization (RTO) planner	There is no national plan	A single regional plan developed by PJM	WECC coordinates TO and RTO plans	ISO makes selected studies to check TO plans. For large projects the ISO forms an open stakeholder study group.	AESO makes single transmission plan	Plans are developed by TOs based on national data and coordinated by GBSO to form a coherent national GB plan (only relevant part visible to TOs.)	There is no single national plan. Plans are developed by regional TOs with bilateral co-ordination if required and some coordination by VDN	There is no single system-wide plan. Plans are developed by national TOs with bilateral coordination if required
c. Role transmission companies play in determining the national/RTO plan	There is no national plan	Planned developed in an open process	Bottom-up plans by TOs and RTOs	Both bottom-up and top-down plans are developed by stakeholder processes	Top-down plan by AESO	Bottom-up planning by TOs		Each TO develops its own national plan

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
d.—Is the national/RTO plan imposed/enforced on individual Transcos, or is it merely guidance?	No national plan	The PJM plan is enforced	WECC stakeholder process for coordination of major expansion projects	No statewide transmission plan, but a new initiative seeks to implement a coordinated state-wide stakeholder planning process	Imposed by AESO on TOs	Enforced—TO plans are subject to scrutiny by the GBSO and ultimately Ofgem	There is no national plan. But TO plans are subject to scrutiny by the FNA	There is no single system-wide plan. National TO plans are subject to national scrutiny. Nordel planning guidance is advisory only (although adhered to in practice)
e. Accountabilities	Utilities and RTOs are subject to regular reliability reviews to determine if the standards are being met. NERC and FERC are capable of prescribing fines for not meeting the standards.				Same except FERC has no authority	OFGEM – approves and enforces the standards	The FNA approves and enforces compliance	National states are ultimately responsible for compliance
5. Who sets the standards?	NERC	NERC/PJM	NERC/WECC	NERC/WECC	NERC/AESO	OFGEM	VDN	Nordel
6. Governance issues with framework:	NERC is governed by an eleven-member independent Board of Trustees		Governance model is approved by FERC	FERC has weighed in on criteria used for appointment of CAISO board members by the CA Governor		GBSO acts as first guardian of compliance; Ofgem is ultimate enforcer if required (e.g. to resolve GBSO vs TO disputes)	VDN consists of representatives of all industry stake-holders including TOs, customers regulators and government	Nordel comprises representatives of all member TSOs – its output is advisory. Nordreg comprises representatives of all member Regulatory Authorities – its has no enforcement powers

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<tr><td>a. Are standards set by an independent body?</td><td colspan="5">NERC and the regional RTOs are independent of the TOs, but the standard setter is also the standard enforcer.</td><td>Yes. (Ofgem)</td><td>Yes, but TOs participate in the collective industry body (VDN)</td><td>Yes, though this is an all TO collective body (Nordel)</td></tr>
<tr><td>b. What separation is there between the standard-setting body and the enforcement/monitoring body</td><td colspan="4">They are the same—NERC enforces the NERC standards, additional utility standards may be enforced by NERC or by individual states</td><td>They are the same</td><td>Ofgem both sets standards and is ultimate enforcer, but GBSO acts as first line of enforcement</td><td>The FNA enforces compliance</td><td>The standards are advisory – whether to comply or otherwise can only be enforced by the national governments/regulators</td></tr>
<tr><td>7. To what degree does the framework specify the actual level of standards:</td><td colspan="5">Standards are set for system response for various categories of contingencies. There is no distinction by voltage level.</td><td>Set for the MITS and for connec-tions. There is no distinction by voltage level.</td><td>380 kV and 220 kV must meet higher standard than 100 kV. Different connection standards apply for conventional and renewable generators</td><td>There is no distinction by voltage level or any other factor.</td></tr>
<tr><td rowspan="2">8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?</td><td colspan="5">The NERC minimum standards are applied universally</td><td colspan="3" rowspan="2">A single standard is universally applied.</td></tr>
<tr><td colspan="4">Some divergence is allowed because individual transmission owners may have criteria more stringent or specific than either the NERC minimums or the standards set by their regional reliability council.</td><td>The AESO sets all transmission planning criteria</td></tr>
</table>

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
9. What issues arise when there are divergent transmission reliability standards across different, but interconnected, transmission networks and/or jurisdictions?	There is no divergence for major issues. Any stakeholder can appeal to FERC over TO or sub-regional standards that are more stringent than NERC. Thermal ratings will be different as will various specific design standards.					There is no divergence for major issues. Scotland has legacy issues from its transition to the new criteria.	There is no divergence for major issues.	In practice there is no divergence
10. How are transmission owners compensated for their transmission costs?	Approved costs are reimbursed based on combination of peak demand ($/kW) and energy ($/kWh) charges to load customers Some transmission costs are shared by all customers across the entire region—In PJM 500 kV is shared, and in CAISO ≥200 kV is shared. In the AESO all transmission costs are shared. (Alberta also charges generators).					OFGEM reviews rates every five years based on operating and capital costs.	The FNA sets allowed revenue for each TO on a confidential bila-teral basis. From 2009, an incentive regulation will be introduced for a 5-year period.	Each TO is subject to a differing regulatory regime
11. Summary comparison with NEM:								
Regional standards	Universal minimum standards with additional regional and local specifics.					Universal		
Mixture of deterministic and probabilistic approaches	Deterministic with a probabilistic view of potential system events					Deterministic (with additional justification based on probabilistic market background)	Deterministic	Same as NERC
Set by individual jurisdictions	National minimum standard with additional regional and local specifics.					Single standard		Set by overarching TSO cooperative

Summary	**North America**					**Europe**		
	NERC	**PJM**	**WECC**	**CAISO**	**AESO**	**GB**	**Germany**	**Nordic**
Security by type of area/customer supplied e.g. CBD	National minimum standard with additional regional and local specifics.					National for MITS; standard for demand security varies by size of demand group	Varies by type of generator (conventional or renewable) and by voltage level	Uniform
Standards are mandatory	Mandatory							Advisory

International Review of Transmission Reliability Standards

Detailed Summaries

Australian Energy Market Commission Reliability Panel

KEMA Inc.
Project team:

P. Jeffrey Palermo, David Korinek, Mike Wilks
1 August 2008

This document is formatted for back-to-back printing. If it is printed single-sided there will be some pages with no text other than the header and footer.

Contents

Tables

Figures

1. Background

The work described in this report is in response to a ministerial directive to developing a consistent national framework for network security and reliability. It is part of a review of jurisdictional transmission reliability standards. In response to these actions the AEMC on behalf of the Reliability Panel engaged KEMA, Inc. to provide a report on transmission planning reliability standards or criteria used in different electricity markets around the world.[1]

This report is a companion to *International Review of Transmission Reliability Standards; Summary Report* prepared by KEMA and dated 27 May 2008. This report provides more detailed summaries for each of the eight example systems and includes supplemental information that provides selected additional detail about the systems.

This report was prepared to assist the Panel in developing a framework for nationally consistent transmission reliability standards for the NEM. The Panel has been asked by the AEMC to provide advice of on such a framework, which will inform AEMC in formulating advice to the Ministerial Council on Energy (MCE).

1.1 Terms of reference

The AEMC Reliability Panel (the Panel) engaged KEMA, Inc. to provide a report on:[2]

- The transmission reliability standards (relating to the planning horizon) used in different electricity markets around the world; and
- The frameworks used in foreign electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple jurisdictions and/or separately owned transmission networks.

The Panel developed ten questions to use in making the necessary comparison. The ten questions were:

1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?
2. What instruments are used in those frameworks to give effect to such consistency:
    a. Grid Codes?
    b. Transmission licenses?
    c. Market Rules?

1. In this report 'criteria' and 'standards' are used interchangeably. Both define the tests performed and acceptable performance of the transmission system in evaluating and developing the transmission system.
2. The Reliability Panel is a specialist body within the AEMC and comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on the safety, security and reliability of the national electricity system and advising the AEMC in respect of such matters.

d. Legislation?

3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?
   a. What form (deterministic, probabilistic, or variants) of standards are used?
   b. What levels of standards (e.g. n-0, n-1, n-2) are applied?
   c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. metropolitan, urban, and rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?
   d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?
   e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?

4. What institutional/governance models are used to support such frameworks?
   a. Regulatory institutions
   b. National planner or Regional Transmission Organization (RTO) planner
   c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?
   d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.
   e. Accountabilities

5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?

6. Governance issues with framework:
   a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?
   b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.

7. To what degree does the framework specify the actual level of standards:
   a. By connection point?
   b. By voltage level?

8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?
10. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.

1.2 Sample power systems and reasons for selection

In consultation with the Reliability Panel, KEMA selected six electric systems to use in the required comparison. KEMA based its comparison on published documents and prior experience in working with the selected systems.

The systems considered suitable for comparison must have been in market environments where there were multiple transmission owners (TOs). In North America we found that there were many TOs but only a few market environments. In contrast, each nation in Europe is part of a market but few had multiple TOs. In addition, only utilities from advanced industrial countries in Europe and North America were considered.

These six selected systems were:

In North America

1. The California Independent System Operator (CAISO)—which includes the three large investor-owned utilities in California.
2. The PJM Interconnection—is a regional organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM operates the world's largest competitive wholesale electricity market and ensures the reliability of the largest centrally dispatched grid in the world.
3. The Alberta Electric System Operator (AESO)—is responsible for the safe, reliable and economic planning and operation of the Alberta (Canada) Interconnected Electric System. They provide open and non-discriminatory access to Alberta's interconnected power grid for generation and distribution companies and large industrial consumers of electricity. In doing so, the AESO contracts with transmission facility owners to acquire transmission services and, with other parties to provide fair and timely access to the system. They also develop and administer transmission tariffs, procure ancillary services to ensure system reliability and manage settlement of the hourly wholesale market and transmission system services.

In Europe,

4. Great Britain—includes the transmission facilities of the National Grid owner of the transmission in England and Wales, Scottish Hydro Electric

owner of the northern Scotland network, and Scottish Power transmission owner of the southern Scotland network.

5. Germany—Four companies operate Germany's national transmission grid, as there is no unified operator for the entire country: RWE/VEW; E.ON, Energie Baden-Wuerttemburg (EnBW), and Sweden-based Vattenfall. Germany enacted a new energy law in July 2005 that vested regulatory oversight of the industry with the newly created Bundesnetzagentur (BNA).
6. The Nordel Market countries—Norway, Sweden, Finland, and Denmark have co-operated for many years to provide their collective populations of about 24 million with an efficient and reliable supply of electric power, and optimal use of total system resources.

In addition information was also developed for

7. The North American Electric Reliability Organization (NERC)—its mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. NERC is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.
8. The Western Electricity Coordinating Council (WECC)—-is responsible for coordinating and promoting electric system reliability and for promoting a reliable electric power system in the Western Interconnection of North America. The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the eight regional councils of NERC. The WECC territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western U.S. states in between.

These systems present a variety of governance/political environments—Single and multiple political jurisdiction; and while all have multiple Transcos they may have a single or multiple control areas managed by a single or multiple system operators. There are also multiple transmission regulatory environments. A comparison of political and regulatory environment of the selected systems is shown in Table 1.

Table 1: Political and regulatory environments of the selected systems

System	Political jurisdictions	Transcos	Control areas	Transmission regulatory regime		
				Regulated rate of return	Incentive-based	
					CPI-X price cap	Revenue cap
CAISO	1	10	1	√		
PJM	14	16	1	√		
AESO	1	3	1	√		
GB	1	3	1		√	
Germany	1	4	4		√	
Nordel	5	6	6	Sweden, Iceland		Norway, Finland, & Denmark

The sample systems include a fairly wide range of experience and practice. From Alberta with strong central control for all utilities in a single province; to Great Britain and PJM with strong control over multiple countries/states; to Germany, the Nordic countries, and NERC that have varying levels standards and control over integrated plans. The sample includes utility systems with liberalized markets with unbundled generation and transmission, and with vertically-integrated utilities.

The summary tables on the following pages are organized to correspond to the ten questions posed by the Panel.

Table 2: Summary findings

<table>
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US</td><td>
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12
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Canada</td><td>
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n/a
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Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
3. What transmission reliability standards are applied in these markets?	All areas must meet the NERC standards as a minimum					A single national transmission reliability standard	A single national transmission reliability standard	A single transmission reliability standard
		More stringent or more specific standards may also be established by regions or individual utilities.			AESO may set specific standards			
a. What form (deterministic, probabilistic, or variants) of standards are used?	Deterministic					Deterministic, with probabilistic scenarios	Deterministic	
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	All are applied to different degrees—n-0, n-1, n-1-1, n-2, and more.					N-2 standard to the Main Interconnected Transmission system	n-1	n-1
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The NERC minimum standards are applied universally					The standards are applied universally. There is varying provision for demand based on the size of the demand being supplied at a connection point	The facilities at 380 kV and 220 kV must meet a higher standard than those at 100 kV. There are also varying standards for connection of conventional versus renewable generator	The standards are applied universally to transmission
		Individual transmission owners may have more stringent standards or more specific tests than NERC's minimum standards			AESO sets all transmission criteria			

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
d. Consistency of standards for transmission and sub-transmission networks	NERC's minimum planning criteria are universally applied, though regions and individual utilities may apply more specific or stringent criteria.					There is no subtransmission distinction		
e. Extent transmission and sub-transmission networks are jointly planned and developed	Applies to all transmission ≥ 100 kV	Applies to all transmission ≥ 69 kV	Applies to all transmission ≥ 100 kV	Applies to all transmission ≥ 100 kV & most 69 kV	Applies to all transmission ≥ 100 kV	Applies to all transmission		
4. Institutional/governance models used to support such frameworks			Board elected by WECC members	Governing Board appointed by CA Governor				
a. Regulatory institutions	FERC backs-up NERC which requires compliance					OFGEM enforces compliance	The Federal Network Agency (FNA) enforces compliance	Nordreg is the coopera-tive organization for the Nordic regulatory authorities – it has no enforcement power. The individual national regulators enforce national requirements within each country.
		PJM has contractual authority over its members	FERC regulates WECC processes	FERC regulates CAISO tariff	FERC has no authority in Canada			

Summary	North America					Europe		
	NERC	**PJM**	**WECC**	**CAISO**	**AESO**	**GB**	**Germany**	**Nordic**
b. National planner or Regional Transmission Organization (RTO) planner	There is no national plan	A single regional plan developed by PJM	WECC coordinates TO and RTO plans	ISO makes selected studies to check TO plans. For large projects the ISO forms an open stakeholder study group.	AESO makes single transmission plan	Plans are developed by TOs based on national data and coordinated by GBSO to form a coherent national GB plan (only relevant part visible to TOs.)	There is no single national plan. Plans are developed by regional TOs with bilateral co-ordination if required and some coordination by VDN	There is no single system-wide plan. Plans are developed by national TOs with bilateral coordination if required
c. Role transmission companies play in determining the national/RTO plan	There is no national plan	Planned developed in an open process	Bottom-up plans by TOs and RTOs	Both bottom-up and top-down plans are developed by stakeholder processes	Top-down plan by AESO	Bottom-up planning by TOs		Each TO develops its own national plan

Summary	North America					Europe		
	NERC	**PJM**	**WECC**	**CAISO**	**AESO**	**GB**	**Germany**	**Nordic**
d.—Is the national/RTO plan imposed/enforced on individual Transcos, or is it merely guidance?	No national plan	The PJM plan is enforced	WECC stakeholder process for coordination of major expansion projects	No statewide transmission plan, but a new initiative seeks to implement a coordinated state-wide stakeholder planning process	Imposed by AESO on TOs	Enforced—TO plans are subject to scrutiny by the GBSO and ultimately Ofgem	There is no national plan. But TO plans are subject to scrutiny by the FNA	There is no single system-wide plan. National TO plans are subject to national scrutiny. Nordel planning guidance is advisory only (although adhered to in practice)
e. Accountabilities	Utilities and RTOs are subject to regular reliability reviews to determine if the standards are being met. NERC and FERC are capable of prescribing fines for not meeting the standards.				Same except FERC has no authority	OFGEM – approves and enforces the standards	The FNA approves and enforces compliance	National states are ultimately responsible for compliance
5. Who sets the standards?	NERC	NERC/PJM	NERC/WECC	NERC/WECC	NERC/AESO	OFGEM	VDN	Nordel
6. Governance issues with framework:	NERC is governed by an eleven-member independent Board of Trustees		Governance model is approved by FERC	FERC has weighed in on criteria used for appointment of CAISO board members by the CA Governor		GBSO acts as first guardian of compliance; Ofgem is ultimate enforcer if required (e.g. to resolve GBSO vs TO disputes)	VDN consists of representatives of all industry stake-holders including TOs, customers regulators and government	Nordel comprises representatives of all member TSOs – its output is advisory. Nordreg comprises representatives of all member Regulatory Authorities – its has no enforcement powers

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
a. Are standards set by an independent body?	NERC and the regional RTOs are independent of the TOs, but the standard setter is also the standard enforcer.					Yes. (Ofgem)	Yes, but TOs participate in the collective industry body (VDN)	Yes, though this is an all TO collective body (Nordel)
b. What separation is there between the standard-setting body and the enforcement/monitoring body	They are the same—NERC enforces the NERC standards, additional utility standards may be enforced by NERC or by individual states				They are the same	Ofgem both sets standards and is ultimate enforcer, but GBSO acts as first line of enforcement	The FNA enforces compliance	The standards are advisory – whether to comply or otherwise can only be enforced by the national governments/regulators
7. To what degree does the framework specify the actual level of standards:	Standards are set for system response for various categories of contingencies. There is no distinction by voltage level.					Set for the MITS and for connec-tions. There is no distinction by voltage level.	380 kV and 220 kV must meet higher standard than 100 kV. Different connection standards apply for conventional and renewable generators	There is no distinction by voltage level or any other factor.
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	The NERC minimum standards are applied universally					A single standard is universally applied.		
	Some divergence is allowed because individual transmission owners may have criteria more stringent or specific than either the NERC minimums or the standards set by their regional reliability council.				The AESO sets all transmission planning criteria			

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
9. What issues arise when there are divergent transmission reliability standards across different, but interconnected, transmission networks and/or jurisdictions?	There is no divergence for major issues. Any stakeholder can appeal to FERC over TO or sub-regional standards that are more stringent than NERC. Thermal ratings will be different as will various specific design standards.					There is no divergence for major issues. Scotland has legacy issues from its transition to the new criteria.	There is no divergence for major issues.	In practice there is no divergence
10. How are transmission owners compensated for their transmission costs?	Approved costs are reimbursed based on combination of peak demand ($/kW) and energy ($/kWh) charges to load customers Some transmission costs are shared by all customers across the entire region—In PJM 500 kV is shared, and in CAISO ≥200 kV is shared. In the AESO all transmission costs are shared. (Alberta also charges generators).					OFGEM reviews rates every five years based on operating and capital costs.	The FNA sets allowed revenue for each TO on a confidential bila-teral basis. From 2009, an incentive regulation will be introduced for a 5-year period.	Each TO is subject to a differing regulatory regime

Summary	North America					Europe		
	NERC	PJM	WECC	CAISO	AESO	GB	Germany	Nordic
11. Summary comparison with NEM:								
Regional standards	Universal minimum standards with additional regional and local specifics.					Universal		
Mixture of deterministic and probabilistic approaches	Deterministic with a probabilistic view of potential system events					Deterministic (with additional justification based on probabilistic market background)	Deterministic	Same as NERC
Set by individual jurisdictions	National minimum standard with additional regional and local specifics.					Single standard		Set by overarching TSO cooperative
Security by type of area/customer supplied e.g. CBD	National minimum standard with additional regional and local specifics.					National for MITS; standard for demand security varies by size of demand group	Varies by type of generator (conventional or renewable) and by voltage level	Uniform
Standards are mandatory	Mandatory							Advisory

2. North America	North American Electric Reliability Corp. (NERC) Standards
1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	The NERC standards apply to all utilities in the United States and Canada. The standards are minimum requirements for bulk system planning and operation. See §2.1 on page 19
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	The NERC standards were established based on Federal legislation. The legislation authorized FERC to establish a reliability corporation—that was later set as NERC—to set and manage the standards. Each standard must be approved by FERC, and not all proposed standards have been accepted. FERC does not have enforcement authority in Canada, but Canada is proceeding with federal efforts to provide authority similar to FERC's within Canada. See §2.2 on page 21
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?	All areas must meet the NERC standards. Higher or more specific standards may also be established by regions or individual utilities. See §2.3 on page 22
a. What form (deterministic, probabilistic, or variants) of standards are used?	The NERC standards are deterministic. There is a hierarchy of the standards, however, that less probable events only need to meet less stringent standards.
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	The NERC standards cover n-0, n-1, n-2, and more severe events.
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The NERC standards are universally applied. It is possible for individual utilities to claim exceptions, but only under special conditions. In addition, regional and utilities can have more stringent or specific requirements.
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	The NERC standards apply to all transmission system ≥100 kV.
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	The NERC standards apply to all transmission ≥100 kV and do not apply to lower voltage networks. NERC does make any plans.

2. North America	North American Electric Reliability Corp. (NERC) Standards
4. What institutional/governance models are used to support such frameworks?	The standards are applied by NERC, though FERC has "backstop authority" to enforce fines or other actions as may be necessary. FERC was given this authority as part of federal legislation passed in 2005.
a. Regulatory institutions	FERC has the final 'legal' authority to enforce any fines or other actions. Even though the standards are developed as part of a collaborative process involving all stakeholders, the standards must receive approval by FERC before they are implemented.
b. National planner or Regional Transmission Organization (RTO) planner	The national minimum standards are set by NERC. Each regional RTO has accepted these standards, and in many cases additional criteria or clarifications have been set. Transmission plans are developed by various institutions that may be and RTO/ISO, or individual transmission owners, and in some cases combinations of both.
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	There is no national plan in Canada, or the United States. Some regions have regional plans and some only have individual transmission owner plans that are coordinated through regional planning committees.
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Transcos.	In those RTOs/ISOs where the plan is developed and approved by the RTO/ISO, the Transcos are required to build the necessary facilities. The Transcos are then allowed to pass-through the cost for those facilities either regionally or locally.
e. Accountabilities	Utilities and RTOs are subject to regular reliability reviews to determine if the standards are being met, but self-disclosure of any known area of non-compliance is also strongly encouraged. NERC and FERC are capable of levying fines for not meeting the standards. Self-disclosure is expected to reduce the severity of fines that an entity may be levied.
5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?	The NERC standards are set as part of an open stakeholder process that involves utilities, customers, generators, transmission owners, environmental groups, and other interested parties. Final standards must be approved by the NERC Board and by FERC.
6. Governance issues with framework:	NERC is governed by an eleven-member independent Board of Trustees.
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	Yes, in part. NERC sets minimum criteria but the regions, RTOs, ISOs or individual utilities may have more stringent criteria.

2. North America	North American Electric Reliability Corp. (NERC) Standards
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	No.
7. To what degree does the framework specify the actual level of standards:	
a. By connection point?	Standards are set for system response for various categories of contingencies.
b. By voltage level?	There is no distinction by voltage except that the NERC criteria cover the system ≥ 100 kV
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	The standards are minimums applied to all interconnected utilities in North America.
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	The standards are applied universally, but there has been and continues to be extensive discussions concerning certain of the standards. FERC must approve all standards, though their focus is not usually on technical matters but on transparency, and fairness.

2. North America	North American Electric Reliability Corp. (NERC) Standards
10. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as NERC vs. NEM (i) universal standard vs. regional standards (ii) deterministic with a probabilistic view of potential system events vs. mixture of deterministic and probabilistic approaches (iii) National minimum standard vs. set by individual jurisdictions (iv) uniform security vs. by type of area/customer supplied e.g. CBD See §2.10 on page 26

Transmission cost recovery and pricing

An important consideration in considering the application of planning standards in the United States is the issue of cost recovery. In the United States almost all transmission owners are able to recover their costs through cost-based rates that are typically updated annually. This means that once a transmission facility is approved the appropriate owner can begin charging their customers for their costs.

There are some exceptions to this general rule, but these are fairly narrow. A few states imposed temporary retail price caps as part restructuring the utilities in their states. These utilities are not always able to pass-through any increases in their costs. There are also several merchant transmission lines that recover their costs through by charging for use of their facilities. Most of these merchant transmission lines use DC technology that lets them physically control the amount of power flowing.

In general, the cost of transmission is allocated to customer loads is based on their monthly energy use. Generators are not charged for use of the transmission system. Generators are charged for the cost of their direct connections to the transmission network (shallow charges). Many areas also charge generators for any additional network improvements that may be required to support delivery of their output (deep charges). There is quite a bit of variability in the specific practices for charging generators for transmission improvements among the various regions in the US.

2.1 Frameworks used to ensure consistency of transmission reliability standards

Across North America there are thousands of individual utilities and over a hundred power system control areas. The utilities include many that are vertically integrated as well as those that have been restructured into separate generation, transmission and distribution units. The utilities include investor-owned, municipal (city-owned), state-owned, and a few federal multi-state utilities. The full list of utilities can be found on the NERC website.[3] The list is 260 pages long.

In regard to reliability standards, there is a history of regional voluntary self-regulation dating from 1968. Utilities in North America voluntarily formed regional reliability councils and an over-arching reliability council (NERC) in response to several major blackouts that occurred earlier in the decade. These voluntary organizations set the framework for reliability standards that exists today—national minimum standards that are supplemented by additional regional minimum standards, which are also supplemented by individual utility minimum standards.

The initial standards were set by the utilities and observed on a voluntary basis. Voluntary compliance was widely obeyed during the period of vertically-integrated utilities as they

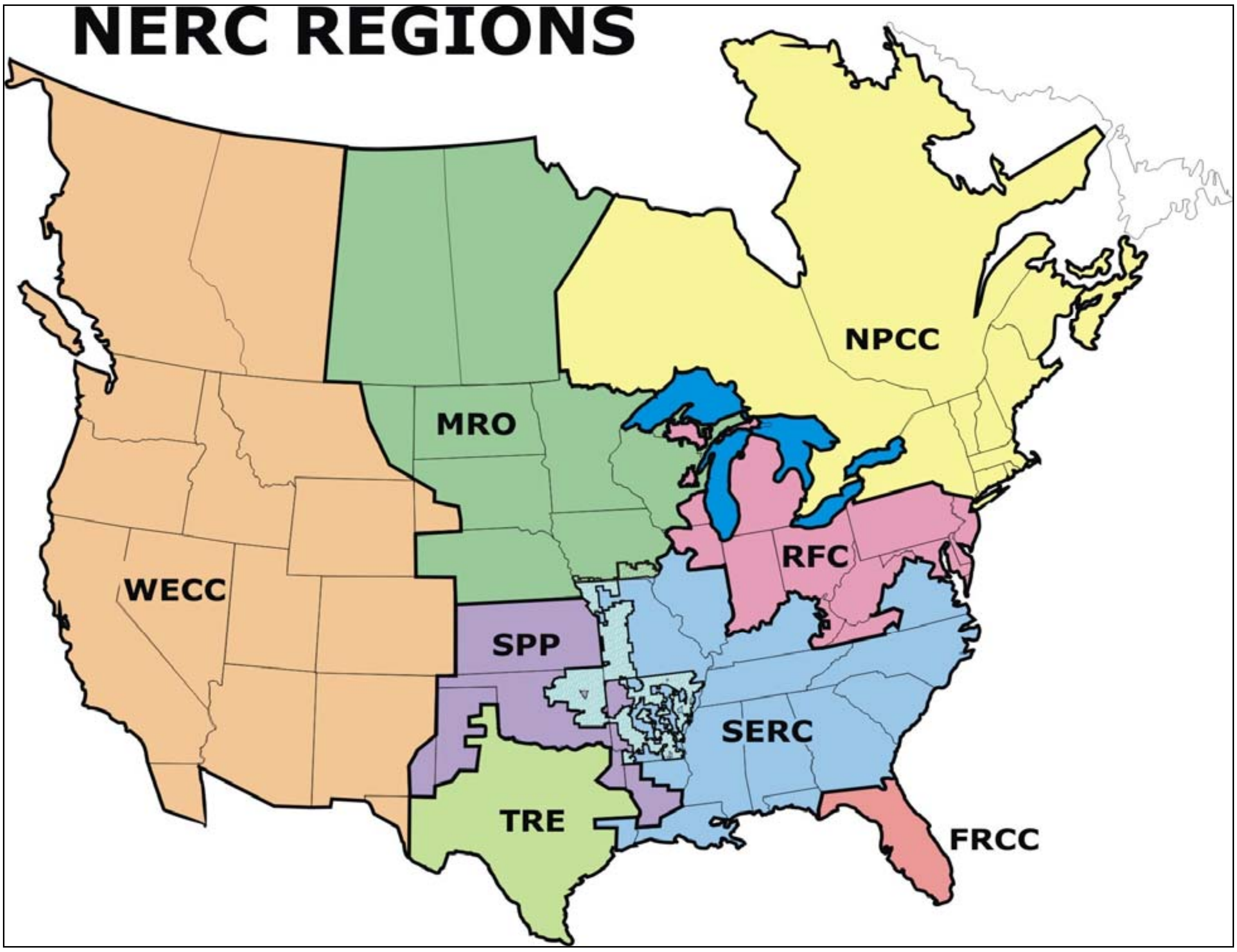
3. For the full list see ftp://www.nerc.com/pub/sys/all_updl/compliance/org/NERC_Compliance_Registry_List.pdf.

were subject to state and federal scrutiny and faced potential law suits for failure to comply with the standards. Breaking the vertical utilities into generation, distribution and transmission businesses/ownership also broke the clear accountability that made the voluntary system effective. There was no longer obvious clarity regarding which entity was responsible for any particular system failure and competition among generators diminished the public service aspect of the industry.

While NERC's role was initially to promote, coordinate and communicate about the reliability of the generation and transmission systems, by the mid-1990s it was clear that such a voluntary organization would be adequate to meets the needs a of a changing industry structure. In 2006 NERC was certified as the "electric reliability organization" for the United States and is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by FERC and governmental authorities in Canada.

NERC works with the eight regional entities shown in Figure 1 to improve the reliability of the bulk power system. The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

Figure 1: The eight NERC regions



Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
ReliabilityFirst Corporation (RFC)
SERC Reliability Corporation (SERC)
Southwest Power Pool, RE (SPP)
Texas Regional Entity (TRE)
Western Electricity Coordinating Council (WECC)

2.2 Instruments used to give effect to consistency of reliability standards

Reliability Standards are the planning and operating rules that electric utilities follow to ensure the most reliable system possible. These standards are developed by the industry using an open and inclusive process managed by the NERC Standards Committee. The Committee is facilitated by NERC staff and comprised of representatives from many electric industry sectors.

Proposed standards are reviewed and approved by the NERC Board of Trustees, which then submits the standards to the U.S. Federal Energy Regulatory Commission and Canadian provincial regulators for approval. Once approved by these governmental agencies, the standards become legally binding on all owners, operators and users of the bulk power system.

Standards must be just and reasonable, not unduly discriminatory or preferential, and in the public interest. Participation by industry experts and compliance personnel in the standards development process ensures that the standards are technically sound, fair and balanced.

2.3 Transmission reliability standards applied to the planning horizon

The criteria applicable to transmission planning are found in four standards:

1. TPL-001-0 — System Performance Under Normal Conditions (Category A);
2. TPL-002-0 — System Performance Following Loss of a Single BES (Bulk electric system) Element (Category B);
3. TPL-003-0 — System Performance Following Loss of Two or More BES Elements (Category C); and
4. TPL-004-0 — System Performance Following Extreme BES Events (Category D).

The purpose for all these standards is to make sure that power system simulations and associated assessments are made periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

The planners must demonstrate through a valid assessment that their portion of the interconnected transmission system is evaluated so that the reliability criteria are met for each of these categories:

- Category A—with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can be operated to supply projected customer demands and projected firm transmission services at all demand levels over the range of forecast system demands, under the conditions defined in Category A.
- Category B—the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B.
- Category C—the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category C. (The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm power transfers may be necessary to meet this standard.)
- Category D—the risks and consequences of a number of each of the extreme contingencies.

The contingencies to be evaluated and the acceptable system responses for each category are shown in Table 3, below.

Table 3: NERC transmission system planning criteria

Category	Contingencies	System limits or impacts		
	Initiating Event(s) and Contingency Element(s)	System stable and both thermal and voltage limits within applicable rating[a]	Loss of demand or curtailed firm transfers	Cascading outages
A No contingencies	All facilities in service	Yes	No	No
B Event resulting in the loss of a single element.	Single line ground (SLG) or 3-Phase (3Ø) fault, with normal clearing: 1. Generator 2. Transmission circuit 3. Transformer Loss of an element without a fault	Yes	No[b]	No
	Single pole block, normal clearing:[e] 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with normal clearing:[e] 1. Bus Section 2. Breaker (failure or internal fault)	Yes	Planned/ controlled[c]	No
	SLG or 3Ø fault, with normal clearing,[e] manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing:[e] 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ controlled[c]	No
	Bipolar block, with normal clearing:[e] 4. Bipolar (DC) line fault (non 3Ø), with normal clearinge: 5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ controlled[c]	No
	SLG fault, with delayed clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes	Planned/ controlled[c]	No
D[d] Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Ø Fault, with delayed clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission circuit 4. Bus section	Evaluate for risks and consequences. • May involve substantial loss of customer Demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.		
	3Ø Fault, with Normal Clearing:[e] 5. Breaker (failure or internal Fault)			
	6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major Load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another regional reliability organization.			

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

2.4 Institutional/governance models supporting the framework

2.5 Entities responsible for setting standards

2.6 Governance issues with framework

Membership in NERC is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American bulk power system. Each member shall elect to be assigned to one of the following membership sectors:

1. Investor-owned utility;
2. State/municipal utility;
3. Cooperative utility;
4. Federal or provincial utility/power marketing administration;
5. Transmission-dependent utility;
6. Merchant electricity generator;
7. Electricity marketer;
8. Large end-use electricity customer;
9. Small end-use electricity customer;
10. Independent system operator/regional transmission organization;
11. Regional reliability organization/regional entity; or
12. Government representatives.

The business and affairs of NERC are managed by an eleven-member Board of Trustees. Ten of the trustees shall be “independent” trustees nominated and elected by the Member Representatives Committee. The twelfth trustee is elected by the board to serve as president of the Corporation. Each trustee has one vote on any matter brought before the board for a vote. All trustees are expected to serve the public interest and to represent the reliability concerns of the entire North American bulk power system.

The Member Representatives Committee elects the independent trustees, votes on amendments to the Bylaws; and provides advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

The Member Representatives Committee consists of

1. Two representatives from each sector except the government representative sector and the regional reliability organization/regional entity sector,
2. Two voting representatives from the regional reliability organization/regional entity sector, with the remaining members of that sector being non-voting members of the Member Representatives Committee,
3. The chairman and vice chairman of the Member Representatives Committee,

4. Any additional Canadian representatives as are selected, and
5. Representatives of the government sector:
    a. two representatives of the United States federal government,
    b. one representative of the Canadian federal government,
    c. two representatives of state governments, and
    d. One representative of a provincial government.

2.7 The actual system level specified in the standards

2.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

2.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

2.10 Compensation of Transmission Owners

Transmission owners in North America are almost universally compensated using a rate base approach. Transmission customers are charged based on energy usage (in $/kWh).

Under state law, an electric utility is granted the right to serve its customers as a monopoly service franchise. As such, an electric utility is traditionally obligated to undertake necessary and appropriate improvements to the transmission and distribution systems it owns or utilizes in order to serve customers. In return for accepting this obligation to build, the utility is provided an opportunity to recover the costs of building its facilities, including a reasonable return (profit) on its capital investment. For instance, transmission owners are allowed a certain return on equity in the form of a regional transmission tariff, as determined by the FERC. In some circumstances there is a state jurisdictional component of that tariff that is set by state regulatory commissions.

In 2003 FERC proposed a three-part Transmission Pricing Policy to encourage RTO and ITC formation and reward new grid investment, FERC has proposed incentives for transmission owners who hand over operational control of their facilities or invest in new transmission as part of an RTO planning process. These incentives would increase the allowable profit margin (return on equity, or ROE) that monopoly service transmission entities could receive for their transmission investments. The pricing policy includes:

- First, in return for joining a Regional Transmission Organization (RTO), an owner of transmission facilities would receive a 0.5% increase in ROE through 2012.

- Second, for creating an Independent Transmission Company (ITC) that would manage its transmission assets, the transmission owner would receive an additional 1.5% increase in ROE through 2022.
- Third, for system enhancements that are made pursuant to an RTO planning process, the transmission owner would receive a 1.0 % increase in its ROE for that project.

2.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are four key areas of difference in applying transmission reliability standards in North America and those adopted within the NEM in Australia. These are expanded as follows:

1. Within North America a universal minimum standard is applied across all eight "regions" within North America that apply to all TOs whereas under the NEM each of the mainland state jurisdictions applies its own "regional" standard and approach to applying these.
2. Within North America NERC sets the universal minimum transmission reliability standards which are deterministic. In the NEM a mixture of deterministic and probabilistic forms of standards and planning methodologies are adopted across the five mainland state jurisdictions ranging from New South Wales and Queensland which apply pure deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.
3. Within North America NERC sets the universal minimum transmission reliability standards, subject to approval by FERC. In the NEM the transmission reliability standards are set by the individual state jurisdictions or by bodies nominated by the jurisdictions.
4. Within North America NERC sets the universal minimum transmission reliability standards, however, some NERC regions and many individual TOs have additional or more specific requirements that are in addition to the NERC standards. The NERC standards allow for single and multiple contingency events. Some individual TOs have additional requirements that provide higher levels of reliability for major load centers, very large customers, and for facilities that have national economic or security needs.
5. Within the NEM the standard for demand security can vary by the type of area of the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

3. Western U.S. & Canada	Western Electricity Coordinating Council (WECC) Standards
1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	The WECC is the FERC approved regional reliability entity for the western portion of the United States and Canada, as shown in §0 on page 30. As one of the eight NERC regions, the WECC oversees the NERC compliance effort in its region.
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	In addition to the NERC reliability standards, as a regional reliability entity WECC has the ability to develop additional standards applicable to its region and submit such standards for approval by NERC and FERC. Once such approvals are granted, entities operating within the WECC region have the same level of obligation to meet the WECC standards as the NERC standards. WECC has received approval of eight such regional standards to date, but none of those apply to the planning horizon. NERC also has the ability to grant deference to a WECC standard as a replacement for a NERC standard, subject to FERC approval, in cases where an exception from the NERC standard is justified by regional conditions. In such cases, the WECC standard would be comparable or more stringent to the NERC standard. No deference requests have been made to date by the WECC. See §3.2 on page 31
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?	Above and beyond compliance with the approved NERC and WECC standards, entities operating within the WECC region are free to establish additional standards, guidelines and criteria that apply within their jurisdiction. However, unlike the FERC approved standards, failure to comply with these individual entity requirements are not subject to FERC penalties and sanctions. (Two particular jurisdictions within the WECC region, California and Alberta, are examined in greater detail in separate templates.)
a. What form (deterministic, probabilistic, or variants) of standards are used?	The criteria are all deterministic.
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	The standards are consistent with the NERC minimum standards.
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The WECC has addition criteria that supplement the NERC minimums that address common corridors, adjacent transmission circuits, and voltage performance. The standards are universally applied within the WECC area.
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission	There is no distinction between transmission and subtransmission.

3. Western U.S. & Canada	Western Electricity Coordinating Council (WECC) Standards
networks?	
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	There is no distinction between transmission and subtransmission.
4. What institutional/governance models are used to support such frameworks?	
a. Regulatory institutions	The WECC is subject to regulation by FERC and regulators in Canada.
b. National planner or Regional Transmission Organization (RTO) planner	There is not WECC regional planning. WECC provides a forum for the TOs to coordinate their individual plans.
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	The TOs develop their individual plans.
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.	There is no WECC regional plan.
e. Accountabilities	The US TOs are accountable to the WECC, FERC, and appropriate individual state regulators. The standards are not yet binding for the one Mexican TO. Provincial legislation in Canada to enforce standards is still being development.
5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?	WECC specific standards are developed through due process with opportunity for comment and participation by stakeholders. Any such standards applying to the planning horizon would also require majority approval by the WECC Planning Coordination Committee, which represents the full cross-section of WECC members, as well as approval by the WECC Board of Directors before submittal to NERC and FERC as a proposed regional standard.
6. Governance issues with framework:	
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	Yes. WECC is and independent body that sets the regional minimum reliability standards, though individual TOs may have additional requirements.
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a	No. WECC enforces the NERC and WECC standards together. NERC and, ultimately, FERC backup the WECC in enforcing the standards.

3. Western U.S. & Canada	Western Electricity Coordinating Council (WECC) Standards
regulator or reliability council.	
7. To what degree does the framework specify the actual level of standards:	WECC can only formulate proposed standards that apply to its own region.
a. By connection point?	The minimum standards apply to all connection points.
b. By voltage level?	The minimum standards apply to all voltage levels.
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	Member entities within WECC are permitted to adopt their own set of additional, more stringent requirements, above and beyond the WECC and NERC standards. However, these are not enforced through the FERC compliance process. Therefore, the entity must have other measures (e.g., contractual) available to enforce such compliance with such standards. See §3.8 on page 32
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	In addition to the option to participate in development of local standards, any stakeholder has the ability to file a complaint regarding such criteria/standard(s) with the FERC if they question the validity of such a standard.
10. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as WECC vs. NEM (v) universal standard vs. regional standards (vi) deterministic with a probabilistic view of potential system events vs. mixture of deterministic and probabilistic approaches (vii) National minimum standard vs. set by individual jurisdictions (viii) uniform security vs. by type of area/customer supplied e.g. CBD

In North America, the North American Electric Reliability Council (NERC) is the organization that coordinates the reliability standards that determine the adequacy of the system. NERC's members are eight regional reliability councils whose members come from all segments of the electric industry: investor-owned utilities; federal power agencies; independent system operators, rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; state and provincial regulatory bodies; and end-use customers. These entities account for virtually all the electricity supplied and used in the United States, Canada, and a portion of Baja California Norte, Mexico.

The Western Electricity Coordinating Council (WECC) is geographically the largest of the eight regional reliability councils that make up the NERC. The WECC was established in 1967 in part, to promote electric system reliability throughout the fourteen USA western states, British Columbia, Alberta and the northern portion of Baja California, Mexico.

The WECC Reliability Criteria includes five main parts: NERC/WECC planning standards; power supply assessment policy; minimum operating reliability criteria; definitions; and process for developing and approving WECC standards.

In introducing their criteria, NERC/WECC state:

> "Electric system reliability begins with planning. The *NERC Planning Standards* state the fundamental requirements for planning reliable interconnected bulk electric systems. The Measurements define the required actions or system performance necessary to comply with the Standards. The Guides describe good planning practices and considerations.
>
> "With open access to the transmission systems in connection with the new competitive electricity market, all electric industry participants must accept the responsibility to observe and comply with the *NERC Planning Standards* and to contribute to their development and continued improvement. That is, compliance with the *NERC Planning Standards* by the Regional Councils (Regions) and their members as well as all other electric industry participants is mandatory."[4]

They further provide the following comments on these reliability standards:

> "The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and maintenance equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.
>
> "Electric systems must be planned to withstand the more probable forced and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels.
>
> "Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the

4 *NERC/WECC Planning Standards*, April 2005, Page 4.

entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

"The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these... Standards on Transmission Systems."

"System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs." [5]

3.1 Frameworks used to ensure consistency of transmission reliability standards

This means they include literally thousands of individual utilities. The utilities include many that are vertically integrated as well as those that have been restructured into separate generation, transmission and distribution units. The utilities include investor-owned, municipal (city-owned), state-owned, and federal multi-state utilities. The list of these utilities is 260 pages long.[6]

NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

3.2 Instruments used to give effect to consistency of reliability standards

Reliability Standards are the planning and operating rules that electric utilities follow to ensure the most reliable system possible. These standards are developed by the industry using an open and inclusive process managed by the NERC Standards Committee. The Committee is facilitated by NERC staff and comprised of representatives from many electric industry sectors.

Proposed standards are reviewed and approved by the NERC Board of Trustees, which then submits the standards to the U.S. Federal Energy Regulatory Commission and Canadian provincial regulators for approval. Once approved by these governmental agencies, the standards become legally binding on all owners, operators and users of the bulk power system.

Standards must be just and reasonable, not unduly discriminatory or preferential, and in the public interest. Participation by industry experts and compliance personnel in the

5. *Ibid.* page 9.

6. The full list of utilities can be found on the NERC website at ftp://www.nerc.com/pub/sys/all_updl/compliance/org/NERC_Compliance_Registry_List.pdf

standards development process ensures that the standards are technically sound, fair and balanced.

3.3 Transmission reliability standards applied to the planning horizon

3.4 Institutional/governance models supporting the framework

3.5 Entities responsible for setting standards

3.6 Governance issues with framework

3.7 The actual system level specified in the standards

3.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

The WECC adopts and meets all the NERC minimum planning standards. They have added or clarified a number of criteria related to voltage collapse and transient stability that more specific than required by NERC. The4se include:

- WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems contained in this section when planning the Western Interconnection. The WECC Disturbance-Performance Table does not apply internal to a WECC Member System.
- The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the common mode contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
- The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.
- There are additional criteria related to voltage performance following a transient event.

3.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

3.10 Compensation of Transmission Owners

3.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are four key areas of difference in applying transmission reliability standards in WECC and those adopted within the NEM in Australia. These differences, very similar to those between NERC and the NEM, are expanded as follows:

1. Within North America a universal minimum standard applies to the WECC whereas under the NEM each of the mainland state jurisdictions applies its own "regional" standard and approach to applying these.
2. Within North America NERC sets the universal minimum transmission reliability standards which are deterministic. The WECC has several addition requirements that are also deterministic. In the NEM a mixture of deterministic and probabilistic forms of standards and planning methodologies are adopted across the five mainland state jurisdictions ranging from New South Wales and Queensland which apply pure deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.
3. Within North America NERC sets the universal minimum transmission reliability standards, subject to approval by FERC. These apply to the WECC. In the NEM the transmission reliability standards are set by the individual state jurisdictions or by bodies nominated by the jurisdictions.
4. Within North America NERC sets the universal minimum transmission reliability standards, however, WECC and some individual TOs have additional or more specific requirements that are in addition to the NERC standards. The NERC standards allow for single and multiple contingency events. Some individual TOs have additional requirements that provide higher levels of reliability for major load centers, very large customers, and for facilities that have national economic or security needs.

   Within the NEM the standard for demand security can vary by the type of area of the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

4. California ISO	
1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	Although there are a variety of political jurisdictions and/or separately owned transmission networks in the state, most of the customer demand in California is supplied over the California Independent System Operator (CAISO) controlled grid. The CAISO oversees the transmission expansion planning processes and transmission operations of the three investor-owned utilities in the state Southern California Edison (SCE), Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), as well as a number of municipal utilities and at least one transmission merchant company that have placed their transmission assets under the control of the CAISO through executing a Participating Transmission Owner Agreement. See §4.1 on page 39
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	The CAISO controlled grid (along with its individual Participating Transmission Owners) is subject to NERC and Western Electricity Coordinating Council (WECC) reliability standards. In addition, all Participating Transmission Owners (PTOs) are contractually obligated / required to comply with the provisions of the CAISO Tariff on file at FERC, which includes provisions related to power system planning and reliability criteria. See §4.2 on page 40
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?	The CAISO's reliability standards relating to the planning horizon are detailed in the "California ISO Planning Standards" as outlined below. See §4.3 on page 40
a. What form (deterministic, probabilistic, or variants) of standards are used?	Deterministic, with certain generation outage planning assumptions based on historical probabilities.
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	Same as NERC and WECC, except CAISO requirements for NERC Category B performance specifies an overlapping outage of one transmission line and one generator (i.e., CAISO deems this to be an "n-1" level contingency). CAISO also observes additional power system reliability criteria (off site grid stability requirements) for nuclear power stations as specified by the Nuclear Regulatory Commission in licenses for the San Onofre and Diablo Canyon nuclear power plants

4. California ISO	
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	CAISO Planning Standards do not differentiate explicitly between different parts of the network. However, CAISO recognizes that it may not be economically justified in every case to construct new facilities in order to avoid involuntary loss of load for NERC Category B events affecting radial and local network customers. In such cases the CAISO Board has the option to determine that capital project expansion is not justified after considering all the costs and benefits.
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	Although NERC and WECC reliability standards apply only to 100 kV and above, the CAISO also controls planning standards for subtransmission facilities down to 69 kV in both PG&E and SDG&E. The CAISO does not differentiate in its planning standards between the system above and below 100kV.
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	The CAISO uses a joint planning approach for transmission and subtransmission.
4. What institutional/governance models are used to support such frameworks?	The CAISO was created by state law, and has a Board of Directors appointed by the Governor. PTO owners are contractually bound to abide by the CAISO Planning Standards and the decisions of the ISO Board. See §4.4 on page 40
a. Regulatory institutions	The CAISO operates under a FERC approved tariff. PTOs are licensed by California.
b. National planner or Regional Transmission Organization (RTO) planner	CAISO filed for RTO status with FERC in 2000, but the proceeding was closed by the FERC in 2005 without reaching a finding.
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	Transcos are eligible to participate in NERC, WECC and CAISO standard development.
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.	Transcos are obligated to observe approved NERC, WECC and CAISO planning standards/criteria.

4. California ISO	
e. Accountabilities	If a PTO fails to meet CAISO Planning Standards, the CAISO has authority to arrange with another PTO or Transco to construct the facilities needed to meet reliability standards and to roll these facilities into its regulated assets (rate base).
5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?	Interpretation of the NERC and WECC reliability criteria and recommendations for any exceptions to those criteria (e.g., for more stringent standards) are developed by the CAISO Grid Planning Standards Committee, which is comprised of CAISO staff members and interested stakeholders.
6. Governance issues with framework:	
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	Yes. The CAISO is independent from PTOs and Transcos.
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	No. The CAISO enforces conformance with its standards.
7. To what degree does the framework specify the actual level of standards:	
a. By connection point?	Not applicable.
b. By voltage level?	Not applicable.
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	All PTO's within the CAISO plan to the same standards. However, non-CAISO transmission owners within the state of California must all meet the NERC/WECC standards though some may have different standards, above and beyond the NERC/WECC requirements.

4. California ISO	
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	Due to the common NERC/WECC standards that apply to all transmission facilities and/or jurisdictions in California, there is minimal divergence between the reliability standards of the CAISO and non-CAISO transmission owners.
10. How are transmission owners compensated for their transmission costs?	PTOs within the CAISO receive cost recovery for transmission costs through FERC approved rates. See §4.10 on page 41
11. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as CAISO vs. NEM (ix) universal standard vs. regional standards (x) deterministic with a probabilistic view of potential system events vs. mixture of deterministic and probabilistic approaches (xi) National/state minimum standard vs. set by individual jurisdictions (xii) Uniform security vs. by type of area/customer supplied e.g. CBD See §4.11 on page 41

4.1 Frameworks used to ensure consistency of transmission reliability standards

All utilities in the state of California are subject to the mandatory reliability standards implemented by NERC and FERC. The vast majority of electric demand within the state of California is served over the CAISO grid, but several notable municipal utilities (Los Angeles Depart of Water and Power, Sacramento Municipal Utility District, etc.), state agencies and state chartered water/power authorities also own and operate transmission within the state. The area covered by the CAISO is shown in Figure 2.

Figure 2: Area included in the CAISO

The CAISO Tariff specifies that the grid shall be planned according to the Applicable Reliability Standard, which is defined as the reliability standards established by NERC, WECC and local reliability criteria, including any requirements of the Nuclear Regulatory Commission (NRC).

4.2 Instruments used to give effect to consistency of reliability standards

CAISO Grid Planning Standards build on, rather than duplicate, standards developed by WECC and NERC. The goals of CAISO's Grid Planning Standards are to:

- Address specifics not covered by NERC/WECC planning standards;
- Provide interpretations of the NERC/WECC planning standards specific to the ISO Grid; and
- Identify whether CAISO requires any more stringent criteria than specified by the NERC/WECC standards.

4.3 Transmission reliability standards applied to the planning horizon

The CAISO reliability criteria relating to the planning horizon are defined by the California ISO Planning Standards.

4.4 Institutional/governance models supporting the framework

The California Public Utilities Commission (CPUC) is currently implementing a statewide resource planning process that encompasses the service areas of all the investor-owned utilities within the CAISO controlled grid. A key component of this resource planning process is the development of Local Capacity Requirements (LCR) by supply areas. At this time the LCR criteria are still being formulated and it is unclear how, of if, they will be incorporated into the CAISO planning standards.

4.5 Entities responsible for setting standards

4.6 Governance issues with framework

4.7 The actual system level specified in the standards

4.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

4.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

4.10 Compensation of Transmission Owners

The cost of transmission facilities above 200kV is shared prorate between all PTO's, regardless of its ownership or location. The cost of transmission facilities below 200kV is borne solely by the host PTO.

4.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are four key areas of difference in applying transmission reliability standards in CAISO and those adopted within the NEM in Australia. These differences, very similar to those between NERC and the WECC, and the NEM, are expanded as follows:

1. Within North America a universal minimum standard applies to the WECC and the CAISO, whereas under the NEM each of the mainland state jurisdictions applies its own "regional" standard and approach to applying these.
2. Within North America NERC sets the universal minimum transmission reliability standards which are deterministic. The WECC has several addition requirements that are also deterministic. The CAISO also has a probabilistic component to the criteria it uses for major generator connection. In the NEM a mixture of deterministic and probabilistic forms of standards and planning methodologies are adopted across the five mainland state jurisdictions ranging from New South Wales and Queensland which apply pure deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.
3. Within North America NERC sets the universal minimum transmission reliability standards, subject to approval by FERC. These apply to the WECC and CAISO. In the NEM the transmission reliability standards are

set by the individual state jurisdictions or by bodies nominated by the jurisdictions.

4. Within North America, NERC sets the universal minimum transmission reliability standards, however, WECC, CAISO and some individual TOs have additional or more specific requirements that are in addition to the NERC standards. The NERC standards allow for single and multiple contingency events. Some individual TOs have additional requirements that provide higher levels of reliability for major load centers, very large customers, and for facilities that have national economic or security needs.

   Within the NEM the standard for demand security can vary by the type of area of the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

5. North America—AESO	The Alberta Electric System Operator (AESO)
1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	The AESO is responsible for operating the power system in real time and for planning the transmission system. In alternating years they publish a *10-Year Transmission System Plan* and *20-Year System Outlook*. They are continuously involved in a stakeholder processes that refine the projects identified in these reports. See §5.1 on page 48
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	The AESO started operation in 2003, but dates from 1996 when one of our predecessor companies, the Power Pool of Alberta, created Canada's first competitive market for electricity. The AESO now operates Alberta's $8-billion wholesale power market. The AESO's role is defined by legislation called the Electric Utilities Act.
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?	The AESO controlled grid is subject to NERC and WECC reliability standards. In addition, the AESO has a number of specialized additional criteria that apply to its unique situation with very limited interconnections to other systems.
a. What form (deterministic, probabilistic, or variants) of standards are used?	The standards are deterministic.
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	They examine all NERC Category A, B, C and D conditions which include single and multiple contingency events.
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The AESO enforces a single set of planning standards that are applied to all TOs in Alberta.
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	Within the province, there is no variation among the TOs. There are several additional requirements or specific conditions that the AESO uses inaddition to the NERC and WECC minimum standards.

5. North America—AESO	The Alberta Electric System Operator (AESO)
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	All network transmission above 69 kV is subject to the same planning standards.
4. What institutional/governance models are used to support such frameworks?	The AESO was created by provincial law, and has an independent Board of Directors. All TOs are bound to implement the transmission plans developed by the AESO.
a. Regulatory institutions	The AESO operates primarily under the authority of the Alberta legislature and is regulated by the Alberta Utilities Commission (AUC).
b. National planner or Regional Transmission Organization (RTO) planner	The AESO is responsible for planning the entire Alberta transmission system.
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	The TOs participate as stakeholders and work collaboratively with the AESO as it develops its plans. The AESO is solely responsible for proposing solutions to criteria violations that it identifies.
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.	The plans are imposed on the TOs. The AESO makes the final decision regarding all plans, subject to approval by the AUC.
e. Accountabilities	The AESO is accountable to the AUC. The TOs are similarly accountable to the AUC that sets and approves electric transmission rates.
5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?	The planning standards are set by NERC, the WECC, and the AESO. There are no individual TO planning standards.

5. North America—AESO	The Alberta Electric System Operator (AESO)
6. Governance issues with framework:	
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	The AESO accepts and enforces the NERC and WECC standards and independently sets and enforces the Alberta standards.
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	No. The AESO is, however, independent of the TOs.
7. To what degree does the framework specify the actual level of standards:	There is a single set of standards that is applied regardless of connection point or voltage level.
a. By connection point?	The importance of reliable service to Calgary and Edmonton is recognized and will have an effect on the priority that may be placed on certain projects.
b. By voltage level?	
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	There is no divergence within Alberta.
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	There are no such issues.
10. How are transmission owners compensated for their transmission costs?	The TOs are compensated based on a combination of energy ($/ kwh) and demand ($/kW) charges set by the AUC. See §5.10 on page 49

5. North America—AESO	The Alberta Electric System Operator (AESO)
11. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as AESO vs. NEM (xiii) Universal standard vs. regional standards (xiv) Deterministic vs. mixture of deterministic and probabilistic approaches (xv) Province-wide standard vs. set by individual jurisdictions (xvi) Uniform security vs. by type of area/customer supplied e.g. CBD See §5.11 on page 49

The AESO, as the transmission system planning and operating authority in the Province of Alberta, has a responsibility under section 16 of the *Electric Utilities Act* "…to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity."

Section 20 of the Act provides that the AESO "may make rules respecting … (e) planning the transmission system, including criteria and standards for the reliability and adequacy of the transmission system".

The AESO:

- Is responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System (AIES).
- Provides open and non-discriminatory access to Alberta's interconnected power grid for generation and distribution companies and large industrial consumers of electricity. In doing so, the AESO contracts with transmission facility owners to acquire transmission services and, with other parties to provide fair and timely access to the system.
- Develops and administers transmission tariffs, procures ancillary services to ensure system reliability and manages settlement of the hourly wholesale market and transmission system services.
- Facilitates Alberta's competitive wholesale electricity market, which has more than 200 participants and about $5 billion in annual energy transactions.
- Ensures a fair, open and efficient market for the exchange of electric energy in Alberta and effective relationships with neighbouring jurisdictions.
- Ensures that Alberta's competitive electricity markets continue to operate in the best way possible, demonstrating that reliability is not compromised and that the structure is sustainable, predictable and adds long-term value.
- Is accountable for the administration and regulation of the provincial load settlement function.
- Is governed by an independent board, which provides advice and direction of market participants and has a diverse background in finance, business, electricity, oil and gas, energy management, regulatory affairs and technology.
- Is a not-for-profit entity, that is independent of any industry affiliations and owns no transmission or market assets.

Planning criteria are designed to ensure that there are adequate transmission resources available to reliably connect generation and load to the system. They take into account variations in load levels, generation dispatch, and transaction levels. Scheduled and reasonably expected unscheduled outages of generation and transmission system elements are also considered.

The AESO, as a member of the WECC and a signatory to the WECC's Reliability Management System Agreement, is required to follow the *NERC/WECC Planning Standards* in planning the Alberta system and its interconnections.[7]

The operation and planning of Alberta's existing transmission system must adhere to criteria developed by NERC/WECC. The NERC/WECC reliability standards and criteria are also central to assessing the adequacy of the future transmission system. With an adequately planned system and prudent operating criteria, the AESO can operate the Alberta Interconnected Electric System (AIES) reliably while facilitating an open and competitive market. For details concerning the AESO's reliability criteria, please refer to the AESO's website, www.aeso.ca. This site has documents that describe the reliability criteria and standards used in planning and operating the transmission system.

5.1 Frameworks used to ensure consistency of transmission reliability standards

The AESO is the sole body responsible for setting transmission standards in Alberta.

5.2 Instruments used to give effect to consistency of reliability standards

5.3 Transmission reliability standards applied to the planning horizon

5.4 Institutional/governance models supporting the framework

5.5 Entities responsible for setting standards

5.6 Governance issues with framework

7 The Standards are relatively lengthy (100 pages). The WECC Standards referred to here are those dated 10 April 2003. The document can be found in the WECC library at http://www.wecc.biz

5.7 The actual system level specified in the standards

5.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

5.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

5.10 Compensation of Transmission Owners

The TOs are subject to rate-base regulation with rates set by the AUC.

5.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are four key areas of difference in applying transmission reliability standards by the AESO and those adopted within the NEM in Australia. These differences, very similar to those between NERC and WECC, and the NEM, are expanded as follows:

1. Within North America a universal minimum standard applies to the WECC and the AESO whereas under the NEM each of the mainland state jurisdictions applies its own "regional" standard and approach to applying these.
2. Within North America NERC sets the universal minimum transmission reliability standards which are deterministic. The WECC has several addition requirements that are also deterministic. In addition, the AESO has special conditions and deterministic standards that affect imports and exports from the region. In the NEM a mixture of deterministic and probabilistic forms of standards and planning methodologies are adopted across the five mainland state jurisdictions ranging from New South Wales and Queensland which apply pure deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.
3. Within North America NERC sets the universal minimum transmission reliability standards, subject to approval by FERC. These apply to the WECC. In the NEM the transmission reliability standards are set by the individual state jurisdictions or by bodies nominated by the jurisdictions.

4. Within North America NERC sets the universal minimum transmission reliability standards, however, WECC and the AESO have additional or more specific requirements that are in addition to the NERC standards. The NERC standards allow for single and multiple contingency events.

   Within the NEM the standard for demand security can vary by the type of area of the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

6. Europe—Great Britain (GB)	
1. What frameworks are used to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	The British Electricity Trading & Transmission Arrangements (BETTA) put in place in April 2004 created an overarching framework by which transmission reliability standards are governed and applied on a consistent basis across the three GB Transmission Owners (TOs) and consequently across GB. See §6.1 on page 55
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	BETTA was enacted by primary UK legislation. This enforced all required changes and consolidation of relevant existing GB electricity industry codes and contractual agreements; as well the creation of the required new industry codes. Transmission reliability standards are specifically governed by the GB Security & Quality Standards of Supply (GBSQSS) document which is administered by the GB System Operator (GBSO). Each of the Transmission Owners (TO) are obliged under their transmission licenses to adhere to the GBSQSS in designing and developing their transmission networks. Furthermore the transmission license requires the TOs to be signatories to the SO/TO Code (again administered by the GBSO) which amongst other things defines the required interaction between the GBSO and the TOs for transmission planning purposes. See §6.2 on page 55
3. What transmission reliability standards (relating to the planning horizon) are applied?	GB has always applied a deterministic form of standard. See §6.3 on page 56
a. What form (deterministic, probabilistic, or variants) of standards are used?	GB uses a deterministic standard applied to a single generation and demand background with additional insight provided by a probabilistic assessment of potential market scenarios (i.e. patterns and types of generations; levels and pattern of demand). See §6.3.1 on page 56
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	GB applies an N-2 standard to the Main Interconnected Transmission system (MITS) in GB and specific connection design criteria relating to generation and demand connections reflecting size of connection. See §6.3.2 on page 57
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The standards are applied universally across GB. The standards provide for varying levels of demand security based on the size of the demand group being supplied at the connection point (e.g. the smaller the demand group the more time is permitted before restoration of supplies). See §6.3.3 on page 61

6. Europe—Great Britain (GB)	
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	There is no distinction between transmission and subtransmission in GB. See §6.3.4 on page 61
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	There is no distinction between transmission and subtransmission in GB. See §6.3.5 on page 62
4. What institutional/governance models are used to support such frameworks?	See §6.4 on page 61
a. Regulatory institutions	OFGEM (the Office for Gas and Electricity Markets), the GB regulator for gas and electricity, enforces compliance with the transmission reliability standards specified in the GBSQSS. This includes investigations and via the regulatory review of the transmission investment plans developed and implemented by the TOs to meet the standards. The regulator takes a particular interest in those investments proposed by the GBSO under the GBSQSS cost/benefit principles See §6.4.1 on page 61
b. National planner or Regional Transmission Organization (RTO) planner	The GBSO administers the SO/TO Code and GBSQSS, respectively covers transmission planning and transmission reliability standards in GB. The GBSO also plays a role by ensuring compliance with the SO/TO Code and GBSQSS. GBSO is the first body responsible for ensuring that TOs comply with obligations and it has the right to refer TOs to OFGEM where the GBSO believes there is an issue of non-compliance and which it is unable to resolve directly with the relevant TO. See §6.4.2 on page 61
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	The TOs develop their transmission plans in accordance with the requirements of the GBSQSS and based on the a data set, including generation and demand forecasts, provided to them by the GBSO under the SO/TO code. See §6.4.3 on page 61
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.	Under the SO/TO Code, the TOs are responsible for development of their transmission investment plans in accordance with the GBSQSS for their respective transmission areas. These are subject to scrutiny by the GBSO and the GBSO can request amendment and/or addition to these transmission investment plans if the GBSO feels they do not comply with GBSQSS. (As previously noted, GBSO can also request additional cost benefit driven transmission investment be included). Where the GBSO and TOs fail to mutually agree finalized transmission investment plans this leads to referral to OFGEM for a determination; which must then be adhered to by all parties. See §6.4.4 on page 62

6. Europe—Great Britain (GB)	
e. Accountabilities	OFGEM – approves and enforces the standards GBSO – administers the standards TOs – apply the standards See §6.4.5 on page 62
5. Who sets the standards?	As indicated in 4.e. above, the standards are approved and enforced by OFGEM, although the GBSO plays a key advisory role as administrator of the GBSQSS in any revisions and the TOs have been joint authors of recent proposed changes to changes and detailed drafting issues. See §6.5 on page 63
6. Governance issues with framework:	See §6.6 on page 64
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	Yes as indicated in 5. above; the GBSQSS principles are approved by OFGEM and the detailed drafting is also endorsed/set by OFGEM (based on industry consultation and guidance/proposals from the GBSO and TOs) See §6.6.1 on page 64
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	In the first instance the GBSO is authorized under the SO/TO Code to monitor compliance with the GBSQSS by the TOs within the defined GB transmission planning process. However, as indicated in 4.d. above, if there is disagreement between the TO and SO, then OFGEM is ultimately responsible for determining and enforcing compliance with the standards. In practice, there is no separation between the standard setting body and the ultimate enforcement/compliance body: either GBSO sets standards and enforces them or OFGEM does so. See §6.6.2 on page 64
7. To what degree does the framework specify the actual level of standards:	See §6.7 on page 64
a. By connection point?	As indicated above, different requirements are specified for the Main Interconnected Transmission System and for generation connections and demand connections. For connections the same requirements are applied regardless of location. Differing standards are applied depending on the size of the generator or demand group at the connection point and Users can opt for a lower level of security.
b. By voltage level?	Under the GBSQSS, the standards are applied universally across transmission voltages
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	In GB, transmission reliability standards are not allowed to diverge across the three AC interconnected TOs i.e. a single GB standard is universally applied. See §6.8 on page 64

6. Europe—Great Britain (GB)	
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	This is not strictly applicable under the current uniform application by the three GB TOs of a universal transmission reliability standard under BETTA. A legacy of BETTA and the requirement for Scotland to apply more onerous transmission reliability standards for planning than pre-2004; is that substantial parts of the Scottish transmission networks owned by the two Scottish TOs do not yet fully meet GBSQSS planning standards. As a consequence, the GBSO incurs significant system operation costs to secure the network in operational timeframes against operational contingencies in compliance with the relevant requirements of the GBSQSS. This has implications for GBSO's costs of operating the transmission system, about which there are regulatory incentives, (and also acts as driver for GBSO requests to TOs to implement cost/benefit driven transmission investments). See §6.9 on page 64
10. How are transmission owners compensated for their transmission costs?	The three GB TOs are now subject to a coordinated 5 yearly regulatory review cycle where OFGEM review all aspects of their transmission business activities to set maximum allowed revenue that is recoverable from regulated services for each of the coming 5 years. A key determinant of this is the opex and capex requirements. On of the core elements of the capex is transmission investments deemed to be required to comply with GBSQSS in the light of projected generation and load developments. The GBSO collects tariffs from all Users and distributes it to the TOs in order that they recover their revenue allowances under their respective licenses See §6.10 on page 65
11. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as GB vs. NEM (i) universal standard vs. regional standards (ii) deterministic (with additional justification based on probabilistic market background) vs. mixture of deterministic and probabilistic approaches (iii) standard set by overarching regulator vs. set by individual jurisdictions (iv) standard for demand security varies by size of demand group vs by type of area/customer supplied e.g. CBD See §6.11 on page 65

Supplemental information

To supplement and/or expand on the answers provided in the tables above for the GB market and its application of transmission reliability standards, KEMA provides additional information for each of the issues the table covers.

The definition of Transmission varies slightly across GB as follows:

- England and Wales - Greater than 132kV
- Scotland - Greater than *or equal to* 132kV.

The transmission/distribution boundary is normally on the low voltage side of the "Grid" transformer. However, anomalies do exist and can be highly complex.

6.1 Frameworks used to ensure consistency of transmission reliability standards

It should be noted that Scotland has its own "regional" Government and thus "regional" political and legal jurisdiction within the overall national UK nation state. Thus BETTA applies across both multiple TOs and multiple political jurisdictions within GB.

6.2 Instruments used to give effect to consistency of reliability standards

Compliance with the GBSQSS is a license obligation on the TOs i.e. it is enforced via their transmission Licenses which they must be granted by the UK Government under the powers of relevant UK primary legislation. The GBSQSS:

- Sets the minimum capacity for Users when planning the system;
- Sets the minimum available capacity when operating the system;
- Embeds a level of security into the network to protect against credible faults - "secured events"; and
- Enables maintenance to be undertaken.

In addition, the GBSQSS contains an economic test for greater investments; but also users of the TO systems (e.g. a newly connecting generator) can choose a lower standard for themselves than that as specified in the GBSQSS. However, in this latter situation the user is deemed not to have "firm access" and forfeits compensation rights for disconnection.

While nominally there is a GBSO and three TOs; in practice National Grid Electricity transmission (NGET) acts as a TSO for England & Wales and Scottish Power Transmission (SPT) and Scottish Hydro Electric Transmission Ltd (SHETL) act as pure TOs for southern and northern Scotland respectively.

Consequently while the transmission planning process covering the roles of the SO and TO is effectively internalized within NGET, there is a requirement for a formal relationship between NGET acting as GBSO and the two Scottish TOs. This is provided for under multiple agreements, procedures and interactions through the SO/TO Code.

Overall the SO/TO Code defines the obligations, rights, procedures and information flows between the parties covering all relevant elements (Planning, Operation and Connection) as covered in the Grid Code. The diagram below indicates the full procedural relationships within the SO/TO Code

6.3 Transmission reliability standards applied to the planning horizon

6.3.1 Form of standards used

GB has always applied a deterministic form of standard. Pre BETTA the definition of the standard differed between England & Wales and Scotland. In short, the England & Wales N-2 standard was more onerous than the standard adopted in Scotland (which was more akin to N-1). Since BETTA, the N-2 deterministic standard has been applied GB-wide.

The GBSQSS standard envisages a single central case to be used for the assessment of the transmission reinforcements to be made and is referred to as the SYS background. This satisfies the obligations on the GBSO to plan the network to the standards.

Application of the deterministic standard within transmission planning continues to evolve, moving away from relying on the single required central forecast of generation and demand background at time of winter peak to recognize that:

- Generation capacity, location and behaviour uncertainty has increased post industry privatization in 1990;
- Demand shape has changed (e.g. due to increased air conditioning);
- Demand uncertainty has increased due to growth of embedded generation and increased wind power;
- SO activities have been subject to cost incentivizes;
- The GB transmission system has become more heavily utilized and thus constrained in operational timescales (given outages) and that the deterministic standards should be considered:
    - Against a number of generation scenarios (firstly via scenarios and now probabilistically)
    - Against off peak periods of demand
    - Against non-intact network
    - With an additional cost/benefit justification for transmission investment

The GSBO has started providing additional information to the market from a probabilistic model of likely transfers that also allow it to make decisions on how to apply the strict rules of the GBSQSS in times of increasing uncertainty, i.e. relying more heavily on these probabilistic models as justification for investments or avoidance of investment on economic grounds.

6.3.2 Levels of standards applied

This section describes the GBSQSS standards and how they are applied in reasonable detail.

6.3.2.1 Main interconnected transmission system (MITS)

For the Main Interconnected Transmission System (MITS) the GBSQSS specifies design requirements to meet N-2 criteria assuming an intact transmission system (i.e. no line or equipment outages) at time of winter peak demand, based on an Average Cold Spell (ACS) definition of demand.

Specifically the GBSQSS defines loss of supply capacity for the following different levels of fault outage (i.e. contingency):

- Single transmission circuit;
- Double circuit on supergrid;[8]
- Double circuit OHL in E&W/SHETL;
- Section of busbar; and
- With planned outage of single transmission.

The allowable loss of supply for each of these contingencies is indicated in the table below.

8. The 'Supergrid' includes transmission facilities at voltages greater than 200kV. The term Supergrid stemmed from the "superimposed grid" that was built on top of the 132kV system in the 1960s.

Table 5.1 Maximum permitted *loss of supply capacity* following *secured events*

Group Demand	Initial system conditions	
	Prevailing system conditions with no local system outage **Note 1,2**	*Prevailing system conditions with a local system outage* **Note 1**
over 1500 MW	None	None **Note 3**
over 300 MW to 1500 MW	None **Note 4**	None **Note 3**
over 60 MW to 300 MW	None except that where such facilities and suitable measures for restoration are available, up to 20 MW by automatic disconnection **Note 5**	Whole group up to *Group Demand* for up to the operational specified time to restore supply capacity
over 12 MW to 60 MW	None except that where such facilities and suitable measures for restoration are available, up to 12 MW by automatic disconnection for up to 15 minutes.	Whole group up to *Group Demand*
over 1 MW to 12 MW	Whole group up to *Group Demand* for up to the operational specified time to restore supply capacity	Whole group up to *Group Demand*
up to 1 MW	Whole group up to *Group Demand* for up to the operational specified time to restore supply capacity	Whole group up to *Group Demand*

In addition the TOs can consider system conditions throughout the year to assess whether there is sufficient network capacity for transfers throughout the year for all foreseeable generation conditions against the deterministic criteria; and furthermore higher standards may be used if these can be economically justified.

The application of the design criteria to ensure n-2 transmission reliability utilizes three key elements:

- Planned Transfer—is based on the generation most likely to run to meet peak system demand with an intact system. The "Planned Transfer" is the power flowing from areas of surplus power to areas in deficit. This is examined for key transmission boundaries on the network; and currently the GBSO will consistently examine 17 such boundaries (with others examined on a more *ad hoc* basis) within transmission planning processes.
- Interconnection Allowance—is used to ensure that limited transmission capacity is not an undue restriction in securing demand. It is important to note, however, that the Interconnection Allowance does not seek to provide a constraint free transmission system. The Interconnection Allowance permits the transmission planner to identify the necessary boundary capacity for a generation shortage in one area to be met by importing from another area (most of the time). Specifically, the N-2 or N-D requirement can be met for ~90% of actual generation and demand outcomes at ACS peak, assuming there is sufficient generation in the exporting area and there are no local constraints.

- Application of the 'Circle Diagram'—the Interconnection Allowance function is represented by a figure, known as the 'circle diagram', for which the abscissa is the sum of demand and generation in the smaller area as a percentage of twice the total peak demand. The 'circle diagram' can be thought of as taking into account such demand uncertainties as well as uncertainties concerning the 'on the day' availability of generation

6.3.2.2 Generation connections

For transmission connections of generation the GBSQSS specifies that:

(i) No loss of power infeed is allowed for
   a. Fault of single transmission line
   b. Planned outage of section of busbar

(ii) A normal loss of infeed (1000MW) is allowed for
   a. Fault outage of busbar section

(iii) An infrequent loss of infeed (1320MW) is allowed for
   a. Two transmission circuits
   b. Fault outage of busbar coupler/section switch

(iv) No loss of supply capacity is allowed for
   a. Fault of single transmission line, double circuit on the supergrid or section of busbar

6.3.2.3 Demand connections

For transmission connections of demand the GBSQSS specifies:

(i) No loss of supply capacity >1MW is allowed for planned outage of single transmission line or section of busbar

(ii) The level of acceptable loss of supply capacity for a planned outage + fault outage of single transmission circuit, using the table below:

Table 3.1 Minimum planning supply capacity following *secured events*

Group Demand	Initial system conditions	
	Intact system	With single *planned outage* **Note 1**
over 1500 MW	**Immediately** *Group Demand*	**Immediately** *Group Demand*
over 300 MW to 1500 MW	**Immediately** *Group Demand* **Note 2**	**Immediately** *Maintenance Period Demand* **Within time to restore *planned outage*** *Group Demand*
over 60 MW to 300 MW	**Immediately** *Group Demand* minus 20 MW **Note 3** **Within 3 hours** *Group Demand*	**Within 3 hours** Smaller of (*Group Demand* minus 100 MW) and one-third of *Group Demand*. **Within time to restore *planned outage*** *Group Demand*
over 12 MW to 60 MW	**Within 15 minutes** Smaller of (*Group Demand* minus 12 MW) and two-thirds of *Group Demand* **Within 3 hours** *Group Demand*	Nil
over 1 MW to 12 MW	**Within 3 hours** *Group Demand* minus 1 MW **In repair time** *Group Demand*	Nil
up to 1 MW	**In repair time** *Group Demand*	Nil

6.3.2.4 Allowable variations from GBSQSS requirements

Lower

A new user seeking direct connection to the transmission grid (i.e. a new connectee) can choose to apply for a lower standard of connection than that specified in the GBSQSS. The user is only able to do this where the consequences of this lower standard of connection is determined (through power system studies) by the GBSO and relevant TO not to impact on any other customer. Only the user can request the lower standard connection—a TO cannot impose it on an unwilling customer.

Higher

Where the GBSO identifies system issues which lead to high system operation costs, under the SO/TO Code it is entitled to request the TOs to undertake a study of potential additional transmission reinforcements/investment which exceed the minimum transmission design requirements specified in the GSQSS (and as outlined above) to alleviate the operational issue. This potential additional transmission investment must pass an economic test i.e. it must be justified on cost benefit grounds (e.g. cost of assts vs. savings in operational costs) to enable the GBSO to require the TOs to undertake such additional transmission investment over and above the minimum specified GBSQSS requirements.

6.3.3 Different levels of standard applied to different parts of network

The requirements are specified differently for the Main Interconnected Transmission System; generation connections, and demand connections.

There is no distinction made for the three TO parts of the overall transmission network based on voltages, geography or any other location specific factor.

6.3.4 Degree of consistency between transmission and sub-transmission networks reliability standards

There is no distinction between transmission and subtransmission in GB. Nonetheless, the GBSQSS and P2/6 standard align immediately either side of the transmission/distribution boundary to ensure effective and efficient development of the transmission and distribution networks.

6.3.5 Joint planning and development of transmission and sub-transmission networks so as to meet the reliability standards at least cost

There is no distinction between transmission and subtransmission in GB.

6.4 Institutional/governance models supporting the framework

6.4.1 Regulatory institutions

OFGEM is the sole regulatory institution concerned with the approving of and compliance with the GBSQSS transmission reliability standards. OFGEM's powers are enacted by relevant primary legislation put in place by the UK Government.

6.4.2 Regional Transmission Organization (RTO) planner

Strictly speaking, such a definition does not apply in the GB context as the GBSO essentially fulfills this role.

6.4.3 Role of transmission companies (GBSO and TOs) in determining the GB transmission investment plan

Great Britain has a national transmission plan which is developed by the GBSO and implemented by the three TOs. One of the TOs, NGET, is both the TO and for England and Wales and acts as the overall GBSO and, thus, interfaces with 2 Scottish TOs. In relation to transmission planning, NGET as the GBSO sets assumptions for planning investments i.e. the underlying market assumptions relating to demand and generation (including forecast generation openings, closures, plant mix and merit orders).

The Scottish TOs create investment plans and submit them to NGET in its role as GBSO. NGET effectively internalize this process as an integrated TSO for England & Wales. As GBSO, NGET identifies impacts on users from TO plans and acts to facilitate these planned works.

The TO's are prevented under the terms of their transmission Licenses and the SO/TO Code from acting until NGET as GBSO makes contractual modifications with the relevant user. Once the GBSO and user agree to such contractual modifications, NGET as the GBSO then puts in place construction agreements with the Scottish TOs for works in their transmission areas and mimics this internally as TSO for England & Wales. The relevant TO then undertakes its planned works in accordance with the construction agreement struck between the GBSO and the user.

NGET creates and shares its investment plans that would have an effect on the TO systems i.e. it provides restricted sight constrained to only the relevant information required by the TO. Where necessary NGET will also share limited information between TOs but fundamentally only NGET as GBSO has full national oversight of GB transmission investment plans.

6.4.4 Nature of planning arrangements—imposed/enforced or merely guidance

The GBSQSS transmission reliability standards are mandatory and TOs are required to apply them within their transmission planning as part of the conditions within their Transmission License granted to them by the UK Government.

The SO/TO code provides for construction offers from the TOs to meet their obligations to provide Offers to Users for connection. The SO/TO code also provides for co-ordination of investment plans and there are specific zones of influence (around the boundaries of the TO) where investments made by either party must be notified. A TO can make representations to another TO to modify its investment plans, however, there is no obligation for those changes to be made.

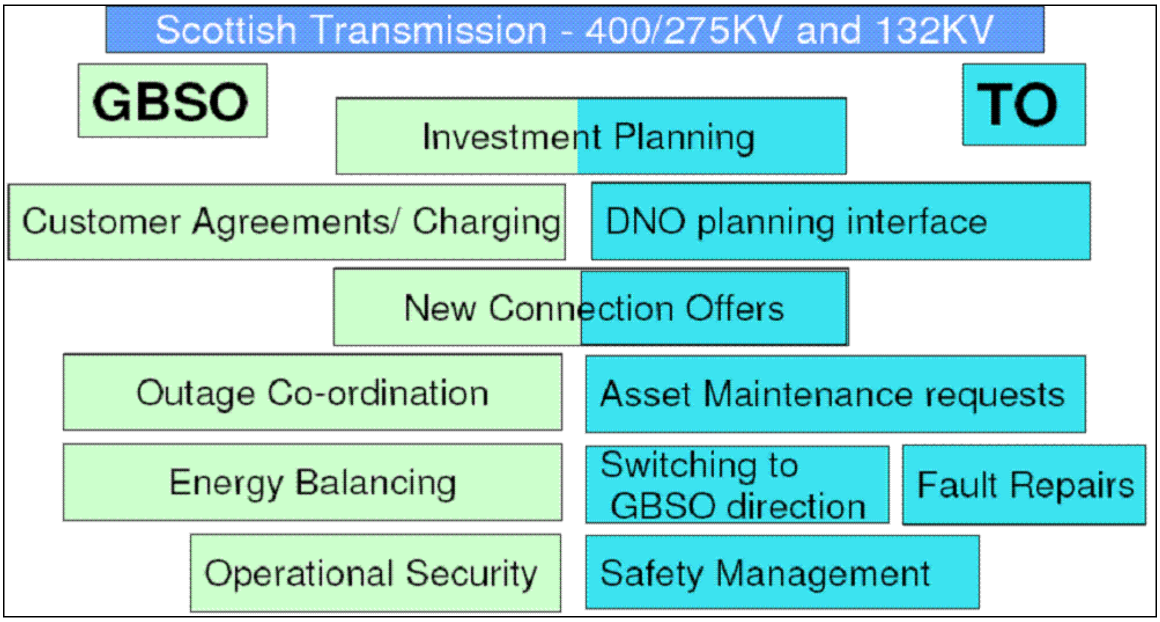
Disputes under the SO/TO code are referable to either Arbitration or to OFGEM (depending on the issue) for final and binding resolution.

6.4.5 Accountability

In essence, the GB electricity (and gas) industry regulator OFGEM approves the standards (and provides guiding principles). The GBSO administers the standards and requires the TOs to apply them within the auspices of the transmission planning process as governed by the SO/TO Code (which authorizes the GBSO to undertake this role). The TOs are thus simply accountable for applying the standards within their transmission planning to ensure compliance of their transmission networks with the requirements of the GBSQSS.

In a wider context, it is perhaps worth further clarifying the respective role of the GBSO and the TOs and where transmission (or investment) planning fits. Figure 3 illustrates the relationship between NGET as GBSO and the two Scottish TOs. Within England & Wales, NGET effectively undertakes and is accountable for all activities shown.

Figure 3: The relationship between NGET as GBSO and the two Scottish TOs



6.5 Entities responsible for setting standards

The standards were originally set by the Central Electricity Generating Board under the state ownership of the electricity industry in England & Wales many years before the industry was restructured in 1990. These were then formalized into an England & Wales SQSS in 1990; and following the implementation of BETTA in 2004, were extended (and refined) to cover GB.

At all stages the implementation and evolution of the standards would be subject to industry consultation. Ultimately under BETTA, the GBSO, as administrator of the GBSQSS, would first present its recommendations for any revisions based on the consultation. Subsequently, OFGEM would either agree and ratify these revisions or require changes to be made before agreeing the revised GBSQSS.

There is an ongoing process of review of the GBSQSS to ensure that it remains fit-for-purpose as more variable sources of generation (primarily wind) are connecting to the network. NGET and the two Scottish TOs have initiated a joint consultation with the industry to seek views on how the standards should be modified. Following that consultation they will undertake detailed drafting to put any changes into effect. The revised draft of the GBSQSS will be submitted to OFGEM for approval of these changes.

6.6 Governance issues with framework

6.6.1 Independence of body setting the standard from that which applies the standard

OFGEM approves the standard and the GBSO discharges its obligations regarding connections to meet these standards through the SO/TO Code. The TOs' transmission license obliges them to ensure that their network complies with the standards.

6.6.2 Separation between the standard setting body and the enforcement/compliance body

OFGEM is the ultimate enforcer/compliance body. Thus, there is no separation between the standard setting body and the ultimate enforcement/compliance body.

6.7 The actual system level specified in the standards

The GB transmission reliability standard is universally applied regardless of connection voltage or connection point.

6.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

No variation are allowed across the three GB TOs

6.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

Apart from the legacy issues relating to the Scottish networks, variations are not allowed. This is a legacy of BETTA that would otherwise require Scotland to apply more onerous transmission reliability standards for planning than existed pre-2004. The pre-2004 Scottish standards resulted in substantial parts of the Scottish transmission networks owned by the two Scottish TOs that do not yet fully meet GBSQSS planning standards e.g. transmission reliability standards in parts of the Scottish TO networks. The Scottish standards were more akin to n-1.

As a consequence, since BETTA was implemented, the GBSO incurs significant system operation costs to secure the network in operational timeframes against operational contingencies in compliance with the relevant requirements of the Grid Code (specifically the Operating Code within it). These costs arise from the constraining off and on of substantial volumes of generation within the Scottish TO networks by the GBSO for which it incurs costs through Bid/Offer instruction it issues within the GB Balancing Mechanism to seek to achieve this. NGET as GBSO is subject to an annual incentive scheme on such costs of operating the transmission system and where costs are materially higher than forecast at the time of agreeing the scheme this can lead to a direct P&L hit for NGET. [Consequently, this issue also acts as a driver for GBSO requests to TOs to implement cost/benefit driven transmission investments.] As there is a degree of sharing of both profits and losses under the GBSO's incentive scheme it also means costs borne by consumers have risen.

6.10 Compensation of Transmission Owners

The TOs are subject to RPI-X regulation by OFGEM. OFGEM sets revenue allowances for five-year periods based on their determination of appropriate capex and opex levels the TOs should incur. A key determinant of capex is transmission investments deemed to be required to comply with GBSQSS in the light of projected generation and load developments. Another driver is the need to replace ageing assets nearing end of their economic asset life or where performance becomes increasing unreliable.

To account for the significant uncertainty regarding generation-connection related expenditure, OFGEM has also implemented revenue drivers that provide a £/MW charge for incremental connection above the forecast known baseline of projects. This amount is set at a zonal level and aims to fund incremental investments in the network to meet the standards to accommodate incremental generation.

In addition, at each review, historic capex is reviewed to assess whether it was efficiently spent, and not unduly under or overspent by the TOs. Where OFGEM determines that "improprietary behaviour" has occurred it can:

(i) In the case of inefficient spend, disallow part or all of the relevant capex spend from the TOs Regulatory Asset Base; or

(ii) In the case of underspend, seek to recover this from the TOs.

Moving forward, OFGEM have also implemented an annual reporting regime to enable annual monitoring of TOs capex spend within regulatory review periods. Furthermore OFGEM are also seeking to implement a regime of transmission output measures against which it can more accurately monitor the TOs transmission performance and more accurately assess the TOs future capex needs (without unduly compromising transmission asset and network performance).

6.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are four key areas of difference in applying transmission reliability standards in GB and those adopted within the NEM in Australia. These are expanded as follows:

1. Within the GB market a universal standard is applied across all 3 "regional" TOs whereas under the NEM each of the mainland state

jurisdictions applies its own “regional” standard and approach to applying these.

2. Within the GB market the universal transmission reliability standard is deterministic (with additional justification based on probabilistic market background seeking to understand the implications of different patterns and mix of generation and demand on system power flows and other key technical characteristics of the transmission network such as voltage and stability. In the NEM a mixture of deterministic and probabilistic forms of standards and planning methodologies are adopted across the five mainland state jurisdictions ranging from New South Wales and Queensland which apply pure deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.
3. Within the GB market the universal transmission reliability standard is set by OFGEM, the GB electricity (and gas) regulator. In the NEM the transmission reliability standards are set by the individual state jurisdictions or by bodies nominated by the jurisdictions.
4. Within the GB market, the standard for demand security varies only by size of demand group i.e. it is independent of location or type of customer. Within the NEM the standard for demand security can vary by the type of area of the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

7. Europe—Germany	
1. What frameworks are used in other electricity markets to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	The Association of German network operators (VDN), which was established in June 2001, created an overarching governance framework for network issues in Germany under a policy document, known as the Associations' Agreement in 2003. Under this umbrella a Transmission Code was created that seeks to ensure transmission reliability standards are consistently defined and applied across the four German Regional Transmission System Operators (RTSOs): E.ON Netz GmbH, RWE Transportnetz Strom GmbH, Vattenfall Europe Transmission AG, and EnBW Transportnetze AG. See §7.1 on page 73
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	Transmission reliability standards are specifically governed by the German Transmission Code document which is administered by the Association of German network operators (VDN). The Transmission Code's legal framework was based on the EC Regulation 1228/ 2003 on conditions for access to the network for cross-border exchanges in electricity, including: the guidelines on congestion management and the Energy Industry Act of 07 July 2005 (EnWG) revising energy industry legislation and the relevant regulations based on the Directive 2003/54/EC concerning common rules for the internal market in electricity as well as the Renewable Energy Sources Act. The Transmission Code, based on EnWG, defines the rules as established by all the German RTSOs, system users, EU representatives, the German Federal Ministry of Economics and Labour representatives and the other members (together they compose the 95% of the German electricity network) within their membership of the VDN as general minimum requirements in order to ensure a well-functioning electricity market and a high technical quality of supply. The Transmission Code becomes binding on all parties involved, and is referenced in bilateral agreements between the RTSOs and market participants, such as network connection, network usage and framework agreements. See §7.2 on page 75
3. What transmission reliability standards (relating to the planning horizon) are applied in other electricity markets?	A single national German transmission reliability standard as defined by the Transmission Code is applied by the four TSOs within Germany. See §7.3 on page 75
a. What form (deterministic, probabilistic, or variants) of standards are used?	The German Transmission Code defines two types of planning: (i) development (i.e. long term) and (ii) operational planning (i.e. short term). Under the first, which is the area of interest for this study, the transmission network is planned and developed in accordance with a deterministic n-1 criterion See §7.3.1on page 75
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	Under the Transmission Code a deterministic N-1 standard is applied to the whole of the transmission system in Germany i.e. covering each of the 4 RTSOs. See §7.3.2 on page 75

7. Europe—Germany	
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The standards are applied universally across Germany i.e. covering each of the 4 German RTSOs. There are differing requirements specified for: (a) Connection of conventional generation versus connection of renewables generation (b) The "wide-spread main transmission system" which comprises network voltages of 220 kV and 380 kV versus transmission network groups of 110kV. See §7.3.3on page 76
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	In Germany, the planning and development of sub-transmission (i.e. distribution) networks is governed and specified by the Distribution Code. There is strong interconnection between the Transmission Code and the Distribution Code i.e. all of the technical characteristics of the networks and the System Services defined by the Transmission Code are treated in the Distribution Code as already defined by the Transmission Code i.e. the Distribution Code directly refers to the Transmission Code. As such the Distribution Code is subordinated to the Transmission Code. One of the key aims of the VDN is to achieve synergy and optimization between transmission and distribution network owners and operators. Thus under the requirements of both the Transmission and Distribution Codes, transmission and distribution system operators elaborate co-operatively their mutual positions and coordinate planning (and operational) activities). This seeks to ensure maximum work efficiency across both transmission and distribution; including in coordination efforts themselves and, at the same time, to minimize information transfer times. See §7.3.4 on page 76
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	See answer to question above (3.d).There is extensive cooperation/liaison between the RTSOs and the relevant distribution network owners in their TSO regions; as mandated by both the Transmission Code and the Distribution Code. See §7.3.5 on page 76
4. What institutional/governance models are used to support such frameworks?	See §7.4 on page 76

7. Europe—Germany	
a. Regulatory institutions	The EnWG (i.e. Energy Industry Act) assigned the task of regulating Germany's electricity and gas markets to the Federal Network Agency. The Federal Network Agency's task is to provide, by liberalization and deregulation, for the further development of the electricity industrial network. For the purpose of implementing the aims of regulation, the Agency has effective procedures and instruments at its disposal including also rights of information and investigation as well as the right to impose graded sanctions. In this context, the central task of the Federal Network Agency is to provide for compliance with the EnWG and its ordinances having the force of law. The legal framework for the empowering the Federal Network Agency is the Energy Industry Act document under which both Transmission and Distribution codes are based; and thus amongst other things, the Federal Network Agency is responsible for regulatory oversight of the transmission reliability standards. See §7.4.1 on page 76
b. National planner or Regional Transmission Organization (RTO) planner	There is no national planner for Germany. The RTSOs each plan the development of their transmission networks such that they have a transmission system which is adequately dimensioned for the projected transmission tasks and which permits secure and reliable system management and economical system use at an adequate quality of supply at National level. However, while there is no national planner, the coordination and harmonization of the RTSOs individual plans is partly assured by VDN in order to achieve the consistently applied transmission reliability standards (and other quality targets). See §7.4.2 on page 77
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	There is no national plan. The RTSOs develop their own transmission investment plans, compliant with the transmission reliability standard as set out in the national Transmission Code. Where necessary (e.g. for cross regional and cross border interconnection developments/works) necessary individual RTSOs will coordinate with each other (and/or other national TSOs) as relevant regarding the specific co-impacting works. See §7.4.3 on page 77
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Trancos.	The RTSOs - in collaboration with the other VDN members - followed the guidelines defined by the Federal Network Agency through the EnWG, to draft and update the Transmission Code which specifies the technical requirements and obligations that the RTSOs and user of the transmission networks are obliged to comply with. This includes development and revision as required/agreed of the transmission reliability standards to be applied nationally across the transmission network in Germany. Finally, as indicated above, the Federal Network Agency enforces compliance of all relevant parties (not just the RTSOs) with the requirements of the Transmission Code and thus enforces compliance by the RTSOs with the specified transmission reliability standards. The Federal Network Agency has effective procedures and instruments at its disposal, including rights: to: gather information, conduct investigations, and the right to impose graded sanctions. See §7.4.4 on page 77

7. Europe—Germany	
e. Accountabilities	Federal Network Agency – approves the standards (within approval of the Transmission Code) and enforces compliance by the RTSOs VDN – set the standards (within the Transmission Code) The RTSOs – apply the standards Where a conflict is identified between Transmission Code and EnWG rules, EnWG takes precedence until resolution of the conflict (typically this would be via amendment of the Transmission Code). See §7.4.5 on page 77
5. Who sets the standards? Does the responsibility for determining standards lie with governments, regulators, Transcos, Independent System Operators (ISOs), RTOs, a Regional Reliability Council, or some sort of multi-national or multi-regional body (e.g. Federal Energy Regulatory Commission (FERC), North American Electricity Reliability Corporation (NERC), Union for the Co-ordination of Transmission of Electricity (UCTE), European Union)?	As indicated above, VDN (comprising representatives from across the electricity industry plus Government and regulatory representatives) sets the standards which are specified with the overall national Transmission Code which the VDN sets the standards, based on the requirements pursuant to the Energy Industry Act. See §7.5 on page 78
6. Governance issues with framework:	See §7.6 on page 78
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	As indicated above, VDN, which sets the standards, consists of representatives of all industry stakeholders including the RTSOs. Thus as the RTSOs apply the standards there is not full independence between the body setting the standards and the bodies applying the standards i.e. the RTSOs will influence the detail of the transmission reliability standards that are set (but can be "out-voted" by other stakeholders) and then apply them. Thus there is neither full independence nor complete unity of the bodies setting and applying the standards. See §7.6.1 on page 78

7. Europe—Germany	
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	No. Although the body that sets the standards (VDN) differs from that which enforces compliance (Federal Network Agency). The Federal Network Agency is a member of the VDN. Thus, there is neither independence nor complete unity of the body setting the standards and the body enforcing the standards. It is worth noting that the Transmission Code delegates to the RTSOs the authority to monitor end-use compliance with transmission network users with the standards; and where the RTSOs suspect user non-compliance with the standards or a user disregards the RTSOs' compliance requirements (in line with the Transmission Code) the RTSOs can refer users to the Federal Network Agency, which is ultimately the responsible body for determination and enforcement of compliance. See §7.6.2 on page 78
7. To what degree does the framework specify the actual level of standards:	See §7.7 on page 79
a. By connection point?	For connections, the same tenets of standards are applied regardless of location. However, as noted earlier (in 3c), differing standards are applied depending on the type of the generating unit i.e. whether they are conventional or renewable generating units. See §7.7.1 on page 79
b. By voltage level?	As indicated above (in 3c), there are differing standards specified for what the Transmission Code defines as the "wide-spread main transmission system" (220kV and 380kV) versus transmission network groups of 110kV. See §7.7.2 on page 79
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	As indicated above (in answer to Question 3), under the common German Transmission Code, transmission reliability standards are not allowed to diverge across the four AC interconnected TSOs. Derogations are granted on a bilateral basis between the TSOs and generator concerned on a case by case basis in the four different interconnected AC transmission networks – these derogations are not made public and required to be approved by the Federal Network Agency. See §7.8 on page 80
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	As indicated in the answer to the previous question, this question is not applicable in Germany, since, subject to a few derogations (as approved by the Federal Network Agency) the German RTSOs plan to a universal transmission reliability standard as defined under the Transmission Code. See §7.9 on page 80

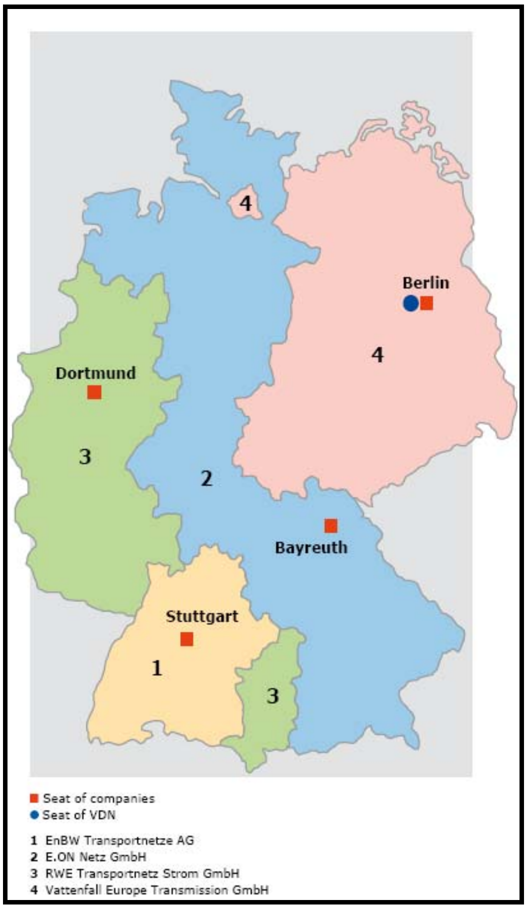
7. Europe—Germany	
10. How are transmission owners compensated for their transmission costs?	The Federal Network Agency sets a revenue allowance for each of the RTSOs on a confidential bilateral basis. From 2009 an incentive regulation similar to that adopted in GB will be introduced i.e. an RPI-X approach for a 5 year period. Given an overarching German legal requirement to put in place an incentive for efficient investment, the Federal Network Agency applies a sliding scale approach to remuneration of capex. Thus allowances for forward transmission investment are based on the Federal Network Agency's determination of required capex from review of RTSO plans and a sliding scale which allocates a share of overspend or underspend against budget directly to the P&L of the RTSO. In addition the incentive regulation of capex assesses security of supply, product (i.e. asset/network quality, service quality and reliability of supply. See §7.10 on page 80
11. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as Germany vs. NEM (xvii) universal standard vs. regional standards (xviii) deterministic vs. mixture of deterministic and probabilistic approaches (xix) standard set by overarching industry cooperative (VDN) vs. set by individual jurisdictions (xx) security variation by type of generator and by voltage level vs. by type of area/customer supplied e.g. CBD See §7.11 on page 81

Supplemental information

To supplement and/or expand on the answers provided in the tables above for the German market and its application of transmission reliability standards, KEMA provides additional information for each of the issues the table covers.

The four German transmission system operators (TSOs) are E.ON Netz GmbH, RWE Transportnetz Strom GmbH, Vattenfall Europe Transmission AG and EnBW Transportnetze AG. Each of them operates its own control areas as shown in .

Figure 4: The four German RTSO control areas



7.1 Frameworks used to ensure consistency of transmission reliability standards

VDN is a registered association that originated from the merger of the DVG Deutsche Verbundgesellschaft (Association of transmission system operators) with the network sections of the German Electricity Association (VDEW) and was established in June 2001. As at September 2005 it incorporated 428 members including the 4 transmission system operators (E.ON Netz GmbH, RWE Transportnetz Strom GmbH, Vattenfall Europe Transmission AG and EnBW Transportnetze AG), 52 regional, 358 municipal and 5 foreign network operators.

The foundation of VDN was the necessary consequence of the electricity market liberalisation, as unbundling of generation, networks and supply required of the German electricity companies in the new competitive German electricity market environment was required to be reflected at the associations' level as well.

According to the Articles of Association of VDN, the General Assembly is the supreme decision-taking body for matters concerning the association, while the Board of Directors, consisting of 15 persons, is the supreme decision-taking body on issues relating to system economy and system technology. Decisions are prepared by two Steering Committees.

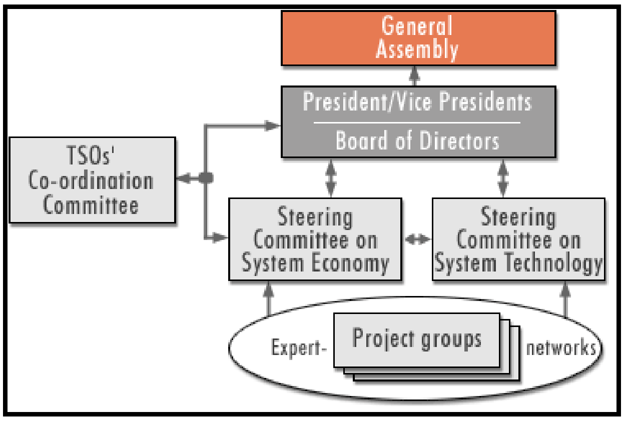
In parallel, the transmission system operators' (TSOs) co-ordination committee has been installed to deal with matters concerning exclusively the TSOs. Draft decisions are usually prepared by project groups composed of expert from across the VDN member companies.

VDN focuses its activities in (i) the network economy sector, (ii) network technology sector, and (iii) network marketing.

It was VDN that created the overarching policy document, the Transmission Code, under which it seeks to ensure transmission reliability standards consistently defined and applied across the German RTSOs. Nonetheless the requirements of the Associates' Agreement, was influenced by political decisions made by the German Government about the desired structure of the electricity market.

VDN is now part of the BDEW (Bundesverband der Energie- und Wasserwirtschaft), the German Federal Association of the energy and water industry.

Figure 5 representation of the committees' structure – Source: VDN web Site



7.2 Instruments used to give effect to consistency of reliability standards

Under Article 13 of the Energy Industry Act (EnWG), the TSOs are required to assume responsibility for the system. In this context the TSOs have developed a common understanding concerning the implementation of their responsibility for the system, the Transmission Code. This code is based upon the following principles:

- It is exclusively the TSO that is responsible for the maintenance of the power balance within its control area in the event of imbalances attributable to balancing groups;
- Network operators are responsible for maintaining voltage limits and equipment loading on their own facilities; and
- All necessary measures are implemented in a cascading manner across all network levels, starting at the transmission system.

7.3 Transmission reliability standards applied to the planning horizon

7.3.1 Form of standards used

In regard to system planning, the Transmission Code requires TSOs to build a transmission system which is adequately dimensioned for the projected transmission tasks and which permits secure, consumer-friendly, efficient and environmentally compatible operation and economical system use at an adequate quality of supply. To achieve these standards, the system reserve must be dimensioned in accordance with the n-1 criterion.. In this context the n-1 criterion addresses all issues relating to:

(i) Network technology, in particular the system services to be provided;

(ii) Equipment utilization;

(iii) The protection concept; and

(iv) Stability issues (where applicable).

The n-1 criterion must also be applied:

- To networks on the basis of postulation of a forced outage of the generating unit having the greatest effect upon the security of supply;
- When the total feed-in capacity can still be transmitted in the event of a failure of an item of network equipment (except for bus-bar faults).

7.3.2 Levels of standards applied

Under the Transmission Code, an n-1 standard is applied to the whole transmission system in Germany i.e. across all of the 4 RTSOs.

7.3.3 Different levels of standard applied to different parts of network

While the standards are applied universally across Germany, There are differing requirements specified for:

(a) Connection of conventional generation versus connection of renewables generation; and

(b) What the Transmission Code defines as the "wide-spread main transmission system", which comprises network voltages of 220kV and 380kV) versus transmission network groups of 110kV. Essentially, there are two additional requirements placed upon the wide-spread main transmission system on top of the requirements specified for the 110kV voltage level transmission network groups (see §7.7.2 on page 79).

7.3.4 Degree of consistency between transmission and sub-transmission networks reliability standards

There is no subtransmission in Germany as the term is understood in NEM. All of the transmission system above 100 kV is classified as transmission.

7.3.5 Joint planning and development of transmission and sub-transmission networks so as to meet the reliability standards at least cost

There is no subtransmission in Germany as the term is understood in NEM.

7.4 Institutional/governance models supporting the framework

7.4.1 Regulatory institutions

The Federal Network Agency for Electricity and Gas was established in 1998 and was given legal basis by the German Energy Industry Act 2005. Its functions, in part, include:

- Granting exemptions to new interconnectors, according to EU legislation
- Enacting ordinance setting rules and terms for the procurement and pricing of balancing and ancillary services
- Enacting ordinances setting the methodologies for the calculation of electric transmission fees
- Approving electricity transmission fees
- Issuing determinations on management and allocation of interconnection capacity
- Monitoring:
  - Rules for management and allocation of interconnection capacity
  - Congestion management mechanisms
  - Connections and repairs

  - Information disclosure obligations on system operators
  - Unbundling of accounts
  - Network access
  - Fulfillment of system operation duties
  - competition

- Hearing complaints between interested individuals (or their associations) and network operators
- Remedying abusive behavior of network operators, with particular reference to non-discrimination
- Imposing fines

7.4.2 Regional transmission organization (RTO) planner

There is no national transmission planner in Germany. However, the VDN (which includes all RTSOs and distribution network owners) helps in coordinating individual RTSO's transmission investment plans.

7.4.3 Role of transmission companies (RTSOs) in determining the national transmission investment plan

The individual RTSOs are each responsible for developing their regional transmission networks in compliance with the transmission reliability standards as set out in the German national Transmission Code. The German electricity industry association, VDN—of which the RTSOs are all members—helps to provide a forum for cooperation and liaison. The VDN also seeks to ensure appropriate interaction of the RTSOs on mutually impacting transmission network developments by specifying the need for such liaison and coordination within the Transmission Code.

7.4.4 Nature of planning arrangements – imposed/enforced or merely guidance

The reliability standards set by VDN and defined within the Transmission Code are mandatory for each of the RTSOs to comply with. The Federal Network Agency has the ultimate responsibility for ensuring the RTSOs are in compliance with this mandatory requirement.

7.4.5 Accountability

The central task of the Federal Network Agency is to provide for compliance with the Energy Act. Its ordinances have the force of law to support its rulings and decisions. The Federal Network Agency is, thus, accountable for ensuring compliance of the four RTSOs with the requirements of the Transmission Code including the development of their transmission networks in compliance with the specified transmission reliability standards.

The VDN is accountable for the development setting and revision of the transmission reliability standards within the Transmission Code (and the transmission Code in general). Consequently it is accountable for ensuring these transmission reliability standards are consistent with the requirements of the Energy Industry Act. In fulfilling this role the VDN holds public specialist meetings to obtain a clearer view of the particular needs of market partners and, vice versa, to communicate to them the bases for secure operation of meshed transmission systems, represented also by the standards.

The RTSOs are responsible for assuring the minimum technical requirements and rules of approach for access and use of the networks (as specified in the Transmission Code). So the RTSOs are accountable for applying the transmission reliability standards in developing their long term plans. The RTSOs also take into account targets defined by the Association of European Transmission System Operators.

7.5 Entities responsible for setting standards

The VDN (which comprises membership from all electricity industry companies, as well as the German Government and regulator) sets the standards through the Transmission Code.

7.6 Governance issues with framework

7.6.1 Independence of body setting the standard from that which applies the standard

In Germany there is neither complete independence nor complete overlap of the bodies setting and applying the standards. Each of the RTSOs applies the standards as specified in the transmission Code when conducting their long term transmission planning. However, all the RTSOs are also members of the VDN—the body responsible for setting the standards. Thus while the RTSOs do not strictly set the standards they will clearly have a major influence and role in that process within the VDN.

7.6.2 Separation between the standard setting body and the enforcement/compliance body

In Germany, TSOs have the double role of helping to set transmission reliability standards (as members of VDN) and to monitor compliance with the standards by users of their transmission networks (as RTSOs). Users themselves, as members of the VDN, also influence the setting of the standard. Furthermore as a VDN member the Federal Network Agency can also influence the setting of the standards.

However, the ultimate monitor and enforcer of compliance is the Federal Network Agency. The RTSOs perform an intermediary role in monitoring transmission network users. In all cases, the Federal Network Agency can investigate and/or imposed graded sanctions if the standards are not applied.

In addition, while the Federal Network Agency does not set the standards in its own right, as a member of the VDN it can exert an influence. Thus, similar to the situation for setting and applying standards; there is neither complete independence nor complete overlap of the bodies setting, monitoring and enforcing the standards.

7.7 The actual system level specified in the standards

7.7.1 Connection level standards

In Germany, there are no connection level differences in transmission reliability standards. The only differences are in the performance characteristics of conventional and renewable generating units. Renewable generators, for instance, have low-voltage ride-through requirements and are exempt from frequency stability requirements. These differences do not significantly affect transmission planning.

There are a few exceptions made for renewable generations, however. An example would be a requirement made by E.On Netz. Because of temporary overloading of selected overhead lines caused by wind power feed-in, E.On Netz established an obligatory active power management requirement for wind turbines as part of their grid code. Renewable generation must be able to reduce power output at a rate of 10% of total network connection capacity per minute from the time that the request is registered, without the system being disconnected from the network. This practice protects the transmission system from overloads due to wind power supply.

7.7.2 Voltage level standards

The German Transmission Code defines the application of the n-1 criterion for two different network groups:

1. Wide-spread main transmission system (380, 220 kV); and
2. 110 kV network groups with transmission function

For those two voltage groups the Transmission Code sets a list of “effects” (i.e. consequences/events) that must be excluded after forced outages in order to respect the n-1 security rule. These “effects” are the following:

(i) Permanent violations of limiting values of network operation variables (operating voltage, voltage ranges, network short-circuit power) and equipment loading (current loading) that may endanger the security of system operation or lead to damage to equipment or to an unacceptable strain on equipment;

(ii) Interruptions of supply in spite of the use of redundancies temporarily available in lower voltage networks and in installations of the transmission system users;

(iii) Secondary tripping through activation of further protection devices on equipment not directly affected by the disturbance, involving the risk of spreading the disturbance; and

(iv) Need to change or, if necessary, interrupt power transfers.

For each transmission network group the n-1 criterion includes the single failure of overhead-line circuits and cable circuits as well as substation transformers.

The two additional requirements that are applied to the wide-spread main transmission system that do not apply to the 110 kV network group are:

1. The wide-spread main transmission system must also remain stable following the loss of any generating unit if it wants to respect the n-1 security rule; and
2. In the event of failures on bus-bars and multiple-circuit lines the transmission network function can only be maintained through use of spare capacity in neighboring transmission networks.

7.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

Apart from allowed derogations, no variations in the reliability standards are allowed across the four German RTSOs. Derogations are granted on a bilateral basis between the RTSO and generator concerned on a case by case basis. These derogations are further subject to scrutiny and approval by the regulator. Details of such derogations are not made public.

7.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

The Transmission Code and a uniform transmission reliability standard apply across the four different German Regional TSOs.

7.10 Compensation of Transmission Owners

The Federal Network Agency sets a revenue allowance for each of the RTSOs on a confidential bilateral basis. (This is a rather different form of compensation from that used in Australia, North America and GB.) Beginning in 2009, an incentivized RPI-X approach system similar to that adopted in GB, will be introduced.

In the past the German Federal Network Agency has set revenues for five-year periods based on its determination of (i) initial asset base; (ii) appropriate rate of return; (iii) appropriate X factor etc. Within this overall regulatory incentive regime, allowances for forward transmission investment are based on the Federal Network Agency's determination of required capex from review of RTSO transmission plans/budgets submitted for review.

Given the overarching German legal requirement to provide incentives for efficient investment, the Federal Network Agency applies a sliding scale approach to remuneration of capex. This allocates a share of overspend or underspend against a target budget directly to the P&L of the RTSO. The remainder is borne by the consumers. As a further incentive, the Federal Network Agency has determined that the lower the target capex accepted by the RTSO the higher the share of benefits a RTSO will receive for underspending.

7.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are five key areas of difference between the frameworks for setting transmission reliability standards in Germany when compared to that adopted within the NEM in Australia:

1. In Germany a universal standard is applied across all four 4 RTSOs, whereas in the NEM each of the mainland state jurisdictions applies its own "regional" standard and approach to applying these;

2. In Germany a common form of transmission reliability standard is used—deterministic, whereas in the NEM the form of standards varies across jurisdictions;

3. In the German market the level of transmission reliability standard is set by a single national agency (the VDN), which is a cross industry association comprising all stakeholders and approved by the national regulator (Federal Network Agency), whereas in the NEM the transmission reliability standards are set by the individual state jurisdictions; and

4. In Germany variations in the level of standards are applied depending on the voltage level, whereas in the NEM the standard for demand security can vary by the type of area or the type of customer supplied in particular a distinction is made between Central Business Districts (CBDs) and other areas, with CBDs being determined to require a higher transmission reliability than for other areas e.g. typically n-2 versus n-1 security.

8. Nordic Market (Norway, Sweden, Finland, Denmark, and Iceland)	
1. What frameworks are used to ensure consistency of transmission reliability standards (relating to the planning horizon) across multiple political jurisdictions and/or separately owned transmission networks?	Nordel is the cooperative association of the national TSOs of Norway, Sweden, Finland, Denmark, and Iceland that was established in 1963 and has formally operated as the organisation of the TSOs since 2000. Nordel's By-Laws were formed in 2000 and since then some minor adjustments have been made. In 2002 the 'Reliability Standards and System Operating Practices (RS&SOPs) were established by Nordel and in 2006 these were reinforced with the publication of the 'System Operation Agreement' which contains rules for the operation of the interconnected Nordic power system. See §8.1 on page 89
2. What instruments are used in those frameworks to give effect to such consistency: Grid Codes? Transmission licenses? Market Rules? Legislation?	Transmission reliability standards are governed by the *Reliability Standards and System Operating Practices* document, which is administered by the Operations Committee of Nordel. On establishing the Nordic electricity market, the parliaments developed similar legislation in all countries. The current system is based on a common Nordic system operation agreement between the Nordic TSOs. An updated version of the Nordic Grid Code, published in 2007, governs technical cooperation between the TSOs of the interconnected Nordic countries. The Grid Code includes the Planning Code, the Operation Code (*System Operation Agreement*), the Connection Code and the Data Exchange Code. The Nordic Grid Code lays down fundamental common requirements and procedures that govern the operation and development of the electric power system. However, it is ultimately subordinate to the national rules of the participant countries. See §8.2 on page 89
3. What transmission reliability standards (relating to the planning horizon) are applied?	A single Nordic transmission reliability standard as defined by the RS&SOPs document is applied by all of the national TSOs within the Nordic market. The Nordic system constitutes a single control area with a common frequency, with the exception of Western Denmark (Jutland), which operates its own control area and is DC interconnected with Norway and Sweden but AC interconnected via Germany with the mainland Western European transmission system that falls within the area of oversight of (i.e. mainland western Europe) of the TSO cooperation organisation UCTE. See §8.3 on page 90
a. What form (deterministic, probabilistic, or variants) of standards are used?	In the Nordic market, transmission is planned and operated on to deterministic N-1 standard applied to a probabilistic view of potential system events which considers both high likelihood/low impact events and low likelihood/high impact events. See §8.3.1 on page 90
b. What levels of standards (e.g. n-0, n-1, n-2) are applied?	The reliability criteria are based on the n-1 criterion. See §8.3.2 on page 92

8. Nordic Market (Norway, Sweden, Finland, Denmark, and Iceland)	
c. Are the form and levels of standards universally applied, or are different levels of standard applied to different parts of network (e.g. Metropolitan, Urban, Rural)? If different standards are applied, what is the basis of this: a) Implied or explicit value of customer load? b) Criticality of load? c) Historical reasons? d) Other criteria?	The standards are applied universally across all parts of the transmission network in each of the national TSO areas governed by Nordel in the Nordic market. See §8.3.3 on page 92
d. What degree of consistency exists between the reliability standards for transmission and sub-transmission networks? Does this consistency contribute to effective and efficient joint development of the transmission and sub-transmission networks?	There is no distinction between transmission and subtransmission in the Nordic area. The Nordic transmission reliability standards were devised to fit with the planning approaches of both the transmission and distribution codes of each of the participant countries in order to ensure the harmonisation of general network planning within the Nordic power market area. See §8.3.4 on page 92
e. To what extent are transmission and sub-transmission networks jointly planned and developed so as to meet the reliability standards at least cost?	The Nordic Grid Code was developed to fit with planning of national distribution systems. Furthermore, according to the Planning Code which sits within the Nordic Grid Code, all parts of the power system are designed so that the electric power consumption will be met at the lowest cost. See §8.3.5 on page 92
4. What institutional/governance models are used to support such frameworks?	See §8.4 on page 93
a. Regulatory institutions	Nordreg is the cooperative organisation for Nordic regulatory authorities in the energy field and is responsible for the evaluation of the codes and agreements developed and applied by Nordel for application within the Nordic market. However, the Nordic codes and regulations are subordinate to the national rules of the member countries. Due to the "cooperative culture" in Scandinavia we believe that no member nation state within the Nordic market have sought to use this to impose standards or practices that diverge from that developed by Nordel and "approved" by Nordreg. See §8.4.1 on page 93
b. National planner or Regional Transmission Organization (RTO) planner	There is no Regional Transmission Organisation (RTO) planner for the Nordic market. However, as indicated above, Nordel as the association of the Nordic TSOs is responsible for the development and application of the Nordic Grid Code and other relevant network agreements within the Nordic market. See §8.4.2 on page 93

8. Nordic Market (Norway, Sweden, Finland, Denmark, and Iceland)	
c. What, if any, role do transmission companies (Transcos) play in determining the national/RTO plan?	Each member TSO within Nordel develops its own national transmission development plan in accordance with its own (national) transmission code. These national Codes are drafted in 'harmony' with the other Nordic national rules, and the Nordic Grid Code. Where necessary (e.g. for cross border interconnection developments/works), necessary individual TSOs will coordinate with each other as relevant the specific co-impacting works. See §8.4.3 on page 93
d. Nature of planning arrangements — is the national/RTO plan imposed/enforced on individual Transcos, or whether it merely provides guidance to the Transcos.	There is no single Regional (i.e. multi-national) plan for the Nordic Market. Each national TSO member of Nordel develops its own national transmission development plan and the TSOs coordinate between each other as relevant in relation to cross-border issues. Member nation states within the Nordic market region have ultimate authority and, thus, strictly speaking, the uniform transmission reliability standards (as provided under the RS&SOPs produced by Nordel and reviewed by Nordreg) are advisory. However, in practice all member states (i.e. national TSOs) adhere to this transmission reliability standard. See §8.4.4 on page 94
e. Accountabilities	Accountabilities of different entities within the Nordic market region are as follows: Nordel – develops and recommends use of the standards by member TSOs within the Nordic market Nordreg – endorses the standards as developed and set by Nordel National TSOs (within the Nordic market) - apply the standards National states (within the Nordic market) – ultimate responsible for seeking compliance with the common Nordic rules or requiring/granting deviations/exceptions from these. See §8.4.5 on page 95
5. Who sets the standards?	The transmission standards of the Nordic market are set by Nordel with the cooperation of all five member countries to seek to ensure 'harmony; with both national and European standards. See §8.5 on page 95
6. Governance issues with framework:	See §8.6on page 96
a. Is the setting of the standard done by a body that is independent from that which has to apply the standard (i.e. the Transco)?	Nordel develops and sets the standards subject to "approval" by Nordreg. The national TSOs, who are each members of Nordel, are responsible for applying the rules within their transmission planning (subject to required over-rides from national government – which as indicated does not occur in practice). Thus, in strict terms, there is not independence of the body setting the standard from that/those applying it. See §8.6.1 on page 96

8. Nordic Market (Norway, Sweden, Finland, Denmark, and Iceland)	
b. Is there a separation between the body that sets the standard setting and the body (or bodies) that enforce the standard or monitor compliance with the standard? For example, the standards could be set by governments and enforced by a regulator or reliability council.	As indicated above, Nordel sets the standard subject to Nordreg approval. Both Nordel and Nordreg are collaborative associations of, respectively, member TSOs and member national regulators within the Nordic market region. Thus as single entities they do not monitor or enforce compliance. This, to the degree it takes place, is undertaken by the individual national regulators. Thus, in strict terms, there is not independence of the body setting the standard from that/those enforcing it. Furthermore, as the RS&SOPs are essentially advisory, there is no formal compliance enforcement. See §8.6.2 on page 96
7. To what degree does the framework specify the actual level of standards:	See §8.7 on page 96
a. By connection point?	The standards are applied universally across all connection points in each of the 5 Nordic market member TSOs' networks.
b. By voltage level?	The standards are applied universally across transmission voltages in each of the 5 Nordic market member TSOs' networks.
8. To what degree are transmission reliability standards (for planning) allowed to diverge across different, interconnected AC transmission networks?	Member nation states within the Nordic market area reserve the right to overrule (i.e. require deviation from or grant exception to) one or more aspects of the uniform Nordic transmission reliability standard as defined under the RS&SOPs. However, in practice no such divergence has arisen, given these standards were developed by a cooperation of the relevant national TSOs (i.e. Nordel) and national regulators (i.e. Nordreg) to ensure "harmony" of national and regional approaches; and Scandinavian culture is "cooperative". See §8.8on page 96
9. What issues arise when there are divergent transmission reliability standards (for planning horizon) across different, but interconnected, transmission networks and/or jurisdictions?	The two apparent divergence issues relate to the two electric systems that are not synchronously connected (AC) to the other Nordic systems—Iceland and Western Denmark. Any divergence in these two areas would have no operating or planning effect on the remaining Nordic systems. While nation states have the right to choose to deviate, in practice they do not and all five member states/TSOs apply a common transmission reliability standard. See §8.9 on page 97

8. Nordic Market (Norway, Sweden, Finland, Denmark, and Iceland)	
10. How are transmission owners compensated for their transmission costs?	Each of the national TSOs within the Nordic market region is subject to differing regulatory regimes as implemented by their respective national regulators. An outline of our understanding of these as they relate to transmission investment is provided below for each country: • Norway – an income cap is set for a multi year period, within which is a deemed capex allowance. Recent changes were made to the regime to put greater priority/emphasis on investing in transmission capacity to relieve congestion. It is not known how regularly the income cap is set. • Sweden – the TSO sets tariffs each year based on its capex and opex activities and these are subject an annual review by the regulator. Currently the regulator is investigating suspected unduly high tariffs for 2007 • Finland – the TSO is subject to a periodic three-year duration revenue cap, within which anticipated capex spend is captured – the current one being set for 2008/09-10/11 • Denmark – the TSO is subject to an income cap determined on a cost plus basis. Within the costs are the indicated forward transmission investments. It is not known how regularly the income cap is set. • Iceland – the costs of the TSO are regulated on a cost plus basis, similar to Denmark. See §8.10 on page 97
11. Provide a summary of the principal differences and similarities between the existing NEM approach for setting transmission reliability standards (for the planning horizon) and the frameworks used in the foreign electricity markets covered in 1 to 9 above.	Expressed as Nordic vs. NEM (xxi) universal standard vs. regional standards (xxii) deterministic form applied to a probabilistic view of potential system events vs. mixture of deterministic and probabilistic approaches (xxiii) standard set by overarching TSO and regulator cooperatives vs. set by individual jurisdictions (xxiv) uniform security vs. by type of area/customer supplied e.g. CBD (xxv) advisory vs. mandatory See §8.11 on page 97

Supplemental information

To supplement and/or expand on the answers provided in the tables above for the Nordic market and its application of transmission reliability standards, KEMA provides additional information for each of the issues the table covers.

Prior to the detailed description of the transmission standards and for their better comprehension, it is considered wise to present some of the general characteristic and definitions of the Nordic electricity market.

The Nordic market (often referred to as Nordpool) is a multi-national market consisting of five member countries—Norway, Sweden, Finland, Denmark, and Iceland. The transmission systems of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected forming a synchronous system. The transmission system of Western Denmark is connected to Norway and Sweden using DC interconnectors and to Western Europe via AC interconnection. The synchronous system and the transmission system of Western Denmark jointly constitute the interconnected Nordic power system. While Iceland is a member of the Nordic market, it does not have any interconnections with the other Nordic countries.

There are two types of market in the Nordic system: the physical market and the financial one:

(i) Elspot - The Elspot market deals with power contracts for physical delivery daily within 24 hours. Elspot's price mechanism is used to regulate the flow of power where there are capacity limitations in the Norwegian grid and between the individual countries. Therefore Elspot may be regarded as a combined energy and capacity market.

(ii) Elbas - this is an organised balance market for Sweden, Finland, Eastern Denmark and Germany. The Elbas market comprises continuous power trading in hourly contracts up to two hours before physical delivery. The Elbas market complements Elspot and balance management by the TSOs.

The supervisory authorities of Denmark, Finland, Norway and Sweden have appointed special system operators, who are comprehensively responsible for the satisfactory operation of each transmission system. These system operators are:

- Energinet.dk for the Danish transmission system, including Bornholm, Fingrid for the Finnish transmission system,
- Statnett for the Norwegian transmission system, and
- Svenska Kraftnät for the Swedish transmission system. Iceland is not covered by this Agreement.

Within the Nordic market, Nordel is the cooperative association of the member national TSOs of Norway, Sweden, Finland, Denmark, and Iceland; and Nordreg is the equivalent cooperative association of the national regulators (sometimes referred to as supervisory bodies).

8.1 Frameworks used to ensure consistency of transmission reliability standards

The planning, expansion and operation of all the national transmission systems are not completely governed by identical rules because the different national transmission systems are subject to different national legislation and to supervision by different official national bodies. However, an objective is that the Nordic Grid Code (2007) should be a starting point for the harmonization of national rules, with minimum requirements for technical properties that influence the operation of the interconnected Nordic electric power system. Thus the guidance provided by Nordel and Nordreg acts as an advisory framework that seeks to ensure consistency of transmission reliability standards. In practice this advisory framework is adhered to by each of the member countries within the Nordic market. Nevertheless, it is the national legislation which has primacy.

8.2 Instruments used to give effect to consistency of reliability standards

In the Nordic region, independent system operation is undertaken by transmission system owners in each country. Coordination is achieved through cooperative agreements that address operational standards and emergency procedures. Market operation is managed through subsidiaries owned by the transmission operators.

The Nordic Grid Code defines the obligations, rights, procedures and information flows between the parties covering all relevant elements. The Nordic Grid code includes a Planning Code, an Operation Code, a Connection Code and a Data Exchange Code.

The *System Operation Agreement* (Operation Code) allows the member countries within the Nordic market to make their own decisions regarding the principles applicable to the system security of their own transmission systems. They agree, however, when taking such decisions, to comply with the intentions and principles of the Agreement as far as is possible and appropriate.

As part of the Operation Code, the 'Reliability Standards and System Operating Practices' (RS&SOPs) document published by Nordel in 2002, sets out the transmission reliability requirements for the interconnected countries of the Nordic power system.

The TSOs are individually responsible for formulating their own agreements concerning system operation cooperation between their own transmission systems and transmission systems outside of the interconnected Nordic power system, with which there are physical transmission links, in such a way that these do not contravene the intentions of, or prevent compliance with, the Agreement.

Each respective Party shall enter into such agreements with companies within its own transmission system as are necessary to comply with the Agreement. Unless otherwise agreed, the Parties shall be responsible for ensuring that measures taken within their own transmission systems, which impact upon the operation of the system, shall not burden the other transmission systems.

8.3 Transmission reliability standards applied to the planning horizon

The rules that the Nordic Grid Code defines, are used for the joint, synchronised Nordic transmission grid (i.e. Norway, Sweden, Finland and Eastern Denmark). This concerns principally the main grid, which consists of mainly 220-400 kV network voltages, and the interconnecting AC links between the various countries. The rules should be used in the planning of the power system. The rules do not cover local supply reliability and other local conditions in the grid.

8.3.1 Form of standards used

The Nordic market applies a deterministic standard and reserve requirements stemming from reliability rules include the area-wide n-1 contingency (dimensioning fault) and the bounds of any area imbalance. A number of fault groups have been specified, against which the grid is tested. The following are defined for every fault group:

- Prefault conditions, and
- Acceptable post fault consequences

The criteria are summarized in Figure 6.

Figure 6: Criteria used for Nordel grid planning

Acceptable consequences

- **A** Stable operation, local consequences and limited intervention of system protection
- **B** Controlled operation, regional consequences
- **C** Instability and breakdown
- **A/B** Consequences in accordance with B for faults in previously weakened area, otherwise A.
- **B/C** Aim should be to limit the consequences according to B but for all faults this cannot be fulfilled

[1] The operating situation has been adapted during 15 minutes after the fault by using the means available (disturbance reserves, etc.)

<table>
<tr><th colspan="3" rowspan="3"></th><th colspan="7">Pre-Fault Conditions</th></tr>
<tr><th colspan="4">Normal operation</th><th>Alert-state operation</th><th>Disturbed operation</th><th>Emergency operation</th></tr>
<tr><th>Grid intact
No critical components out of operation
PC0</th><th>Planned maintenance
Shunt or series component out of operation
PC1</th><th>Spontaneous loss and adapted operation[1]
Shunt component out of operation
PC2</th><th>Spontaneous loss and adapted operation[1]
Series component out of operation
PC3</th><th>Exceeded transfer limits / insufficient reserves. Adapt operation by adjusting new transfer limits and / or activating reserves within max. 15 min.</th><th>Exceeded transfer limits and / or insufficient reserves</th><th>Exceeded transfer limits and / or insufficient reserves
Load shedding effected</th></tr>
<tr><td rowspan="5">Fault groups</td><td rowspan="3">N-1 faults</td><td>Single fault that does not affect series components FG1</td><td rowspan="3">A</td><td rowspan="3">A</td><td rowspan="3">A</td><td>A</td><td rowspan="3">B/C</td><td rowspan="2">B/C</td><td>B/C</td></tr>
<tr><td>Single fault that affects series components FG2</td><td>A/B</td><td rowspan="4">C</td></tr>
<tr><td>Uncommon single faults and special combinations of two faults FG3</td><td>B</td><td rowspan="3">C</td></tr>
<tr><td rowspan="2">Serious faults</td><td>Other combinations of two faults caused by the same event FG4</td><td>B</td><td>B</td><td>B</td><td rowspan="2">C</td><td rowspan="2">C</td></tr>
<tr><td>Other multiple faults FG5</td><td>C</td><td>C</td><td>C</td></tr>
</table>

The planning criteria used are deterministic, although probabilistic considerations have been taken into account. In the criteria, demands are made on disturbance consequences that are acceptable for various combinations of operating conditions and fault types. In principle, more serious consequences are acceptable for less common combinations of faults and operating conditions.

8.3.1.1 Principles of the planning code

The rules of the Planning Code are used for the joint, synchronized Nordic transmission grid. This concerns principally the main grid, consisting of network voltages of 220-400 kV, and the interconnecting AC links between the various countries. The aim is that the operation and planning work should be based on the same reliability philosophy, and that the rules should also be able to serve as a guide at the operating stage. The rules do not cover local supply reliability and other local conditions in the grid.

In order to safeguard a certain minimum reliability level for the interconnected Nordic power system, certain minimum demands on reliability for the required transmission capacity have been defined through the planning rules. The demands have been given concrete form by a number of criteria, which must be met in grid design. The criteria are based on a balance between the probability of faults and their consequences, i.e. more serious consequences may be acceptable for faults with lower probability.

The required transmission capacity can be achieved by a number of measures affecting the construction of primary equipment, system protections and auxiliary systems, as well as disturbance reserves and other operational measures. In the case of more severe disturbances than those directly taken into account in the criteria, it is assumed that operational facilities are available in the power system for restoring operation.

8.3.1.2 Investment approach adopted under the planning code

The long-term economic design of the grid seeks to balance the costs of investments, maintenance, operation, and supply interruptions while taking into account environmental demands and other limitations.

The work of Nordic planning includes both the need to extend the grid and the need to provide system services. Transmission planning takes place on a higher level and therefore does not include the distribution networks. It is concerned only with the part of the transmission networks that are important for the interconnected Nordic electric power system.

Possible investments are evaluated on the basis of costs and benefit values. Socio-economic principles are used in the benefit evaluation. Important criteria for planning are:

1. Production optimization and energy turnover;
2. Less risk of energy rationing;
3. Less risk of power shortage;
4. Changes in active and reactive losses;

5. Trading in regulating power and system services;
6. The value of a better-functioning electric power market; and
7. Sufficient capacity.

8.3.2 Levels of standards applied

The reliability standards are deterministic n-1 redundancy criteria that are universally applied by each member TSO within the Nordic market.

8.3.3 Different levels of standard applied to different parts of network

The Nordel reliability standards are applied universally across the Nordic market in 'harmony' with the national rules and requirements set by the TSOs.

While there is no difference in transmission planning criteria, it is worth noting that the System Operation Agreement defines special conditions for the Danish TSO, Energinet.dk, regarding the operational reserves, since Western Denmark is a member of UCTE. (It should be pointed out that the n-1 planning criterion is also adopted as the uniform transmission reliability standard for transmission planning and development within member countries of the UCTE).

According to the Code, if n-1 security is maintained with the help of adjacent national transmission systems (e.g. using system protection), this must be approved by the adjacent national TSOs.

8.3.4 Degree of consistency between transmission and sub-transmission networks reliability standards

There is no distinction between transmission and subtransmission in the Nordic area. The Nordic transmission reliability standards were devised to fit with the planning approaches of both the transmission and distribution codes of each of the participant countries in order to harmonize general network planning within the Nordic power market area.

8.3.5 Joint planning and development of transmission and sub-transmission networks so as to meet the reliability standards at least cost

There is no distinction between transmission and subtransmission in the Nordic area.

8.3.5.1 Grid planning for interconnections between the Nordel area and other areas

With the exception of West Denmark, the Nordel system is operated asynchronously with other electric power systems. Decisions on the establishment of new interconnections to and from the Nordel area have been formalized in the form of bilateral agreements. Such interconnections will nevertheless affect the entire Nordic electric power system, not just the TSOs that establish the new interconnection. It is therefore important that the planning of such interconnections is coordinated with the Nordic grid master plan.

8.4 Institutional/governance models supporting the framework

8.4.1 Regulatory institutions

Nordel (consisting of the national TSOs for each of the member countries within the Nordic market) is the responsible for setting the framework for the Nordic electricity market. However, a number of Codes and reports are reviewed, evaluated and “approved” by Nordreg (the cooperative organization for the national regulatory authorities of each of the 5 member countries within the Nordic market) whose members are responsible for actively promoting legal and institutional framework and conditions necessary for developing the Nordic and European electricity markets. Nevertheless, it should be pointed out that those documents are subordinate to the national rules of the participant countries; although in practice due to the “cooperative culture” in Scandinavia; we believe that no member nation state within the Nordic market have sought to use this to impose standards or practices that diverge from that developed by Nordel and “approved” by Nordreg.

8.4.2 Regional Transmission Organization (RTO) planner

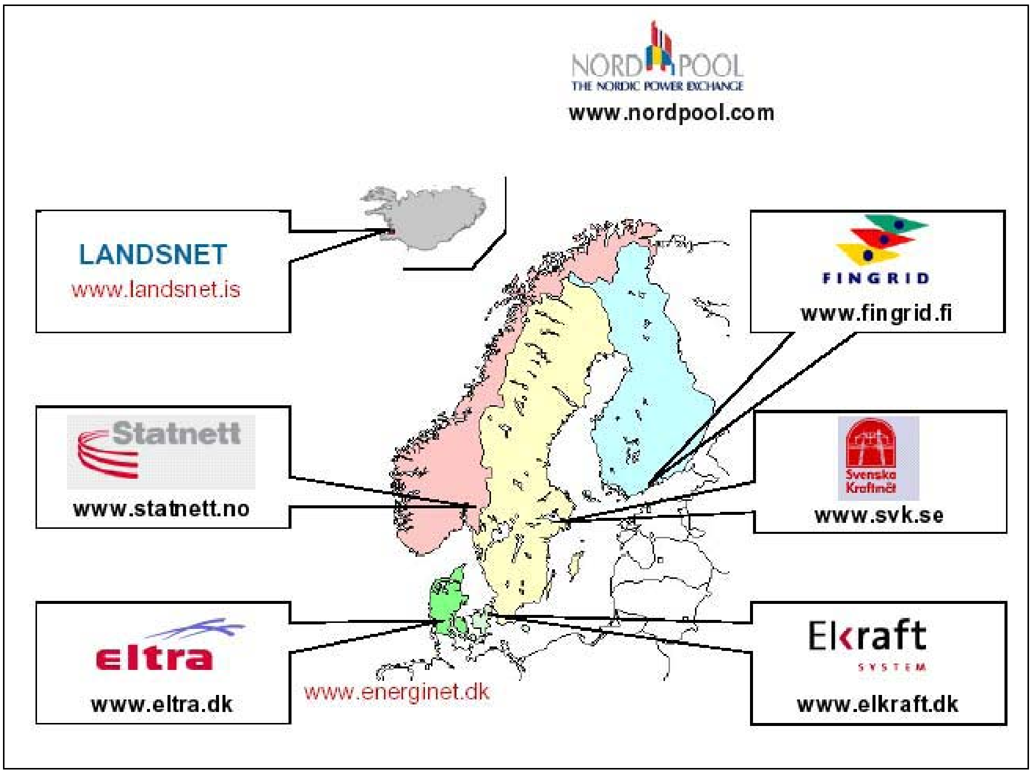
There is no Regional Transmission Organization (RTO) planner for the Nordic market. However, each member country has its own transmission code that should be in ‘harmony’ with the other Nordic national rules, as well as with the Nordic Grid Code.

Nordel, as the association of the Nordic TSOs, is responsible for the development and application of the Nordic Grid Code and other relevant network agreements within the Nordic market.

8.4.3 Role of national transmission companies in determining the Nordic transmission investment plan

In establishing the Nordic market, parliaments in each country passed legislation establishing national transmission system operators. There are five Nordic TSOs: Eltra and Elkraft (Western and Eastern Denmark, respectively), Fingrid (Finland), Statnett (Norway), and Svenska Kraftnät (Sweden). The service areas of these five along with Iceland are shown in Figure 7.

Figure 7: Service areas of Nordel TSOs



Each TSO is responsible for:

- Ensuring equal treatment and open access for all market participants,
- Facilitating physical delivery of electricity purchased under bilateral contracts or from the power exchange,
- Ensuring system adequacy and system reliability according to common reliability standards,
- Managing transmission constraints and operational disturbances,
- Maintaining system protection, and
- Managing market imbalances.

Thus, each member TSO within Nordel develops its own national transmission development plan in accordance with its own (national) transmission code. Where necessary (e.g. for cross border interconnection developments/works), individual TSOs will coordinate with each other as relevant the specific co-impacting works.

8.4.4 Nature of planning arrangements—imposed/enforced or merely guidance

According to the Nordic Grid Code, the System Operation Agreement and the Data Exchange Agreement are binding agreements between the participants TSOs in the national and regional markets, with specific dispute solutions and are being administered by Nordel committee.

In case of disputes under the System Operation Agreement, the participant TSOs should initially attempt to resolve their conflict through negotiation. If this does not succeed, the dispute will, under Swedish law, conclusively be settled by arbitration in accordance with the Rules of the Arbitration Institute of the Stockholm Chamber of Commerce. The arbitration procedure will take place in Stockholm.

The National TSOs are not generally bound by the planning recommendations set by Nordel. The relationship between the member countries is mainly based on the cooperation in order to achieve coherent and coordinated Nordic operation. Therefore, if a TSO chooses (or is required by the national government) not to follow the recommendations of the Planning Code and the Connection Code, it is not prevented from doing so but the other TSOs must, if this is considered possible and necessary, be informed before the deviation takes place. The System Operation Agreement and the Data Exchange Agreement are binding agreements between the parties, with specific dispute solutions.

8.4.5 Accountability

The Nordic market regulator association, Nordreg, evaluates and approves the standards and recommendations of the power market set by Nordel (consisting of the 5 member countries' national TSOs) and the national TSOs. The compliance or enforcement of the rules is a role of the national committees since Nordel presents an advisory character in the Nordic market. Additionally, Nordel ensure that the enforced rules are in harmony with the national operational specifications.

- Nordel – develops and recommends use of the standards by member TSOs within the Nordic market
- Nordreg – endorses the standards as developed and set by Nordel
- National TSOs (within Nordic market) - apply the standards
- National states (within Nordic market) – ultimate responsible for seeking compliance with the common Nordic rules or requiring/granting deviations/exceptions from these.

8.5 Entities responsible for setting standards

The reliability standards, as part of the System Operation Agreement, are set by the ad hoc committee of Nordel, with the contribution of all Nordic countries, and are then evaluated and approved by Nordreg.

However, in each member country, the national TSOs define specific requirements and standards for its network and internal market. Statnett in Norway relies on its market-based solution, the Regulation Capacity Option Market (RCOM), for provision of operating reserves. In Sweden, Svenska Kraftnät (SvK) has separate arrangements for fast and slow reserves, including peaking turbines and load shedding. Fingrid operates a Reserves Bank and a Regulating Power Market and Elkraft System and Eltra of Denmark have made agreements with the power producers Energi E2 and Elsam, respectively, on the supply of regulation capacity and provision of reserves

8.6 Governance issues with framework

8.6.1 Independence of body setting the standard from that which applies the standard

In the Nordel area there is a linkage between the body that sets the transmission planning standards (Nordel) and the bodies that apply these standards (TSOs). Nordel sets the planning and operating recommendations of the Nordic market along with the ad hoc committees of the national TSOs. The individual national TSOs, as members of Nordel, are then responsible for applying these recommendations within the boundaries of their interconnected networks.

8.6.2 Separation between the standard setting body and the enforcement/compliance body

The governance issues concerning the separation of enforcement powers from standard-setting powers are not really applicable in the Nordic area. This is so because the transmission reliability standards developed and set by Nordel for the Nordic market are advisory, with each member country/TSO reserving the right to deviate from this (although in practice they do not)..

8.7 The actual system level specified in the standards

The Nordic transmission reliability standard is universally applied regardless of connection voltage or connection point and indeed this applies for any variational aspect of the Nordic transmission network (such as size or type of customer).

8.8 Allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

The two apparent divergence issues relate to the two electric systems that are not synchronously connected (AC) to the other Nordic systems—Iceland and Western Denmark. Any divergence in these two areas would have no operating or planning effect on the remaining Nordic systems.

Nonetheless, it is possible to allow variations in transmission standards across different networks, given the primacy of national legislation over Nordic market rules. In practice, however, no such divergence has arisen as these standards were developed through the cooperation of the relevant national TSOs (i.e. Nordel) and national regulators (i.e. Nordreg) to ensure "harmony" of national and regional approaches; and Scandinavian culture is "cooperative".

8.9 Issues arising from allowed variations in transmission reliability standards across different, interconnected AC transmission networks or jurisdictions

All five member states/TSOs apply the common transmission reliability standard.

8.10 Compensation of Transmission Owners

Each of the national TSOs within the Nordic market region are subject to differing regulatory regimes as implemented by their respective national regulators. An outline of our understanding of these as they relate to transmission investment is provided below for each country:

- Norway – an income cap is set for a multi year period, within which is a deemed capex allowance. Recently changes were made to the regime to put greater priority/emphasis on investing in transmission capacity to relieve congestion. It is not known how regularly the income cap is set.
- Sweden – the TSO sets tariffs each year based on its capex and opex activities and these are subject an annual review by the regulator. Currently the regulator is investigating suspected unduly high tariffs for 2007.
- Finland – the TSO is subject to a periodic 3yr duration revenue cap within which anticipated capex spend is captured – the current one being set for 2008/09-10/11.
- Denmark – the TSO is subject to an income cap determined on a cost plus basis. Within the costs are the indicated forward transmission investments. It is not known how regularly the income cap is set.
- Iceland – the costs of the TSO are regulated and we believe it is on a cost plus basis, similar to Denmark.

8.11 Summary of the principal differences and similarities with the existing NEM approach for setting transmission reliability standards

There are five key areas of difference between the application of transmission reliability standards in the Nordic market versus that adopted within the NEM in Australia. These are expanded as follows:

(i) Within the Nordic market, a universal form of standard is applied across all 5 member countries (Norway, Sweden, Finland, Denmark and Iceland) by the respective national TSOs, whereas in the NEM each of the mainland state jurisdictions applies its own “regional” standards in transmission planning.

(ii) Within the Nordic market, the universal form of transmission reliability standard is deterministic applied to a probabilistic view of potential system events which considers both high likelihood/low impact events and low likelihood/high impact events. In the NEM, on the other hand, a mixture of deterministic and probabilistic forms of standards and planning approaches are adopted across the five state jurisdictions—ranging from New South Wales and Queensland which apply purely deterministic transmission reliability standards to Victoria which applies a probabilistic transmission standard.

(iii) Within the Nordic market, the universal transmission reliability standard is set by a cooperation of the member national TSOs (Nordel) as endorsed by a cooperation of the national regulators (Nordreg), covering the Nordic market region. In the NEM the transmission reliability standards are set by the individual state jurisdictions.

(iv) Within the Nordic market, there is no variation in the form or level of standard applied by location, voltage, type of customer or any other factor. Within the NEM the standard for demand security can vary by the type of area or the type of customer supplied. In particular, a distinction is made between Central Business Districts (CBDs) and other areas; with CBDs requiring a higher transmission reliability than other areas e.g. typically n-2 versus n-1 security.

(v) Within the Nordic market, the transmission reliability standards produced by Nordel and “approved” by Nordreg are advisory; as member states can choose to override these standards (though, to date they have not made any exceptions). Within the NEM, the transmission reliability standards specified for each of the member states are mandatory, i.e. compliance is enforced.

International Review of Transmission Reliability Standards

Additional response regarding probabilistic planning methodologies

AEMC Reliability Panel

KEMA Inc. Project:

P. Jeffrey Palermo
31 July 2008

Contents

Figures

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On 27 May 2008 KEMA delivered its report *International Review of Transmission Reliability Standards* to the Australian Energy Market Commission Reliability Panel (the Panel). This report compared the frameworks for establishing consistent transmission planning standards across multiple transmission network owners (TOs). A selection of six international power systems was chosen that had multiple transmission owners and operated within wholesale electricity markets.

Among the key findings were that all the international power systems studied use a deterministic form of standard together with a deterministic planning methodology. In these systems the level of standards is generally n-1 (or higher) and the overall minimum standards do not diverge across connection points (or groups of connection points) in the power system though regions and individual systems are allowed to have more stringent criteria.

One of the ways that these selected markets were different from the Australian National Energy market (NEM) was that the form of the standards in the NEM is a mixture of deterministic and probabilistic approaches whereas the sample systems all used the deterministic form of standards. In particular, the TO that serves Victoria (VENCorp) uses probabilistic methods in planning its transmission systems.

Stakeholders comments

Following release of the KEMA report and the Reliability Panel's draft report *Review of Nationally Consistent Framework for Transmission Planning Standards*, comments were made by several stakeholders. Several of these comments addressed specific portions of the KEMA report.

As a result, AEMC engaged KEMA to follow up on the stakeholder responses that addressed the topics in the KEMA report. Specifically AEMC asked KEMA to address four issues:

1. Review deterministic, probabilistic, and hybrid planning methodologies;
2. Compare the probabilistic planning methods of British Columbia, California, and New Zealand with that used in Victoria;
3. Respond to the comments regarding the KEMA report made by VENCorp and the Group, and
4. Critically review the pros and cons of these general approaches to transmission planning.

These four points are addressed below.

1. Deterministic, probabilistic, and hybrid planning methodologies

Blackouts are usually caused by a sequence of low probability outages. Disturbances have occurred after a series of successive unscheduled equipment outages more severe than n-2 following low probability events.

History has shown that even scheduled outages have affected power systems' balanced operation demonstrating the grid's complexity during managed conditions. Examples include the August 1996 cascading disturbance in North America affecting more than 7.5 million people and the August and September 2003 blackouts in North America and Europe that each affected about 60 million people. None of these blackouts occurred during peak load conditions. The point is that blackouts often occur when conditions are outside those normally included in planning criteria.

Another frequent aspect of blackouts is that some equipment does not operate as designed. The bulk power system includes hundreds of elements such as transmission lines, generators and substations. Each of these elements includes hundreds of individual components. At any given time the system has literally tens of thousands of components that could fail or misoperate. That the bulk electric system continues to operate in face of such complexity is because of planned redundancy and operator flexibility during real-time operation.

Sometimes even experts lose the sense of planning criteria being realistic tests of the system, but not being tests of actual system conditions. The range of actual operating conditions would be impossible to evaluate effectively. Bulk transmission systems typically have about 3% of their elements out of service on any given day. These outages are due to equipment failures, routine outages, scheduled maintenance, etc.

A recent NEM scheduled outage list showed 45 transmission network elements were scheduled to be out of service.[1] Of these, seven were scheduled to be out of service in VENCorp alone. So during this day the VENCorp system was in an "n-7" condition before any additional contingencies were considered. This is a long way from the n-1 or n-2 conditions that are typically studied in developing transmission plans, even when allowing that these were not peak-load conditions. Assuming that the VENCorp system has about 200 transmission elements (lines and transformers), there would be about 285 billion combinations of n-7 events for each hour.[2] It is staggering to even consider actually studying this many combinations of outages.

Sometimes there is confusion regarding power system 'planning' and 'operating' criteria. Planning criteria must address a much more uncertain future than operating criteria. It might appear logical that if the system fails the planning criteria, the planner can fall back

1 For 7 July 2008, file: "NEM PUBLIC_NOSDAILY_2008070700000023.CSV" available at www.nemmco.com.au/powersystemops/NOS.html.

2. The calculation is (200 factorial/193 factorial)/7 factorial.

on the flexibility that system operators have to solve problems. But this ignores the much higher uncertainty in planning for conditions five and ten years in the future.

The planning criteria are set to allow for this difference in uncertainty. It is just wrong to mix planning and operating criteria and studies.

Failing planning criteria means that the system has reached an unacceptable risk of having a blackout. The failure means that plans must be developed to remove the criteria violations.

1.1 Deterministic methods

Deterministic transmission planning methods have been used for transmission system planning throughout the worldwide power industry for many decades and will, no doubt, continue to be used for years to come. These deterministic methods evaluate the outcomes of a predetermined set of contingencies. This type of analysis is often referred to as “n-1” or “n-2”, etc. as the system is tested for the loss of one or two (or more) elements.

In a deterministic planning method, expected future conditions are simulated for a few load levels and system conditions. For each load level a computer model is used to simulate the effect of losing any single element on equipment thermal loadings and voltages. An acceptable limit for thermal loading is set for each element as is a range of acceptable voltages. So long as the results are within the acceptable limits no action is required. If the limits are violated then plans must be developed to eliminate the violation.

Because there are so many possible system conditions that could occur in the future, deterministic criteria are set to test the system to see that it is robust enough that it can survive the many other events that are not actually being studied.

Deterministic transmission planning criteria are similar to the kinds of tests a physician might make. As an analogy, consider someone getting a blood cholesterol test. If the cholesterol level is above 200 then that person is considered to be at risk. There is no assessment of the risk that that person will have a heart attack that day, or that year, or the next year. They may never have a heart attack. But they have reached a predetermined level where they are considered to have an unacceptable risk for heart attack. A prudent person would not wait until they experienced chest pains but would take actions to reduce their cholesterol level so that the risk of failure (heart attack) is reduced to acceptable levels.

In a similar way, the system planner must make plans to modify the system so that the unacceptable risk of failure is reduced to acceptable levels based on planning criteria.

With the deterministic method alternative plans are ranked based on cost and, where possible, transfer capability—a technical measure as to how much the solution strengthens the system.

1.2 Probabilistic methods

One major weakness of deterministic methods is that it does not directly consider the probability of outages. Probabilistic methods consider both the impact of an event (contingency) and its probability. Probabilistic planning can also capture multiple component failures and recognize not only the severity of the events but also the likelihood of their occurrence.

The deterministic method assumes that the "worst" case has been identified for study. But the worst case may be missed. Some serious system problems may not necessarily happen at the peak load. And the system is exposed to risk under less than worst-case conditions. Probabilistic methods can be used to quantify the risk for many of these system conditions.

As discussed above, most major outages are usually associated with multiple component failures. These severe outages will not usually be captured by deterministic analyses. Probabilistic methods offer the possibility of including such events by using risk management techniques in planning to keep system risk below an acceptable level.

The big advantage of the probabilistic method is that it can be used to estimate an expected value of load at risk. The expected value can be in MWh or MW. Either of these measures could be converted into a customer cost using an estimate of the impact on customers. It is the combination of the impact of an event (in MWh or MW) together with its probability that is at the heart of the probabilistic method.

Probabilistic methods can be used to provide many additional measures of reliability. These include expected energy not served (the most commonly used measure); and the number, frequency and duration of outages; as well as, similar delivery point indices.

1.3 Hybrid methods

Hybrid methods combine deterministic and probabilistic methods. In practice, as will be seen when specific utility methods are described below, the probabilistic methods being used are actually hybrid methods.

There is no inherent conflict between the deterministic and probabilistic methods. In a hybrid method each method acts a check on the other. In the hybrid method, deterministic methods are used to identify any needed system improvements. Probabilistic methods are then used to see if there additional system improvements that can be economically justified when considering probabilities, especially of rare or combination events.

There are two noted variations regarding whether improvements identified by the deterministic methods must then be justified by a probabilistic analysis:

- In the first approach, projects identified in the deterministic analysis are not reviewed using the probabilistic analysis. With this approach, projects identified in the probabilistic analysis can add to the list of proposed projects but will not eliminate or delay projects identified in the deterministic analysis. This approach might be called "hybrid-neutral".

- In the second approach, any projects identified in the deterministic analysis are subject to review using the probabilistic analysis. Any deterministic projects that do not pass the probabilistic analysis are delayed or eliminated as justified by the probabilistic analysis. This approach might be called "hybrid-subtractive".

In both approaches, a project that was not justified in the deterministic analysis can be added to the expansion plans if it is justified by the probabilistic analysis.

To demonstrate, let us consider a simple example with three possible projects. Project 'A' can be justified by both the deterministic and probabilistic analyses. Project 'B' is justified by the deterministic analysis but not the probabilistic analysis. Finally, project 'C' is not justified by the deterministic analysis but can be justified by the probabilistic analysis. These three projects are represented in Table 1.

Table 1: Example comparing two broad hybrid approaches

Project	Is project required by analysis:		Result: is project included in final plan:	
	Deterministic	Probabilistic	Hybrid-neutral	Hybrid-subtractive
A	Yes	Yes	Yes	Yes
B	Yes	No	Yes	No
C	No	Yes	Yes	Yes

All three projects would be added with a hybrid-neutral approach. In contrast, the hybrid-subtractive method would eliminate or delay project B because, while it passes the deterministic test, it does not pass the probabilistic test.

2. Probabilistic planning methods of British Columbia, California, New Zealand, and Victoria

Probabilistic methods are being used, to at least some extent, in British Columbia (Canada), California, New Zealand, and Victoria (Australia). There are also efforts being developed by the Electric Power Research Institute (EPRI) and the Western Electricity Coordinating Council (WECC) in the United States. These are described below.

2.1 Probabilistic planning methods of British Columbia

The transmission planning approach used in British Columbia combines the deterministic and probabilistic methods. The British Columbia Transmission Corporation (BCTC) is the Crown corporation that plans, operates and maintains the province's publicly owned electrical transmission system. BCTC was created in 2003 to ensure fair and open access to the transmission system. BC Hydro owns the transmission assets and BCTC manages those assets.

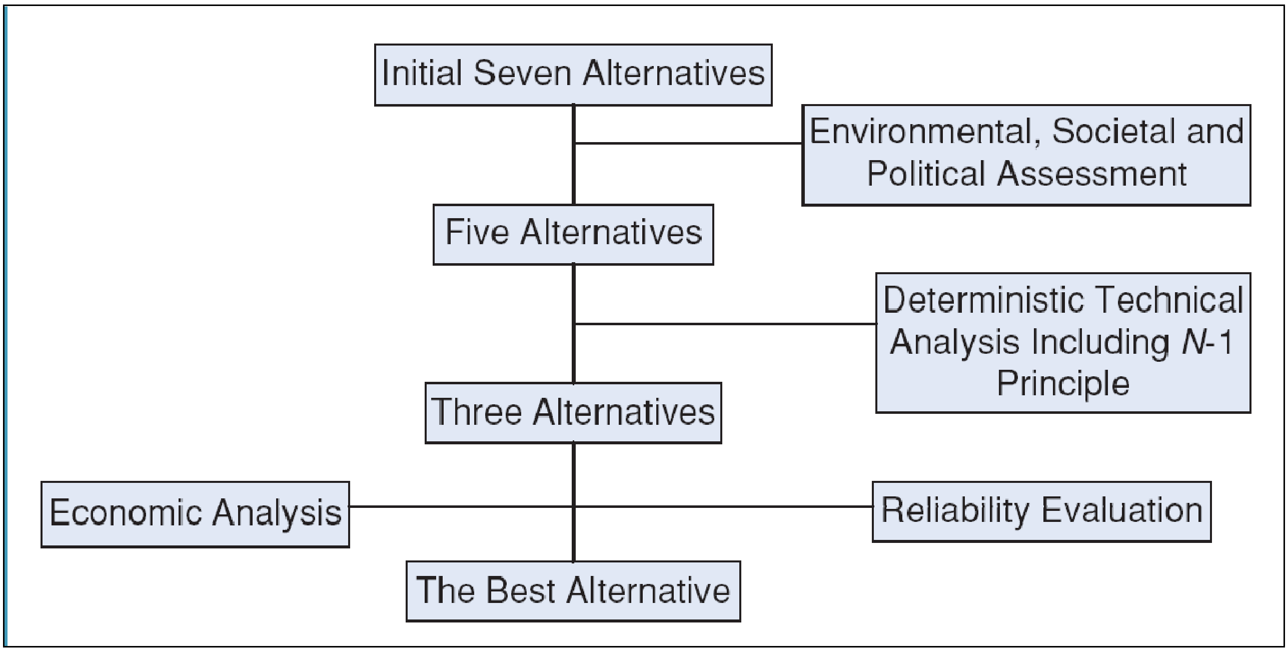
In the BCTC approach there is no conflict between deterministic and probabilistic approaches. The BCTC system planning process includes societal, environmental, technical and economical assessments while probabilistic reliability evaluation is a part of the whole assessment process. System criteria violations are identified by deterministic methods then probabilistic methods are used to select the best alternative solution.

In regard to probabilistic planning, BCTC has a fairly well developed set of computer models and data definitions and collection methods. Their models and methods are worth further investigation by those considering using probabilistic methods.

A simple example can be used to demonstrate how BCTC uses probabilistic methods in developing its transmission plans. Consider an example in which seven candidate planning alternatives are being considered as shown in Figure 1, below. [3] Assuming two of them are excluded based on environmental, societal or political considerations; there will be five that remain for further analysis. The deterministic criteria are then applied to the remaining five alternatives. Assume that two more alternatives are eliminated from the candidate list due to incapability to meet the deterministic contingency criterion. Economic analysis and probabilistic reliability evaluation are performed to select the best of the remaining three alternatives. Both deterministic and probabilistic methods are used.

3. The figure and example are based on material presented in *Probabilistic Reliability Planning Guidelines*, report BCTC SPPA-R011, dated June 2006.

Figure 1: Example of BCTC's use of the probabilistic method



Other examples exist where BCTC has identified transmission system additions where there was no deterministic criteria violation but that probabilistic analysis was able to justify the network addition.

So using the nomenclature of §1.3 and Table 1, the BCTC method is hybrid-neutral.

2.2 Probabilistic planning methods of California and the western US

2.2.1 Western US and the WECC

The California Independent System Operator is part of the larger region—the Western Electricity Coordinating Council (WECC)—that spans the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.

The WECC is a nonprofit corporation with the mission to maintain a reliable electric power system in the Western Interconnection that supports efficient competitive power markets, assuring open and non-discriminatory transmission access among Members and provides a forum for resolving transmission access disputes between Members consistent with FERC policies.

The WECC has adopted the limited use of probabilistic methods in determining system needs for overlapping outage events. The method uses historical outage rates and the expected probability of the event.

The WECC allows a transmission owner (TO) to reclassify a specific multi-contingency event from category C (two-element contingency) to one that has less stringent performance requirements (category D—extreme contingencies).[4] A TO can obtain such a change by demonstrating that the probability of the specific contingency has a mean time between failure (MTBF) greater than 300 years (frequency less than 0.0033 outages/year).

While some contingency events within WECC have been granted such treatment, its use has been very limited in scope. It has never been used for a single contingency (category B) event—the most common basis for capital expansion projects. The cases where WECC has granted this treatment generally deal with important transfer paths—where the impact has been on economic transfers within WECC and less on reliability.

2.2.2 The California Independent System Operator

The California Independent System Operator (CAISO) is developing an expanded probability-based transmission planning criteria—the *New Transmission versus Involuntary Load Interruption Standard*.[5] The intention of these criteria is "to develop consistent reliability standards for the CAISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-CAISO planning standards."

Historically, there has been a wide variation in approaches among the CAISO TOs. One TO might allow involuntary loss of load following a specific type of contingency while another TO would build a project to prevent loss of load for the same contingency. This new standard is intended to eliminate these inconsistencies and provide the information needed ensure that transmission system additions are cost-effective.

It should be noted that unlike the WECC process which has focused on multiple contingencies, the CAISO criteria is proposed to apply to single contingency events.

The use of probabilistic methods is not new to the CASIO. In the past, the CAISO has factored event probabilities when determining if it is economically justified to add a second transmission source to radially-fed substations. Under this standard, the CAISO has required that the expected annual "cost" of losing the single source to a radially-fed substation is greater than the levelized annual capital cost of building a second circuit to the substation. (The outage "cost" is based on the probability of the event and the economic impact of an involuntary outage to customer load at the substation.)

In many cases this has deferred construction of a second circuit beyond when it would have been built based on simple deterministic rule-of-thumb criteria (e.g., add a second source when load exceeds 100 MW). On the other hand, if the probability and economic consequences of a substation outage were found to be severe enough, construction of a second transmission source into the substation could in fact be advanced under this standard. In at least one case the methodology was also used to justify construction of a

4. The planning Standards can found at the North American Electric Reliability Organization (NERC) website—www.nerc.com.

5. The draft is dated May 6, 2008, titled "California ISO Grid Planning Standards".

third transmission source to a substation already supplied by two radial circuits because it was determined that the probability and economic consequence of the double-contingency event were severe enough to justify a third circuit.

These applications are special cases in that the NERC criteria allow for load to be lost for single contingencies at radially-fed substation. So the applications described above set standards for when service to radially-fed substations can be justified.

The CAISO is now seeking to implement an expanded version of the criteria that would be used for all single contingencies (category B) that cause performance violations (e.g., overloads or undervoltages). The CAISO has proposed that any TO seeking to construct a capital expansion project based on performance violations for a category B event would need to meet this new standard. The TO would need to demonstrate that the expected annual cost of involuntary load lost due to the contingency would be greater than the levelized annual capital cost of the transmission expansion project needed to mitigate the system performance violation.

So using the nomenclature of §1.3 and Table 1, above, the existing method is hybrid-neutral while the new method will be hybrid-subtractive.

It is unclear how FERC will react to this new approach. Generally FERC has been more concerned with fairness and transparency of the criteria as long as all stakeholders have agreed to a technical criteria change.

2.3 Probabilistic planning methods developed by EPRI

The Electric Power Research Institute (EPRI) conducts research and development for the electricity sector. It is an independent, nonprofit organization, whose members represent more than 90 percent of the electricity generated and delivered in the United States. EPRI has been a proponent and developer of probabilistic planning tools for more than a decade. In recent years, the focus of EPRI software deployment in this area has been on their probabilistic reliability assessment (PRA) software.

There was a heightened level of interest in probabilistic transmission planning tools by the North American utility industry circa 2002-2005, however, since then deployment has stalled somewhat. There has been some level of deployment of these tools on a preliminary basis at Kansas City Power and Light, the Midwest ISO, American Electric Power, Consolidated Edison, and Entergy. However, it appears all of these examples were actually applications in the system operations arena rather than the system planning arena. The potential impact of these tools on capital expansion planning in North America still appears to be a work in progress.

Part of the reason for this slow deployment of such tools may be the mandatory reliability standards established by NERC and FERC in 2005. These transmission planning standards are based entirely on deterministic methods. This creates a significant level of uncertainty as to how (or when) probabilistic methods will be applicable under a mandatory reliability standards regime.

EPRI has acknowledged that institutional changes will need to take place in order to support further deployment of tools like PRA for transmission planning.[6] Widespread adoption of probabilistic methods will require acceptance by a wide range of stakeholders including regulators, ISOs, TOs, and technology developers. Acceptance will require institutional changes, technological development, resolution of data issues, and a program to promote understanding and awareness.

Now that mandatory reliability standards have been adopted, it could easily take a decade before the institutional issues are sorted out and the long-term trajectory of probabilistic planning deployment becomes clear in North America.

Recent research plans released by EPRI discuss developing an expanded suite of probabilistic planning tools beginning in the next few years. The plans describe a more "holistic" suite of EPRI probabilistic software that will take into account the variability of the marketplace among other factors.[7]

2.4 Probabilistic planning methods of New Zealand

The 2003 New Zealand Electricity Governance Rules require the Electricity Commission to determine the most appropriate Grid Reliability Standards (GRS).

In 2004 the Electricity Commission engaged a consultant to examine alternative options available in support of optimized investment planning, based on a prudent and well-considered approach to the quantification of risk from a transmission system and customer perspective. They delivered their report in August 2004.[8]

Their consultant recommended: "that the Commission implement the use of probabilistic transmission planning methods in conjunction with deterministic criteria, in the first instance, as a means of ensuring future investments in the New Zealand grid provide an appropriate cost/benefit, in accordance with a transparent transmission planning standards policy guideline."[9] The report also acknowledged the complexity of probabilistic planning techniques for widespread application to the NZ grid.

In April 2005 the Electricity Commission made its recommendation to the Minister of Energy regarding the GRS.

In developing the GRS, the Commission signaled its commitment to pursuing an economic approach to grid reliability, strongly linking the GRS with the application of the Grid Investment Test (GIT). However, the Commission acknowledged that there is concern among a number of stakeholders about the uncertainties and implementation issues associated with moving to such an approach. The Commission, therefore, developed a two-part grid

6. Zhang, P. "Moving Toward Probabilistic Reliability Assessment Methods," Dec. 2003, pp vi, and 1-4 to 1-7.

7. See EPRI's 2008 Program40 Grid Planning at: mydocs.epri.com/docs/Portfolia/PDF/2008_P040.pdf

8. Parsons Brinkerhoff Associates report, *Probabilistic Transmission Planning Comparative Options & Demonstration*, August 2004.

9. Ibid., page 9.

reliability standard, with an economic standard for the whole grid, underpinned by a “safety net” of an N-1 standard for contingencies on the Core Grid.[10]

The New Zealand National Grid is required to deliver a reliable and secure electricity supply under a range of system and environmental conditions, in a manner consistent with the Government’s energy policy objectives and the regulatory framework.

Transpower New Zealand Ltd. is the owner, operator and planner of the National Grid which comprises the electrical transmission system that stretches across both North and South Islands, connecting generation sources to local substations serving rural and urban customers. It also facilitates the competitive wholesale electricity market which underpins the pricing of electricity to all New Zealanders.

The national Grid is generally designed and operated to meet n-1 security criteria. With respect to outages specifically, the grid meets the GRS when, with all assets reasonably expected to be in service, the system remains in a satisfactory state during and following any single credible contingency event occurring (such as n-1) on the core grid.

Planning the New Zealand transmission system is an evolving process. Transpower and the Commission are currently considering ways to improve the transmission planning process. Probabilistic transmission planning techniques are one of the options being considered. However, the current transmission planning process involves only deterministic methods.

2.5 Probabilistic planning methods of Victoria

VENCorp is the major State Government owned entity within Victoria's privatized energy sector and it reports to the Minister directly responsible for the energy industry. It was established on December 11, 1997 and is a central component of Victoria's gas and electricity industries. The organization is funded by the industry on a cost recovery basis and plays an important part in delivering the benefits of energy industry reform. They are responsible for planning, expanding and approving connections to the Victorian high voltage electricity transmission system, and directing expansion of the network.

VENCorp uses a two-step hybrid approach in developing its transmission plans:

- The first step involves a deterministic analysis of the coming ten-year period. This analysis is used to identify points on the shared transmission network where there might be deterministic reliability criteria violations.
- The second step uses probabilistic methods to further evaluate the system and refine proposed solutions to the criteria violations during the coming five-year period. In the first five years of the planning horizon, probabilistic planning methods are applied to alternative solutions to the criteria violations found the first step.

10. *Revised Explanatory Paper*, New Zealand Electricity Commission, December 2005, page 3.

The deterministic method of the first step is fairly straightforward. Expected future system conditions are evaluated the coming ten-year period for various contingencies and load conditions to determine the year when load shedding or generation redispatch will be required to comply with the system performance requirements. This review normally identifies a number of possible network needs. Each of these possible needs in the first five years of the plan is then assessed in detail by applying the VENCorp's probabilistic planning method.

The probabilistic method of the second step is used to estimate the probability and amount of customer load shedding that would be expected for the base case and for each potential expansion plan. The expected customer loss of load, among other factors, is used to determine a cost for the base case and each plan. The difference between the cost of the base case and each alternate is the benefit associated with each plan.

The probabilistic analysis is made for each year of the five-year period with the various possible expansion plans. The costs and benefits of the plans are then compared. A comparison of the costs and benefits is used to determine the best plans and the timing of the necessary additions to be made.

In a sense, the deterministic method is used to generally identify future needs over a ten-year period. Probabilistic methods are then used to refine the selection and timing of the specific plans for the first five years. Any needs and plans identified with the deterministic approach must be validated, and likely adjusted, by the probabilistic analysis.

So using the nomenclature of §1.3 and Table 1, the VENCorp method is hybrid-subtractive.

3. Response to comments regarding the KEMA report made by VENCorp and the Group

3.1 VENCorp's use of probabilistic planning

The response by VENCorp noted that KEMA's description of their planning approach could be misleading. The VENCorp approach was briefly described on page 14 of the KEMA report:

> "In Victoria, VENCorp uses a combination of deterministic and probabilistic criteria. It is our understanding that they use deterministic criteria to establish the need for any network improvements and identify the best solution. VENCorp then use probabilistic techniques to justify the specific timing of any needed improvements. This is different from using fully probabilistic planning criteria to evaluate the system and develop plans as discussed above."

We agree that this was too brief a description and that it could be misleading.

As described above, while VENCorp uses a series of deterministic tests on the network over the next ten years to identify any parts of the network which fail deterministic tests, they also use probabilistic methods to evaluate the first five years. These probabilistic analysis and planning methods are also used to develop a range of options to address criteria violations and any other enhancements whose benefits exceed costs. Significantly, VENCorp applies probabilistic planning analysis and methodology on a case-by-case basis when further evaluating options.

3.2 The complexity and uniqueness of probabilistic methods

In its submission to the Panel's Draft Report, the Group noted that two of the main arguments against probabilistic planning were complexity and uniqueness.[11] Additional comments by the Group pointed out the probabilistic planning developments in California and New Zealand, and at EPRI. These have been discussed above.

In regard to complexity, the Group believes that complexity, in itself, is not sufficient reason to reject probabilistic methods. We agree. The Group notes that the deterministic methods are simplified approaches to a very complex power system planning problem. The Group argues that the complexity of the probabilistic approach should only be rejected if the added complexity is trivial or simply not practical.

It is clear from the discussion of the practices of other utilities above, that the complexity of probabilistic methods can be overcome. It should be noted, however, that those international electric systems that use probabilistic methods limit their scope or use in at least some important ways.

11. The Group includes Loy Yang Marketing Management Company, AGL Hydro, International power Australia, TRUenergy, and Flinders Power. Their comments were dated 27 May 2008.

In regard to uniqueness, the Group points out that VENCorp has used their probabilistic method for more than 10 years and that this planning methodology is well-entrenched in Victoria. The Group goes on to note that even though probabilistic planning methods are in their infancy internationally there is a "growing recognition to move in this direction." Again, we agree.

At some point, new methods, techniques, and technologies must have first adopters. This would apply to probabilistic transmission planning methods. However, as is discussed in §4 below, we would advise that caution be used in moving to adopt probabilistic transmission planning methods. It may be most prudent to adopt a hybrid-neutral approach until the full impacts can be observed.

We have also observed that it often takes fifteen years, or more, to see the true impact of major changes in regard to utility planning. Not until new generations of transmission facilities and power plants have been built and operated for a period of years can the full impact of such changes be observed.

4. The pros and cons of deterministic, probabilistic and hybrid approaches to transmission planning

4.1 Deterministic approaches—pros and cons

The big advantages for deterministic methods are that they have been used for decades and that they are easier to explain to the public and regulators. In addition the data and models are already in place at utilities. These are not small advantages—the deterministic methods are known and understood.

The disadvantages of deterministic methods are that:

1. They offer no relative merit comparison of the benefits to customers of different proposed solutions to any identified criteria violations;
2. They are arbitrary in that the conditions studied are indicative and based on a few selected system conditions; and
3. They do not distinguish between low and high impact events or those with low or high probability.

The conditions and tests performed with deterministic methods are based on past experience—both conditions where problems have occurred and conditions that proved challenging for system operators. This is both an advantage and a disadvantage. It is a disadvantage in that only known or expected conditions are studied—probabilistic methods study a wider range of conditions and contingencies. It is an advantage in that system conditions can be carefully represented and studies made to test these known conditions.

Because of their known limitations deterministic criteria have been set to provide a kind of cushion or safety margin which provides flexibility to system operators for the many situations (i.e. contingencies and operating conditions) that are not evaluated. The tests and pass/fail criteria are intended to indicate the health of the system.

As discussed above, this is like someone getting a (deterministic) blood cholesterol test. In a similar way, the system planner uses deterministic criteria to plan the transmission system so that the unacceptable risk of failure (blackout) is reduced to acceptable levels.

4.2 Probabilistic and hybrid approaches—pros and cons

All the applications of probabilistic planning methods also include a deterministic component. They are all a form of the hybrid approach.

Clearly the big advantage of probabilistic approaches is that they quantify a benefit associated with each expansion option. Knowing the benefit allows many economic evaluation and decision-making techniques to be applied to transmission planning. Such techniques appear to be well-suited to use in electric utility markets.

As is often the case, the biggest strength is also the biggest weakness. None of the probabilistic analyses can, in themselves, capture all the benefits due to proposed transmission system improvements. While these methods are capable of doing a credible job of evaluating most single and double contingencies, there are still so many system conditions that are beyond their capability for analysis. This means that probabilistic methods will tend underestimate the benefits of any particular plan or option.

For this reason, the hybrid-neutral approaches are more attractive than the hybrid-subtractive approaches. With a hybrid-neutral approach there is no reduction in the performance or reliability that would be obtained from a purely deterministic approach.

It is interesting to note that while acknowledging that the VENCorp approach is less than ideal, the Group prefers VENCorp's probabilistic approach that they believe is likely "to deliver a closer-to-optimum network strategy and timetable than an over-simplified deterministic approach."

In the VENCorp approach, projects are selected and their timing determined based on a cost/benefit analysis.[12] The 'costs' are those for constructing new facilities and any incremental operating cost increases. The benefits come from the probabilistic analysis and are the expected value of the load "not lost" by customers because of the new project and any reductions in operating costs. If the benefits exceed the costs the project is justified.

Past experience in Victoria with the VENCorp method has shown that the probabilistic benefits exceed the costs 3-4 years later than would be indicated by the deterministic method.[13] Regardless of the reason for this difference in timing, the resulting system is both less expensive and less reliable than if the projects had been added sooner based solely on the deterministic test.

Assuming that the estimate for costs is reasonably reliable, the risk for error in the approach is found in the amount of benefit estimated in the probabilistic method. There at least two general reasons for this difference in timing of projects:

1. The benefit determined by the probabilistic method is too low either because the value of and/or expected amount of customer outages is too low; or
2. The system has been overbuilt using the deterministic criteria.

There is no clear way to determine whether the deterministic criteria result in overbuilding the system. Perhaps in time, with the new methods such the probabilistic methods discussed here it will be come clear.

The probabilistic methods depend on two important components that are subject to further scrutiny. One is the cost to customers of interruptions—a value that may be underpriced.

12. See, for instance, *Victorian Electric Transmission Network Planning Criteria*, VENCorp, 3 May 2007; *National Electricity Rules, Version 20,* 1 May 2008; and VENCorp's *annual Planning Report 2008*.

13. Ibid footnote 11.

The other is the estimation of the amount of customer outages—an amount that is likely to be underestimated.

As was discussed above in §1 on page 2, there are many more combinations of system outages and operating conditions than can be evaluated by existing probabilistic methods. This guarantees that the calculated risk will be underestimated—even if it is not clear how much of an underestimation would result. There are, for instance, common periods of high risk during the spring and autumn when, while customer load is lower, many transmission facilities will be out of service for maintenance and many generators will not be operating. These risk associated with such periods are not included in the probabilistic analyses.

5. Summary

Neither approach—deterministic or probabilistic—is clearly superior or is guaranteed to include all reliability risks:

- The deterministic approach can only identify criteria violations identified for the few conditions that it studies. And while the quality of the cases studied may be superior, they are limited in number and scope. This is why the results of deterministic approaches are treated as an 'index' of system health rather than a measure of reliability.
- Probabilistic approaches consider a wider range of system conditions and a larger number of contingencies. They can be used to calculate a range of reliability measures and provide the basis for cost/benefit analysis. Because probabilistic measures cannot evaluate the millions of possible system states, they will underestimate the potential benefit of a given project or plan.

Either approach has limitations that might cause it to 'miss' a needed system improvement. For the time being, it would seem most prudent to evolve a hybrid-neutral approach that would allow projects identified by either the deterministic or probabilistic approach to move forward. The hybrid-neutral approach is preferred over the hybrid-subtractive because the probabilistic analysis, which may underestimate benefits, should not eliminate or delay projects or plans identified by the deterministic approach.

Good planning criteria and methods have three characteristics:

1. They clearly identify starting conditions including load levels, generation dispatch, system configuration, import/exports, etc.
2. They clearly identify the tests to be performed including the type of contingencies (single and multiple), the transmission elements that can suffer these contingencies, what system adjustments are allowed following a contingency (for multiple contingency events), etc.
3. They clearly state decision criteria, the measures to be used and what constitutes passing each test.

In addition, it is very helpful if the specific detailed criteria are in a form that can be revised from time to time as necessary. This usually means that the criteria are part of an appendix to a more general reliability document. The general reliability document will spell out the procedures and requirements for changing the criteria. While it may be appropriate for the general reliability document, it is usually better that the specific detailed criteria are not part of government legislation, acts, or administrative rulings.

Table 2 uses these three characteristics to compare the main features of deterministic and probabilistic methods for transmission planning. The table notes where there is an apparent preference by using a star (★) symbol.

Table 2: Summary comparison of methods

	Deterministic	Probabilistic	Comment/preference (★)
Starting conditions			
Load levels	Typically just a few—winter and summer peak, and 'stressed' conditions	★ Usually many hours of a 'standard' year are simulated	★ Probabilistic methods study many more load levels and conditions
Generation dispatch	Usually optimized for each load level	Usually evaluates many more generation scenarios than deterministic, but usually does a poorer job of scheduling unit outputs	★ Deterministic allows tailored generation dispatch to match conditions being studied, but probabilistic considers many more generation scenarios, so there is no obvious preference
Special conditions	★ Unusual system configurations as well as special import/.export conditions can be studied	Special conditions are generally not studied	★ Deterministic methods consider these special conditions
Tests performed			
Contingencies-single	★ Evaluates all single contingencies	Evaluates all single contingencies	★ Both study all single contingencies, but deterministic can do a better job of redispatch for important generation contingencies
Contingencies-multiple	Evaluates selected multiple contingencies including extreme events (more severe than n-2)	★ Evaluates all double contingencies, does not evaluate extreme events (more severe than n-2)	★ Probabilistic can identify important contingencies that deterministic may miss
Contingencies-combinations of generation and transmission	Evaluates selected important combination contingencies, conditions can be tailored to match the conditions	Evaluates nearly all combinations but uses a generic approach to generation redispatch	★ No advantage
Contingency probabilities	Based on judgment	Based on generalities	★ No advantage
Generation redispatch	★ Tailored to specific conditions being studied	Uses a generic approach to redispatch	★ The deterministic method allows for a generation redispatch to be tailored to the specific conditions being studied
Analysis types	★ Steady-state and dynamic	Steady state	★ Deterministic can consider dynamic and voltage/var limits more thoroughly

	Deterministic	Probabilistic	Comment/preference (★)
Decision criteria			
Easily understood	★ They are easily understood by the stakeholders and regulators	Less so, though they are easier for economic comparisons	★ Deterministic is easier to understand and explain
Violations tracked	Pass or fail	★ Can calculate many indices	★ Probabilistic provides information regarding many more reliability indices
Cost/benefit	Does not provide any reasonable measure of customer benefits	★ Provides estimated customer benefits for various plans and alternatives	★Probabilistic provides much more useful information for decision-making