Incorporation of DSM Measures into Network Planning

Research Report No 3
Task XV of the International Energy Agency Demand Side Management Programme

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THE IEA DEMAND SIDE MANAGEMENT PROGRAMME

The International Energy Agency (IEA) was established in 1974 as an autonomous agency within the framework of the Economic Cooperation and Development (OECD) to carry out a comprehensive program of energy cooperation among its 25 Member countries and the Commission of the European Communities.

An important part of the Agency's program involves collaboration in the research, development and demonstration of new energy technologies to reduce excessive reliance on imported oil, increase long-term energy security and reduce greenhouse gas emissions. The IEA's R&D activities are headed by the Committee on Energy Research and Technology (CERT) and supported by a small Secretariat staff, headquartered in Paris. In addition, three Working Parties are charged with monitoring the various collaborative energy agreements, identifying new areas for cooperation and advising the CERT on policy matters.

Collaborative programs in the various energy technology areas are conducted under Implementing Agreements, which are signed by contracting parties (government agencies or entities designated by them). There are currently over 40 Implementing Agreements, including the IEA Demand-Side Management. Since 1993, the following 20 member countries and the European Commission have been working to clarify and promote opportunities for DSM.

Australia	France	New Zealand
Austria	Greece	Norway
Belgium	Italy	South Africa
Canada	India	Spain
Denmark	Japan	Sweden
European Commission	Korea	United Kingdom
Finland	Netherlands	United States

A total of 20 Tasks (multi-national collaborative research projects) have been initiated by the IEA DSM Programme, 13 of which have been completed. Each Task is managed by an Operating Agent (Project Director) from one of the participating countries. The Operating Agent is responsible for overall project management including project deliverables, milestones, schedule, budget and communications. Overall control of the program rests with an Executive Committee comprised of one representative from each contracting party to the Implementing Agreement. In addition, a number of special ad hoc activities–conferences and workshops–have been organized.

The actual research work for a Task is carried out by a combination of the Operating Agent and a group of Country Experts, depending on the nature of the work to be carried out. Each country which is participating in a Task nominates one or more persons as its Country Expert. Each Expert is responsible for carrying out any research work within his/her country which is required for the Task All the Experts meet regularly to review and assess the progress of the work completed by the Operating Agent and by the group of Experts. Experts meetings are usually held between two and four times a year.

The IEA DSM Programme has undertaken the following Tasks to date:

Task I	International Database on Demand-Side Management
Task II*	Communications Technologies for Demand-Side Management
Task III*	Cooperative Procurement of Innovative Technologies for Demand-Side Management
Task IV*	Development of Improved Methods for Integrating Demand-Side Management
Task V*	Investigation of Techniques for Implementation of Demand-Side Management Technology in the Marketplace
Task VI*	Mechanisms for Promoting DSM and Energy Efficiency in Changing Electricity Businesses
Task VII*	International Collaboration on Market Transformation
Task VIII*	Demand Side Bidding in a Competitive Electricity Market
Task IX*	The Role of Municipalities in a Liberalized System
Task X*	Performance Contracting
Task XI*	Time of Use Pricing and Energy Use for Demand Management Delivery
Task XII	Cooperation on Energy Standards (not proceeded with)
Task XIII*	Demand Response Resources
Task XIV*	Market Mechanisms for White Certificates Trading
Task XV	Network-Driven Demand Side Management
Task XVI	Competitive Energy Services
Task XVII	Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Renewable Energy Sources
Task XVIII	Demand Side Management and Climate Change
Task XIX	Micro Demand Response and Energy Saving
Task XX	Branding of Energy Efficiency

* Completed Task

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FOREWORD

This report is a result of work which was completed within Task XV of the International Energy Agency Demand-Side Management Programme. The title of Task XV is "Network-Driven Demand Side Management." Task XV is a multinational collaborative research project which is investigating demand-side management (DSM) measures which may provide viable alternatives to augmentation of electricity networks and also provide network operational services.

Task XV is organised into five subtasks as follows:

- **Subtask 1:** Worldwide Survey of Network-Driven DSM Projects.
- **Subtask 2:** Assessment and Development of Network-Driven DSM Measures.
- **Subtask 3:** Incorporation of DSM Measures into Network Planning.
- **Subtask 4:** Evaluation and Acquisition of Network-Driven DSM Resources.
- **Subtask 5:** Communication of Information About Network-Driven DSM.

This report summarises the results from Subtask 3.

The Operating Agent (Project Director) for Task XV is Energy Futures Australia Pty Ltd, based in Sydney, Australia.

The work of Task XV is supported (through cost and task sharing) by the seven participating countries: Australia, France, India, New Zealand, South Africa, Spain and the United States. Participants provided one or more Country Experts who were responsible for contributing to the work of the Task and for reviewing work as it was completed. Some countries also nominated representatives who also contributed to the work of Task XV.

Information for this report was collected, and the document was reviewed by, Country Experts and representatives from the organisations listed in the Table on page vii.

The Principal Investigator for, and main author of, this report is Dr David Crossley of Energy Futures Australia Pty Ltd. Any errors and omissions are the sole responsibility of the Principal Investigator.

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EXECUTIVE SUMMARY

In the electricity industry, the term 'demand-side management' (DSM) is used to refer to actions which change the electrical demand on the system. Task XV of the IEA DSM Programme, and consequently this report, are concerned with a particular type of DSM – "network-driven DSM". Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators.

This report has three objectives:

- to describe in detail how network-driven DSM measures interact with the electricity market structures and regulatory regimes existing in each participating country;
- to identify and characterise the network planning processes implemented in each participating country; and
- to develop options for modifying network planning processes to incorporate DSM measures as alternatives to network augmentation.

Among the seven countries studied in this report, planning processes for electricity transmission and distribution systems vary significantly, particularly in relation to the types and functions of the various organisations involved, the detailed planning processes and methodologies used, and the policy and regulatory regimes within which electricity network businesses operate. However, there is sufficient commonality to identify a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.

There are four key areas in which such changes can and should be made.

Forecasting future electricity demand. Forecasting methodologies frequently reduce global load forecasts by an assumed (usually small) amount to take account of DSM activity. Such methodologies discount the potential contribution by DSM towards supporting electricity networks. Forecasting methodologies for network planning should be modified to recognise more accurately the potential contribution of DSM.

Communicating information about network constraints. Information about future network constraints is often retained inside network businesses. It is then very difficult for anyone else to propose options for relieving network constraints. Network businesses should make this information publicly available so that other organisations with the required expertise can develop DSM options to relieve the constraints.

Developing options for relieving network constraints. Network businesses should provide formal opportunities for third parties with expertise in DSM to participate in the development of options that use demand-side resources to relieve network constraints.

Establishing policy and regulatory regimes for network planning. Governments and regulators should change policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks. There are two ways in which this can be achieved: by providing policy and regulatory incentives to network businesses; and/or by imposing policy and regulatory obligations on network businesses.

1. INTRODUCTION

1.1 NETWORK-DRIVEN DSM

In the electricity industry, the term 'demand-side management' (DSM) is used to refer to actions which change the electrical demand on the system. Task XV of the IEA DSM Programme, and consequently this report, are concerned with a particular type of DSM – "network-driven DSM"[1].

Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators. In Task XV, network-driven DSM is defined as follows:

> *Network-driven demand-side management is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation.*

Task XV has identified the following two prime objectives for network-driven DSM:

- to relieve constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions; and/or
- to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support.

Finally, in Task XV, the following network-driven DSM measures are considered:

- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- interruptible loads;
- integrated DSM projects;
- load shifting;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs; and
- smart metering..

[1] For a more comprehensive discussion of network-driven DSM see the first report from Task XV: Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

1.2 FOCUS OF THIS REPORT

This is the third report from Task XV and it is intended to achieve the objective of Subtask 3 which is "to investigate how existing network planning processes can be modified to incorporate the development and operation of DSM measures over the medium and long term."[2]

This report has three objectives:

- to describe in detail how network-driven DSM measures interact with the electricity market structures and regulatory regimes existing in each participating country;
- to identify and characterise the network planning processes implemented in each participating country; and
- to develop options for modifying network planning processes to incorporate DSM measures as alternatives to network augmentation.

[2] Energy Futures Australia (2004). *Prospectus: Research Project on Network-driven DSM*. Hornsby Heights, NSW Australia, EFA, p 5.

2. INTERACTION BETWEEN NETWORK-DRIVEN DSM, ELECTRICITY MARKETS AND REGULATORY REGIMES

In Subtask 3 of Task XV, the objective of Activity 3-1 is to describe in detail how network-driven DSM measures interact with the electricity market structures and regulatory regimes existing in each participating country[3]. This section of the report summarises the results from Activity 3-1.

2.1 AUSTRALIA

2.1.1 Electricity Industry Structure

2.1.1.1 Restructuring

The restructuring of the Australian electricity industry has now been proceeding for 16 years since the industry itself set up a reform working group during 1990. This process has been the most profound and major restructuring in the 100 year life of the Australian electricity industry.

Until the mid-1990s, in some Australian states (eg Victoria, South Australia and Tasmania) the four functions of generation, transmission, distribution and electricity retailing (also called 'electricity supply' in some countries) were carried out within a single, vertically-integrated, monopoly business. In other States (eg New South Wales and Queensland) generation and transmission were contained in a single monopoly business, while distribution and retailing were carried out by a number of businesses, each with a monopoly franchise covering a specified geographical area within the State.

A major objective of electricity industry restructuring in Australia has been to unbundle the four functions into separate businesses:

- several competing generation businesses have been established in each State;
- a single monopoly transmission business has been established in each State;
- geographical monopoly franchises for distribution have been retained in States that already had them and have been created in the other States. In some States, the number of existing franchises, and therefore of distribution businesses, has been reduced;
- a two tier system has been established for electricity retailing in each State:
    - ♦ 'first tier' retailers are attached to a distribution business with a monopoly geographical franchise in that State. First tier retailers can sell electricity to customers throughout the State, whether or not the customers are located within the accompanying distribution franchise. The retail business is "ring fenced" from the distribution business (ie established as a separate accounting entity within one holding company);

[3] Energy Futures Australia (2004). *op cit*.

- ‘second tier’ retailers are stand-alone businesses not attached to a distribution business in the relevant State. Second tier retailers can also sell electricity to customers throughout the State. A second tier retailer in one State may be a first tier retailer in another State.

2.1.1.2 Privatisation

For the 50 years prior to the mid-1990s, the majority of electricity businesses in Australia were owned by State governments. Some distribution/retail businesses were owned by local governments (municipalities) and a handful of relatively small electricity businesses located in remote areas were privately owned.

Commencing in the mid-1990s, some State governments (eg New South Wales and Victoria) consolidated their hold on the Australian electricity industry by legislating to take ownership of the local government electricity businesses. After unbundling the electricity industry functions into separate businesses, some State governments (eg Victoria and South Australia) sold these businesses to the private sector, including foreign owners from the United States, United Kingdom and South-east Asia. All other States retained electricity businesses in government ownership.

More recently, there has been wave of selling of electricity businesses by the original private sector owners to new private sector purchasers. These new purchasers often own more than one electricity business. The end result has been some rebundling of the ownership of the previously unbundled ESI functions, eg with approval from the regulator, a single owner may own both an electricity generator and a retail business, though these must be operated as separate businesses.

2.1.2 Electricity Markets

2.1.2.1 Wholesale Electricity Market

The major Australian wholesale competitive electricity market, the National Electricity Market (NEM), comprises the sale of bulk electricity by generators to electricity retailers and large end-use customers in southern and eastern Australia.

The NEM operates in the States of New South Wales, Victoria, Queensland, South Australia and Tasmania and in the Australian Capital Territory. Western Australia and the Northern Territory will always be excluded from the “National” Electricity Market because of the lack of electrical interconnections and the vast distances between their load centres and the interconnected electricity network in the southern and eastern States. Western Australia has a wholesale competitive electricity market that operates only in that State.

The NEM operates one of the world’s longest interconnected power system – from Port Douglas in Queensland to Port Lincoln in South Australia – a distance of more than 4000 kilometres (see Figure 2.1). Up to AUD7 billion of electricity is traded annually in the NEM to meet the demand of the almost eight million end-use customers[4].

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[4] National Electricity Market Management Company Ltd (2005). *An Introduction to Australia’s National Electricity Market*. Melbourne, NEMMCO.
Available at: www.nemmco.com.au/nemgeneral/000-0187.pdf

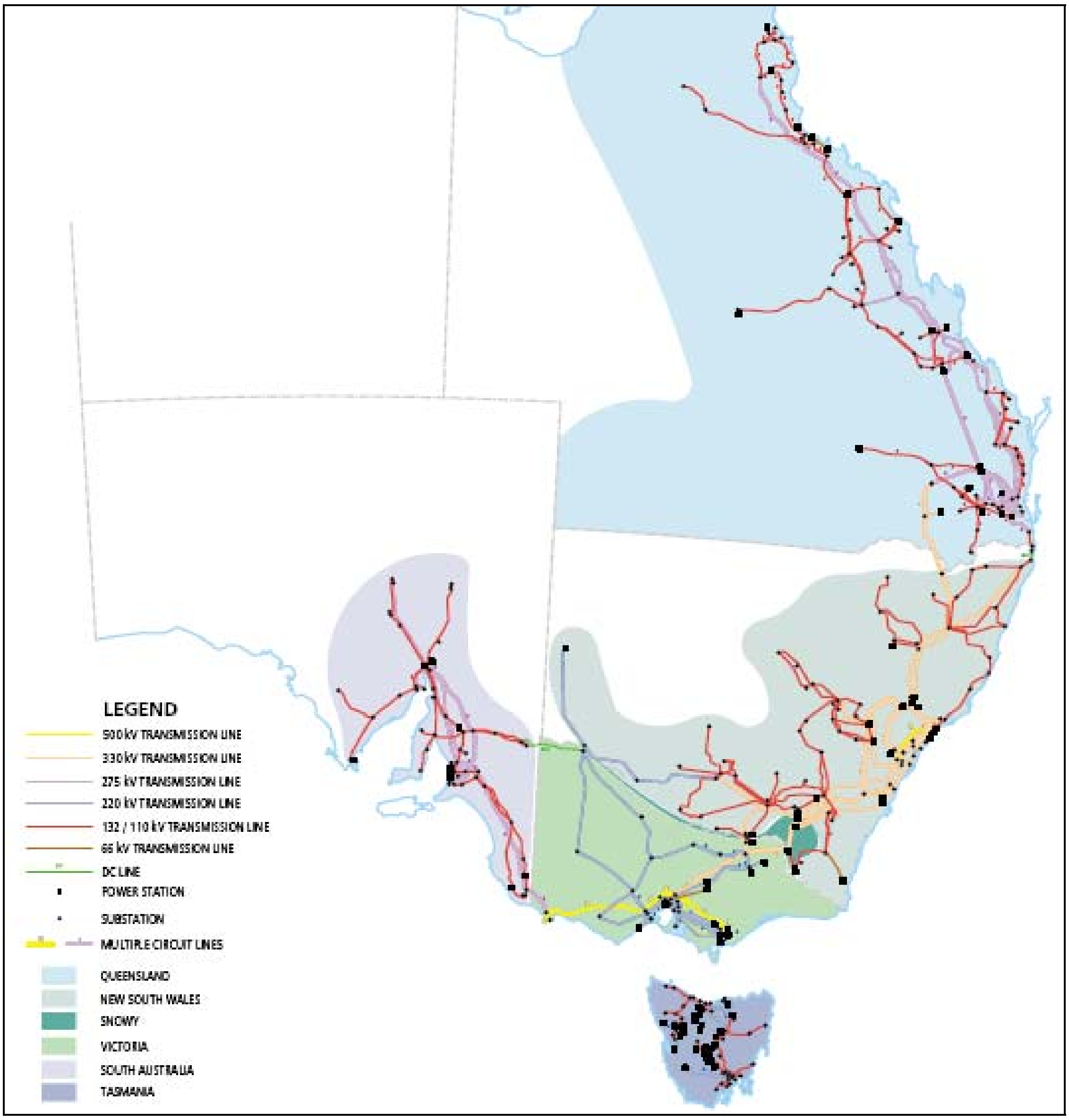

Figure 2.1 The Interconnected System Covered by the Australian National Electricity Market[5]

The NEM commenced on 13 December 1998 and it currently operates under a detailed set of rules called the *National Electricity Rules*. The NEM comprises a physical spot market with energy traded through a commodities-type pool and a spot price set every five minutes (and averaged over half hour periods) by the most expensive generator selected to run. All electricity sold at the wholesale level is accounted for through the pool (this is called a "gross pool" or "energy-only pool"). There are six geographical regions in the NEM and constraints on interconnectors can cause marginal spot prices to separate between the regions.

5 NEMMCO Ltd (2005). *Op. cit.*

The market operator for the NEM is the National Electricity Market Management Company (NEMMCO). The owners of the company are the five States and the Territory within which the NEM operates. NEMMCO was established in 1996 to fulfil the roles of both market operator of the NEM and operator of the power system that underpins NEM operations. NEMMCO is responsible for generator dispatch, reliability management and financial settlements in the NEM.

In addition to physical spot trading through the NEM, there is a separate over the counter (OTC) short term forward trading market for electricity. In this market, purchasers lock in energy prices through financial hedging contracts ("contracts for differences"). Under a standard bilateral hedging contract, the purchaser (typically an electricity retailer) agrees to purchase a specified physical quantity of energy from the spot market at a set price (the "strike price"). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counterparty to the contract (typically an electricity generator or a financial institution) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counterparty the difference.

Hedging contracts are financial instruments and can be traded in a market similar to other financial markets. There are numerous variations on the standard hedging contact available in the market, often containing complicated financial arrangements. The purpose of hedging contracts is to manage the price risks involved in purchasing electricity from the wholesale spot market. Prices in the spot market are highly volatile and the spot price can spike to several hundred times the average price for short periods.

2.1.2.2 Ancillary Services Markets

The National Electricity Market also includes a range of different markets for ancillary services, managed by NEMMCO, including:

- eight distinct markets for Frequency Control Ancillary Services in which providers make offers of services to manage frequency within specifications up to a 5-minute horizon; and
- long term contracts for Network Control Ancillary Services and System Restart Ancillary Services negotiated between NEMMCO (on behalf of the market) and the market participant providing the service.

2.1.2.3 Retail Electricity Market

The retail electricity market comprises sales of electricity by retailers to end-use customers. Within the area covered by the NEM, the retail market is partly competitive and partly operates on a franchise basis.

In the competitive retail market, electricity retailers compete to supply the vast majority of large customers who choose not to purchase directly from the wholesale market and smaller customers who opt out of purchasing electricity from their first tier retailer. Such customers are termed 'contestable'.

In most jurisdictions in which the NEM operates (eg New South Wales, Victoria, South Australia and the Australian Capital Territory), retailers can sell electricity to all end-use customers down to the household level, ie all customers are contestable. Where this is the case, customers may continue purchasing electricity from their local first tier retailer and the tariffs they pay are controlled by the electricity industry regulator. Alternatively, customers can choose to purchase electricity under a competitive retail contract from a first or second tier retailer in their State. There are no controls on prices under such competitive retail contracts.

In Tasmania currently only larger customers can be offered competitive retail contracts by retailers. Smaller customers continue to purchase electricity under controlled tariffs from their local first tier retailer. All small customers are scheduled to become contestable in in Tasmania by July 2010. However, the Tasmanian Government has reserved a final decision as to whether retail contestability will be extended to households and small businesses (from 1 July 2010) until a public benefit test has been undertaken.

Under this structure for the retail electricity market, retailers actually shield retail customers from the price volatility in the NEM wholesale spot market. In effect, retailers provide price risk insurance for retail customers, with the retail price paid by the customer including an insurance premium component.

Currently, there is a move to abolish retail price controls for all customers in all jurisdictions in which the NEM operates. This is likely to be introduced progressively over the next few years as competition in the retail electricity markets in each jurisdiction becomes more effective.

2.1.3 Network Charges

Originally, network charges, covering the cost of transporting electricity from the generator to the point of end-use, were bundled together with energy charges in calculating the electricity price to be charged to the end use customer.

Following the establishment of the NEM, both generators and end-use customers are required to pay separate network charges. In the wholesale market, market participants who purchase electricity directly from the spot market are responsible for paying connection charges and ‘use of system’ charges directly to their local transmission and distribution network owners. In the retail market, network charges incurred by end-use customers are paid for them by their electricity retailer who packages these network charges together with the energy charge. In some electricity bills the network charges are separately identified but many bills continue to show one price to the end-use customer.

2.1.4 Regulatory Regime

Prior to the mid-1990s, regulation of the Australian electricity industry was carried out on an informal basis because most of the businesses were government-owned and were operated as a public service rather than as profit-making commercial ventures. For example, increases in electricity prices were often agreed in informal meetings between the senior management of the electricity businesses and the relevant government Minister.

Once competition was introduced into the electricity industry, and particularly as some electricity businesses became privately owned, a more formal system of regulation was required. Consequently, State and territory governments established new agencies to regulate the electricity industry (plus often other industries as well). By mid-2004, this jurisdictional-based regulation resulted in the Australian electricity industry being regulated by 13 separate agencies. Commencing in 2005, this situation was rationalised with regulation of the industry being progressively transferred to national regulatory agencies.

Currently, regulation of the electricity industry in Australia is mainly carried out by two relatively new statutory commissions that were established under the *National Electricity Law* and which commenced operation on 1 July 2005:

- the Australian Energy Market Commission (AEMC); and
- the Australian Energy Regulator (AER).

The Australian Energy Market Commission (AEMC) has responsibility for rule-making and market development in relation to the NEM. The AEMC reports directly to the Ministerial Council on Energy (MCE). The MCE includes Commonwealth, State and Territory energy ministers, in addition to ministers from New Zealand and Papua New Guinea as observers. The MCE has the power to direct the AEMC to carry out reviews of the National Electricity Market and the *National Electricity Rules*.

The AEMC is responsible for[6]:

- administration and publication of the *National Electricity Rules*;
- the Rule making process under the *National Electricity Law*;
- making determinations on proposed Rules;
- undertaking reviews on its own initiative or as directed by the MCE; and
- providing policy advice to the MCE in relation to the National Electricity Market.

The Australian Energy Regulator (AER) performs economic regulation of the wholesale electricity market and electricity transmission and distribution networks in the NEM, and enforcement of the *National Electricity Law* and *National Electricity Rules*. These functions will expand over time as electricity retail functions are progressively transferred to the AER.

Under the *National Electricity Law* and *National Electricity Rules*, the AER's key responsibilities currently include[7]:

- regulating the revenues of transmission network service providers by establishing revenue caps;
- regulating the revenues of distribution network service providers;
- monitoring the wholesale electricity market;
- monitoring compliance with the *National Electricity Law*, *National Electricity Rules* and *National Electricity Regulations*;

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[6] Australian Energy Market Commission (2006). *What the AEMC Does*. Page on the AEMC website at: www.aemc.gov.au/whataemcdoes.php

[7] Australian Energy Regulator (2006). *What We Do In Electricity.* Page on the AER website at: www.aer.gov.au/content/index.phtml/itemId/659171/fromItemId/659159

- investigating breaches or possible breaches of provisions of the *National Electricity Law*, *Rules* and *Regulations*;
- instituting and conducting enforcement proceedings against relevant market participants;
- establishing service standards for electricity transmission network service providers;
- establishing ring-fencing guidelines for business operations with respect to regulated transmission services; and
- exempting network service providers from registration.

State and territory regulators continue to be responsible for regulation of some retail functions within the jurisdictions in which the NEM operates. This includes the responsibility for regulating retail prices. Previously, the individual State and territory regulators adopted somewhat different regulatory approaches within their jurisdictions. As the responsibility for regulating all electricity functions is progressively transferred to the AER, it is likely that a single national approach to regulation will be adopted.

2.1.5 Opportunities for Network-driven DSM

Opportunities for network-driven DSM in Australia arise in three ways:

- through bidding demand-side resources into the National Electricity Market;
- through targeted load shifting by network operators; and
- through discrete DSM projects targeted at particular network elements and aimed at relieving network constraints and/or deferring network augmentation.

Demand-side resources are able to bid schedules into the NEM, and such resources could be used to provide operational services to network operators. However, at present, only loads such as water pumping and large industrial loads are bid into the NEM; this bidding tends to take place on a regular basis and is not currently used to provide short-term network operational services.

Distribution network services providers (DNSPs) in some Australian States routinely use ripple control remote switching technology to shift residential water heating loads to off-peak periods, particularly to the middle of the night. This is a long-standing network-driven DSM measure which has been used in Australia for over 50 years. In some highly congested distribution networks with aging infrastructure, shifting of hot water load targeted at particular network elements has been used very actively, simply to keep the network operating.

More recently, DNSPs in Australia have been trialling the use of short-term demand response measures to shift load from network peaks, particularly peaks caused by residential air conditioning on hot summer days. Various measures have been trialled to achieve demand response, including direct load control remote switching technologies and pricing initiatives aimed at encouraging changed behaviour by end-use customers.

Discrete DSM projects targeted at particular network elements have been increasingly implemented in Australia since the late 1990s. Some State regulators have provided incentives for DNSPs to implement DSM projects for this purpose. Until recently, there has been a particular emphasis on using energy efficiency load reductions to defer network augmentations such as the construction or upgrading of substations and feeders. In the future, it is expected that the emphasis will shift to deferring augmentation through short-term demand response load reductions at peak times on targeted network elements, eg by cycling air conditioners at peak time during hot summer days.

2.2 FRANCE

2.2.1 Electricity Industry Structure

Electricity generation in France is dominated by Electricité de France (EDF), a vertically integrated utility which owns outright approximately 84 % of the existing generation capacity, and in addition has some part-ownership of other generators. French law has deregulated electricity generation, but no significant independent generators have yet entered the market. Between 2001 and 2003, EDF's dominance was slightly reduced by the compulsory auctioning of capacity contracts totalling 6000 MW in several multi-auction rounds of 250 MW each, the so-called Virtual Power Plants or VPPs[8].

The French electricity industry was nationalised after the Second World War and EDF was originally fully owned by the Government of France. In July 2004, the government converted EDF into a traditional joint stock company. In an attempt to raise capital, EDF undertook an initial public offering (IPO) in 2005. However, French law requires that the government maintain a 70 percent holding in EDF.

The other three significant electricity generators in France are:

- Compagnie Nationale du Rhône (CNR), owned by the Belgian utility Electrabel (49.95%), a French public financial institution, Caisse des Dépôts et Consignations (29.43%), and several consortia of local communities (20.62%). CNR operates 19 hydroelectric plants on the Rhône River;
- Société Nationale d'Electricité Thermique (SNET), owned by the Spanish utility Endesa (65%), EDF (18.75%) and Charbonnages de France (16.25%). SNET owns four coal plants in France totalling 2,604 MW, representing around 2.5% of the French electricity generation system;
- Société Hydroelectrique du Midi (SHEM), owned by the French national railways company SNCF (60%) and Electrabel (40%). SHEM has 800 MW of hydro plants, production from which is sold in France by Electrabel.

8 Finon, D. (2002). *Introducing Competition in the French Electricity Supply Industry: the Destabilisation of a Public Hierarchy in an Open Institutional Environment*. Cambridge, Mass., Centre for Energy and Environmental Policy Research, Massachusetts Institute of Technology.

There are several other small generators (mini-hydro, renewables) and self producers (cogeneration, etc.) in France. There are also significant imports and exports of electrical energy across interconnections between France and other countries.

Electricity production by generators in France is shown in Figure 2.2 which also shows the other components of the electricity industry in France.

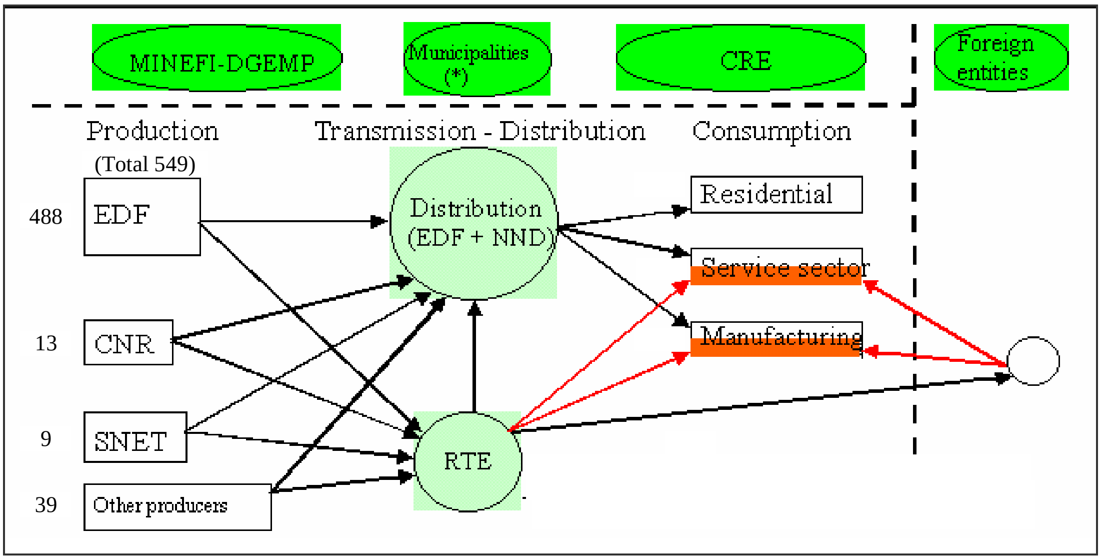

Figure 2.2 Structure of the Electricity Industry in France[9]
(Numbers show electricity generation in terawatt-hours in 2005)

The electricity transmission network in France is owned and operated by Gestionnaire du Réseau de Transport d'Electricité (RTE), which was established on 1 July 2000 as part of the liberalisation of the French electricity market required under European Union Directive 96/92/CE of 19 December 1996. RTE was created by the French Law of 10 February 2000 relating to the modernisation and development of the public electricity system[10]. The high-voltage network operation and generation dispatch functions were separated from EDF and a separate budget and specific confidentiality rules were established to create a “Chinese wall” between RTE and the sales and production divisions of EDF. Since 2005, RTE has been a separate company owned by EDF and RTE now operates as a largely independent entity.

The French Law of 10 February 2000 requires that RTE allow equal and non-discriminatory access to the transmission network for all electricity generators and distributors.

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9 Maillard, D. (2002). The Role of French Public Authorities in the Field of Energy in the Framework of Liberalized Markets. Presented at: *The Global Foundation, Inc. - International Energy Conference. Addressing Vulnerabilities : Science and Technology in Secure Energy Systems*. October 10-12, Washington, DC. Available at: www.industrie.gouv.fr/cgi-bin/industrie/frame0.pl?url=/energie/sommaire.htm

10 Loi n° 2000-108 du 10 Février 2000 *Loi relative à la modernisation et au développement du service public de l'électricité.* Available at: *www.legifrance.gouv.fr/texteconsolide/RIEAY.htm*

The management and operation of the electricity distribution network in mainland France is mainly the responsibility of EDF Réseau de Distribution (ERD), a business unit of EDF. ERD is responsible for managing the distribution assets under licence and for ensuring that connection and access to the network is available on a non-discriminatory basis. It is also responsible for relations with the energy regulation authority.

In some rural areas, independent municipal companies manage and operate the distribution network. There are 162 municipal distributors which are generally small, only account for about 5% of consumers and, in practice, work closely with EDF. These municipalities own the local electricity distribution network and are responsible for the distribution of electricity and for the augmentation and reinforcement of the network. Augmentation and reinforcement is usually undertaken by associations of a number of local authorities (Syndicats Intercommunaux d'Electrification), generally at the regional level.

Under French law deregulating the electricity industry, EDF's distribution units and the local distributors are subjected to strict rules ensuring confidentiality between the network control units and marketing units[11].

Historically, electricity retailing in France has been dominated by EDF, either directly selling to end-use customers in urban areas or supplying customers in rural areas under concessional contracts with the local authorities. Following liberalisation, several new players have entered the retail market, including other generators, independent retailers, brokers and traders; some of these entities are foreign-owned. In addition, Gaz de France has announced that it plans to begin offering electricity to its existing natural gas customers. Because EDF is not required to divest any of its generating capacity, most newly-entering retailers continue to purchase electricity from EDF.

2.2.2 Electricity Markets

2.2.2.1 Wholesale Electricity Market

The French wholesale electricity market was deregulated in 2000. The market has four components:

- a market for over the counter (OTC) bilateral contracts between generators and contestable customers, or for contracts established through transactions involving brokers or traders. This market includes both contracts for the physical delivery of energy in the form of block power supply and complete contracts including balancing services;
- a spot market for physical deliveries of energy on the electricity network in France;
- a balancing market that compensates for any gap between customers' forecast purchases and their actual consumption; and
- a purely financial trading market for electricity futures contracts.

[11] Finon, D. (2002). *Op cit*.

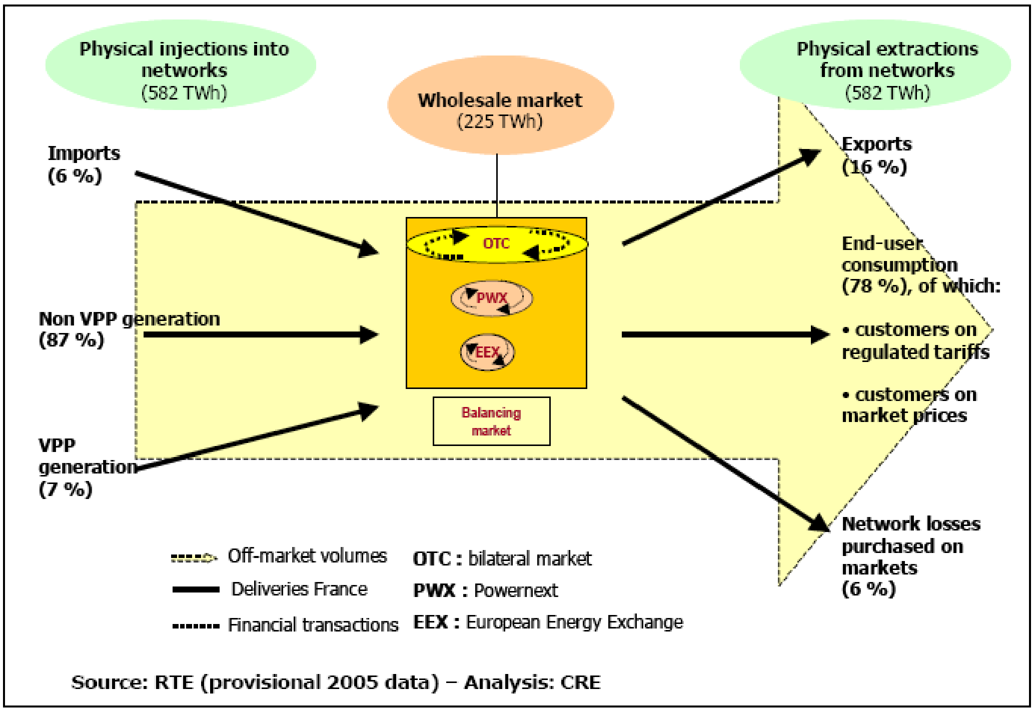

Figure 2.3 The French Wholesale Electricity Market[12]

Figure 2.3 shows the structure of, and energy flows through, the wholesale electricity market.

The Powernext electricity spot market was established by the Euronext stock exchange and RTE in 2001. The spot market auctions standard day-ahead hourly contracts for physical deliveries of energy at any point on the French electricity network and defines the hourly price by comparing the offer and demand bids. RTE is responsible for delivering the energy, while Clearnet, a subsidiary of the stock exchange, guarantees the auctions. The spot market enables the adjustment of quantities in bilateral contracts and provides a reference price for these contracts.

In 2004, Powernext also established a financial trading market in electricity futures contracts. The European Energy Exchange established the EEX France market in 2005 to trade electricity futures contracts with physical delivery.

The Balancing Responsible Entity is an intermediary between eligible customers and RTE. It is responsible for the financial risks associated with the adjustments that RTE must make to ensure the overall balance of the network.

2.2.2.2 Ancillary Services Market

Electricity generators connected to the transmission network in France are required to contribute ancillary services to maintain satisfactory levels of primary and secondary reserves on the network.

[12] Commission de Régulation de l'Énergie (2006). *Electricity and Gas Market Observatory: 2nd Quarter 2006*. Available at: www.cre.fr/pdf/observatoire_Q2_2006_VA.pdf

The specific obligations are as follows:

- generation units >40 MW are required to contribute to primary frequency control;
- power stations (sites) >120 MW are required to contribute to secondary frequency control;
- all generation units are required to contribute to primary voltage control;
- power stations (sites) >225 kV are required to contribute to secondary voltage control.

All generation units must conform with technical specifications that enable them to meet their ancillary services obligations before being allowed to connect to the network.

The contribution of each generator to the specified ancillary services is determined by a bilateral agreement with RTE. Hence, there is no actual market for ancillary services.

The allocation of each generator to provide ancillary services is achieved through a non-discriminatory process. The remuneration for this contribution is based on the costs incurred by the generator. The cost to RTE of purchasing ancillary services is recovered through the network access tariff, like other network charges.

2.2.2.3 Retail Electricity Market

The deregulation of the French retail electricity market took place in several stages[13]:

- in June 2000, all sites with an annual electricity consumption over 16 GWh per annum became eligible (ie contestable);
- in February 2003, all sites with an annual electricity consumption over 7 GWh per annum became eligible;
- in July 2004, all customers who were not private individuals became eligible.

Each contestable customer has a choice between two different types of contract:

- contracts under regulated tariffs (offered by incumbent retailers only);
- contracts at market prices (offered by both incumbent and alternative retailers).

Incumbent retailers comprise EDF and the local distribution companies. All other retailers are classified as alternative retailers.

Therefore, since July 2004 the entire non-residential sector in France has been open to retail competition. This represents over 70 percent of the French retail electricity market. By 2007, deregulation will be extended to the residential sector.

Following deregulation of the non-residential retail market, numerous small retailers have emerged. These retailers purchase wholesale electricity from EDF, then on-sell it to large industrial and commercial customers. These new companies undercut EDF's prices and are becoming a more important part of the French retail electricity market[14].

[13] Commission de Régulation de l'Énergie (2006). *Op cit.*

[14] United States Energy Information Administration (2006). *France Country Analysis Brief: Electricity.* Page on the EIA website at: www.eia.doe.gov/emeu/cabs/France/Electricity.html

2.2.3 Network Charges

In France, customers pay tariffs for using public electricity networks (*tarifs d'utilisation des réseaux publics d'électricité*, TURP). Separate tariff are paid for the use of transmission and distribution networks. These tariffs are set by decisions by the Ministry of Economy, Finance and Industry, based on proposals from the French energy regulator, CRE. The following general principles apply to setting tariffs for the use of electricity networks:[15,16]

- **tariff equalisation principle:** the tariff is identical across the whole of the country in accordance with the principle of equal treatment mandated by the law of 10 February, 2000;
- **postage stamp principle:** the tariff is independent of the distance travelled by the energy between the point of injection and the point of extraction (eg between the generating site and the consuming site);
- **tariffs depend on voltage level, contracted demand and energy flows:** the applicable tariff depends on the voltage level, the contracted demand level selected by the customer, and the measured physical flows of energy at the consumer's network connection point;
- **price variability over time and season** (distribution network tariffs only)**:** prices may vary according to the seasons, the days of the week and/or the hours of the day;
- **pricing depends on energy at injection** (transmission network tariffs only)**:** customers injecting into the public transmission system at above 130 kV pay a network access fee proportional to the physical flux injected.

2.2.4 Regulatory Regime

The Commission de Régulation de l'Énergie (CRE) was created in 2000 as part of the first phase of deregulation of the French electricity industry. In relation to electricity, CRE has two main areas of operation:

- access to public electricity networks; and
- market regulation.

CRE is the guarantor of the right of access to public electricity networks, ensures the smooth running and development of electricity facilities and systems, and is the guarantor of the independence of network system operators. CRE proposes tariffs for the use of public electricity networks, approves RTE's annual investment program, and makes recommendations on the long term development of the transmission network. CRE also supervises the organisation of the balancing mechanism and approves the operating rules of balancing proposals and programs, as well as the criteria for choosing between balancing proposals submitted to RTE.

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15 Gestionnaire du Réseau de Transport d'Electricité (2006). *Tariff Principles*. Page on the RTE website at: www.rte-france.com/htm/an/offre/offre_acces_tarif_principes.jsp

16 EDF Réseau Distribution (1995). *Tarif d'Utilisation du Réseau Public d'Électricité*. Paris,, ERD.

CRE ensures the smooth running of electricity markets, carries out market monitoring and also monitors cross-border exchanges of electricity. If generation capacities are inadequate, the Minister for Energy may issue a tender for new capacity that CRE is responsible for implementing. CRE also makes recommendations on the regulated tariffs applicable to non-contestable customers.

2.2.5 Opportunities for Network-driven DSM

In France, the transmission network operator, RTE, is prevented by its founding legislation from undertaking DSM. Consequently, network-driven DSM has been undertaken by the distribution units of EDF and the rural local distributors, usually in collaboration with the French Government's environmental and energy management agency Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME).

DSM has not been used to provide network operational services in France. Network-driven DSM has been used mainly in projects aimed at deferring network augmentation and reinforcement, particularly in rural areas. It is expected that this use will increase in the future as it becomes more difficult to obtain environmental approvals to build new transmission and distribution lines. In July 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of a transmission line in the French Riviera. A major DSM program is thus being studied. Its objective would be to limit load growth in the region while some necessary adjustments are made to the network by RTE to help secure the supply to this region, until a long-term and sustainable solution can be achieved[17].

EDF also utilises a network-driven DSM measure, the Tempo critical peak pricing tariff, to enable smoothing of both the annual and daily electricity load curves[18]. Under the Tempo tariff, each day of the year is colour coded. There are three colours, blue (*jours bleus*), white (*jours blancs*) and red (*jours rouges*) which correspond to low, medium and high electricity prices. The colour of each day is determined mostly by EDF based on the forecast of electricity demand for that day - the level of demand is mainly influenced by the weather. RTE also has the ability to determine the day colour if there is significant congestion on the electricity network.

The Tempo tariff was designed specifically for the situation where EDF is a monopolistic generator and retail supplier of electricity. However, it is not adapted to an open market situation. In particular, in the current French retail electricity market:

- the tariff for the use of the network does not vary between seasons; and
- the value of peak load reduction is not reflected in spot prices for energy which are less volatile than the marginal costs of supply.

If EDF needs to manage its global load curve in an open electricity market, it will probably have to develop other types of dynamic pricing for mass market customers.

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[17] A detailed case study of the French Riviera DSM program is included in the first report from Task XV: Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

[18] A detailed case study of the Tempo tariff is also included in the first report from Task XV.

2.3 INDIA[19]

2.3.1 Electricity Industry Structure

Under the Indian Constitution, the electricity sector is the joint responsibility of the state and central governments. Until the enactment of *Electricity Act 2003*, the Indian electricity sector was governed by three principal Acts. The *Indian Electricity Act 1910* dealt with the functioning and regulation of private licensees in the electricity sector. The *Indian Electricity (Supply) Act 1948* mainly dealt with the establishment and functioning of State government-owned integrated utilities called State Electricity Boards (SEBs). The more recent *Electricity Regulatory Commissions Act 1998* provided for establishment of state level and central level Electricity Regulatory Commissions for regulating the functioning of private licensees as well as the SEBs.

The SEBs were formed in the 1960s and soon took over numerous small private generation and distribution utilities in their respective states. Except for a few urban-based private distribution licensees in cities like Mumbai, Kolkata and Ahmedabad, the SEBs held monopolies over electricity generation, transmission and distribution within their states.

The central government established the National Thermal Power Corporation (NTPC), in the late 1970s to carry out electricity generation from large pithead coal-fired thermal generating stations. Currently, NTPC accounts for around 20% of India's total installed capacity and sells power to various state utilities (ie SEBs). Apart from NTPC, the central government also established companies such as Bharat Heavy Electricals Limited (BHEL) to manufacture electrical equipment (turbine, transformers, boilers) and Power Grid Corporation of India Limited (PGCIL) to construct and maintain interstate transmission lines.

2.3.1.1 Restructuring

Restructuring of the electricity sector in India commenced with the enactment of the *Electricity Act, 2003*. The key objectives of the Act can be summarised as follows:

- to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity;
- to promote competition in all aspects of the electricity sector, protecting the interests of consumers and the supply of electricity to all areas;
- to create transmission entities and system operators providing non-discriminatory open access to all electricity market participants;
- to rationalise electricity tariffs and ensure transparent policies regarding subsidies;
- to promote efficient and environmentally benign policies;
- to establish the Central Electricity Regulatory Commission (CERC), the State Electricity Regulatory Commissions (SERCs), the Appellate Tribunal and related matters.

[19] This section has been mainly developed from material in: ABPS Infra (2008). *Research Report No 4. Incorporation of DSM Measures into Network Planning*. Mumbai, ABPS Infra.

The key changes that the *Electricity Act* brought into the industry are shown in Table 2.1.

Table 2.1. New Initiatives Under India's *Electricity Act 2003*	
Area	**Key Policy/Regulatory Initiatives**
Generation	No licensing or State government approval required to establish new generating plant, leading to much faster implementation.
	Freedom to construct, operate and maintain Captive Power Plants[20].
	Tariffs charged by regulated utilities to embedded customers (ie franchise customers) to be set under the jurisdiction of appropriate regulators. Tariffs charged by Captive Power Plants and to open access customers to be set through commercial negotiations.
Transmission	All transmission entities to provide non-discriminatory open access to all market participants.
	Transmission licensees barred from participating in trading activities and trading entities barred from owning or operating transmission systems.
Distribution	All bulk purchases of electricity by distribution licensees to be on a competitive bidding basis.
	Parallel distribution networks may be established.
	Consumers with more than 1 MW load to be allowed open access by January 2009.
	Remaining tariffs charged to embedded customers to be rationalised in a phased manner with subsidies made transparent.
Trading	Trading to become a licensed activity.
	A power exchange to be established.

Following the enactment of the *Electricity Act*, SEBs in most States have been unbundled into corporatised generation, transmission, and distribution/retailing entities. The remaining States are in various stages of the reform process. The private sector commenced participating in electricity generation and distribution in the 1990s and this has increased since restructuring. In addition, there is a well-established electrical engineering and manufacturing industry in India.

2.3.1.2 Current Structure

Figure 2.4 (page 19) shows the current electricity industry structure in India. Despite restructuring, government currently still dominates the electricity sector in India. As at March 2008. the central and State governments control nearly 86% of electricity generation, 100% of transmission and 90% of distribution.

[20] Captive Power Plants are generating units established and commissioned to generate electricity primarily for the use of the power plant owner.

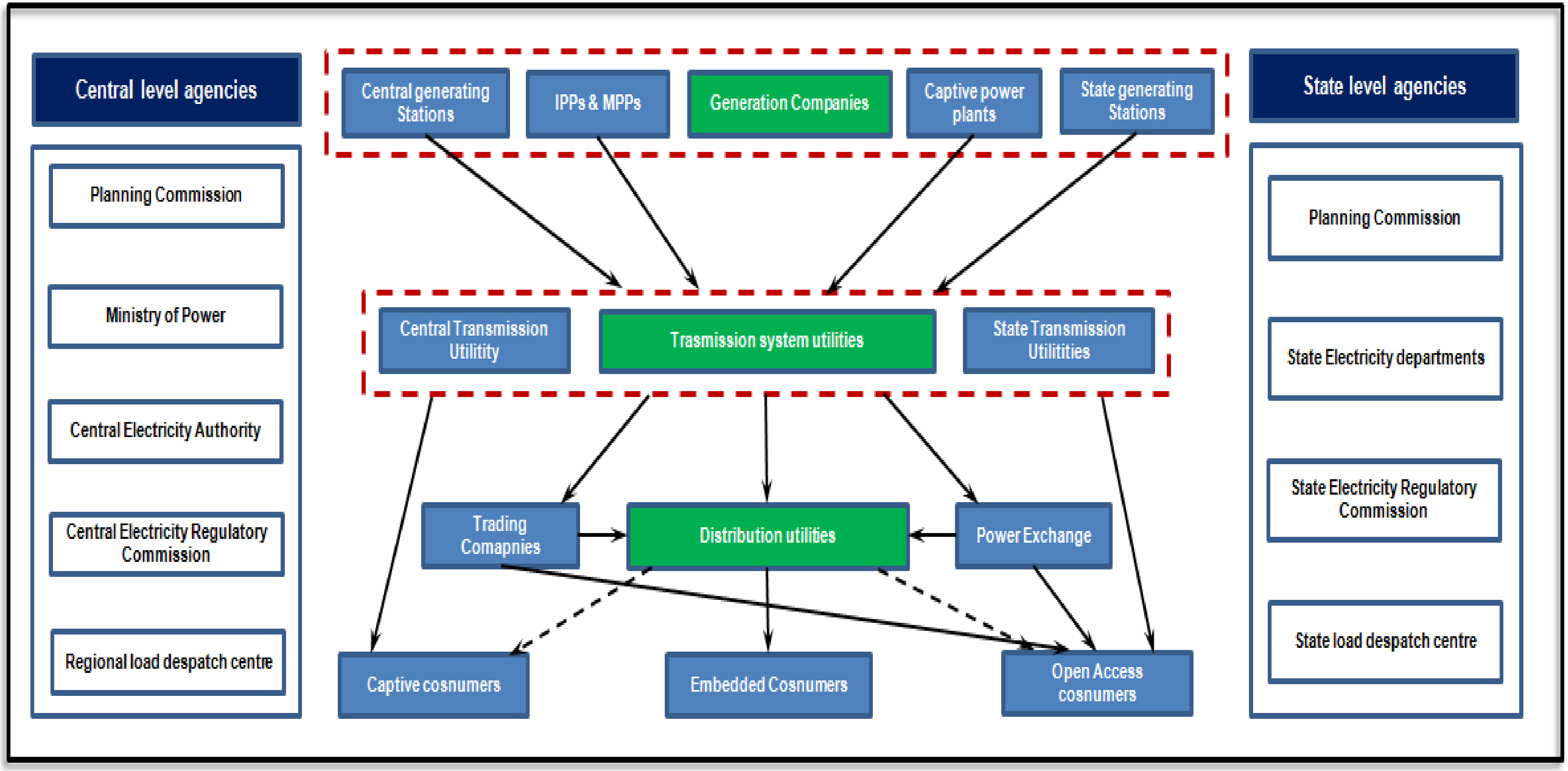

Figure 2.4 Current Electricity Industry Structure in India

2.3.2 Electricity Markets

The most significant reform initiative under the *Electricity Act 2003* was the move towards a multi buyer, multi seller system as opposed to the traditional structure, which permitted only a single buyer to purchase electricity from generators. In the wholesale market, the Act required all bulk purchases of electricity by distribution licensees to be on a competitive bidding basis. A power exchange has established to facilitate these transactions. The Act also progressively introduced competition into the retail market, initially providing that consumers with more than 1 MW load are to be allowed open access to a range of electricity suppliers by January 2009.

A National Load Dispatch Centre (NLDC) is being established in New Delhi by Power Grid Corporation of India to act as system operator at the national level. It is envisaged that regional and state load dispatch centres will also be established. At present, state transmission utilities act as system operators but it is expected that, in the future, this function will be allocated to state load dispatch centres.

2.3.3 Network Charges

In India, tariffs and charges are set separately for electricity generation, transmission and distribution (including retailing). Tariffs for end-use customers are skewed and involve high levels of cross-subsidies. Tariffs for certain consumer categories such as agriculture, are far below the cost of supply, which encourages inefficient consumption. Certain charges, such as a minimum consumption charge, do not provide any incentive to reduce demand on the system.

About 50 to 60% of the energy sold in India is not metered. In addition, as much as 30 to 50% of the energy generated is lost in transmission and distribution. The revenue collection arrears are also quite high – 30% to 200% of the annual revenue of a typical utility and almost all the SEBs make losses.

2.3.4 Regulatory Regime

The Indian electricity sector is regulated by overlapping jurisdictions of central and State governments. Following the enactment of the *Electricity Act 2003*, the roles and responsibilities of the centre and States have been clearly demarcated.

At the central level, the Ministry of Power is responsible for the policy-related aspects of the sector. The overall sector planning has been entrusted to the Central Electricity Authority (CEA), which was created under the *Indian Electricity (Supply) Act 1948*. All generation and distribution schemes above a particular size require the approval of the CEA. The non-conventional energy sector is managed by the Ministry of New and Renewable Energy (MNRE), and nuclear power by the Department of Atomic Energy (DAE). Organisations that supply fuel – coal, oil, natural gas – are also managed by the central government under different ministries.

Currently, there are no separate roles of policy and planning at the State level; both are the responsibility of the relevant State government ministry or department. In States where restructuring has not taken place, a State Electricity Board operates as a vertically integrated utility with generation, transmission and distribution functions. SEBs were structured to operate without the direct control of State governments, but even though there are no formal control mechanisms, SEBs are actually under State control through budget provisions and top level appointments which are decided by the State government.

At the central level, a Central Electricity Regulatory Commission, set up in 1998, carries out detailed regulation of the electricity sector, particularly[21]:

- the regulation of tariffs for electricity generation by generators owned or controlled by the Central Government or which operate in more than one State;
- the regulation of inter-State transmission of electricity; and
- the regulation of tariffs for inter-State transmission of electricity.

All States, except Arunachal Pradesh and Nagaland, have formed State Electricity Regulatory Commissions (SERCs) that carry out similar regulation of the electricity sector at the State level.

Regulatory Commissions have emerged as significant organisations in the electricity sector in India and have been providing new directions to the sector. They are quasi-judicial in nature and are set up to carry out regulation independent of government and make it more transparent and participative. They control the functioning of transmission and distribution/retailing utilities through regulation and a public consultative process. The regulatory regime became more flexible under the *Electricity Act 2003*. Regulation now has a multi-year approach and allows Regulatory Commissions greater freedom in determining tariffs, without being constrained by rate of return requirements. The *Electricity Act* also set up an Appellate Tribunal for Electricity at the national level, which accepts appeals on decisions made by any Regulatory Commission.

2.3.5 Opportunities for Network-driven DSM

In India, power shortages are a major problem. In financial year 2007/08, India faced a peak capacity deficit of about 14% and an energy shortage of 9.6%. The shortages are primarily caused by inadequate capacity additions, high T&D losses, poor interregional transmission links, and fuel supply bottlenecks.

Therefore, the most important opportunities for DSM in India derive from its potential to mitigate power shortages, to reduce capital needs for electricity sector capacity expansion as well as to enhance the energy security of the country. In particular, opportunities for network-driven DSM in India arise in the following ways:

- utilisation of distributed generation to mitigate load shedding and to optimise investment in the transmission and distribution sectors;
- promotion of solar water heating systems as a fuel substitution program;
- design, development and implementation of energy efficiency programs in the agricultural and municipal sectors; and
- reform of electricity pricing and tariffs.

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[21] Central Electricity Regulatory Commission website accessed 9 October 2008 at: http://www.cercind.gov.in/about.htm

2.4 NEW ZEALAND[22]

2.4.1 Electricity Industry Structure

2.4.1.1 Restructuring

The restructuring of New Zealand's electricity industry commenced in the late 1980s. Prior to 1987, the New Zealand Government had a statutory monopoly on the development of electricity generation and transmission. Generation and transmission activities were handled by the Ministry of Energy. The country was also split into municipal authorities run by locally elected Boards, known as the Electric Power Boards (EPB). These 61 EPB's took care of electricity distribution and retail sales.[23].

In the early to mid 1980s, there arose amongst New Zealand constituents major concerns over the efficiency of the public service and criticism of role confusion where Government departments often had a mixture of commercial, social, regulatory and policy responsibilities. Therefore, consistent with international trends at the time, the newly elected Labour Government embarked on a process of establishing a competitive model for electricity.

The first step in this process was the corporatisation of the New Zealand Electricity Division, which was a part of the then Ministry of Energy. The *State Owned Enterprises Act* was passed into law in December 1986. The Electricity Corporation of New Zealand (later known simply as ECNZ) was registered as a limited liability company in February 1987, with operational responsibility for generation and transmission from 1 April 1987.

Over the next 12 years, there was a series of restructurings that successively separated the industry into two components, monopoly network services and competitive energy supply:

- In 1988, electricity transmission was put in a subsidiary to ECNZ called Trans Power.
- The *Energy Companies Act 1992* enabled the formation of energy companies and the dissolution of the Electric Power Boards.
- The *Electricity Act 1992* removed the need for area specific licences to sell electricity along with the obligation to sell electricity to specific customers.
- In July 1994, transmission was split from generation with the separation of Trans Power from ECNZ. This company became a state owned enterprise (SOE) and exists today under the name Transpower New Zealand Limited.
- During the mid 1990s there was concern that the perceived power of ECNZ was hindering the entry of independent power producers. Consequently, part of ECNZ was separated and in February 1996 a new competing company, Contact Energy, was formed as an SOE.

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22 This section has been contributed by Transpower New Zealand Limited.

23 Kalderimis, Daniel (2000). "Pure Ideology: The 'Ownership Split' of Power Companies in the 1998 Electricity Reforms". *Victoria University Law Review*, Vol 31 (2), pp 255-316.

- The wholesale electricity market was established and commenced operations in October 1996 under a voluntary multilateral agreement, the New Zealand Electricity Market or NZEM.
- Between 1996 and 1999, ECNZ sold a number of its smaller generation stations to third parties.
- In 1998, Contact Energy was privatised by the then National Government.
- Responding to continuing concerns over the dominance of ECNZ, the Government then split ECNZ into a further three competing generation companies, now known as Meridian Energy, Genesis Energy and Mighty River Power. These new companies commenced operations on 1 April 1999; all are SOEs.
- In 1998 the Government also made it mandatory to separate the ownership of network lines from electricity retailing. The EPB's sold their retail businesses to the generation companies that existed at the time, namely Contact Energy and ECNZ. Those retail customer bases that were purchased by ECNZ were then subsequently allocated across the three newly formed generation companies. Despite full separation not being required until 2003, this process was completed before 1 April 1999.
- Around the same time a consolidation of the distribution activities commenced. Eventually, from the 61 EPB's fewer than 30 distribution companies were created.

In 1999, the Government changed and the newly elected Labour Government set about reviewing the structure of the electricity industry. The new Government was concerned about the apparent lack of regard for small consumers, the lack of a transmission investment regime and the ability of the country to be protected against short supply situations which, being dominated by hydro stations, occurred periodically due to dry weather patterns.

The initial proposal of the new Government was to encourage the electricity industry to extend the voluntary wholesale electricity arrangements to cover transmission investment. However, for a number of reasons, industry participants failed to reach agreement. In July 2003, the Government announced its intention to form a new regulatory body, the Electricity Commission and in September 2003 the Electricity Commission commenced operations[24].

Since 2003, many of the changes in the industry have been driven from amendments and expansion of the *Electricity Governance Rules* under which the Electricity Commission operates and which form the statutory requirements for the industry.

2.4.1.2 Current Structure

Currently. New Zealand has:

- five large vertically integrated generator/retailers, three of which are SOEs;
- several smaller independent generation and retail companies;

[24] The Electricity Commission did not actually take over operational control of the wholesale electricity market until March 2004.

- one transmission provider, the state owned Transpower, which also is the system operator under contract to the Electricity Commission; and
- 28 distribution level network companies with a variety of ownership structures including trusts and public (municipal) ownership.

As New Zealand is an island nation, there are no transmission interconnections with other countries. The only major interconnection New Zealand has is a 270/350KV bipole HVDC interconnection between the North and South Islands[25].

The majority of Government ownership is structured in accordance with the *State Owned Enterprises Act 1986*, under which the Government owns the shares in the businesses and requires the businesses to operate as any other commercial entity with their own Boards of Directors.

2.4.2 Electricity Markets

The New Zealand electricity market commenced operations in October 1996. The market is operated by a number of service providers under contract to the Electricity Commission. The market consists of three levels:

- the wholesale spot market;
- ancillary service markets; and
- the retail market.

2.4.2.1 The Wholesale Spot Market

The wholesale spot market operates a security-constrained, bid and offer based dispatch with nodal prices. Generators make price/quantity offers for production and purchasers place price/quantity bids for consumption. Voluntary demand reductions can be used by purchasers to reduce wholesale market costs. This process will be facilitated by the Electricity Commission's Demand-side Bidding and Forecasting project, which will provide consumers with better information on the effects of demand changes on wholesale prices[26].

As opposed to day-ahead commitment markets as seen in many other countries, the New Zealand market is closer to real-time, enabling bids and offers to be changed up to two hours before delivery (with a rolling time horizon). Prices are produced for each half hour for the approximately 288 nodes around the transmission network, the so-called 'nodal pricing'. Prices will differ between the nodes to reflect transmission constraints and transmission losses.

All wholesale electricity is traded through the spot market. The spot market is energy only (i.e. there are no payments for long term capacity) and there is no price cap on the spot market.

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[25] Note that the 270kV connection is based on older mercury arc technology and is being phased out. A proposal to replace it with newer technology has been submitted to the Electricity Commission..

[26] See: http://www.electricitycommission.govt.nz/consultation/dsbJuly07/view

There is currently no formal day ahead contract trading. However, over the counter (OTC) contacts are available from and between generators themselves, negotiable individually. There is also a voluntary inter-generator hedge market called Energy Hedge, which trades standard quarter MW contracts for each three months going out two years. A significant volume of energy is in effect internally hedged within each of the major generation/retail companies.

2.4.2.2 Ancillary Services Markets

The New Zealand electricity market includes a range of ancillary services, including:

- **Frequency keeping** – short term reserve contracted to keep the frequency of the system at 50Hz, the frequency keeping band being typically +/- 50 MW in each island.
- **Instantaneous reserve** – short term capacity to cover a potential credible event on the power system. The procured and dispatched reserves are to cover such an event, for example the loss of the largest generation unit on the system. New Zealand has two classes of reserve, fast (less than 6 seconds response time) and sustained reserve (60 seconds response time). There are reasonable quantities of interruptible load offered into the market as both fast and sustained reserves.
- **Voltage support services** – in identified regions requiring additional reactive support (voltage support) the System Operator procures the services from asset owners with the reactive power capability. The cost of procuring the additional reactive power is met by the distributors and dispatched generators in that region.
- **Over frequency reserve** – generators are armed to trip at pre-set frequencies for the purpose of arresting grid over-frequency following the loss of the inter-island HVDC link during high north transfer.
- **Black start services** – services are procured from specific generators who have demonstrated their capability to provide restarting of the grid following a total or partial blackout.
- **Automatic under frequency load shedding (AUFLS)** – significant load blocks are available at all times for in the event of an emergency.

Ancillary services are procured from ancillary service agents (generation companies, distributors and directly connected consumers) by the System Operator under various mechanisms (with the exception of AUFLS). Fast and slow reserve is co-optimised with energy when calculating the half hourly spot prices.

Overall these services are managed through the System Operator's annual Procurement Plan, which commences 1 December each year. The System Operator is required to use reasonable endeavours to implement the Procurement Plan by entering into contracts for ancillary services.

2.4.2.3 Retail Market

In New Zealand, the retail electricity market consists of electricity sales to end-use consumers by the retailers. The market is dominated by the five larger retailers who are vertically integrated with generation. Network companies are required by law to have ownership separation from retail.

Competition in the retail market has in theory existed since 1994, however it was not until around 1999 that the mechanisms were in place for customer switching between retailers. Initially, the switching and customer transfer process between retailers was a significant issue. However, this issue has largely disappeared with the establishment of the customer registry and industry wide switching processes.

Over the years, retailers have developed many different retail products for their customers, including options for split fixed and spot price components. In recent times advanced metering has started to be rolled out by some of the retailers. There is no price cap for retailers – instead New Zealand relies on competition to constrain prices.

2.4.3 Network Charges

2.4.3.1 Transmission

The Electricity Commission and the Commerce Commission have joint responsibility for transmission network charges. The Commerce Commission is responsible for the overall revenue Transpower is able to recover from its customers and the Electricity Commission is responsible for the method for allocation of the revenue, in accordance with the process required under the *Electricity Governance Rules.*

In 2008, the Electricity Commission moved to a new allocation methodology which includes a charge for peak usage by distribution companies based on regional co-incident peaks.

2.4.3.2 Distribution

As with transmission, the Commerce Commission is responsible for regulating the overall revenue requirement of distribution network companies. However, there is no formal regulatory method for calculating distribution prices themselves. Hence the methodology used to determine the price signal to be passed to retailers and end consumers varies between distributors.

2.4.4 Regulatory Regime

The primary legislation governing the sector is the *Electricity Act 1992*. The Act provides for the regulation of the supply of electricity and the electricity industry, and for regulation and control of electrical workers. The Act's coverage includes powers and duties of electricity operators and other owners of electricity works, electrical codes of practice, registration and licensing of electrical workers, restriction on electrical work and governance of the electricity industry. The Electricity Commission was established under powers provided in this Act.[27]

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[27] This section is based on information from the Ministry of Economic Development website at: http://www.med.govt.nz/templates/StandardSummary____42.aspx.

The *Electricity Industry Reform Act 1998* enforced full ownership separation of distribution (lines) businesses from supply (retail and generation) businesses. The main reasons for the separation were to encourage competition in generation and retailing and to prevent cross-subsidisation of generation and retailing from lines customers. These cross-ownership restrictions have been relaxed twice since 1999 to allow lines businesses to own some generation and to sell the output from those stations.

There are a number of Government bodies responsible for regulation and policy development covering different aspects of the industry.

The industry regulator is the Electricity Commission, which is primarily responsible for implementing the Government's policy objectives through the development of the industry rule book and the appointment of service providers. It is responsible for the monitoring and approvals where required under the rules. The Government Policy Statement sets out the Government's expectations for the Electricity Commission and covers such things as:

- the Government's overall objectives;
- transmission investment;
- transmission pricing;
- energy efficiency;
- the wholesale market;
- the retail market; and
- information provision.

Network company revenue regulation is the responsibility of the New Zealand Commerce Commission. The Commerce Commission is New Zealand's competition watchdog but is also responsible for industry specific regulation of a number of industries.

New Zealand also has an Electricity and Gas Consumer Complaints Commission that provides a free independent dispute resolution service for consumer complaints about electricity or gas lines or retail companies. From 18 April 2005, complaints up to a value of NZD20,000 can be handled through this Commission. Note that this is a independent industry body. It has no regulatory powers, is not established under any Act and is voluntary

The Ministry of Economic Development (MED) is responsible for developing and implementing policy for the electricity sector, in particular relating to the regulatory framework and governance. It also monitors market performance, including competition issues and electricity prices and the performance of the Electricity Commission, and it has ownership responsibilities for the Whirinaki electricity reserve generation plant.

The Energy Efficiency and Conservation Authority (EECA) is the Government body responsible for delivering the Government's energy efficiency agenda. Its function is to encourage, promote and support energy efficiency, energy conservation and the use of renewable energy sources.

In October 2007 the Government published the New Zealand Energy Strategy (NZES). The NZES sets out the Government's vision and an action plan for the future of energy in New Zealand. The Government's vision is stated as being[28]:

> *"for a reliable and resilient system delivering New Zealand sustainable, low emissions energy services, through:*
>
> - *Providing clear direction on the future of New Zealand's energy system*
> - *Utilising markets and focused regulation to securely deliver energy services at competitive prices*
> - *Reducing greenhouse gas emissions, including through an emissions trading scheme*
> - *Maximising the contribution of cost-effective energy efficiency and conservation of energy*
> - *Maximising the contribution of cost-effective renewable energy resources while safeguarding our environment*
> - *Promoting early adoption of environmentally sustainable energy technologies*
> - *Supporting consumers through the transition."*

The NZES currently forms the overarching policy basis for the New Zealand electricity industry going forward.

2.4.5 Opportunities for Network-driven DSM

2.4.5.1 Current Opportunities

Opportunities for network driven DSM in New Zealand currently arise in five ways:

- through provision of demand side alternatives for transmission grid support, whether to defer the need for transmission investment or manage the risk of delayed delivery of transmisison or higher than expected demand growth;
- through provision of demand side alternatives for distribution investment or deferral of the need for distribution investment;
- through targeted load shifting by distribution network operators responding to pricing incentives or for security purposes. This includes the use of ripple control for the potential reduction in network losses;
- through demand side bidding in the wholesale market to assist in the removal of network constraints;
- through price signals at the distribution network level.

[28] Ministry of Economic Development website, accessed March 2008 at: http://www.med.govt.nz/templates/StandardSummary____42.aspx

The *Electricity Governance Rules* require that when assessing transmission upgrades, Transpower, as grid planner, considers alternatives to the proposed transmission investment. These alternatives include consideration of demand side options that might replace or defer transmission investment.

Likewise distribution network companies have a regulatory obligation to consider demand side alternatives when considering new investments. There are, however, currently no requirements for these companies to call for proposals for demand side solutions, or to accept a demand side proposal if it is more economic than a traditional network solution.

2.4.5.2 Current DSM Capability

In regard to targeted load shifting, the Existing Capabilities Working Panel final report[29] noted that the owners of transmitters for load management systems (including ripple control) appear committed to continuing to provide load management. The report identified a number of themes from the survey of transmitter owners. Load control signals are largely used by transmitter owners for:

- peak load control;
- planned contingency management;
- emergency situation management;
- fixed time load switching;
- street and community lighting;
- deferment of network capacity expenditure; and
- tariff switching.

According to the report the current capability for load control is approximately 880MW (about 14% of peak demand) [30]. The Value Price Working Group[31] identified that some firms also use load control to reduce the impact of nodal pricing.

There are also currently some electricity distributors that provide peak demand signalling to connected customers. This is primarily done through a combination of physical signalling to customers when demand should be reduced and price penalties imposed on consumption in those periods[32]. These arrangements are targeted at commercial and industrial consumers with time-of-use meters. There is potential for these types of arrangements to be extended to other parts of the country.

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[29] See: http://www.electricitycommission.govt.nz/pdfs/advisorygroups/rmag/27sep06/5d-ECWP-final-rpt.pdf

[30] Based on a peak system demand of approximately 6500MW.

[31] The Value Price Working Group, was a working group established by the Electricity Commission. Its final report was reviewed by the Retail Market advisory group in August 2007. See: http://www.electricitycommission.govt.nz/advisorygroups/rmag/rmagmeetings/7Aug07

[32] The Christchurch based network company Orion utilizes this method.

There is also an opportunity for additional peak load management through the introduction of smart metering for demand management and efficiency. This requires retail product development in order for pricing signals to be effective.

Further development of demand side bidding in the wholesale spot market is also an opportunity for the development of network-driven DSM. The purpose of this would be to relieve short term constraints on the transmission system in real time. This would work in combination with the distribution network company load control programs.

2.5 SOUTH AFRICA[33]

2.5.1 Electricity Industry Structure

The electricity industry in South Africa has not yet been restructured. Eskom is a government-owned, national, vertically integrated company that performs all four electricity industry functions: generation, transmission, distribution and retailing throughout South Africa.

There are also many municipalities which reticulate and sell electricity mainly in urban areas. Very few of them have any forms of electricity generation. The South African Constitution states that municipalities have the right to 'reticulate' electricity. There have been many debates as to whether 'reticulation' means only low voltage reticulation or also includes the distribution of electricity at higher voltages. As electricity sales are a large portion of the income of municipalities they are reluctant to restructure and possibly lose this source of income. The South African government is currently working on legislation to make it easier to restructure the electricity industry.

Eskom is a parastatal, which means it is owned by the South African government but operates as a ring-fenced public utility. Eskom only receives finance from the government to electrify houses, schools and clinics which do not yet have electricity.

Eskom owns generation capacity totalling 38,168 MW, which is more than 95% of generation capacity in South Africa. A breakdown of the types of generation is shown in Figure 2.5 (page 31).

Eskom also imports 1,490 MW of generation from the Cahorra Bassa dam in Mozambique. In 1999 Eskom indicated to the South African Government that new power stations would be required by 2007. The government stated that they wanted to create a competitive environment by introducing independent power producers (IPPs) into the market. This has not materialised and the Government has now requested Eskom to build new power stations and are providing a loan for Eskom to do so.

All the coal powered power stations are in the north of the country where the coal mines are located. There is therefore an extensive transmission network of 765kV, 400kV and 275kV lines and substations that transports the electricity to the rest of the country.

[33] This section has been contributed by Eskom.

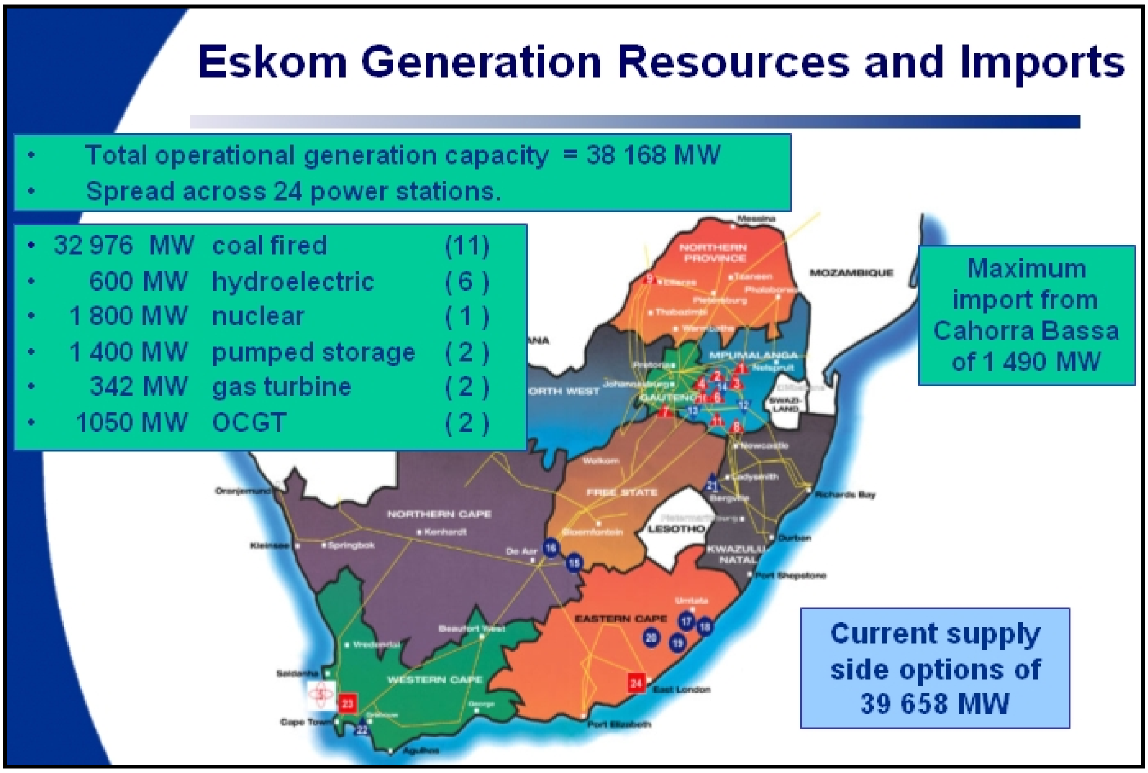

Figure 2.5 Eskom Generation Resources and Imports

Eskom Distribution is ring-fenced into six regions and supplies power to all customers. Most urban customers are within municipalities and Eskom Distribution supplies these municipalities with bulk supplies. The municipalities then reticulate and sell the electricity to these urban customers.

Eskom Distribution also has a vast quantity of rural 33kV, 22kV and 11kV networks that supply farmers and rural households. There is a target to supply every household in South Africa by 2012.

2.5.2 Electricity Markets

There is not yet an open electricity market in South Africa. Customers are either supplied by a municipality or Eskom Distribution. Eskom Distribution has national tariffs and the municipalities each have their own tariffs. The National Energy Regulator of South Africa (NERSA) has been established to regulate these tariffs.

Eskom generates some of the cheapest electricity in the world. This is due to the abundance of cheap low grade coal that Eskom burns to generate electricity. This makes it very difficult for independent power producers (IPPs) to enter the market and compete with Eskom.

The government is planning to reorganise the Eskom Distribution business into six regional electricity distributors or REDs. It is intended that the electrical departments of municipalities will amalgamate with these REDs. The boundaries of the REDs have been created so that each RED can be financially independent and profitable. However, most municipalities are not in favour of this because they would lose the source of income from electricity sales. To address this problem, the government is proposing that the REDs pay a subsidy to the municipalities for a few years after the formation of these REDs. This subsidy will be reduced over time and eventually phased out.

Another issue that is hampering the formation of the REDs is the uncertainty about the provision in the South African Constitution that municipalities have the right to reticulate electricity. Therefore, it is probably going to take a few more years and some new legislation to achieve the reorganisation of the electricity sector in South Africa.

2.5.3 Network Charges

Until recently Eskom network charges were bundled together with the energy charges. Eskom tariffs included a basic charge as a contribution to fixed costs such as capital, meter reading, billing and maintenance. This contribution differed for each tariff. Most of the large power user tariffs also included a transmission percentage surcharge. This was, and still is, based on a percentage of the active and reactive energy charges, and in some cases the demand charge, and on the distance from Johannesburg, where most of the generation capacity is situated. These percentages are shown in Figure 2.6.

≤ 300 km	0%
> 300 km and ≤ 600 km	1%
> 600 km and ≤ 900 km	2%
> 900 km	3%

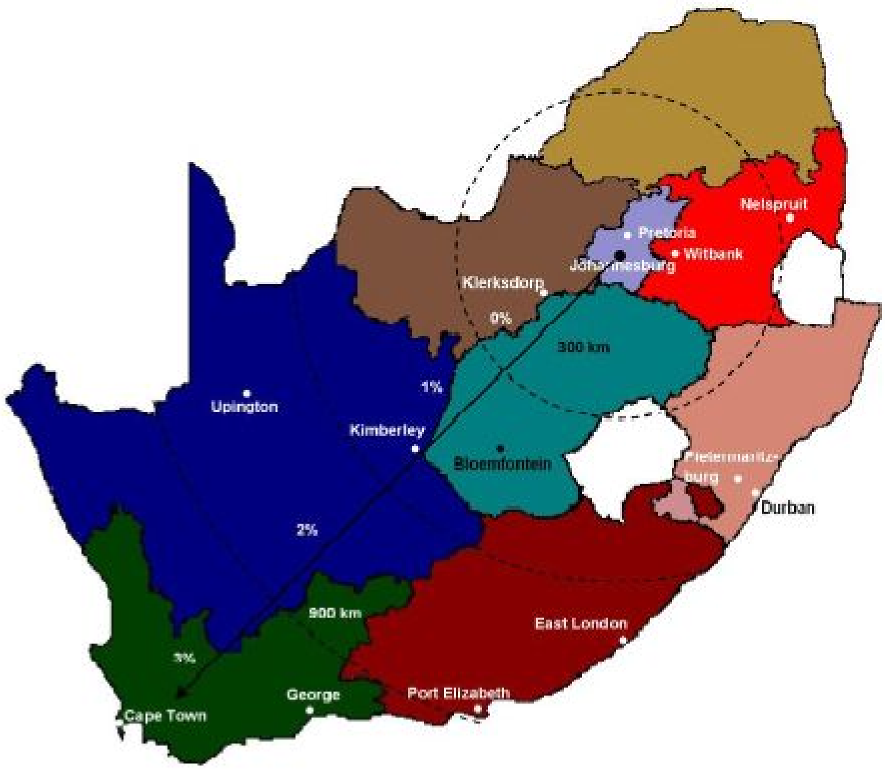

Figure 2.6 Transmission Percentage Surcharge in South Africa

Eskom has recently made their tariffs far more cost reflective and transparent in anticipation of entering a competitive environment. The basic charge has been unbundled into service, administration, network demand and network access charges. The service and administration charges are based on a rand per day charge. The network demand and network access charges are based on a rand per kVA charge.

In most municipalities the network charges are still bundled with the energy charges.

2.5.4 Regulatory Regime

In 1995 the National Electricity Regulator (NER) was formed in South Africa. According to the *National Energy Regulator Act*[34], the functions of the regulator are to:

- issue licenses for the generation and distribution of electricity;
- set or approve tariffs;
- act as mediator or arbitrator;
- settle customer disputes.

Recently the NER has been reconstituted as the National Energy Regulator of South Africa (NERSA)[35,] and its powers have been extended to include the gas and petroleum industries.

2.5.5 Opportunities for Network-driven DSM

At present Eskom has zero generation reserve capacity. South Africa is also experiencing growth rates in electricity consumption of up to 5% in certain areas. Eskom has therefore embarked on a huge DSM drive, managed by a national DSM department based in Johannesburg.

The focus of Eskom's DSM activities is to reduce load everywhere and throughout the day and night. Regional targets have recently been incorporated in the regional performance measurements of the six Eskom Distribution regions. There is an Energy Services Manager in each region who is tasked with achieving these targets.

A large portion of the Eskom DSM drive takes place in residential areas within urban municipal service territories. This complicates the process as the customers are not direct Eskom customers. Municipalities are not always willing to take part in this initiative, probably because they fear a loss of income.

In the residential market Eskom has two main initiatives:

- swapping incandescent light bulbs for compact fluorescent lamps;
- installation of water heating load control systems.

Eskom provides capital for municipalities to install water heating load control systems and then binds them contractually to reduce load during peak times. Private Energy Services Companies (ESCOs) have been established with the help of Eskom to assist municipalities in installing, operating and maintaining these control systems.

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[34] See: http://www.info.gov.za/gazette/acts/2004/a40-04.pdf

[35] See: http://www.nersa.org.za

Eskom Transmission and Eskom Distribution are ring-fenced and a wholesale time of use electricity tariff is charged by Eskom Transmission for energy sold to the Distribution business. Eskom Distribution in turn charges most of its large customers a time of use tariff called Megaflex which has the same peak, standard and off peak periods as the wholesale tariff. In the winter months of June, July and August the rates are higher because this is when the peak loads occur.

Eskom has also recently introduced subsidies for the installation of solar water heaters and subsidies for replacing motors with more efficient ones.

DSM project evaluation committees have been set up in the six Eskom Distribution regions to evaluate any project proposals to save 1MW or less. If a project is approved, Eskom will provide the capital for the project. All approved projects undergo a metering and verification process to ensure that the forecast savings are actually achieved.

2.6 SPAIN

2.6.1 Electricity Industry Structure

2.6.1.1 Restructuring

In November 1997, the Spanish Parliament passed a new law, the Spanish *Electricity Act 54/1997*, that established the framework for a liberalised electricity sector. The basis of this law was the principle that the State should not carry out any activity related to electricity supply and that government involvement in guaranteeing the supply, quality and price of electricity should be replaced by specific regulation of electricity businesses.

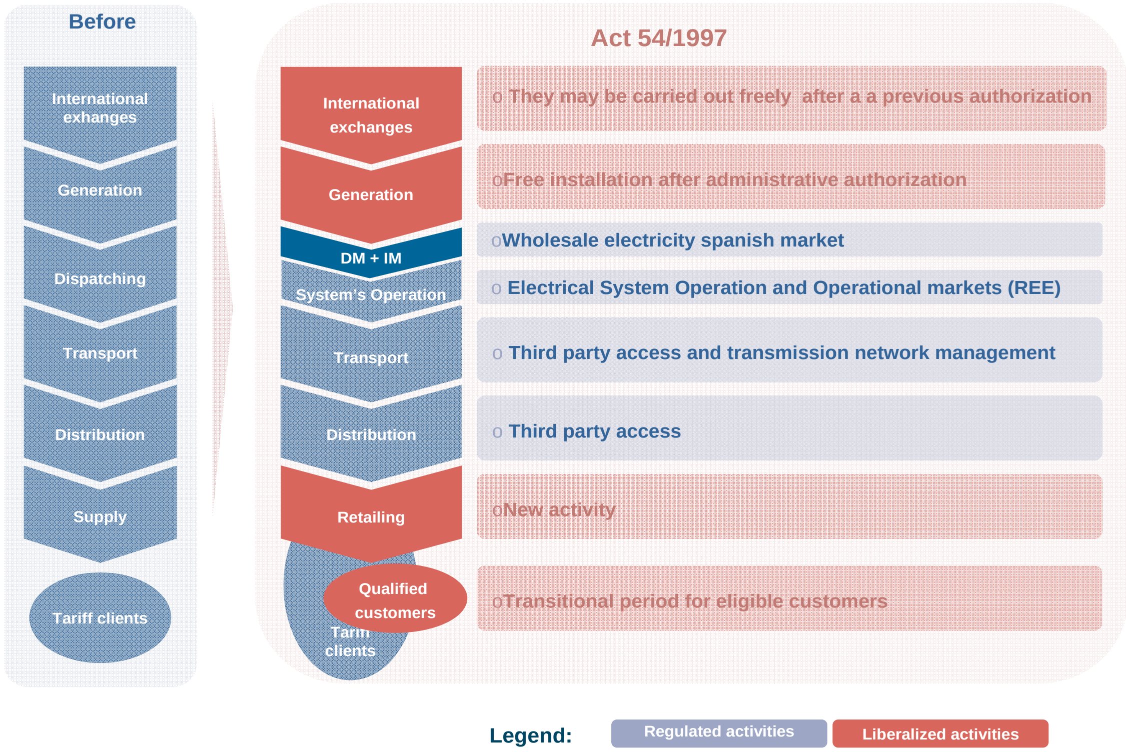

Figure 2.7 Regulated and Non-regulated Activities According to the Spanish *Electricity Act 1997*

The *Electricity Act* introduced significant changes into the Spanish electricity industry through vertical unbundling of electricity supply activities (see Figure 2.7, page 34). Following are the main provisions of the new legal framework that the *Act* established[36].

The *Act* distinguishes between regulated and non-regulated activities. Transmission, distribution and economic and technical management of the electricity system are regulated while electricity generation, retailing and international exchanges of electrical energy are non-regulated. To ensure transparency, the *Act* requires the unbundling of regulated and non-regulated activities into separate businesses and the accounting separation of regulated activities within the same business (also known as 'ring-fencing').

Establishment of new electricity generation facilities is no longer subject to economic regulation. Generation planning is merely indicative and is aimed at facilitating decision making by investors. Electricity generators gain revenue through their participation in the wholesale electricity market.

Transmission and distribution of electricity are considered to be natural monopolies. Owners and operators of network assets have to provide access to their networks to other users on fair and reasonable terms. The Spanish government imposes economic regulation on network businesses to avoid possible abuse of market power arising from the natural monopoly position of network owners. As a regulated activity, the results of network planning are binding on network owners and operators.

The *Electricity Act* enabled all customers in Spain to purchase electricity under competitive retail contracts from any retailer from 1 January 2003. However, a transition period for full retail contestability was established with customers retaining the right to stay under regulated tariffs until 2007, at which point they will have to buy their electricity from the competitive retail electricity market.

The Market Operator is responsible for the economic management of the system. This is no longer based on unit commitment carried out by the System Operator as in previous years. Instead, it is based on market participants' decisions. The Market Operator is a private trading company that manages offers for selling and buying electrical energy.

The System Operator is responsible for the technical management of the system. The System Operator is also a private trading company that carries out activities related to energy flows management. It takes into account interconnections with other systems, determines and assigns transmission network losses, and manages ancillary services markets.

2.6.1.2 Current Structure

Spain currently has four large investor-owned electricity utilities (Endesa, Iberdrola, Union Fenosa, and Hidrocantabrico) that have operated competitively since the electricity market was deregulated. The Spanish Government has a "golden share" in Endesa, the largest of the four utilities.

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[36] Spanish *Electricity Act 54/1997*.

The four utilities are vertically integrated and carry out the three functions of generation, distribution and electricity retailing. There are also some small independent operators that carry out generation from renewable energy sources, distribution and/or retailing. Altogether there are 11 distribution companies (which also undertake retailing) and 65 “trader agents” which are pure retailers[37]. Both are either affiliated with other market actors or are independent companies. Trader agents supply 30% to 35% of end-use electricity consumption in Spain.

In 1985, the Spanish government created Red Eléctrica de España (REE) to manage the state-owned portions of the high voltage electricity transmission network. Since its foundation, REE has slowly increased its control of the country’s transmission network through the acquisition of transmission assets from electricity utilities. The Spanish Government still owns 28.5% of REE, while the four large utilities each own a 3% stake[38]. The remainder of the company is owned by investors.

2.6.2 ELECTRICITY MARKETS

2.6.2.1 Wholesale Electricity Market

The wholesale electricity market in Spain commenced operations in January 1998. Following the provisions of the new Spanish *Electricity Act*, Red Eléctrica de España (REE) created Compañía Operadora del Mercado Español de Electricidad S.A. (OMEL), the Market Operator, as a subsidiary company fully owned by REE. In the summer of 1998, REE sold the new company to private investors.

The wholesale electricity market consists of two inter-linked markets[39].

The **day-ahead market** has scheduling periods of one hour and a unique marginal price for each hour during the day ahead. Market participants in the day-ahead market present their buy or sell offers for electrical energy to OMEL and OMEL matches the various offers. The matching algorithm ensures that the matching results respect the maximum international capacity established by the System Operator. OMEL determines the marginal price and the volume of energy that is accepted for each buy and sell unit and each time period. Most sale/purchase transactions for electricity take place in this market.

The **intra-day balancing market** operates as an adjustment market; only 1.7% of the energy bought and sold is traded in this market. There are six intra-day sessions, approximately every 3 hours, with a unique marginal price for each session during the day. Any market participant authorised to participate in the day-ahead market can also participate in the balancing market as a seller or buyer. However, participation in the balancing market is not mandatory.

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[37] Scarpelli, P. (2005). Project Participant Country Comparison Report. Prepared for International Energy Agency Demand Side Management Programme, Task XIII. Norcross, GA, RETX Energy Services Inc.

[38] United States Energy Information Administration (2005a). *Spain Country Analysis Brief.* Page on the EIA website at: www.eia.doe.gov/emeu/cabs/spain.html

[39] Red Eléctrica de España (2006). *The Spanish Power System*. Page on the REE website at: www.ree.es/apps/i-index_dinamico.asp?menu=/ingles/i-cap07/i-menu_sis.htm&principal=/ingles/i-cap07/i-sintesis-2.htm

In addition, electricity generators and qualified consumers can also deal directly with each other by negotiating bilateral contracts for the physical purchase and sale of electrical energy.

Any authorised electricity buyer or seller may participate in the wholesale electricity market (see Figure 2.8). Market participants include: electricity generators, distributors and retailers, qualified consumers, and other companies or consumers which have their residence in other countries and are authorised to participate as external actors. Only generators and qualified consumers have the option to choose between participating in the wholesale electricity market and negotiating bilateral contracts.

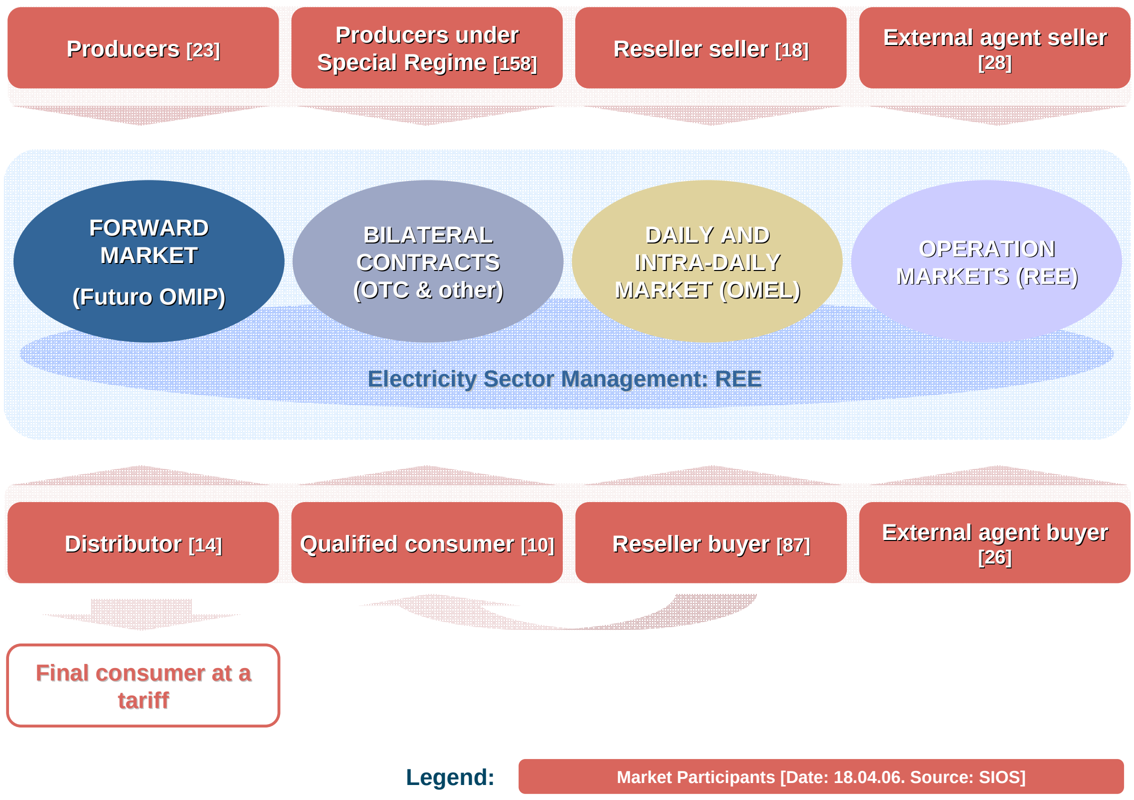

Figure 2.8 Participants in the Spanish Wholesale Electricity Market

OMEL is responsible for the management of both the day-ahead and intra-day energy markets. However, the actual dispatching of generation plant is carried out by the System Operator, Red Eléctrica de España (REE), to ensure the safety and reliability of the system. Therefore, the transactions programs resulting from the day-ahead market and each intra-daily market are analysed by REE to ensure compliance with supply safety criteria and to reassign generators to resolve any technical restrictions[40].

OMEL handles the settlements and reports the payments and collections carried out in accordance with the final energy prices from market trading. OMEL is currently also exploring the development of electricity futures financial products for long term trading.

[40] Red Eléctrica de España (2006). *Op cit*.

In November 2001, Spain and Portugal formally signed an agreement to create a pan-Iberian wholesale electricity market (Mibel). The integrated market will allow generators in the two countries to sell their electricity on both sides of the border. The new market was initially intended to commence operation in 2003, but this was delayed. OMEL and Portugal's equivalent, OMIP, were then scheduled to merge in April 2006 to create a single operator for the integrated Iberian electricity market[41]. However, government changes in both Spain and Portugal have delayed the start of the new electricity market.

2.6.2.2 System Operations

The technical operation of the Spanish electricity system is managed by Red Eléctrica de España (REE), as the System Operator. From the results of the day-ahead and intra-day markets, previously communicated by OMEL, REE is responsible for planning the dispatch of generation units and solving technical constraints, in accordance with market rules (see Figure 2.9). REE also issues instructions for the adequate operation of the generation and transmission systems according to established reliability and security criteria and manages several ancillary services markets.

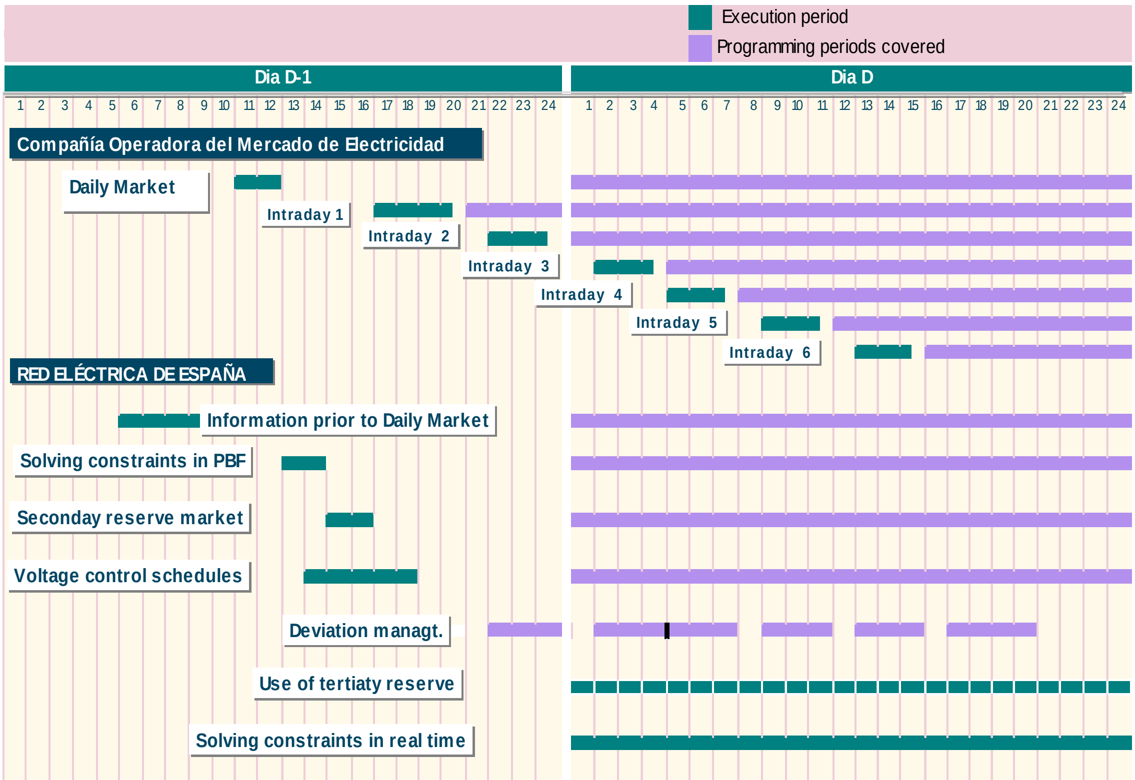

Figure 2.9 Scheduling of Energy and System Operations Markets in Spain

REE, in cooperation with the Spanish Government, is also responsible for establishing reserve margins in the Spanish electricity system. The current minimum reserve margin is 10%

41 United States Energy Information Administration (2005a). *Op cit*.

Solving of Technical Constraints

After each intra-day market: This process is managed by REE in two phases. In the first phase, the System Operator introduces modifications and limits to solve technical constraints. In the second phase it adjusts generation to resolve any imbalance between generation and demand caused by the withdrawal of bids from the intra-day market.

In real time: REE solves constraints by adjusting international exchanges and/or increasing or reducing generation or electricity consumption for load storage pumping.

Ancillary Services

All market-driven ancillary services are procured through competitive auctions.

Frequency Regulation: There are two frequency regulation markets: secondary regulation and tertiary regulation.

Only licensed generation units located in relevant regulation areas may participate in the **secondary regulation market**. Generation units must respond to frequency variations on the scheduled exchange program with France within <= 100 seconds. Generators make capacity bids (€/MW) into the secondary regulation market and they are paid a reliability payment (€/MW) at the marginal price. Generators are also paid for any energy used for secondary regulation at the marginal market price (€/MWh).

All authorised generation and load storage pumping units must participate in the **tertiary regulation market**. Units are operated manually to follow the load on the system and recover secondary reserves (15 minute response maintained over two hours). Units are paid the marginal price of the accepted bids for each hour.

Voltage control: This market is still being developed. Generators, distributors and consumers are remunerated for maintaining a voltage set point at the connecting node with the transmission grid. This service is partly mandatory and partly optional.

Deviation management market: This market is a subsequent process to the intra-day market sessions when there are foreseen deviations over 300 MWh between scheduled generation and forecasted demand. These deviations may be caused by unscheduled outages of generation units or scheduled changes in dispatch schedules already communicated from generation units. The market covers deviations during the period between two intra-day market sessions. The provider is paid the marginal price and the units are allocated following the merit order.

There are also two non-market ancillary services that market participants must make available as a condition of their participation in the market.

Primary regulation: All generation units must provide this service when required and it is a non-paid service. Units have to respond to frequency variations within 30 seconds. Primary regulation requirements are determined each year by the European Union for the Coordination of Transmission of Electricity (UCTE).

System restart services: These services are contracted by REE directly with the providers and are activated by REE when national or regional interruptions require system restart.

2.6.2.3 Retail Electricity Market

Since 1 January 2003, all end-use customers in Spain have been able to choose their electricity retailer. Customers have the option of staying under regulated tariffs until 2007, at which point they will have to buy their electricity from the competitive retail electricity market. Currently, the competitive sector accounts for about one-third of Spain's total retail electricity market.

2.6.3 Network Charges

In Spain, electricity customers pay one tariff to gain access to both the transmission and distribution networks. This network tariffs has two terms: a power term (€/kW) and an energy term (€/kWh). Rates for this tariff depend on the voltage levels at which customers are connected. These rates are fixed from time to time by the Spanish Government.

2.6.4 Regulatory Regime

Prior to 1998, regulation of the Spanish electricity industry was carried out by the government through the then Ministry of Industry and Energy (currently the Ministry of Industry, Trade and Tourism).

The National Energy Commission (Comisión Nacional de la Energía, CNE) was set up under the *Hydrocarbons Act No 34 of 1998*. NCE is the regulator of the Spanish energy markets: the electricity market and the liquid and gaseous hydrocarbons market. The main goal of CNE is to ensure competition in the Spanish energy markets and transparency in their operation for the benefit of all consumers and all market participants.

CNE is a public body with its own legal identity and powers. It is attached to, and supervised by, the Ministry of Industry, Trade and Tourism. CNE prepares its own annual budget and submits it to the Treasury Department for approval and subsequent referral to the Spanish Parliament as part of the State General Budget.

The functions of CNE include:

- developing and implementing legal rules and standards;
- preparing proposals and reports on general provisions affecting energy markets and energy planning;
- drafting of proposals for the determination of tariffs, rates and remuneration of energy activities;
- acting as a consultative body for authorising new energy installations;
- ensuring free competition in the energy markets and acting as an arbitrator in any disputes about the management of the electricity system and third party access to the network;
- carrying out the settlement of electric power transmission and distribution costs, system permanent costs and any other cost that may be determined for the whole electricity system;
- investigating and conducting enforcement proceedings against relevant market participants responsible for deficiencies in electricity supply.

- settling disputes related to third party access contracts, disputes between electricity sector agents and consumers, and disputes concerning the economic and technical management of the transmission system;
- inspecting the technical condition of electrical installations;
- investigating compliance with requirements under current legislation, including criteria for tariff setting and calculating revenue requirements, effective availability of generation units, distribution and retailing trade conditions, quality and continuity of electricity supply, and effective unbundling of electricity generation, distribution and retailing activities.

2.6.5 Opportunities for Network-driven DSM

2.6.5.1 Interruptibility Progam

The main opportunity for network-driven DSM in Spain[42] is through REE's interruptibility program in which consumers obtain a discount for partial interruption of load during periods called by REE. REE may call for loads to be interrupted to cover operational shortfalls in either network or generation capacity.

Currently there are about 2600 MW of interruptible load registered in the REE interruptibility program. The requirements for end-users to participate in the program are as follows:

- the interruptible load must be supplied at high voltage under a general tariff;
- the interruptible load offered must be larger than 5MW (in some cases, smaller loads may be accepted);
- the customer site must have adequate facilities to measure the size and duration of any load reductions[43].

Table 2.2 shows the four types of interruption options available in the REE program.

Table 2.2 Options in the Red Eléctrica de España Interruptibility Program

Interruption Type	Maximum Duration of Interruption	Advance Notice
A	12 hours	16 hours
B	6 hours	6 hours
C	3 hours	1 hour
D	45 minutes	5 minutes

[42] Detailed case studies of REE DSM programs are included in the first report from Task XV: Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd..

[43] Spanish Ministerial Decree, 12 January 1995.

The maximum duration of interruption for types A and B is divided into three periods with different load reduction requirements:

Pmaxi: Maximum load demanded will be equal to or lower than the maximum load established in the interruption program.

P50%: Maximum load demanded will be equal to or lower than Pmaxi + 0.5(Pc–Pmaxi), where Pc is the contracted power for the interruption period.

Pc: Maximum load demanded will not be limited by the interruption order.

Currently, the Regulator (CNE) and the System Operator (REE) are working on developing the interruptibility program to modify contract conditions so new consumers can be included, particularly in the eastern and southern coastal areas of Spain, where summer peak has increased considerably in recent years.

2.6.5.2 Active/Reactive Power Exchange

Eligible customers that are directly connected to the transmission network may obtain a discount on their network access tariff for operating their reactive compensation equipment when requested by the System Operator (REE).

2.6.5.3 Demand-side Participation in Electricity Markets

Currently, end-use customers are able to offer load reductions into the market for solving constraints in real time. However the participation rate is very low. Eligible customers also have the option to provide voltage control services to the System Operator. Customer participation in other operational markets such as the Secondary Regulation Market and the Deviation Management Market are currently under evaluation.

2.7 UNITED STATES

2.7.1 Electricity Industry Structure

The structure of the United States electricity industry is complex and is undergoing significant change as electricity markets are progressively restructured and competition is introduced into some markets. Governments at both the federal and state levels are involved in this restructuring with the result that the electricity industry can be structured quite dissimilarly in different jurisdictions.

2.7.1.1 Electricity Businesses

The United States electricity industry comprises:

- traditional electric utilities;
- non-utility power producers; and
- other, recently established entities.

Traditional Electric Utilities

The more than 3,000 traditional electric utilities in the United States are responsible for ensuring an adequate and reliable source of electricity at a reasonable cost to all consumers in their individual, geographically distinct service territories[44]. Electric utilities include investor-owned, publicly-owned, cooperative, and Federal utilities.

Investor-owned Electric Utilities. These privately owned entities represent 8 percent of the total number of electric utilities and approximately 75 percent of electric utility generating capability, generation, sales, and revenue in the United States. Like all private businesses, investor-owned electric utilities have the fundamental objective of producing a return for their investors. Investor-owned electric utilities are granted service monopolies in certain geographic areas and are obliged to serve all consumers. As franchised monopolies, these utilities are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities carry out all four functions of generation, transmission, distribution and electricity retailing.

Publicly-owned Electric Utilities. These are non-profit agencies established to provide service to their communities and nearby consumers at cost, returning excess funds to consumers in the form of community contributions, increased economies and efficiencies in operations, and reduced rates. The majority are owned by municipalities, though some are public power districts that operate independently of municipal governments and others are associated with State government agencies. Most publicly-owned electric utilities carry out distribution and electricity retailing, although some large ones also carry out generation and transmission. There are about 2,000 publicly-owned electric utilities in the United States.

Cooperative Electric Utilities. These electric utilities are owned by their members and were established to provide electricity to those members. They operate in rural areas with low concentrations of consumers because these areas historically have been viewed as uneconomical operations for investor-owned utilities. There are about 900 cooperative electric utilities operating in 47 States.

Federal Electric Utilities. These 10 entities are part of several agencies in the United States Government. Three Federal agencies operate electricity generating facilities.

Non-utility Power Producers

The more than 2,000 non-utility power producers in the United States include[45]:

- facilities that qualify under the *Public Utility Regulatory Policies Act* of 1978 (PURPA);
- cogeneration facilities that produce steam and electricity, but are engaged in business activities other than the sale of electricity;

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[44] United States Energy Information Administration (2005b). *Electric Power Industry Overview.* Page on the EIA website at: www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html

[45] United States Energy Information Administration (2005b). *Op. cit.*

- independent power producers that produce and sell electricity on the wholesale market at non-regulated rates, and do not have franchised service territories; and
- exempt wholesale generators under the *Energy Policy Act* of 1992 (EPACT).

Qualifying Facilities. PURPA facilitated the emergence of a group of non-utility electricity generating companies called *qualifying facilities* (QFs). QFs are either small-scale producers who self-generate electricity for their own needs but may have occasional or frequent surpluses, or incidental producers who happen to generate electricity as a byproduct of other activities. When a facility of this type meets requirements set by the Federal Energy Regulatory Commission (FERC) for ownership, size and efficiency, utility companies are obliged to purchase energy from the QF based on the utilities' avoided costs, rather than at rates based on the embedded costs of the QF. The purchase rates tend to be highly favourable to the producer, and are intended to encourage more production of this type of energy as a means of reducing emissions and dependence on other sources of energy.

Cogenerators. Cogenerators are primarily engaged in business activities (such as, agriculture, mining, manufacturing, transportation, education). The electricity that they do generate is mainly for their own use, but any excess is sold to the host utility. Many cogenerators have status as QFs.

Independent Power Producers. These facilities (known as IPPs) operate within the franchised territories of host utilities. They do not own transmission facilities or sell electricity on the retail market (that is, all their sales are wholesale or sales for resale). By definition, a facility that has QF status is not an IPP.

Exempt Wholesale Generators. In 1992, EPACT modified the *Public Utility Holding Company Act* and created another class of non-utility power producers: *exempt wholesale generators* (EWGs). EPACT exempted EWGs from the corporate and geographic restrictions imposed by PUCHA. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.

Recently-established Entities

The deregulation of the United States electricity industry and the introduction of competition into the wholesale and retail electricity markets has encouraged the break-up of traditional vertically-integrated electric utilities and the establishment of separate entities that carry out only one of the four functions of generation, transmission, distribution and electricity retailing. In some cases, these businesses, though functionally separate, are still owned by a utility holding company; in other cases they are entirely independent businesses.

In addition, a wave of new single function entities has been established to take advantage of new opportunities in deregulated electricity markets. In 1996, FERC made provision for open access to transmission networks in the United States and this facilitated the creation of power marketers and power brokers as new participants in the United States electricity industry. Power marketers and power brokers are examples of new single function entities in the retail market. Several new independent transmission-only entities have also been established.

Power Marketers. Power marketers are entities engaged in buying and selling wholesale electricity and fall under the jurisdiction of FERC, since they take ownership of electricity and are engaged in interstate trade. About 500 power marketers have filed with FERC and had rates approved. Power marketers usually do not own or operate generation, transmission, or distribution facilities nor sell electricity to retail customers. However, continuing deregulation of the electricity industry is allowing power marketers the possibility of entering retail electricity markets.

Power Brokers. These entities do not take ownership of electricity, are not regulated by FERC and are not considered to be electric utilities. Nevertheless, they are active in facilitating sales and purchases of electricity by their clients.

Independent Transmission Companies. Independent transmission companies (Transcos) can operate either on a cost-of-service basis (ie they have a rate base determined by the regulator) or on a merchant basis (ie they have no rate base and determine their own prices). All cost-of-service Transcos operate in markets administered by Independent System Operators ISOs[46].

2.7.1.2 Electricity Networks

The United States bulk power system has evolved into three major networks of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another (see Figure 2.10). These transfers are restricted, on occasion, because of a lack of contractual arrangements or because of inadequate transmission capability.

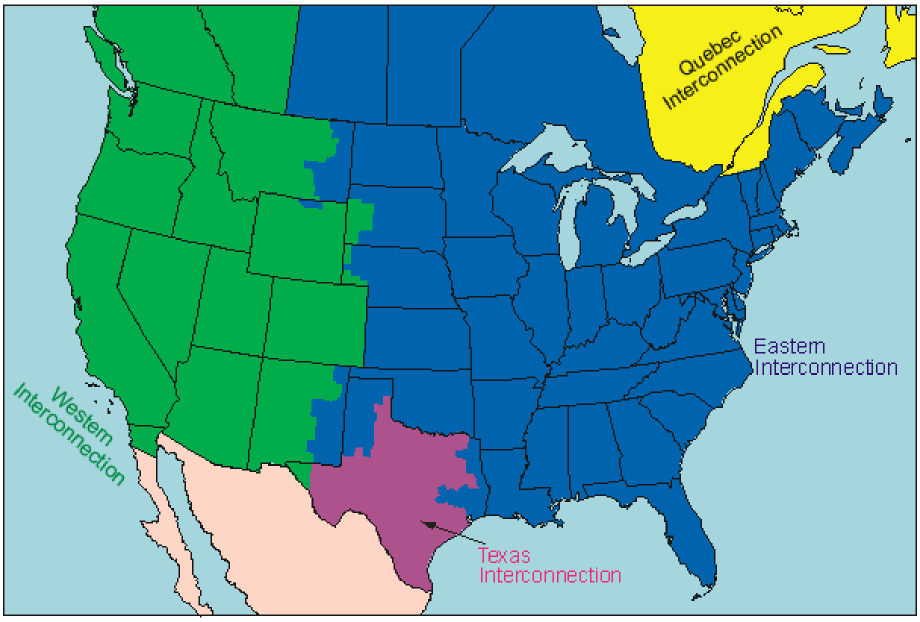

Figure 2.10 Major Interconnected Networks in the Contiguous United States[47]

[46] O'Neill, R. (2006). *Complete Markets Under EPAct: No Market Participant or Product Left Behind*. Presentation to Harvard Electricity Policy Group, 2 March. Available at: www.ksg.harvard.edu/hepg/Papers/ONeill_EPAct_0306.pdf

[47] United States Energy Information Administration (2005c). *Op. cit.*

The three major networks are[48]:

- the Eastern Interconnected System, covering the area east of the Rocky Mountains;
- the Western Interconnected System, covering the Rocky Mountains and the area further west; and
- the Texas Interconnected System, consisting of most of the State of Texas.

The few interconnections among the three major networks are through direct current lines. Both the Western and the Texas Interconnect are linked with different parts of Mexico. The Eastern and Western Interconnects are completely integrated with most of Canada or have links to the Quebec Province power grid.

2.7.2 Electricity Markets

The United States electricity industry is currently evolving from a highly regulated, monopolistic industry with traditionally structured electric utilities to a less regulated, competitive industry that will eventually change the nature of the way electricity is priced, traded, and marketed in the United States.

2.7.2.1 Wholesale Electricity Markets

Virtually all United States electricity utilities are interconnected with at least one other utility by the three major networks; the exceptions are in Alaska and Hawaii. The interconnected utilities within each network coordinate operations and buy and sell electricity at the wholesale level among themselves. The three networks each include smaller groupings or power pools within which wholesale electricity markets operate.

In traditional wholesale electricity markets in the United States, the authority for transactions (buying and selling electricity) is based on pre-approved interconnection agreements (contracts) between physically interconnected electric utilities (and those that have coordination agreements with physically interconnected utilities). Such agreements may include[49]:

- **Purchase transactions** that involve buying electricity from electric utilities and non-utility power producers.
- **Sales for resale transactions** that comprise electricity sold by one electric utility or power marketer to other electric utilities for distribution.
- **Exchange transactions** that involve the availability of excess generating capacity or diversity in load requirements. For instance, an electric utility with low winter load may offer excess capacity in exchange for additional capacity to meet its high summer load.
- **Wheeling transactions** that comprise the movements of electricity from one utility to another over the transmission facilities of one or more intervening utilities.

48 United States Energy Information Administration (2005c). *Overview - Power Transactions & Interconnected Networks.* Page on the EIA website at: www.eia.doe.gov/cneaf/electricity/page/prim2/chapter7.html

49 United States Energy Information Administration (2005c). *Op. cit.*

These traditional wholesale electricity markets are now progressively changing from highly regulated, monopolistic structures to less regulated, more competitive markets. The *Public Utility Regulatory Policies Act* of 1978 (PURPA) opened up competition in the generation market with the creation of qualifying facilities. The *Energy Policy Act* of 1992 (EPACT) removed some constraints on ownership of electric generation facilities and encouraged increased competition at the wholesale level[50].

EPACT enabled any electric utility to apply to the Federal Energy Regulatory Commission (FERC) for an order requiring another electric utility to provide transmission services (wheeling). Prior to EPACT, FERC could not mandate that an electric utility provide wheeling services for wholesale electric trade. This change in the law permitted owners of electric generating equipment to sell wholesale power (*sales for resale*) to non-contiguous utilities.

In April 1996, FERC issued two final rules implementing EPACT's provisions for open access to transmission lines. Rule 888 addressed equal access to the transmission network for all wholesale buyers and sellers, transmission pricing, and the recovery of stranded costs. Rule 889 required jurisdictional utilities that own or operate transmission facilities to establish electronic systems to post information about their available transmission capacities.

In response to the 1996 rulemakings, utilities formed Independent System Operators (ISOs) to operate the transmission grid, regional transmission groups, and open access same-time information systems to inform competitors of available capacity on their lines. In 2005, by passing a new *Energy Policy Act*, the US Congress reaffirmed a commitment to competition in wholesale electricity markets and specifically encouraged the establishment of independent transmission organisations.

Consequently, in many parts of the United States, an ISO or regional transmission organisation (RTO) has been established to manage the day-to-day operation of the transmission system and, in some cases, to also administer the wholesale electricity market (see Figure 2.1, page 48).

Independent system operators include: ISO-New England, PJM Interconnection, New York ISO, Midwest ISO, California ISO, and the Electric Reliability Council of Texas. Additional RTOs and ISOs have been proposed.

In wholesale electricity markets administered by an ISO or RTO, purchases of electricity (ie energy) may be made from a central power exchange with prices established independently through market forces. There may also be specific markets for capacity, and exchange transactions may be replaced by spot and futures markets.

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[50] United States Energy Information Administration (2005b). *Op. cit.*

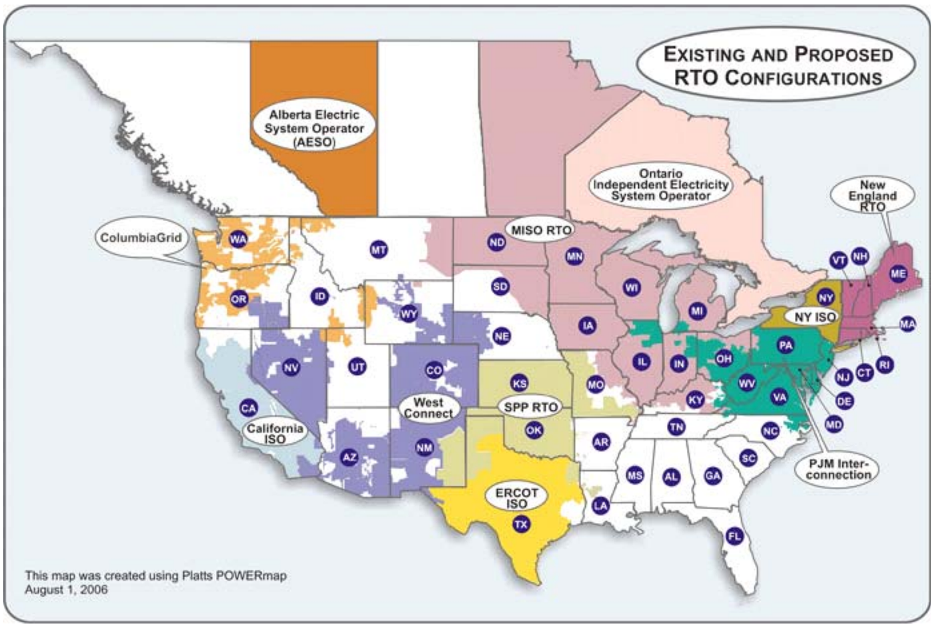

Figure 2.11 Existing and Proposed Independent System Operators and Regional Transmission Organisations in the United States and Canada[51]

2.7.2.2 Ancillary Services Markets

FERC's recommended method of operation for ancillary services markets in the United states is set out in the *Pro Forma Open Access Transmission Tariff*[52], which was originally developed as part of the 1996 rulemakings on open access to transmission lines.

FERC defines ancillary services as:

- **Scheduling, System Control and Dispatch –** scheduling the amount of energy to be delivered, assigning load and ensuring operational security;
- **Reactive Supply and Voltage Control** – maintaining correct voltage through adjustments to generator output;
- **Regulation and Frequency Response** – following the moment-to-moment variations in the demand or supply in the local Control Area;
- **Energy Imbalance –** providing energy correction for any hourly mismatch between a transmission customer's energy supply and demand served;
- **Spinning Reserves** – providing immediate backup service from a reserve unit to serve load in case of a system contingency;
- **Supplemental Reserves** – serving loads when a contingency exists; not available immediately to serve load but can be available within a short time;

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[51] United States Federal Energy Regulatory Commission (2006a). *Regional Transmission Organization Activities*. Page on the FERC website at: www.ferc.gov/industries/electric/indus-act/rto.asp

[52] United States Federal Energy Regulatory Commission (2006b). *Pro Forma Open Access Transmission Tariff.* Proposed revised version. Available at: www.ferc.gov/industries/electric/indus-act/oatt-reform/nopr/pro-forma.pdf

- **Generator Imbalance** – providing energy correction for any hourly mismatch between a generator's energy production and schedule.

Under the terms of the *Pro Forma Open Access Transmission Tariff*, transmission network service providers (TNSPs) are required to provide (or offer to arrange the provision of) ancillary services to the local Control Area operator. A utility serving load within the relevant load Control Area is required to acquire these ancillary services, whether from the TNSP, from a third party, or by self-supply. The utility may not decline the TNSP's offer of ancillary services unless it demonstrates that it has acquired the ancillary services from another source.

In February 2007, FERC made a ruling (Order No 890) that changed the *Pro Forma Open Access Transmission Tariff* to put demand-side resources, for the first time, on an equal footing with other resources in directly contributing to the reliability and efficient operation and expansion of the United States electricity transmission system[53]. The changes provide that demand-side resources, distributed generation, and other non-generation resources capable of providing the service may provide the ancillary services Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalances, Spinning Reserves, Supplemental Reserves, and Generator Imbalances.

2.7.2.3 Retail Electricity Markets

The United States Congress and many State legislatures have passed, or are considering, legislation that will allow competition in retail sales of electricity. By February 2003, 24 States and the District of Columbia had either enacted enabling legislation or issued a regulatory order to implement retail competition[54] (see Figure 2.12, page 50).

In some States, competitive retail electricity markets were actually introduced. However, following problems with some of these competitive markets, the introduction of retail competition in other States has now largely stalled. For example, in 2001 the major investor-owned utilities in California faced bankruptcy from a combination of factors widely blamed on the introduction of a competitive retail electricity market. Currently, most retail electricity customers in the United States are not able to choose their electricity retailer and they purchase electricity from incumbent utilities under regulated rates.

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[53] Federal Energy Regulatory Commission (2007). *February 15, 2007 Open Commission Meeting: Statement of Commissioner Jon Wellinghoff*. Washington DC, FERC.

[54] United States Energy Information Administration (2004). *Status of State Electric Industry Restructuring Activity.* Available at: www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

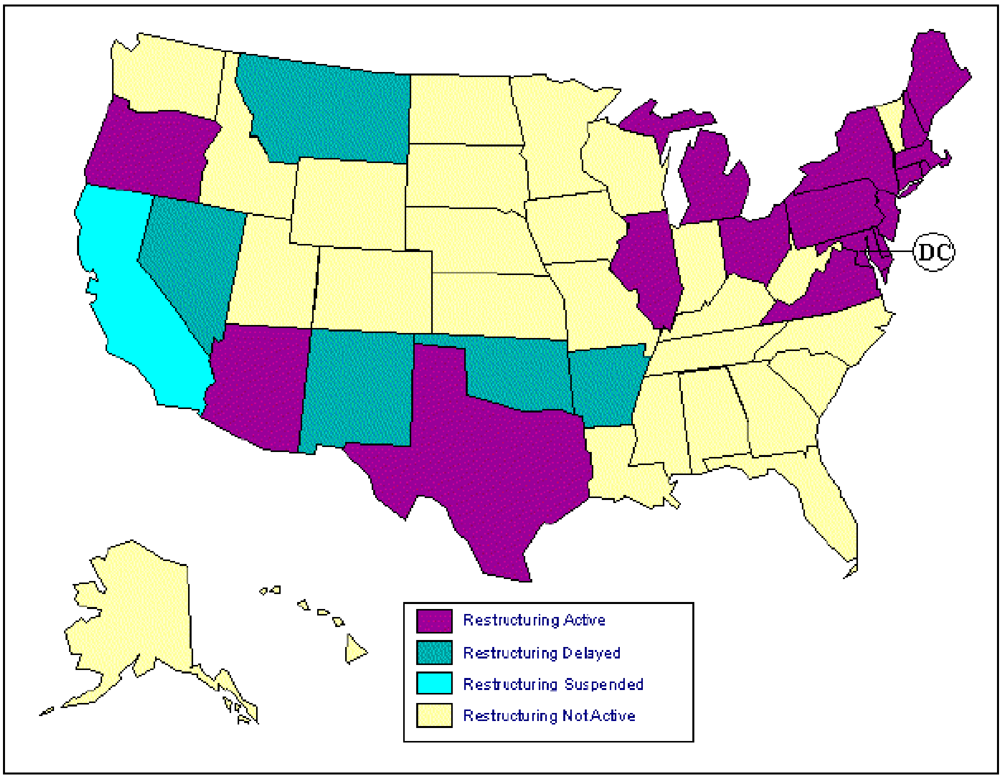

Figure 2.12 Status of Retail Electricity Market Restructuring in the United States as at February 2003[55]

2.7.3 Network Charges

2.7.3.1 Transmission Network Services

Various models for a deregulated power system are currently being implemented in the United States. In very general terms, users who want to move power on the system must arrange for transmission delivery services from the relevant Independent System Operator (or equivalent). Although specific methods vary from system to system, usually delivery services are arranged by using an electronic bulletin board called the Open Access Same Time Information System (OASIS). OASIS lists information about transfer capability, ancillary services, and prices for various network services for the next hour, day, week and month.

Buyers of transmission services can log on to OASIS and reserve the services they need. In particular, buyers of transmission network capacity can check prices and reserve capacity for their use. Transmission capacity service is listed as "network service" or "point to point" service. Point to point service is for moving a specific amount of energy from one point to another, Cincinnati to Cleveland for example. Network service is for moving energy from one group of points (generators) to another group of points (buses). Users can reserve either long term or short term use of the transmission network. Some regulatory models allow a user to re-sell transmission capacity they have reserved.

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[55] United States Energy Information Administration (2004). *Op. cit.*

The price for transmission capacity should cover the expenses of the transmission investment, operation and maintenance, should provide an incentive for efficient use of the transmission system, and should provide an incentive for investment in new transmission facilities where they are needed. Many system operators are developing Location Based Marginal Pricing where the price users pay for transporting energy is a function of both location and time. The system operator uses an extensive computer program to calculate the cost of congestion and to find a fair price that encourages reasonable buying and selling and investment decisions. Locational prices can motivate contract patterns that will adjust flows to avoid congestion. The market "takes care" of the congestion and provides revenue to fix the problem.

2.7.3.2 Distribution Network Services

As noted in section 2.7.2.3 (page 49), most retail electricity customers in the United States purchase electricity from incumbent utilities under regulated rates. In these cases, the charges for distribution network services are not separately identified and are bundled into the regulated rates.

However, in areas where the electricity industry has been restructured, access to distribution systems is being opened up. The local franchise distribution company still owns and operates the wires, but other retailers are allowed to use the distribution system to deliver power to customers. Currently, in markets that have not restructured, a distribution company has an obligation to both connect customers and to supply them with power (called "load serving" in the United States). Under open access, the local distribution company may only have an obligation to connect. The retail energy supplier will then have the obligation to serve customers' loads, and will pay the distribution company for the use of their system.

2.7.4 Regulatory Regime

In the United States, the Federal Energy Regulatory Commission (FERC) has regulatory authority for transmission and electricity wholesaling. Within each individual State, the State Public Utility Commission (PUC) usually has regulatory authority for distribution and electricity retailing. In addition, approximately 25 percent of electricity customers in the United States are served by publicly-owned electricity businesses or rural electric cooperatives which are typically not regulated by State PUCs but instead are regulated by local elected or appointed boards.

FERC is an independent agency that among other functions:

- regulates the transmission and wholesale sales of electricity in interstate commerce;
- licenses and inspects private, municipal, and state hydroelectric projects;
- ensures the reliability of high voltage interstate transmission system;
- monitors and investigates energy markets;
- uses civil penalties and other means against energy organisations and individuals who violate FERC rules in energy markets;
- oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives.

FERC helped facilitate the deregulation of the wholesale electricity markets in the early 1990s.

Within each State, the State PUC is usually responsible for:

- regulating retail electricity and natural gas sales to consumers;
- approving the physical construction of electric generation, transmission, and distribution facilities;
- regulating the activities of municipal power systems and most rural electric cooperatives.

From the mid-1990s, some PUCs established rules for full or partial deregulation of electricity retailing. However, as noted in the section on retail electricity markets (page 49), most of the United States currently does not have competition at the retail level and therefore the large majority of end-use customers are not able to choose their electricity retailer.

In addition to regulation by FERC and State PUCs, the United States electricity industry is subject to rules designed to ensure the reliability of the electricity system. Overall reliability planning and coordination of the interconnected power systems are the responsibility of the North American Electric Reliability Corporation (NERC), which was voluntarily formed in 1968 by the electricity industry following the 1965 power failure in the northeast region[56].

NERC started as a self-regulatory organisation, relying on reciprocity and the mutual self-interest of all those involved. The changes taking place in the electricity industry have altered many of the traditional mechanisms, incentives, and responsibilities for maintaining reliability to the point that the voluntary system of compliance with reliability standards is no longer adequate. Following adoption of the new *Energy Policy Act* that came into force in the United States in August 2005, NERC became the Electric Reliability Organization, with the statutory authority (under FERC) to enforce compliance with reliability standards among all market participants[57].

NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. To fulfil its mission, NERC sets standards for the reliable operation and planning of the bulk electric system and monitors, assesses, and enforces compliance with reliability standards[58]. NERC's eight regional councils cover the 48 contiguous States and portions of Canada and Mexico. The councils are responsible for overall coordination of bulk power policies that affect the reliability and adequacy of service in their areas. They also regularly exchange operating and planning information among their member utilities. The boundaries of the NERC regions follow the service areas of the electric utilities in the region, many of which do not follow State boundaries.

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56 United States Energy Information Administration (2005c). *Op.cit.*

57 North American Electric Reliability Corporation (2006). *About NERC*. Page on the NERC website at: www.nerc.com/about/

58 North American Electric Reliability Corporation (2006). *Op. cit.*

2.7.5 Opportunities for Network-driven DSM

Utilities in the United States have a long history of implementing DSM programs, commencing in the early 1980s. Originally, utilities were required to implement these programs by regulators and the programs were mostly concerned with increasing end-use energy efficiency and efficient resource use rather than with achieving network-related objectives.

More recently, United States utilities have implemented load management programs that can be used to relieve network constraints as well as to respond to generation capacity shortfalls. These include time-based pricing (primarily TOU), interruptible rates, curtailment programs, and direct load control programs. The most active of these have been direct load control programs, particularly of customer HVAC and residential hot water systems.

With the advent of open access to transmission networks and the development of competitive wholesale electricity markets in many parts of the United States, there has been increasing use of DSM measures to provide short-term network operational services. There is a rapid evolution underway from traditional load management to demand response concepts and programs, and the capabilities that new load control technologies provide to utilities, system operators, customers and other actors in electricity markets[59].

Demand response can offer benefits by managing risk in relation to system reliability as well as high market prices. This was recognised by FERC in February 2007, when it made a new ruling (Order No 890) that enables certain ancillary service to be provided by demand-side resources[60]. The new Order also permits demand-side resources capable of performing the needed functions to participate on a comparable basis in an open, transparent transmission planning process.

Today, some Independent System Operators conduct demand response programs through which demand-side resources can be offered to the market. This is typically done through a market participant, e.g., a utility, demand response aggregator, or competitive retail supplier[61].

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59 Scarpelli, P. (2005). *Op cit.*

60 Federal Energy Regulatory Commission (2007). *February 15, 2007 Open Commission Meeting: Statement of Commissioner Jon Wellinghoff*. Washington DC, FERC.

61 Detailed case studies of some of these ISO demand response programs are included in the first report from Task XV: Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd..

To date, there has not been much use of DSM programs to defer network augmentations in the United States. One pilot project was the Model Energy Communities Program (Delta Project) implemented by the Pacific Gas and Electric Company (PG&E) from 1991 to 1993[62]. The Delta Project successfully deferred capital investment in a substation for at least two years, albeit for a shorter deferral period than originally projected. More recently, some utilities, particularly the Bonneville Power Administration, are again starting to use DSM to defer network augmentations[63].

62 Kushler, M., York, D. and Vine, E. (2005). Energy-efficiency measures alleviate T&D constraints. *Transmission & Distribution World*, 1 April. Available at: www.tdworld.com/mag/power_energyefficiency_measures_alleviate/index.html

63 A case study of the Bonneville network-driven DSM program is included in Crossley, D.J. (2008) *Op cit*.

3. IDENTIFICATION OF NETWORK PLANNING PROCESSES

Activity 3-2 of Subtask 3 identifies and characterises the network planning processes implemented in each participating country[64]. This section of the report summarises the results from Activity 3-2.

3.1 AUSTRALIA

3.1.1 Introduction

Prior to the restructuring and deregulation of the Australian electricity industry, network planning was carried out entirely within the network units of vertically integrated utilities or distribution/retailer businesses. This activity was concerned primarily with the geographical service area of the entity carrying out the planning, a State in the case of transmission and a local service territory in the case of distribution. There was limited coordination between entities in relation to network assets which crossed service territory boundaries, but a network business was solely responsible for network planning within its service territory.

Therefore, electricity networks were built to meet the supply and demand needs of an individual State or a local distribution service territory. Consequently, planning and investment decisions were not designed around the operation of a competitive market in electricity.

With the establishment of the competitive National Electricity Market (NEM), there have been major changes to how network planning is carried out in Australia. In particular, the process has become much more transparent and open, with planning at the transmission level now being undertaken across the whole of the NEM, and significant quantities of information being made publicly available. The rationale behind this is to encourage other players to participate in network planning and to contribute to network augmentation and reinforcement projects[65]. This provides significant opportunities for proponents of network-related DSM projects.

3.1.2 Transmission Network Planning

Transmission network planning in the majority of Australia is now carried out across the geographical area covered by the National Electricity Market[66], is governed by the provisions of the *National Electricity Rules*, and is regulated at the national level by the Australian Energy Regulator.

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64 Energy Futures Australia (2004). *Prospectus: Research Project on Network-driven DSM*. Hornsby Heights, NSW Australia, EFA.

65 In late 2006, major participation by new players has so far taken place at the transmission level, specifically in relation to interconnectors between regions. Two interconnectors have been built by TransEnergie, a subsidiary of Hydro Québec.

66 In Western Australia and the Northern Territory, which are not covered by the NEM, somewhat different network planning processes apply.

3.1.2.1 Role of Jurisdictional Planning Bodies

Within each State, an organisation is nominated to be the Jurisdictional Planning Body (JPB) responsible for the planning and development of transmission networks. In New South Wales, Queensland and Tasmania the JPB is the transmission network service provider (TNSP), ie the network operator. Victoria and South Australia each has an independent transmission network planning body that is not a TNSP.

The role of a JPB includes:

- representing its jurisdiction on the Inter-regional Planning Committee (IRPC) established by the market operator, NEMMCO;
- providing jurisdictional information to the IRPC to enable it to assist NEMMCO in producing its annual *Statement of Opportunities* (SOO) and *Annual National Transmission Statement* (ANTS).

The *Statement of Opportunities* is a public document intended to assist existing and potential NEM participants when assessing the future need for electricity supply capacity; demand-side management; and transmission network augmentation in support of NEM operations. Commencing in 2004, the *Statement of Opportunities* incorporates the *Annual National Transmission Statement* which provides an integrated overview of the current state and potential future developments of national transmission flow paths.

3.1.2.2 Role of TNSPs

The *National Electricity Rules* require a TNSP to:

- analyse the future operation of its transmission network to determine the extent of any future network constraints;
- conduct joint annual planning reviews with distributors to determine the extent of any emerging constraints at points of connection between the TNSP's network and the distributor's network and determine options for the relief of constraints;
- coordinate a consultative process for consideration and economic analysis of network augmentation options in accordance with the regulator's Regulatory Test and determine the recommended option;
- after resolution of any disputes concerning the recommended option, arrange for its implementation in a timely manner; and
- prepare and publish an *Annual Planning Report* for its jurisdiction by 30 June of each year.

The *Annual Planning Report* must include:

- load forecasts;
- results of annual planning reviews with distributors;
- planning proposals for future connection points;
- forecast of network constraints over 1, 3 and 5 years;
- summary information for proposed network augmentations; and
- consultation reports on proposed new small network assets (defined as costing between AUD 1 million and AUD 10 million).

3.1.2.3 The Regulatory Test

When the Australian electricity industry was restructured, network businesses were seen as natural monopolies and were separated from the competitive generation and retail businesses. Networks traditionally face limited direct competition because of significant economies of scale and high barriers to entry. These businesses therefore have the ability to exert market power in either upstream or downstream markets. In recognition of these characteristics, network businesses are subjected to economic regulation which aims to deliver outcomes consistent with what would be achieved in a competitive market.

Given that the revenues of a network business are largely determined by the size of its asset base, it is important to ensure that its proposed investments in the network, such as network augmentations, are economically efficient. The tool used in the NEM to assess the efficiency of investments is the Regulatory Test administered by the Australian Energy Regulator.

The Regulatory Test is an economic cost-benefit test applied by network service providers in the National Electricity Market (NEM) to assess and rank the economic viability of network and non-network options. The regulatory test contains two 'limbs'[67]:

- the 'reliability limb' – is used for considering reliability driven augmentations, which are based on the service obligations imposed on network service providers. This arm of the test takes the form of a least cost test;
- the 'market benefits limb' – is used for assessing non-reliability driven investments, and involves the application of a net present value analysis, which is concerned with assessing the present value of a project's benefits against the present value of its costs.

The Regulatory Test states[68]:

> *An option satisfies the regulatory test if:*
>
> *(a) in the event the option is necessitated solely by the inability to meet the minimum network performance requirements set out in [the National Electricity Rules} or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction - the option minimises the present value of costs, compared with a number of alternative options in a majority of reasonable scenarios;*
>
> *(b) in all other cases - the option maximises the expected net present value of the market benefit (or in other words the present value of the market benefit less the present value of costs) compared with a number of alternative options and timings, in a majority of reasonable scenarios.*

The Regulatory Test specifically states that demand-side options should be taken into account in determining "reasonable scenarios".

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67 Australian Energy Regulator (2005). *Compendium of Electricity Transmission Regulatory Guidelines*. Melbourne, AER. Available at: www.aer.gov.au/content/item.phtml?itemId=688824&nodeId=77350c2953a9c34a4192dd2b9ec53d20&fn=Compendium of electricity transmission regulatory guidelines.pdf

68 Australian Energy Regulator (2005). *Op. cit*, p 32.

3.1.3 Distribution Network Planning

Distribution network planning in the majority of Australia covered by the National Electricity Market is carried out mainly within distributors' service territories, is governed by the provisions of the *National Electricity Rules*, and is regulated at the State level by jurisdictional regulators. It is intended that the regulation of distribution network planning will eventually be carried out at the national level by the Australian Energy Regulator.

The *National Electricity Rules* place similar responsibilities and obligations on distribution network service providers (DNSPs) as on TNSPs, but these relate only to the DNSP's service territory. In particular, a DNSP has to carry out annual planning reviews with the TNSP that supplies its distribution network; such reviews are usually published by the DNSP as an annual network management plan or similar. Network augmentations planned by DNSPs have to pass the Regulatory Test. In contrast to transmission network augmentations, the *Rules* specifically require DNSPs to consider demand-side options as alternatives to network augmentations.

In addition to their responsibilities and obligations under the *National Electricity Rules*, DNSPs may be subject to specific requirements placed on them by jurisdictional regulators. Some of these local requirements relate specifically to DSM.

3.2 FRANCE

3.2.1 Introduction

Prior to restructuring of the French electricity industry in 2000, network planning was carried out within Electricité de France (EDF), which at that time was a vertically integrated company carrying out all four electricity industry functions: generation, transmission, distribution and retailing.

Immediately following the restructuring, Réseau de Transport d'Electricité (RTE) was created in June 2000, as the French transmission system operator (TSO). On its creation, RTE took charge of the operation, development and maintenance of the transmission network (50 kV to 400 kV networks), as well as the connection of customers to this network.

Transmission network planning in France is therefore the responsibility of RTE. Distribution network planning remains mainly the responsibility of EDF Réseau de Distribution (ERD), a business unit of EDF. In some rural areas, independent municipal companies manage and operate the distribution network.

3.2.2 Transmission Network Planning

The transmission network planning process is undertaken by RTE and is overseen by the regulator of the energy sector, Commission de Régulation de l'Energie (CRE). Any change to the network planning method proposed by RTE would have to be validated by CRE.

The Law of 10 February 2000[69] requires RTE to draw up a Public Transmission Network Development Plan. The Plan sets out an overview of the requirements that the network will have to satisfy in the future, and identifies areas where it may need to be adapted in order to maintain the security and quality of supply in the long term.

The Plan forms part of a global approach aimed at forecasting medium term developments in the power system (see Figure 3.1, page 59). The planning process commences with the development of a Generation Adequacy Report (also produced by RTE), the purpose of which is to verify that supply is sufficient to meet demand in France over the medium term (around fifteen years).

In accordance with the Law, the Development Plan is drawn up every two years and approved by the Minister for Energy, following a review by CRE. The Plan is developed on a regional basis in association with a regional consultation body set up in conjunction with the Regional Conference on Territorial Planning.

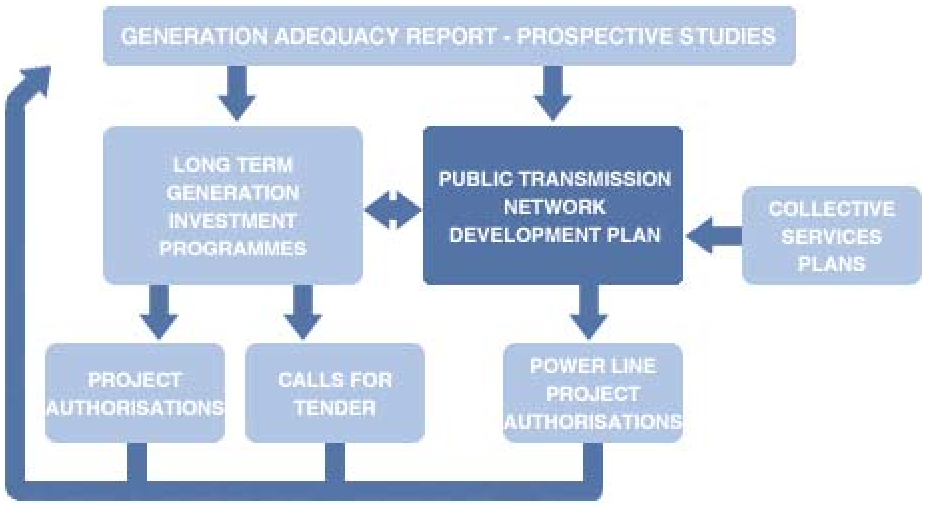

Figure 3.1 The Transmission Network Planning Process in France[70]

Based on an assessment of existing electricity network assets in each region and network development investments that have already been determined, the Plan sets out projections looking 10 or 15 years ahead. It includes a set of scenarios that are used to estimate future changes in electricity consumption and generation in each region, taking into account collective energy service plans and the multi-annual investment programme. Collective energy service plans were adopted by Decree on 18 April 2002. They reflect the need for long-term planning for nine public policies that determine regional network planning, and include sustainable development obligations.

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69 Loi n° 2000-108 du 10 Février 2000 (op cit).

70 Gestionnaire du Réseau de Transport d'Electricité (2006). *The Development Plan*. Page on the RTE website at: www.rte-france.com/htm/an/activites/schema.jsp

The collated data are used to create maps for each region showing "electrically fragile zones". The Plan also details projects to build new network assets that have already been submitted for consultation. The individual regional development plans are then used to establish an overall national Development Plan.

After completing the Development Plan, RTE carries out comprehensive studies looking at all the possible solutions for dealing with network constraints for which no project has yet been identified, including:

- adapting the network, by optimising existing infrastructure and extending the working lifetimes of existing network assets to avoid having to build new ones, in line with RTE's commitments under the public service contract[71];
- augmenting and/or expanding the network, to remedy high demand on certain network elements and anticipate future growth in demand, respond to a new connection requirement, or meet contractual commitments on quality of supply.

Because RTE is prevented by its founding legislation from undertaking DSM, demand-side alternatives to augmentation and/or expansion of the transmission network are not considered in the Development Plan. However, the network planning studies rely on demand forecasts, which include assumptions regarding the expected growth of DSM for each type of electricity usage. These DSM growth assumptions are derived from a global national scenario of demand versus supply for the next 10 years that has been approved beforehand by the Ministry of Industry. The demand forecasts also include assumption about the decommissioning of generation units and the connection to the network of new units.

In each study, several candidate augmentation projects are assessed, and compared to select the best one. The assessment of each candidate project takes into account:

- the reduction of thermal losses on the network resulting from the proposed augmentation project. This type of benefit is valued through a unitary reference value reflecting the average cost paid by RTE when purchasing the amount of energy necessary to cover the losses on its network;
- the reliability benefit achieved through the augmentation project. This benefit is valued through the reduction of the expected unsupplied energy expected to be achieved through the proposed augmentation project. The valuation also takes into account a set of reference unitary values for achievable curtailable load;
- the reduction of congestion on the network achieved through the augmentation project. Whenever congestions exist on the network, RTE may have to call for the use of better located, but more expensive generation units. This is a cost RTE has to meet until a network augmentation relieves the congestion.

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[71] The Public Service Contract, signed with the Government of France on 24 October 2005, sets out the various public service commitments entrusted to EDF and RTE for the period 2005-2007. Under the contract, RTE undertakes to strengthen and extend consultation by: making it easier for the public to take part in defining and improving network augmentation and expansion projects; improving the information available to community groups; and defining the best possible measures for integrating network infrastructure into the environment.

Finally, a Net Present Value (NPV) analysis is carried out for each candidate augmentation project. This analysis enables the identification of the most cost-effective project.

The selected project is then subjected to a consultation process with all involved third parties, in order to achieve the best level of integration of the project into its natural and social environment. This process may result in some changes to the original project, provided that such changes do not materially reduce its cost-effectiveness.

Each transmission network augmentation project proposed by RTE has to be submitted to the Ministry of Industry for approval. The main criteria used during the approval process include the economic efficiency of the project, its impact on the environment and whether the project meets legal and regulatory requirements. The calculations which are required to assess the economic efficiency of the network augmentation projects are carried out by RTE.

3.2.3 Distribution Network Planning

3.2.3.1 Current Situation

EDF Réseau de Distribution (ERD) currently uses a network planning tool known as GDO (Management of Facilities), designed in the 1980s and based on:

- a complete database of the network (cables, transformers, connections, etc.) and consumers (consumption, power levels etc); and
- a series of calculation models which predict future consumption levels and the network reinforcements needed in order to prevent voltage drops which are outside the permitted tolerances (230 V, +6%, -10%).

The GDO planning tool takes account of DSM activities in only a very limited way.

For several decades ERD has also used a load control facility known as PULSADIS to manage the automatic switch-on of certain types of electrical equipment, of which the best known are night-storage water heaters. The centralised control of switching on these devices allows peak demand on the network to be reduced by moving some load into the night-time off-peak hours. This technology has its limitations: over-systematic use may create other local peaks (e.g. the Lot Département in the Midi-Pyrénées region of France experiences “off-peak” hours in the middle of the day between noon and 2 pm.).

Although the electricity distribution sector is massively dominated by EDF, which exercises a virtual technical and financial monopoly in the distribution of electricity, local authorities in rural France play a significant part in managing the investments required for extending and reinforcing the distribution network.

This situation is explained by three major factors:

- firstly, the political will, on emerging from the 1939-45 war, to set up a national equalisation system for electricity prices, to ensure that prices are the same at all locations across the country;

- secondly, the natural limitation on the economic effectiveness of network investments, which in a sparsely-populated rural area are very high for the small number of consumers served; this means that in rural areas distributing electricity has very poor profitability, even for a public company;
- finally, and also politically, the continuation of an active role in this field for the decentralised public local authorities known as *communes*.

In order to achieve these different objectives, a dual system of financial compensation was created in the 1930s and 1950s:

- the distribution network manager transfers funds (effectively cross-subsidies) between areas of high population density and sparsely-populated areas, to enable the necessary network investments to be implemented;
- in addition, a compensation fund known as the Fund for the Amortisation of the Costs of Electrification (FACE) provides funds derived from urban areas to *communes* situated in rural areas, to enable them to finance unprofitable network augmentations and reinforcements.

This dual system has not been modified by the liberalisation of the electricity market, since it only operates in the "natural monopoly" of the electricity network. The financial compensation system is fiercely defended by French local elected officials, who see it as the only solution for dealing with the continuing growth in electricity consumption and in the quantity of energy conveyed over the distribution network, which they consider to be absolutely inevitable.

3.2.3.2 Alternative Planning Methodologies

Some commentators in France have noted that, while the financial compensation system may be commendable from a social point of view, it has had the perverse effect of reducing electricity prices in rural areas, where renewable energies are available in abundance at low cost. In their view, the equalisation of energy prices in France has thus given electricity a very strong competitive advantage in rural areas, which has prevented the development of alternative energies and the implementation of DSM activities.

Since the early 1990s, a small number of researchers in economics and social sciences have analysed the financial compensation system and developed:

- a quantification of the resource transfers involved; and
- methods for integrating DSM measures into distribution network planning.

The approach to integrating DSM is based on the following principle: since it is the *communes* which undertake the large investments for network development in rural areas, from their point of view, competition must be introduced between network development and DSM solutions which reduce load levels on the network and thus allow the investments to be avoided or deferred.

Two methods have been developed for incorporating DSM measures into distribution network planning.

The first method is based on a local micro-economic analysis of the network, which identifies the technical and financial dimensions of “tailored” DSM measures required to avoid costly reinforcements to supply only a limited number of consumers. This approach offers good economic efficiency, but requires complex studies and is suitable for only a limited number of network situations. A small number of investigations using this method have been undertaken or are in progress in Maine et Loire (see Figure 3.2), Loire and Bourgogne.

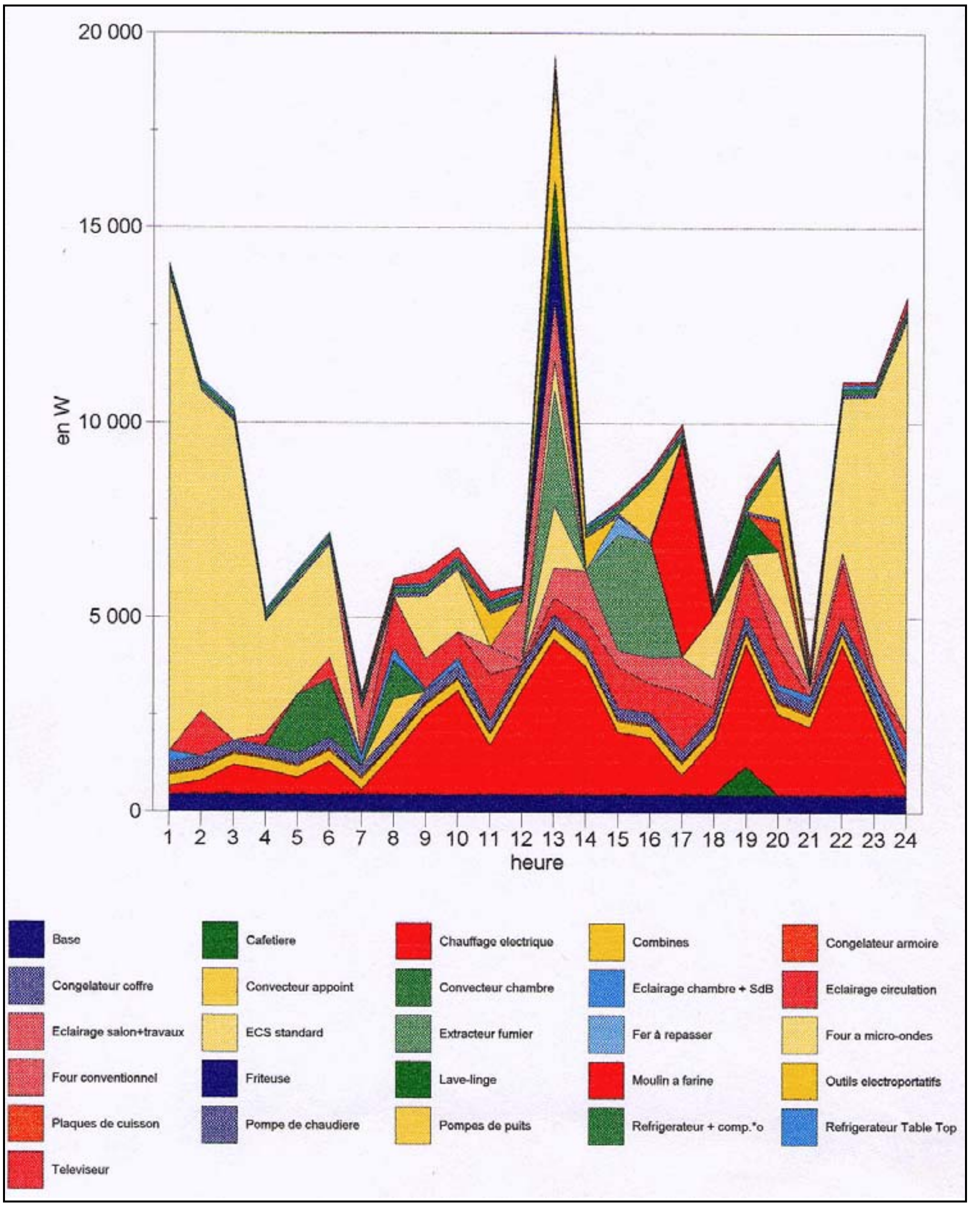

Figure 3.2 Disaggregation of the Synchronous Daily Peak Using the Equipment Simulation Program EVE, Maine et Loire, France[72]

[72] Bureau d'études FR2E (2000). *Rapport MDE Réseaux ruraux Maine et Loire - Départ de Chanteloup les Bois*. Report prepared for ADEME and EDF.

The second method is based on a macro-economic analysis covering a geographical area whose network/consumption characteristics enable "tailored" DSM activities to be developed before being proposed to all consumers in the area. This geostatistical type of analysis can be a powerful tool for use in network planning studies. However, the geographical localities in which DSM measures will be implemented must be properly defined. The economic efficiency of the analysis will be reduced if some of the DSM measures are applied to parts of the network which are not subject to constraints. The method is still experimental and one study has been carried out in the Oise Département in France (see Figure 3.4).

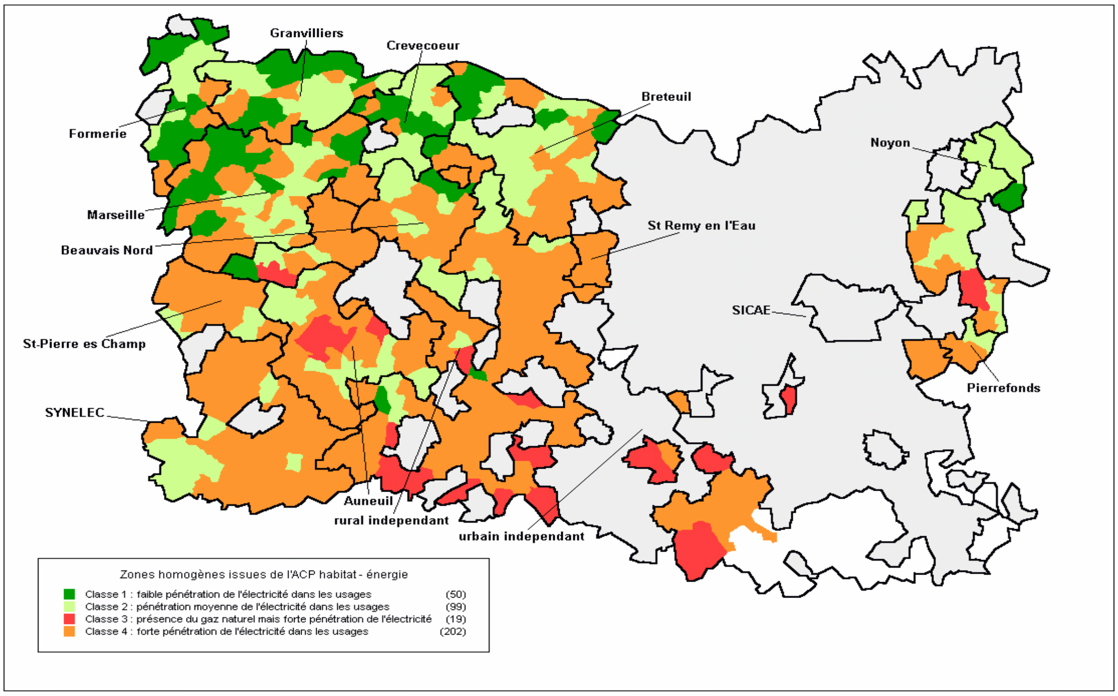

Figure 3.3 Mapping of Electricity Load Levels Across a Geographical Area, Oise, France[73]

3.2.3.2 Future Development

The future development of the French system for distribution network planning will take place within the following constraints:

- within the next 10 years, the distribution network management activity will be opened up to competition. This will require EDF Réseau de Distribution to define very precisely the boundaries of its activity and its physical and intellectual property, including the planning tools which the organisation controls (eg calculation models such as GDO);

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[73] Bureaux d'études CIRED (2004). *Etude de faisabilité d'une opération MDE Macro dans l'Oise*. Report prepared for ADEME and EDF.

- local authorities will gain increased competence as the local organising bodies for electricity distribution. These authorities will initially devote their attention to producing an inventory of the network, which is their asset, and then to gaining better knowledge of the local consumption conditions, in order to develop and implement appropriate public policies.

The French Government's environmental and energy management agency ADEME will contribute to achieving the integration of DSM measures into distribution network planning by: assisting with the design of appropriate methods and tools; improving geostatistical information about electricity distribution service territories; undertaking practical operations including DSM activities and decentralised electricity generation; and developing appropriate sales and evaluation techniques.

3.3 INDIA

3.3.1 Introduction

In India, national level planning in the electricity sector is coordinated by the Central Electricity Authority (CEA) with participation by other central agencies. Plans produced by the CEA provide inputs for the Five Year Plans prepared for all sectors of the economy. The CEA undertakes in-depth analysis of the electricity system, and carries out demand analysis across all the States. The CEA uses energy consumption data from various consumer categories and, after applying an appropriate load factor, develops a demand projection for that category. The cumulative demand projections of all categories provide the overall demand projections for that State.

At the State level, the SEBs (State Electricity Boards) co-ordinate the planning exercise. In States where SEBs have been unbundled, the transmission utility plays this role with inputs from the distribution utilities. The State government gives policy directions and the State Electricity Regulatory Commission (SERC) facilitates the review of the plan. Based on the state level plan, the distribution utilities, generation utilities and support group prepare their own plans.

3.3.2 Transmission Network Planning

3.3.2.1 Transmission Planning Process

In India, the responsibilities for transmission planning are specified in the *Electricity Act 2003*. The Act mandates the 'Central Transmission Utility' (CTU) and the 'State Transmission Utility' (STU) to discharge all functions related to inter-State transmission planning and intra-State transmission planning, respectively.

Figure 3.4 (page 66) shows the transmission planning process.

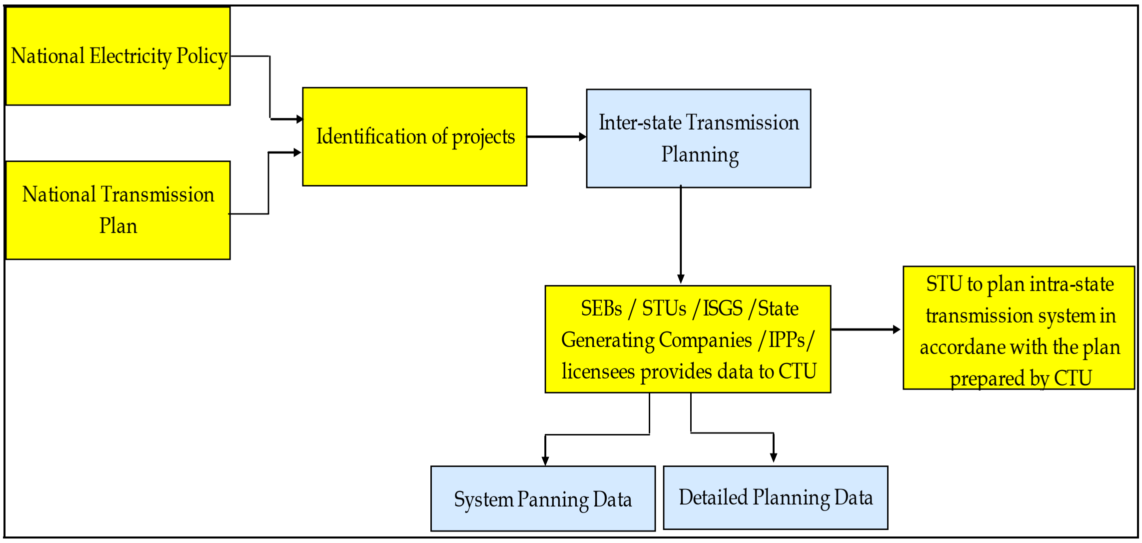

Figure 3.4 The Transmission Planning Process in India

The CTU (ie the Power Grid Corporation of India) and the STU have to ensure development of an efficient, co-ordinated and economically viable system of inter- or intra-State transmission lines for smooth flow of electricity from generating stations to the load centre. The steps involved in transmission planning, as generally adopted by the CTU and STU, comprise:

1. **Conceptualisation of the Transmission Plan** – identification of the requirements of the transmission system for connecting generating plants to load centres and the agencies responsible for carrying out transmission planning at various levels.
2. **Specification of the Transmission Plan** – specification of the focus areas of the transmission system to be addressed by the plan taking into account the economics of generation and transmission, losses in the system, load centre requirements, grid stability, security of supply, quality of power including voltage profile and environmental considerations[74].
3. **Scope of the Transmission Plan** – Within a framework established by the CEA, the transmission plan details the transmission capacity augmentations required across the various regions of the country or State, taking account of various dispatch scenarios, seasonal variation as well as time of day variations.

3.3.2.2 Inter-State Transmission Planning

The Indian Electricity Grid Code (IEGC) Regulation 2005, which came into effect from April 1, 2006 specifies a Planning Code for inter-State transmission planning. The Indian electricity system has been demarcated into five regions which have unique generation and consumer characteristics.

Following are the components of the process of inter-regional transmission planning.

- All constituents and agencies are required to supply to the CTU planning data to enable the CTU to formulate and finalise its plan.

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74 These requrements are specified in Clause 3.2, of the *National Electricity Policy.*

- The SEBs / STUs / Inter-State Generating Stations / State Generating Companies / IPPs / licensees are required to supply two types of data: system planning data and detailed planning data.
- System planning data is required to assess the impact on the inter-State transmission system resulting from load growth.
- Detailed planning data is provided only when required by the CTU.
- For better voltage management in inter-State transmission of energy, special attention is accorded to the planning of capacitors, reactors, static var compensators and Flexible Alternating Current Transmission Systems (FACTS).
- The actual program of implementation of transmission lines, inter-connecting transformers, reactors/capacitors and other transmission elements is determined by CTU in consultation with the concerned agencies.
- In accordance with the plan prepared by the CTU, State transmission utilities are required to prepare their transmission plan for importing energy from the inter-State transmission system.

3.3.3 Distribution Network Planning

In addition to the demand analysis carried out by the CEA at the national level, distribution companies are also required to carry out demand analysis in their respective service territories, as specified in the Indian Electricity Grid Code as well as in most of the State Electricity Grid Codes. Distribution licensees are required to assess:

- the demand at the time of system peak;
- hourly demand for the day of the system peak;
- daily, monthly, seasonal or annual demand;
- total energy consumption by day, month, season or year;
- the diversity factor or the coincidence factor and load factor in each customer category;
- non-coincident peak demand for each of the domestic, commercial, industrial, and agriculture consumer categories.

Distribution Licensees are required to plan and develop their distribution systems on the basis of the following technical and design criteria.

- The planning of the distribution system must always keep in view cost effectiveness and reduction in energy losses without sacrificing the requirements of security standards and safety standards for the distribution system.
- The load demand of all existing users connected to the distribution system and all users seeking connection must to be met. All circuits must have adequate capacity to supply electricity in a safe, economical and reliable manner.
- The load must to be arranged as far as possible in discrete load blocks to facilitate load management during emergency operations.

- Load flow and other system studies must be conducted to locate the position of 33 / 11 KV substations, capacitor installations and distribution transformers, so as to contain voltage variation and energy losses within reasonable limits.
- Distribution Licensees must develop load curves for their service territories from the metering data available at the connection points to substations owned by the STU / Transmission Licensee. These data must be compiled for the entire service territory of the Distribution Licensee, combining the load curves of each substation feeding its distribution system.
- The actual energy imported by the distribution system, as recorded in the energy meters installed at connection points, must be reconciled with the actual energy sales. The distribution losses computed from these data must be provided to the STU and State Electricity Regulatory Commission (SERC) every month.
- Distribution Licensees must assess and forecast the load demand of each category of consumers in their service territories on an annual basis or more frequently as required by the SERC, for each of the succeeding five years.
- Distribution Licensees must have a thorough knowledge of the usage of electricity by users and the way they use electrical energy and other alternative sources of energy in their service territories. Load forecasting must take into account this information along with conservation programs and demand side management or off-peak usage programs which the Licensee may sponsor, resulting in reductions in energy and peak demand of consumers.
- Distribution Licensees must create a database of connected as well as operating loads for each consumer category and for each distribution substation connected to the distribution system and update it on annual basis. Such data must be compiled and made available for a period of at least fifteen years.
- Distribution Licensees must implement appropriate load research programs for the systematic collection of data describing consumers' energy usage patterns and analyse these data to develop energy and demand forecasts.
- The pattern of energy consumed by each sector and the load demand, the period of peak demand must be measured by means of a sample survey, taking representative samples from each sector for its different seasonal requirements. A suitable questionnaire must be prepared for these sample surveys and the data obtained must be analysed using suitable statistical models. Proposals for load research programs must be filed with the SERC for its consideration.

3.4 NEW ZEALAND[75]

3.4.1 Transmission Network Planning

Transmission network planning in New Zealand is governed by the *Electricity Governance Rules*. In general terms, Transpower is responsible for identifying and proposing enhancements in the grid, while the Electricity Commission is responsible for reviewing and approving or otherwise Transpower's proposals.

At a high level, transmission network planning involves three broad stages of activity:

- Establishment of planning standards and parameters. This is carried out by the Electricity Commission through the development and publication of a Statement of Opportunities and the Grid Planning Assumptions. These are published in a two year cycle.
- Identification of investments on the grid required for either reliability or economic purposes by Transpower within Transpower's Annual Planning Report. This is a continuous process.
- Development of common and project assumptions and of specific investment proposals. The investment proposals are developed by Transpower and submitted in the form of a Grid Upgrade Plan to the Electricity Commission for approval.

Transpower and the Electricity Commission are currently developing an operational policy document to cover the more detailed process for transmission network planning.

3.4.1.1 The Role of Transpower

As noted above, the grid owner Transpower is responsible for identifying and proposing network investments for approval by the Electricity Commission. Under the *Electricity Governance Rules* Transpower is required to:

- identify the type of investment that is necessary – investments are categorised as either economic or reliability investments, the primary difference being reliability investments are associated with reducing loss of load at grid exit points;
- assess the options for meeting the investment requirements including generation and demand side options that might delay or negate the need for an upgrade of the transmission system;
- apply the Grid Reliability Standards, Good Electricity Industry Practice and the Grid Investment Test in accordance with the *Electricity Governance Rules;*
- seek feedback from stakeholders as to the proposed investments and the basis for their analysis.

The Grid Investment Test (GIT) is the regulatory test applied by the Electricity Commission to proposals. This is an economic cost-benefit test applied to the investment in question. The GIT is designed to assess the economic trade-off between the costs of the proposal, such as the capital cost and the benefits of the proposal such the reduction in unserved energy that might result from increasing the capacity of the existing grid, as well as other benefits such as deferred capital and reductions in losses and dispatch costs.

[75] This section has been contributed by Transpower New Zealand Limited.

An opportunity exists for demand side involvement in a proposal by being included as a credible alternative to transmission investment. While there is currently no formal mechanism for demand side alternatives to receive funding for projects, Transpower is proposing to enable these via the introduction of grid support contracts.

3.4.3.2 Signals for DSM in Transmission Planning

Three types of market signals exist for network-related demand side management in New Zealand.

1. There are short-term price signals in wholesale market nodal prices. These include loss differences between nodes and, when binding, transmission constraints are signalled. In the case of constraints the market price will split upstream and downstream of the constraint, and the nodal prices will typically differ by more than the marginal cost of transferring power from the surplus node to the deficit node. The price differences can be considerable although typically not enduring and once the constraint ceases to bind, the constraint price difference is eliminated. However, on average the price difference between nodes provides a longer term signal to demand.
2. The current Transmission Pricing Methodology creates a long-term incentive for lines companies (and directly connected customers) to level out their peak demands, through the interconnection charge based on their contribution to the regional co-incident peak demand.
3. When a new investment in transmission is needed, Transpower is required to evaluate any non-transmission alternatives, such as load management. If load management proves to be possible and economic (resulting in a net benefit by displacing or deferring the need for network investment), and have a proponent, then Transpower can sign grid support contracts with the parties offering the load management services.

Therefore, there is some opportunity in New Zealand for demand side participants to have an impact within the transmission planning framework.

3.4.2 Distribution Network Planning

3.4.2.1 Distribution Planning Processes

In New Zealand, distribution network planning is carried out by the 28 distribution network companies for their own network areas. The distributors are subject to the Commerce Commission's Electricity Information Disclosure requirements and the *Electricity Information Disclosure Handbook*, developed by the Commerce Commission under Part 4A of the *Commerce Act 1986*, which specifies their obligation to consider non-network alternatives. Schedule 2 of the *Handbook* sets out the information that must be included in asset management plans. Clause 5(g) requires asset management plans to include:

> *"a description and identification of the network development programme (including distributed generation and non-network solutions) and actions to be taken, including associated expenditure projections."*

The above requirement is further explained in the Network Development Planning section (4.5.5) of the *Handbook*, as follows:

> *"The network development plan should include:*
>
> *a. a detailed description of the projects currently underway or planned to start in the next twelve months;*
> *b. a summary description of the projects planned for the next four years; and*
> *c. a high level description of the projects being considered for the remainder of the [asset management plan] planning period.*
>
> *For projects where decisions have been made, the reasons for choosing the selected option should be stated. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations."*

While there is an obligation for distributors to consider non-network approaches when considering a new investment, there is currently no requirement for distributors to call for proposals for non-network approaches, nor to accept one of these proposals if it is more economic than the network options. Additionally, network distribution companies have the ability under the Commerce Commission's threshold regime to pass through transmission charges to their customers and hence also have limited direct incentives to respond to any transmission pricing signals. Therefore the incentives for them to invest in demand-side alternatives are limited.

However, there are some examples of demand-side alternatives currently being used to defer distribution investments in New Zealand. These include customer-owned generation and fuel switching. These deferrals are being brought about indirectly by peak pricing (supported in some cases by the provision of information to customers around the timing of congestion periods), rather than by contracts between distributors and consumers to achieve deferral of specific projects.

3.4.2.2 Pricing Incentives

In New Zealand, the development of load management at the distribution and retail level has been driven by the historical pricing structures that placed emphasis on demand charges. The widespread installation of ripple control systems enabled the integrated retail and distribution companies (pre 1998) to control water-heating demand and shift some space heating from the daytime peak periods to night time.

The methodology used to determine the price signal to be passed to retailers and end consumers varies between distributors, as does the tariff structure used and the current level of the pricing signal. Specific load control tariffs or a general price signal may be offered by some distributors to retailers or directly to customers. In a very small number of networks, load control is a mandatory requirement of connection. In some cases distributors themselves add a further price signal to reflect the cost of investment in their own assets. Therefore, while there is a potential for DSM to play more of a part in distribution network planning, such as in minimising network losses, currently in most cases, price signals do not exist.

3.5 SOUTH AFRICA[76]

3.5.1 Transmission Network Planning

In South Africa, transmission network planning is all done by Eskom from a central office in Johannesburg. All plans are produced, published and approved internally; these are 10 year plans which are revised annually.. Transmission planners do not consider DSM solutions as options in their plans.

Recently there has been talk of making transmission planning documents public. Eskom has created a National Network Integration Forum (NNIF) to ensure that transmission and major distribution plans support and complement each other.

3.5.2 Distribution Network Planning

Distribution network planning is centralised in each of the six regions of Eskom Distribution. Each region is divided into several Network Development Planning Areas. Ten year Network Development Plans (NDPs) are produced and revised annually for each NDP area. The plans are created, approved and published internally. There is no participation by the public or the National Energy Regulator in these plans.

Network planners are encouraged to consider DSM solutions to network constraints but it is not a requirement to obtain approval of a plan. There are several reasons why network planners may not consider DSM solutions:

- high growth rates – the payback period is too short before conventional network strengthening is still required;
- lack of adequate DSM evaluation tools;
- a culture of sticking with the things you know best, ie network strengthening;
- most residential load is within municipalities and therefore it is more difficult to apply DSM solutions;
- where national peak load does not coincide with local peak loads and DSM is being applied to reduce the national peak, it can be difficult to apply DSM to reduce the local peak;
- some national DSM initiatives are resulting in increased local peak loads;
- regions are prohibited from having their own local tariffs which they could use to affect customer load behaviour;
- savings in regional energy purchases that are achieved by DSM solutions are not passed on to the regions to use to maintain the DSM initiatives;
- lack of information, knowledge and understanding of the composition of loads. If not enough is known about the load, it is difficult to know how the load shape could be altered by DSM initiatives.

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[76] This section has been contributed by Eskom.

3.6 SPAIN

3.6.1 Introduction

In Spain, the transmission system operator, Red Eléctrica de España (REE), is responsible for transmission network planning and the individual distribution companies are responsible for distribution network planning.

Prior to 1985, network planning was carried out by the vertically integrated utilities or distribution business. Electricity networks were built by the utilities primarily to transport electrical energy from the power plants they owned to their customers and the individual networks were not oriented to the operation of a competitive market. Transmission networks were conceived as interconnections between different local distribution networks, and the total system was not sufficiently meshed to enable the operation of generation units to be coordinated and integrated at a national level.

3.6.2 Transmission Network Planning

3.6.2.1 Establishment of National Transmission Planning

After the establishment of Red Eléctrica in 1985, transmission network planning changed to become more focussed on the operation of the whole Spanish electrical system at the national level. Consequently, investments in network infrastructure made between 1988 and 1997 were aimed at the elimination of constraints in generation unit operation, the establishment of a guaranteed quality standard for the transmission activity, and the integration of different electrical areas at a national level.

During this period, transmission network planning was carried out by REE, as the Transmission System Operator (TSO), and submitted to the Ministry of Industry, Trade and Tourism for final approval with the participation of regional governments.

Relevant issues for transmission network planning in this period were:

- construction of large transmission axes that served generation units and demand independently of the ownership of generation and distribution networks;
- completion of transmission network rings servicing high load areas;
- providing access to the 400 kV network to new markets areas under development.

3.6.2.2 Transmission Network Planning Following Market Liberalisation

Since the establishment of competitive electricity markets under the Spanish *Electricity Act 54/1997*, further changes have occurred in transmission network planning. The TSO still undertakes the detailed planning, but this is now a National Administration responsibility, with the participation of regional governments. Because the transmission network is essential for security of supply, the results of transmission network planning are legally binding on electricity network businesses. In contrast, generation planning is not binding and is regarded as only indicative. The uncertainty caused by the deregulation of electricity generation directly affects the transmission network planning methodology followed by the TSO.

The Spanish *Electricity Act 54/1997* required the preparation of a plan for electricity (and gas) transmission network development. In September 2002 this transmission network development plan[77] was approved by the Council of Ministers and afterwards submitted to the Economics and Treasury Commission at the Chamber of Deputies. The approved plan is legally binding, sets out the electricity and gas networks to be built during the specified period, and includes a detailed economic analysis for each network.

Figure 3.5 shows the procedure followed for the preparation of the transmission network development plan.

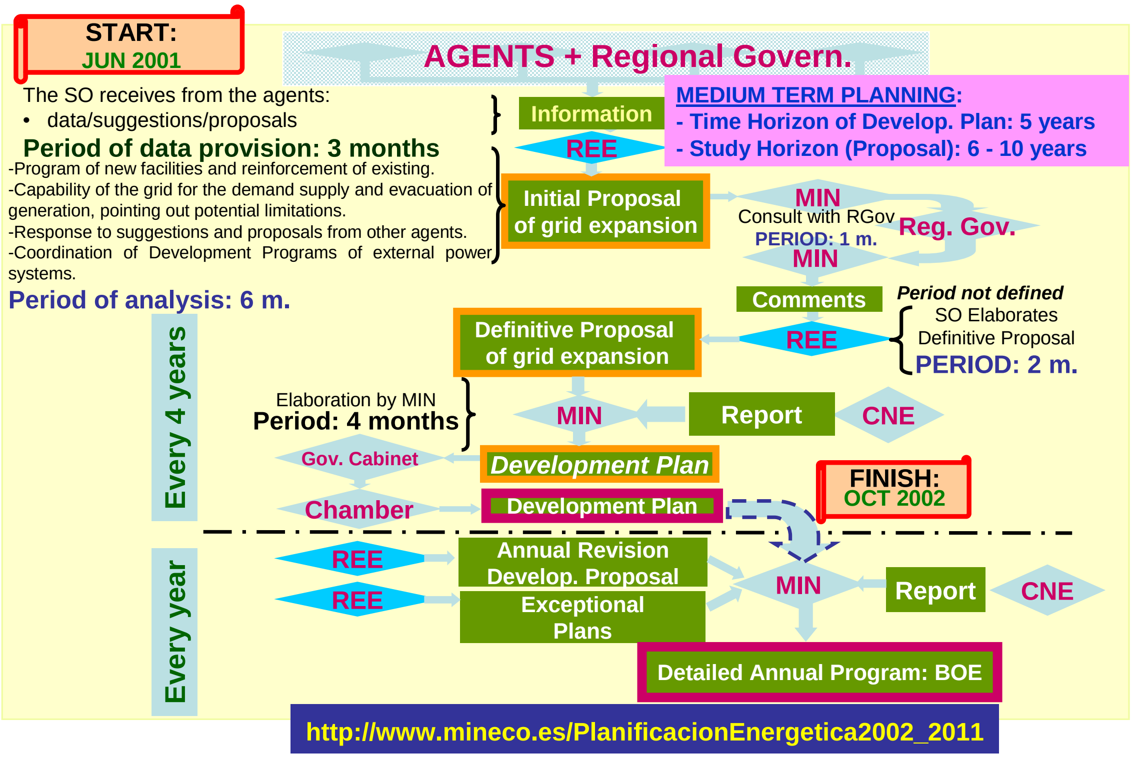

Figure 3.5 Procedure for the Preparation of the Transmission Network Development Plan in Spain[78]

The plan was prepared using information provided by the operators and agents of the electrical system, regional governments and proponents of new projects who made their proposals to the Ministry and to REE.

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77 *Electricity and Gas Sectors Planning and Transmission Network Development 2002-2011*

78 Source: Red Eléctrica de España.

Following the completion of the initial transmission network development plan, every year REE submits a development proposal, or a revision of the original plan, to the Ministry of Industry, Trade and Tourism. After consultation with the electricity industry regulator, Comisión Nacional de la Energía (CNE), the Ministry publishes the detailed Annual Program[79].

3.6.2.2 Methodology for Transmission Network Planning

The methodology for transmission network planning adopted by REE commences with the development of a scenario that represents the electrical system and its condition at a given time. The scenario includes profiles for electricity generation and consumption and also represents the physical structure of the network.

To guarantee the proper functioning of the electrical system in the future, the system's behaviour in a future year N is simulated, based on the status of the transmission network as at 31 December of year N-1. The nodal demand is modelled in accordance with the information provided by the distribution companies, to which is added the forecast load for high-speed rail lines and other individual large loads, to obtain the final modelled demand.

Once the generation groups have been assigned to the different nodes, generation profiles are developed by following an order of merit for the different generation technologies based on forecasts of fuel costs and also in accordance with the expected market penetration of renewable energies as shown in the *Renewable Energies Development Plan* for 2005-2010[80].

For each scenario static, dynamic and economic analyses are carried out.

Static Analysis. Compliance with a series of technical conditions is analysed to ensure that certain variables are within the limits of acceptability established in the Spanish System Operating Procedure. Forecast line loadings are compared with thermal capacities in winter and summer; forecast transformer loads are compared with their nominal capacities, and the forecast voltage levels at each node are compared with the nominal voltage assigned to the node to achieve optimal voltage control of the transmission network.

Dynamic Analysis. This analysis examines the transient stability of the electrical system and analyses its capacity to withstand faults without its basic parameters (frequency and voltage) exceeding standard transient limits or permanent system limits for unacceptable periods of time.

Economic Analysis. Only assets which contribute economic benefits to the electrical system in the form of cost savings are incorporated into the development plan. The economic analysis aims to minimise the sum of investment costs and operating costs:

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[79] Ministry of Industry, Trade and Tourism (2006). *Planificación de los Sectores de Electricidad y Gas 2002-2011. Revisión 2005-2011*.

[80] Red Eléctrica de España (2006). *Grid Planning and Development*. Page on the REE website at: www.ree.es/apps/i-index_dinamico.asp?menu=/ingles/i-cap01/i-menu_quien.htm&principal=/ingles/i-cap01/i-pr12.htm

- **investment costs** include the capital invested in assets that contribute to the development of the transmission network, as well as the costs of operating and maintaining these assets, over a recovery period equal to the estimated lifetime of the assets;
- **operating costs** comprise the variable costs derived from the expansion of the transmission network, including transmission losses and costs due to technical constraints. The model used for the assessment of operating costs considers a price profile and simulates a large number of different system states, using a probabilistic perspective according to hypotheses considered in the different scenarios.

The final transmission Annual Program includes proposals for network augmentation and expansion that minimise the costs involved in achieving a set reliability level for the transmission system[81]. This reliability level is defined as no more than 15 minutes per year of unplanned outages at the time of system peak.

The addition of any new network asset must be carried out in such a way that connection to and disconnection from the system do not cause a breakdown of the physical structure of the transmission network or of its operation. For this purpose certain criteria are established, including:

- limitation of the number of non-meshed nodes between two meshed nodes;
- limitation of the generation capacity concentrated at one node;
- coordination between the development plans of the transmission network and of the distribution networks;
- coordination of the acceptance of requests for new connections (for both generation and consumption) with the planning of the network.

3.6.3 Distribution Network Planning

In Spain, distribution network planning is carried out within distributors' service territories and is governed by the Spanish *Royal Decree 1955/2000*, through which electricity transmission, distribution, retailing and supply activities, and procedures related to the authorisation of electrical energy facilities are regulated. Regulation of distribution network planning is carried out at the regional level by regional governments.

Distribution companies are responsible for distributing electrical energy as well as for building, operating and maintaining distribution network infrastucture[82]. They are bound by law to provide a network connection in response to any request for electricity supply within their service territories[83]. In addition, distribution companies must design their networks with sufficient capacity to meet demand growth forecasts within their areas.

[81] Spanish *Royal Decree 1955/2000*
[82] Spanish *Electricity Act 54/1997*.
[83] Spanish *Royal Decree 1955/2000.*

Because the electricity distribution system is a natural monopoly, any development or modification of distribution network infrastructure requires approval from the regulator. Factors considered during the approval process include the cost effectiveness of the proposal and any impact on existing distribution network businesses.

Distribution network costs are estimated as the sum of investment and operating costs. Once the network assets needed within each distribution area are identified, they are multiplied by their unitary standard cost (cost per km for lines, and cost per kVA for substations and transformers). Total costs for each distribution area are used to establish the total revenue requirement for the distribution activity. Tariff levels are then set to recover this revenue amount.

3.7 UNITED STATES

3.7.1 Introduction

Historically, the dominant model for the electricity industry in the United States comprised vertically integrated utilities that carried out all four functions of electricity generation, transmission, distribution and retailing within defined geographical service territories[84] (see section 2.4.1, page 22). Within this model, most network planning at both the transmission and distribution levels was carried out relatively independently by the individual utilities.

During the 1990s, the *Energy Policy Act* of 1992, and particularly the 1996 FERC rulings, mandated increasingly open access to transmission lines (see section 2.4.2, page 24). Consequently, transmission network planning was required to be carried out across and between regions rather than within individual utility service territories.

Independent system operators (ISOs) and regional transmission operators (RTOs) were established in some regions to (among other things) facilitate coordination between utilities on transmission network planning. However, network planning at the distribution level remains largely the responsibility of individual electricity businesses.

3.7.2 Transmission Network Planning

The transmission network planning process in the United States is complex, involving many parties with various responsibilities and capabilities. Transmission owners, system operators, regional reliability organisations, the North American Electric Reliability Corporation, and state and federal regulators are all involved[85].

The North American Electric Reliability Corporation (NERC) was formed in 1968 as the utility industry organisation which develops, on a continental scale, voluntary reliability rules to govern how the bulk power system is planned and operated. As noted in section 2.4.4 (page 26), under the 2005 *Energy Policy Act*, the voluntary

[84] However, despite the dominance of vertically integrated utilities in the United States, about 25% of the total electrical load is served by other types of electricity businesses.

[85] The following description of transmission network planning processes in the United States is taken from: Kirby, B. (2006). *The Role of Demand Resources in Regional Transmission Expansion Planning and Reliable Operations*. Oak Ridge, TN, Oak Ridge National Laboratory.

structure is being replaced with enforceable reliability rules but, in early 2007, the process is only partially completed. The eight regional reliability councils abide by NERC standards and impose additional requirements of their own on their member Balancing Authority (Control Area) operators. ISOs, RTOs and Balancing Authorities have very specific concerns within the transmission systems they operate.

Transmission planning is conducted to identify system upgrade and expansion needs for reliability and economic benefit. Details of the planning process vary from entity to entity but the basic process is the same. The power system is modelled under expected future conditions. When inadequacies in the transmission system are identified there are specific processes that are utilised to find solutions. Typically, system planning analysts use load flow, transient stability, and voltage collapse analysis to assess system adequacy. This is an elaborate, well orchestrated, inclusive, effective process which typically provides years of warning concerning the need to upgrade transmission systems in order to meet the expected needs.

ISOs, RTOs, regional reliability councils, and regional planning organisations do not typically have the obligation or authority to directly design or implement transmission enhancement solutions. These organisations are typically independent of markets and required to remain so. Once they identify transmission system inadequacies they publicise the needs and expect transmission, generation, and demand side investors to propose projects to solve the problems.

The planners evaluate the proposed projects to see if they meet the technical and economic requirements. The best projects are endorsed and included in the regional transmission expansion plan. The projects must then be approved by state and federal regulators before being incorporated into transmission tariffs and/or the rate base. The technical opinions of the regional transmission planning organisations typically carry great weight with regulators but the actual authority to select projects does not generally lie with the regional organisations.

Processes for coordinated transmission network planning in the United States are still evolving. As a recent report from the ISO/RTO Planning Committee states[86]:

> *In the early days of an ISO/RTO planning effort, transmission expansion plans often represented a compilation of the member utilities' local transmission plans. As the planning organization and stakeholder relationships grow stronger, the plans grow in scope and complexity, starting with work to conduct reliability planning on an intraregional basis and then moving to interregional reliability and economic or environmental improvement projects. Often, the next step is to strengthen the plan to address a particular system need or policy issue that exceeds reliability alone.*

[86] ISO/RTO Planning Committee (2006). *ISO/RTO Electric System Planning, Current Practices, Expansion Plans, and Planning Issues*. Folsom, CA, California ISO. Available at: www.caiso.com/179c/179c9e0086c0ex.html

In the Western and Southeastern United States, where ISOs and RTOs do not exist, traditional vertically integrated utilities still carry out more traditional transmission planning within their service territories, though the West is currently undertaking regional transmission planning on an ad-hoc voluntarily coordinated basis.

In the West, transmission planning is also carried out by the Western Area Power Administration and the Bonneville Power Administration (BPA), both electricity generators and transmission network operators owned by the Federal Government. BPA, in particular, has changed its network planning methods to bring demand-side options into the transmission planning process as so-called 'non-wires solutions'. BPA defines non-wires solutions as a broad array of alternatives, including demand response, distributed generation, energy efficiency measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system[87].

In February 2007, FERC made a new ruling (Order No 890) which attempts to bring some uniformity to transmission network planning in the United States. The new Order requires that[88]:

- transmission providers participate in a coordinated, open and transparent planning process on both a local and regional level;
- each transmission provider's planning process meet the FERC's nine planning principles, which are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation;
- each transmission provider must describe its planning process in its tariff.

FERC will allow regional differences in transmission planning processes.

Restructuring of the electricity industry in the United States has had a major impact on transmission system planning. In the previously vertically integrated structure, each utility operated as a cohesive whole and was able to manage and plan for all aspects of operations. Virtually all of the trade-offs between various planning options were visible to the utility and, to a large extent, to the state regulator. The highest value choices were usually easily identified and utilities were expected to pursue them on behalf of electricity customers.

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87 A detailed case studies of the BPA non-wires solutions project is included in the first report from Task XV: Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

88 Federal Energy Regulatory Commission (2007). *Fact Sheet: Order No 890*. Washington DC, FERC.

However, an unintended aspect of restructuring was to unbundle the planning process in a way that makes it more difficult to both identify economic choices and to implement them[89]. This has had a negative impact on the use of DSM as an alternative to expanding the transmission network. NERC reliability standards do not directly address the use of DSM as an alternative to transmission expansion. Instead, forecasted demand and any expected demand reductions resulting from DSM are evaluated for their impact on the adequacy of the transmission system. The reliability rules are then used to determine the realisable capacity of the physical transmission system[90].

FERC's recent Order No 890 is likely to increase participation by demand-side resources in transmission network planning by permitting demand-side resources capable of performing the needed functions to participate in the transmission planning process on a comparable basis to demand-side resource. The new Order also provides a forum for stakeholders to come forward with demand response project proposals that they wish to have considered in development of the transmission plan[91].

3.7.3 Distribution Network Planning

In the United States, distribution network planning is essentially the sole responsibility of each electricity distribution wires business within its geographical service territory. State regulators (the Public Utility Commissions) oversee many of these businesses[92] but distribution level planning is not an area which has historically received a lot of regulatory attention[93].

Each electricity business takes a slightly different approach to making distribution planning decisions. Nevertheless, there is a common process that describes how most utilities select which distribution network expansion and augmentation projects to pursue. This process is illustrated in Figure 3.6 (page 81).

[89] Shirley, W. and Weston, R. (2005). *Mid-Atlantic Distributed Resources Initiative Regulatory Subgroup Scoping Paper*. Second draft. Gardiner, ME, The Regulatory Assistance Project. Available at: www.raponline.org/Pubs/RAPRegulatoryScopingPaperRedline2005-06-03.doc

[90] Kirby, B. (2006). *Op cit*.

[91] Federal Energy Regulatory Commission (2007). *February 15, 2007 Open Commission Meeting: Statement of Commissioner Jon Wellinghoff.* Washington DC, FERC.

[92] Though approximately 25 percent of electricity customers in the United States are served by publicly-owned electricity businesses or rural electric cooperatives which are typically not regulated by State PUCs but instead are regulated by local elected or appointed boards.

[93] Shirley, W. and Weston, R. (2005). *Op cit.*

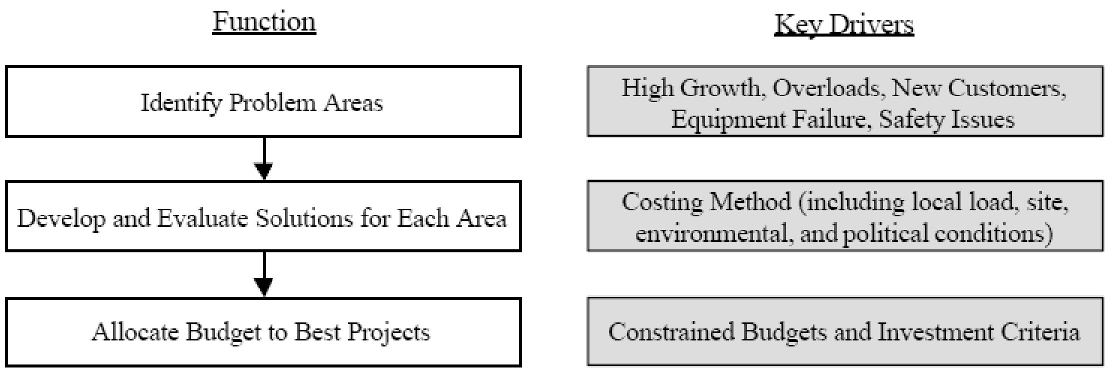

Figure 3.6 High Level Overview of Distribution Network Planning in the United States[94]

In the first step, engineers and planning staff identify problem areas. These are specific geographical localities within which electric power delivery deficiencies are likely to occur, typically within a10 year planning horizon[95]. The next step is to develop possible solutions to address the issues in the identified problem areas, considering capacity, load growth, operability and reliability. A capital budget request and justification are then developed for each area. Planners then formulate their proposed 'best' solution for each problem area, resulting in projects that are submitted for consideration in the overall utility capital budget. Capital budgeting then allocates the available resources to those projects deemed to be the most important.

How project costing is performed is critical in determining which projects are eventually implemented[96]. Costing is used to rank different potential solutions for an area and ultimately determines which projects are submitted in a request for funding from the capital budget. Depending on the specific practices within individual electricity businesses and any requirements imposed by the regulator, DSM alternatives may also be considered along with traditional 'poles and wires' solutions.

[94] Energy & Environmental Economics Inc and Pacific Energy Associates (2006). *Costing Methodology for Electric Distribution System Planning*. San Francisco, The Energy Foundation. Available at: www.energetics.com/MADRI/pdfs/CostMethodFinal.pdf

[95] Putnam, J.L. (2005). *Typical Approach: Electric Utility Distribution Planning*. PowerPoint presentation. Sacramento, CA, California Energy Commission. Available at: http://www.energy.ca.gov/distgen_oii/documents/2005-04-29_workshop/2005-04-22_PLANNING.PDF

[96] Energy & Environmental Economics Inc and Pacific Energy Associates (2006). *Op cit*.

4. OPTIONS FOR MODIFYING NETWORK PLANNING PROCESSES

Activity 3-3 of Subtask 3 develops options for modifying network planning processes to incorporate DSM measures as alternatives to network augmentation[97]. This section of the report summarises the results from Activity 3-3.

The primary function of electricity network businesses is to build, manage and operate network infrastructure assets, such as poles, wires, transformers and control and communication equipment. Typically, these businesses have little knowledge about, or expertise in, using demand-side resources as alternatives to network augmentation or more generally to support electricity networks. Therefore, left by themselves, network businesses would be unlikely to include consideration of demand-side resources in network planning. This section reviews the changes that will be required to encourage network businesses to take demand-side resources into account in their network planning.

4.1 INTRODUCTION

Among the seven countries studied in this report, planning processes for electricity transmission and distribution systems vary significantly, particularly in relation to the types and functions of the various organisations involved, the detailed planning processes and methodologies used, and the policy and regulatory regimes within which electricity network businesses operate. However, there is sufficient commonality to identify a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.

These key areas include:

- forecasting future electricity demand, both in relation to the network as a whole and on particular network elements (eg lines and substations);
- communicating information about network constraints;
- developing options for relieving network constraints;
- establishing policy and regulatory regimes for network planning.

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97 Energy Futures Australia (2004). *Prospectus: Research Project on Network-driven DSM*. Hornsby Heights, NSW Australia, EFA.

4.2 FORECASTING FUTURE DEMAND

The first step in any electricity network planning process involves forecasting future demand for electricity, both across the service territory of the network business as a whole and in relation to individual network elements.

Frequently, DSM is taken into account during this forecasting process by assuming a particular level of energy efficiency activity, and reducing the global load forecasts by a corresponding (usually quite small) amount. Following is a typical methodology for including DSM in load forecasts adopted by Tri-State Generation and Transmission Association, a wholesale supplier of electricity to 44 member distribution systems throughout Colorado, Nebraska, New Mexico and Wyoming[98]:

> *The econometric method used to prepare the forecasts accommodates changes in technology or customer preferences that impact the energy use per account through the use of time-trend variables. There is not sufficient data to explicitly model these impacts. Tri-State sponsors an 'Energy Efficiency Credits' program, which encourages certain levels of building insulation efficiency and/or provides incentives for the purchase of high-efficiency motors. It is not possible to quantify with confidence the amount of load reduction as a result of these programs.*

Such methodologies have the effect of discounting the potential contribution by DSM towards supporting electricity networks. In particular, they assume that DSM will have a similar, small effect on demand across the whole of the network and that the resulting load reduction will be undifferentiated in relation to both the geographical location and the time at which it occurs.

As the worldwide survey of network-related DSM projects[99] has shown, DSM projects can be designed to deliver load reductions at specific locations and at particular times of the day, particularly at peak load times. The treatment of DSM in demand forecasting for network planning should be modified to recognise more accurately the potential contribution of DSM.

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[98] Tri-State Generation and Transmission Association Inc (2003). *Electric Least Cost Resource Plan.* Presented to the Colorado Public Utilities Commission. Westminster, CO. p 28.

[99] Crossley, D.J. (2008). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Second edition. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

4.3 COMMUNICATING INFORMATION ABOUT NETWORK CONSTRAINTS

The second step in network planning is to compare the demand forecasts with the available capacity on the network elements that will be used to transport the required electrical energy. From this information, likely future constraints on the network are identified and characterised according to their specific timing and geographical locations.

Information about future network constraints is often not published, but instead is retained inside network businesses. Where this is the case, it is very difficult for anyone outside electricity businesses to propose options for relieving network constraints. DSM is rarely considered in developing such options because the staff of network businesses usually do not have expertise in DSM program development and implementation. However, if information about network constraints was made available outside network businesses, it is possible that other organisations with the required expertise may be able to develop DSM options to relieve the constraints.

In Australia, the *National Electricity Rules* require both transmission and distribution network businesses to publish information about likely future network augmentations. The *Rules* also require demand-side options to be considered when such augmentations are being planned.

Some Australian states take this process further, particularly New South Wales and South Australia. In New South Wales, electricity distributors are subject to a *Demand Management Code of Practice*[100] that requires them to publish annual Electricity System Development Reviews. These documents identify likely future constraints on the distribution network. Before augmenting or reinforcing the network, the *Code* specifically requires distributors to carry out investigations to ascertain the cost-effectiveness of avoiding or postponing this work by implementing DSM strategies.

Some third parties have used the information in the Electricity System Development Reviews to enhance the availability of information about network constraints. For example, Figure 4.1 (page 85) shows a map of likely future network constraints in the Sydney region prepared from published information.

[100] Department of Energy, Utilities and Sustainability (2004). *Demand Management for Electricity Distributors: NSW Code of Practice*. Sydney, DEUS. Available at: www.efa.com.au/Library/DMCode3rdEd.pdf

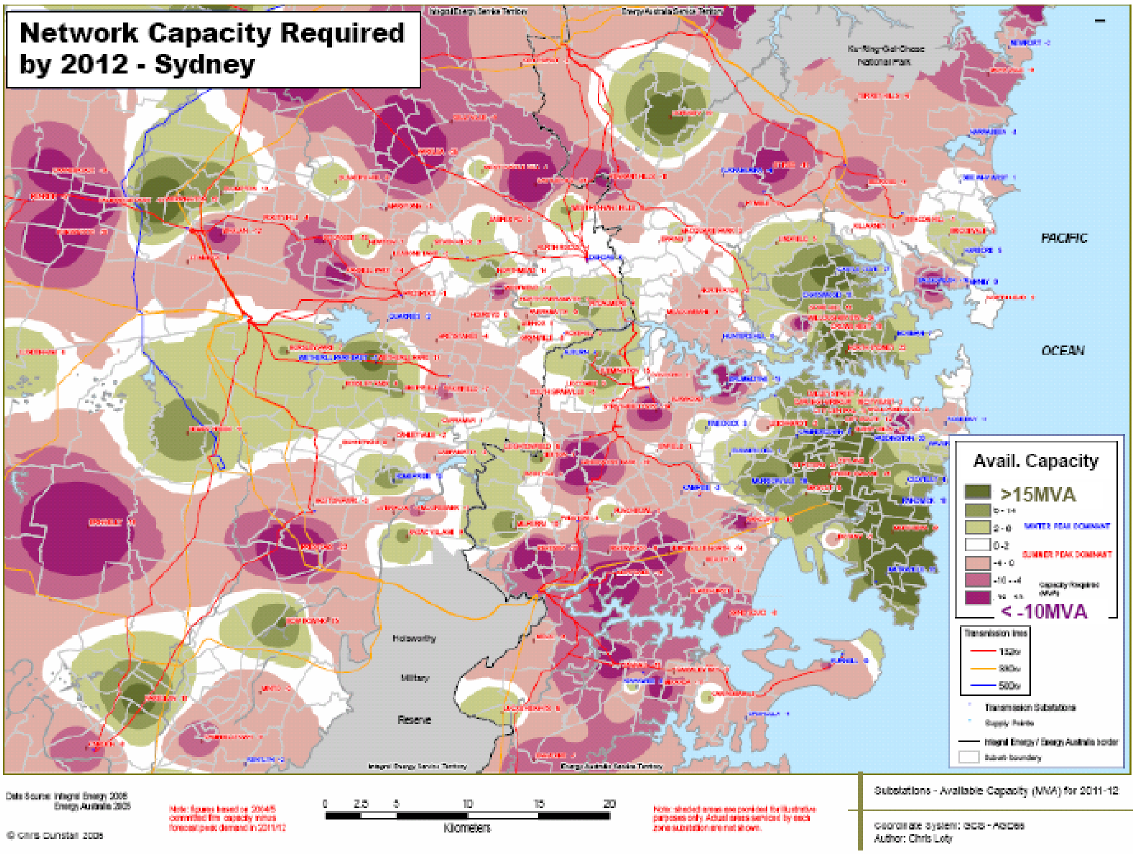

Figure 4.1 Map of Network Constraints Prepared from Published Information[101]

4.4 DEVELOPING OPTIONS FOR RELIEVING NETWORK CONSTRAINTS

As noted in section 4.3 (page 84), if specific information about electricity network constraints is made available outside network businesses, this provides an opportunity for third parties with expertise in DSM to participate in the development of options that use demand-side resources to relieve the constraints.

The *Demand Management Code of Practice*[102] in force in the Australian state of New South Wales requires electricity distributors to provide specific opportunities for third parties to take part in option development. Opportunities are provided through a formal process for procuring demand-side resources for network support, as shown in Figure 4.2 (page 86). There are two types of procurement offers that may be made to providers of DSM: negotiable offers and standard offers.

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[101] Dunstan, C (2006). Five steps to a fairer market for demand management and distributed generation. PowerPoint presentation. *Workshop on Challenges and Opportunities for Promoting Decentralised Energy*. Melbourne, 14 December.

[102] Department of Energy, Utilities and Sustainability (2004). *Op cit.*

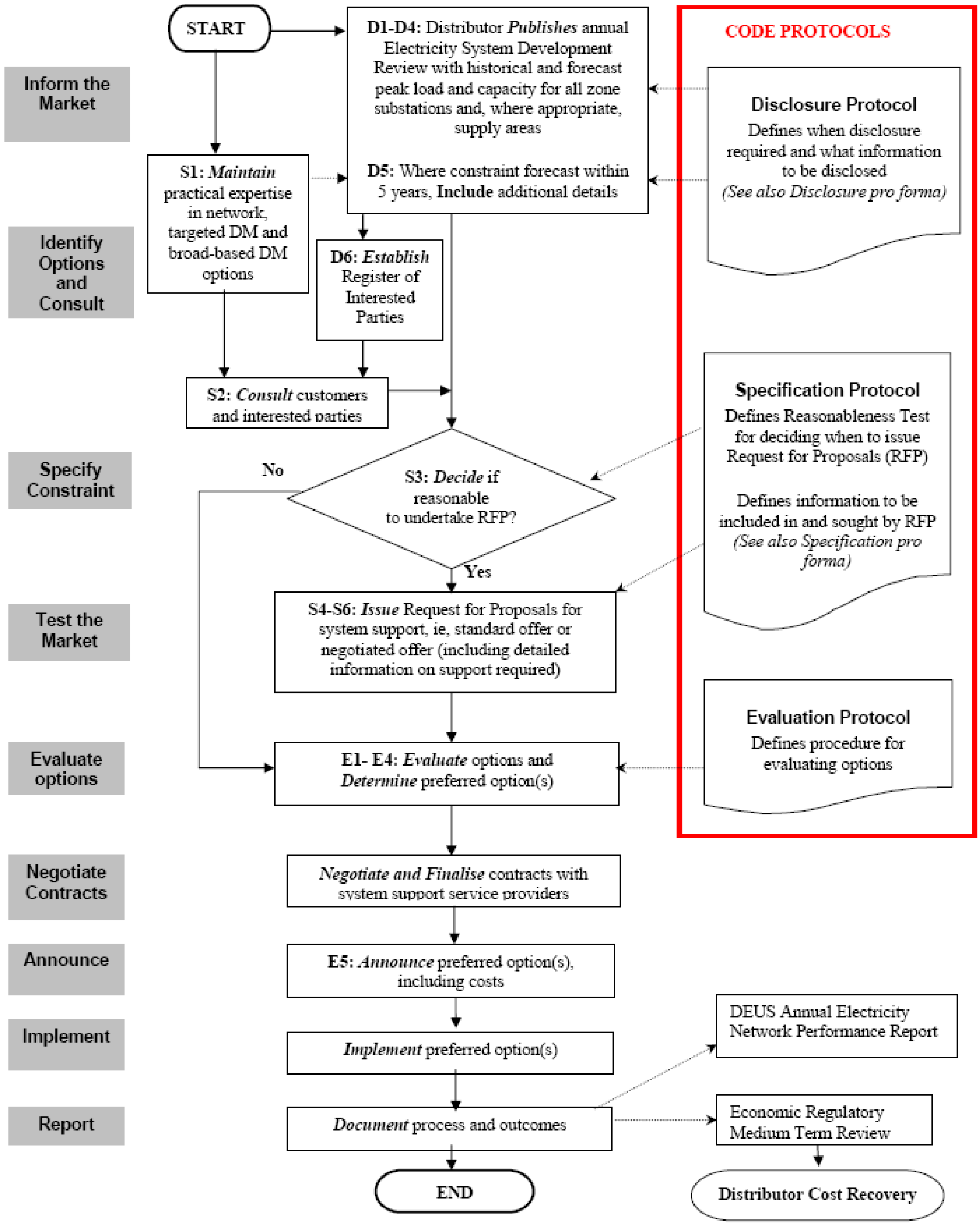

Figure 4.2 Electricity System Development Procedure for Distributors in New South Wales, Australia[103]

103 Department of Energy, Utilities and Sustainability (2004). *Op cit.*

For negotiable offers, the distributor and the proponent of a DSM project (who may also be a network customer) negotiate a contract specifically designed for that particular project. Negotiable offers are more appropriate for larger-scale, relatively complex DSM projects where the transaction costs and time associated with negotiating a unique contract are relatively insignificant compared with the benefits from the project.

Standard offers specify the conditions for the provision of demand-side resources in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis. Standard offers may be targeted to shorter-term network constraints or to capture demand reduction opportunities that provide longer-term distribution network benefits by delaying future, less well-defined constraints.

A standard offer may be made in conjunction with, prior to, or in place of, a negotiable offer being issued or a constrained area being identified. A subsequent negotiable offer or Request for Proposal may revise the standard offer as the details of the constraint and the requirement to overcome the constraint are more clearly defined.

The *Code* suggests that distributors make standard offers where the firm rating of the local distribution network will be exceeded within a ten year forecast period. A standard offer can be made during the early period of a constraint being identified and may be re-evaluated and incorporated into a Request for Proposals in accordance with the timeframe shown in Figure 4.2 (page 86).

A somewhat similar process may be established in the United States under the February 2007 ruling (Order No 890) by the Federal Energy Regulatory Commission (FERC) which permits demand-side resources capable of performing the needed functions to participate in the transmission planning process on a comparable basis to demand-side resource. The new Order also provides a forum for stakeholders to come forward with demand response project proposals that they wish to have considered in development of the transmission plan[104].

4.5 ESTABLISHING POLICY AND REGULATORY REGIMES

The policy and regulatory regimes under which electricity network businesses operate can create significant disincentives to businesses using demand-side resources to support electricity networks. This can occur particularly when the regulatory regime remunerates network businesses on the basis of a rate of return on the value of network infrastructure assets they own; and/or the quantity of electrical energy transported through the network.

In these cases, the revenues of network businesses can be significantly reduced if they make use of demand-side resources that defer or eliminate the need to construct additional network infrastructure assets; and/or reduce the quantity of energy transported through the network. This is illustrated in Figure 4.3 (page 88).

[104] Federal Energy Regulatory Commission (2007). *February 15, 2007 Open Commission Meeting: Statement of Commissioner Jon Wellinghoff.* Washington DC, FERC.

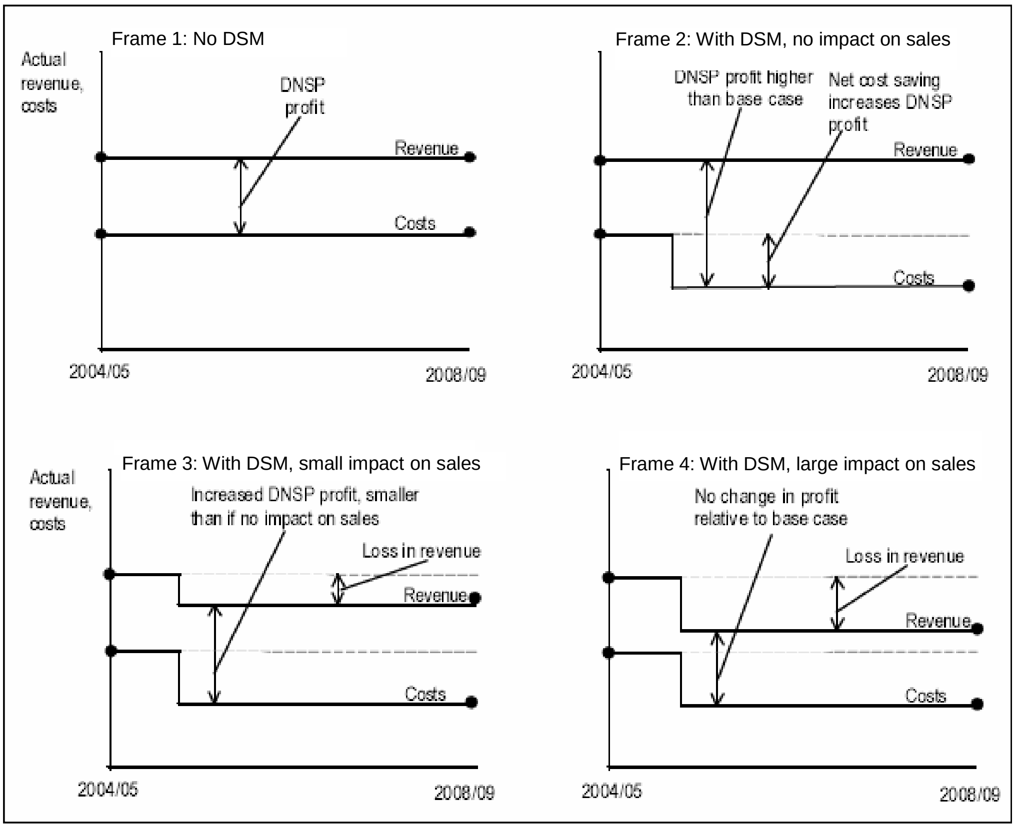

Figure 4.3 Impact of DSM on Electricity Business Revenue[105]

Figure 4.3 shows the case of a distribution network service provider (DNSP), ie an electricity distributor, whose revenue is dependent on sales volume. The distributor has an opportunity to undertake a DSM network support project which is less expensive than a network solution that produces an equivalent result.

Frame 1 in Figure 4.3 presents the base case, where the distributor undertakes no DSM during the regulatory period. For simplicity, it is assumed that revenues and costs remain constant over the regulatory period, in the absence of DSM. The difference between revenue and costs represents the distributor's profit.

Frame 2 illustrates the case in which the DSM project achieves a reduction in costs with no impact on sales, as might be the case with a load shifting or distributed generation DSM project. In this case, the distributor's profit is increased by the amount of the cost saving.

Frame 3 shows what happens when a DSM project leads to a small reduction in sales for the distributor. This reduction is revenue forgone by the distributor as compared with the revenue it would have received in the absence of the DSM project. In this

[105] Independent Pricing and Regulatory Tribunal (2004). *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09. Draft Decision.* Sydney, The Tribunal.

case, the foregone revenue is smaller than the cost saving achieved by the distributor through implementing the DSM project. Therefore, while the increase in profit is smaller than when there is no foregone revenue, the profit is still larger than in the base case. In this scenario, there is still an incentive to undertake DSM, but it is smaller than if there were no impact on revenues.

Frame 4 illustrates the scenario where the DSM project results in a reduction in revenue that matches the reduction in costs. Here, there is no change in the distributor's profit relative to the base case. In this situation, there would be no financial incentive for the distributor to undertake a DSM project rather than the higher cost network solution. However, the community's welfare would be improved if the distributor undertook the demand management project because the project would lower the total resource cost of meeting the demand for electricity.

Governments and regulators can make changes to policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks. There are two ways in which this can be achieved:

- by providing policy and regulatory incentives to network businesses; and/or
- by imposing policy and regulatory obligations on network businesses.

4.5.1 Policy and Regulatory Incentives

Various policy and regulatory mechanisms have been deployed to provide incentives for network businesses that use demand-side resources to support electricity networks. The following mechanisms are described below:

- revenue regulation;
- recovery of revenue foregone and DSM program costs;
- direct incentives to encourage the use of demand-side resources for network support.

4.5.1.1 Revenue Regulation

Under revenue regulation, the total 'allowable' revenue of an electricity network business is set each year at a particular dollar figure. Within this revenue cap, the business is free to set the structure and levels of network charges in any way it chooses. Any over- or under-collection of revenue in one year is corrected in determining the 'allowable' revenue for the following year[106].

Revenue regulation can be used to 'decouple' revenue from the volume of sales (ie the quantity of energy transported through the network). The formula used for calculating the allowable revenue can be set to achieve various percentages of decoupling from 0% to 100%. With 100% decoupling, the network business becomes indifferent to the sales volume, and the disincentive to use demand-side resources for network support is therefore removed.

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[106] Crossley, D., Maloney, M., Watt, G., 2000. *Developing Mechanisms for Promoting Demand-side Management and Energy Efficiency in Changing Electricity Businesses*. IEA DSM Programme, Task VI Research Report No. 3. Energy Futures Australia Pty Ltd., Hornsby Heights NSW, Australia.

For example, in 1994 the electricity regulator in the Australian State of New South Wales proposed a revenue regulation formula to apply to the distribution 'wires' businesses in that State. The formula had the following form[107]:

$$R = a + b_r N_r + b_c N_c + b_i N_i + cM + dL$$

where

R is the annual allowable revenue for a distributor set by the regulator

N is the actual number of customers served by the distributor in the residential (N_r), commercial (N_c) and industrial (N_i) sectors

M is the actual number of megawatt-hours sold per annum by the distributor

L is the actual length in kilometres of network lines owned by the distributor

b is the allowable number of dollars per customer in the residential (b_r), commercial (b_c) and industrial (b_i) sectors as set by the regulator

c is the allowable number of dollars per megawatt-hour sold as set by the regulator

d is the allowable number of dollars per kilometre of network line as set by the regulator

a is a residual term capturing other costs; this term would be set specifically for each distributor.

Since this formula includes a term for allowable dollars per megawatt-hour sold, it does not achieve 100% decoupling of revenue from sales volume. The actual level of decoupling would depend on the value of c set by the regulator. Application of the formula was expected by the regulator to reduce the bias against implementation of DSM by distributors in New South Wales.

During the second half of the 1990s and the early 2000s, revenue regulation was used for electricity businesses in Australia, the United Kingdom and the United States. However, it has since fallen out of favour with some regulators.

4.5.1.2 Recovery of Foregone Revenue and DSM Program Costs

As illustrated in Figure 4.3 (page 88), when a network business is remunerated on the basis of the quantity of electrical energy transported through its network, any reduction in this quantity caused by the implementation of DSM results in revenue foregone by the business. Also network businesses incur costs in implementing DSM, including project design and testing costs, marketing costs, costs of purchasing and installing DSM-related equipment, and annual operating costs.

There are two views among policy makers and regulators about how foregone revenue and DSM program costs should be treated. One view maintains that both foregone revenue and DSM program costs are entirely the responsibility of the network business and should be fully taken into account when the business is evaluating the cost effectiveness of DSM versus network augmentation options. A second view maintains that the network business should be allowed to recover at least some of the foregone

[107] Government Pricing Tribunal of New South Wales (1994.) *Price Regulation and Demand Management.* (Discussion Paper No 7). Sydney, the Tribunal.

revenue and DSM program costs and the value of this recovery should not be included in the cost benefit analysis of DSM versus network augmentation options.

In the Australian State of New South Wales, the introduction of revenue regulation (see page 89) did not result in a major increase in the implementation of DSM by electricity distributors. For the five year regulatory period to 2009, the regulator changed its method of regulating distributors from revenue regulation to price control but also allowed distributors to recover foregone revenue and DSM project costs. To achieve this, the regulator introduced a D-factor into the weighted average price cap control formula that allowed distributors to recover[108]:

- non-tariff-based DSM implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;
- tariff-based DSM implementation costs;
- revenue foregone as a result of non-tariff-based DSM activities.

These provisions are regarded as generous and have stimulated distributors in New South Wales to increase their implementation of DSM measures to defer network augmentations. However, the provisions only operate for five years. Responsibility for carrying out distribution network pricing determinations in the State will then be transferred from the State-based regulator to a national regulator. It is unclear what the national regulator's position will be in relation to recovery of foregone revenue and DSM program costs.

4.5.1.3 Direct Incentives for DSM

Direct incentives for electricity network businesses to implement DSM usually take the form of direct payments to the businesses. These payments may be made from a special fund established for this purpose.

In South Australia, the electricity industry regulator provided AUD 20 million for DSM initiatives to be implemented by the sole electricity distributor in the State over the five-year regulatory period beginning July 2005[109]. The distributor was required to submit to the regulator for approval a program for implementation of DSM initiatives and expenditure of the approved funding over the regulatory period. The approved funding is being treated as operating expenditure, and does not impact on the regulator's consideration of approved capital expenditure for network augmentation purposes in the regulatory period.

[108] Independent Pricing and Regulatory Tribunal of New South Wales (2004). *NSW Electricity Distribution Pricing 2004/05 to 2008/09: Final Report*. Sydney, IPART. Available at: www.efa.com.au/Library/IPART2004DistribRevFinalRpt.pdf

[109] Essential Services Commission of South Australia (2004). *Demand Management and the Electricity Distribution Network. Draft Decision*. Adelaide, ESCOSA. Available at: www.escosa.sa.gov.au/webdata/resources/files/040830-DemandMgmt_DD.pdf

In the Australian State of Victoria, the electricity industry regulator, has allowed specific provision for DSM initiatives of AUD 0.6 million for each distributor[110]. This provision will provide additional revenue for the trial of DSM initiatives during the 2006 to 2010 regulatory period. The regulator requires distributors to report on an annual basis the demand-side activities that have been undertaken and the outcomes that have been delivered.

In France, an incentive is provided for DSM measures in particular geographical areas through the recently implemented energy efficiency certificates ("white certificates") scheme. Under the scheme, eligible energy efficiency measures are assigned particular levels of energy savings (kilowatt-hours reduced) calculated according to a standard methodology. The energy savings are then converted to tradeable energy efficiency certificates, thus providing a monetary value for the energy savings. Energy efficiency measures implemented in areas where the electricity network is constrained (specifically Corsica, Réunion, Guadeloupe, and Martinique) are assigned double the number of kilowatt-hours reduced, thereby also doubling the monetary value of the energy savings achieved in these geographical areas.

In the United States, many states that adopted electricity industry restructuring also created public benefits funding mechanisms to help ensure the continued implementation of DSM programs. Public benefits funding mechanisms for electricity DSM typically involve the collection of a small per-kilowatt-hour public benefits charge (also often known as a 'system benefits' or 'wires' charge) as a part of the revenues of an electricity utility (typically an electricity distributor). These revenues are used to fund DSM programs implemented either by utilities or by designated government or independent organisations.

By the end of the 1990s, public benefits funding had emerged to be perhaps the most significant new policy supporting energy efficiency DSM in the United States in a decade[111]. Since that time, although the move toward electricity industry restructuring has largely stalled[112], public benefits funding for energy efficiency DSM has continued unabated. Every state (18 in all) that initiated public benefits energy efficiency DSM programs continues to operate those programs today.

The required funding level across these 18 states varies from USD0.00003 to USD0.003 per kilowatt-hour with a median value of between USD0.0011 and USD0.0012 per kilowatt-hour. Combined annual expenditures are over USD900 million and annual incremental savings are nearly 2.8 million megawatt-hours. Cost-effectiveness estimates from nine of the most active states show the programs, in aggregate, to be

[110] Essential Services Commission (2005). *Electricity Distribution Price Review 2006-10. Final Decision. Volume 1: Statement of Purpose and Reasons*. Melbourne, ESC. Available at: www.esc.vic.gov.au/NR/rdonlyres/AF67E65E-9F47-4139-9702-58471B03A9DD/0/FinalDecisionVolume1StatementPurposeOct05.pdf

[111] Kushler. M. and York, D. (2004). State public benefits policies for energy efficiency: What have we learned? *Proceedings of the 2004 ACEEE Summer Study on Energy Efficiency in Buildings*, pp 5-156 to 5-167.

[112] No additional states have passed restructuring since 2000, and several have repealed or suspended their restructuring policy.

very cost-effective with median benefit/cost ratio in the range of 2.1 to 2.5 and median cost of energy savings equal to USD0.03 per lifetime kilowatt-hour saved[113].

4.5.2 Policy and Regulatory Obligations

Early DSM programs in the United States were driven by electricity regulators who actively supported any DSM program which saved energy at a lower societal cost than the electricity industry could deliver kilowatt-hours. In many states, regulators pressured electricity utilities to undertake extensive DSM programs.

From the mid-1980s to the mid-1990s, the imposition of regulatory obligations resulted in DSM becoming a major activity in the US electricity industry. State-based regulators imposed stringent requirements on electricity utilities to implement broadly-targeted, environmentally-driven DSM programs. DSM was seen as being more cost-efficient than supply-side resources and it also had environmental and social benefits. Many US utilities were required by regulators to undertake "integrated resource planning" (aka "least cost planning") in which supply-side and demand-side options were compared to determine which were the most cost-effective from the societal perspective.

Most regulators in the United States did not require utilities to implement DSM specifically targeted to relieving network constraints. Consequently, until the late 1990s, only a few specifically network-driven DSM programs had been developed. More recently, as problems with ageing network infrastructure become more apparent, increasing numbers of network-driven DSM programs are being implemented and are being supported by regulators. Some of these recent programs use short-term demand response to ameliorate transient network problems.

In other countries, regulators generally have not imposed obligations on the electricity industry to implement DSM. However, in those countries with ageing network infrastructure, regulatory obligations may be considered in the future as a mechanism for encouraging network businesses to use DSM for network support.

[113] Kushler. M. and York, D. (2004). *op cit.*

5. CONCLUSION

Among the seven countries studied in this report, planning processes for electricity transmission and distribution systems vary significantly, particularly in relation to the types and functions of the various organisations involved, the detailed planning processes and methodologies used, and the policy and regulatory regimes within which electricity network businesses operate. However, there is sufficient commonality to identify a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.

There are four key areas in which such changes can and should be made.

Forecasting future electricity demand. Forecasting methodologies frequently reduce global load forecasts by an assumed (usually small) amount to take account of DSM activity. Such methodologies discount the potential contribution by DSM towards supporting electricity networks. Forecasting methodologies for network planning should be modified to recognise more accurately the potential contribution of DSM.

Communicating information about network constraints. Information about future network constraints is often retained inside network businesses. It is then very difficult for anyone else to propose options for relieving network constraints. Network businesses should make this information publicly available so that other organisations with the required expertise can develop DSM options to relieve the constraints.

Developing options for relieving network constraints. Network businesses should provide formal opportunities for third parties with expertise in DSM to participate in the development of options that use demand-side resources to relieve network constraints.

Establishing policy and regulatory regimes for network planning. Governments and regulators should change policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks. There are two ways in which this can be achieved: by providing policy and regulatory incentives to network businesses; and/or by imposing policy and regulatory obligations on network businesses.