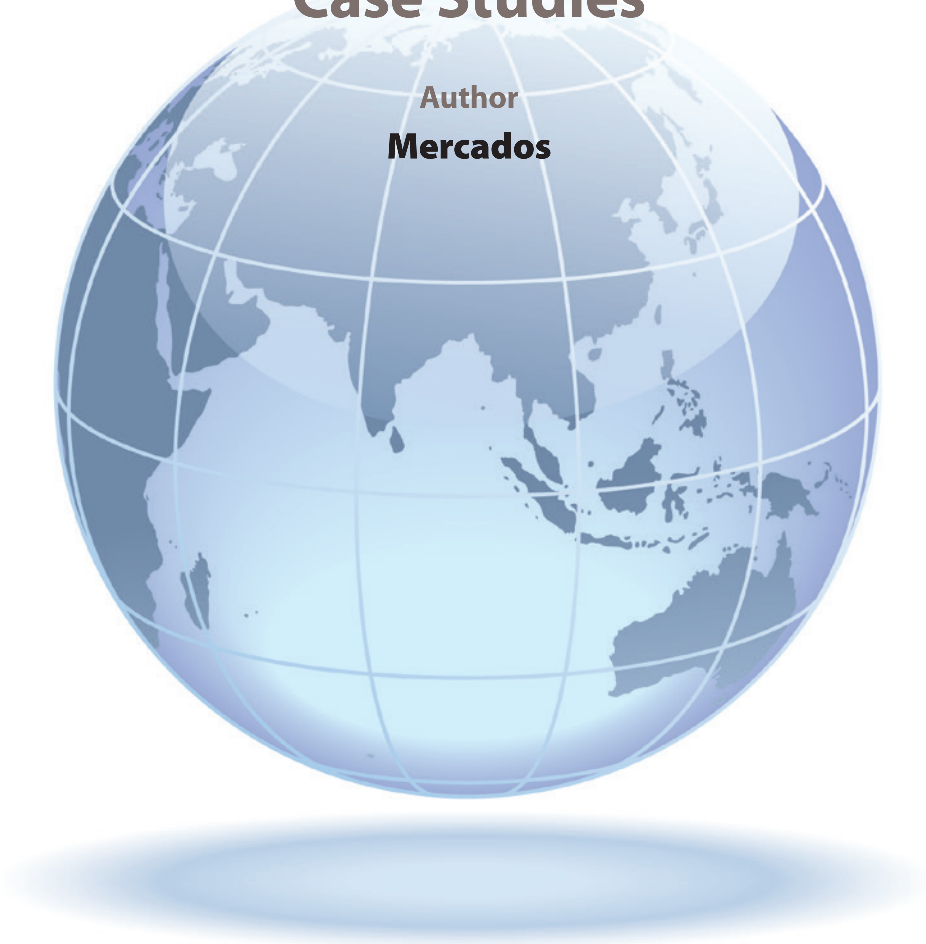
Global Power Best Practice Series 13

Current Practices In Electricity Transmission

Case Studies

Author
Mercados



RAP Energy solutions for a changing world

April 2013

The Global Power Best Practice Series was funded by the Climate Works Foundation (CWF) and The Regulatory Assistance Project (RAP). The information and material provided in this series is general in nature. RAP and CWF make no warranty or guarantee regarding the accuracy of any forecasts, estimates or analyses contained in the Global Power Best Practice Series reports. RAP and CWF are not responsible for any liability in association with this content.

Electronic copies of this paper and other RAP publications
can be found on our website at **www.raponline.org**.

To be added to our distribution list,
please send relevant contact information to
info@raponline.org.

RAP

mercados
ENERGY MARKETS INTERNATIONAL

Table of Contents

Foreword 5
Introduction 6
I. Brazil 8
A. Electricity System Overview 8
1. Regulatory Institutions 8
2. Electricity System Architecture 9
3. Renewable Generation Policy and Implementation Mechanisms 9
4. Transmission Network Overview 10
B. Transmission Planning and Investment Processes 11
1. The Planning Process 11
2. The Investment Process. 11
C. Connection and Access to the Transmission Network 12
1. Connection Capacity Allocation 12
2. Capacity Firmness and Congestion Management 13
D. Transmission Pricing 13
E. Renewable Generation Operation 14

II. China 15
A. Electricity System Overview 15
1. Regulatory Institutions 15
2. Electricity System Architecture 16
3. Renewable Generation Policy and Implementation Mechanisms 17
4. Transmission Network Overview 18
B. Transmission Planning and Investment Processes 18
1. The Planning Process 18
2. The Investment Process. 20
C. Connection and Access to the Transmission Network 21
1. Connection Capacity Allocation 21
2. Capacity Firmness and Congestion Management 22
D. Transmission Pricing 23
E. Renewable Generation Operation 23
1. Generation Forecasting 23
2. Participation in Balancing Services 24
3. Imbalance Settlement 24

III. India 25
A. Electricity System Overview 25
1. Regulatory Institutions 25
2. Electricity System Architecture 26
3. Renewable Generation Policy and Implementation Mechanisms 26
4. Transmission Network Overview 27

B. Transmission Planning and Investment Processes 28
1. The Planning Process 28
2. The Investment Process. 28
C. Connection and Access to the Transmission Network 28
1. Connection Capacity Allocation 28
2. Capacity Firmness and Congestion Management 29
D. Transmission Pricing 29
E. Renewable Generation Operation 29

IV. Spain 31
A. Electricity System Overview 31
1. Regulatory Institutions 31
2. Electricity System Architecture 32
3. Renewable Generation Policy and Implementation Mechanisms 33
4. Transmission Network Overview 34
B. Transmission Planning and Investment Processes 34
1. The Planning Process 34
2. The Investment Process. 35
C. Connection and Access to the Transmission Network 36
1. Connection Capacity Allocation 36
2. Capacity Firmness and Congestion Management 37
3. Generation Embedded in the Distribution Networks 37
D. Transmission Pricing 38
1. Connection Charges 38
2. Generation Transmission Use of System Charges. 38
E. Renewable Generation Operation 38
1. Generation Forecasting 38
2. Participation in Balancing Services 38
3. Imbalance Settlement 39

V. The United Kingdom 40
A. Electricity System Overview 40
1. Regulatory Institutions 40
2. Electricity System Architecture 42
3. Renewable Generation Policy and Implementation Mechanisms 42
4. Transmission Network Overview 43
B. Transmission Network Planning and Investment Processes 44
1. The Planning Process 44
2. The Investment Process. 47
C. Connection and Access to the Transmission Network 48
1. Connection Capacity Allocation 48
2. Capacity Firmness and Congestion Management 49
3. Generation Embedded in the Distribution Networks 50
D. Transmission Pricing 50
1. Connection Charges 51
2. Generation Transmission Use of System Charges. 51

E. Renewable Generation Operation . . . 52
1. Generation Forecasting . . . 52
2. Participation in Balancing Services . . . 52
3. Imbalance Settlement . . . 53

VI. US: NYISO . . . 55
A. Electricity System Overview . . . 55
1. Regulatory Institutions . . . 55
2. Electricity System Architecture . . . 56
3. Renewable Generation Policy and Implementation Mechanisms . . . 56
4. Transmission Network Overview . . . 57
B. Transmission Planning and Investment Processes . . . 59
1. The Planning Process . . . 59
2. The Investment Process . . . 61
3. Administrative Permits . . . 62
C. Connection and Access to the Transmission Network . . . 63
1. Connection Capacity Allocation . . . 63
2. Capacity Firmness and Congestion Management . . . 63
D. Transmission Pricing . . . 64
1. Connection Charges . . . 64
2. Generation Transmission Use of System Charges . . . 64
E. Renewable Generation Operation . . . 65
1. Generation Forecasting . . . 65
2. Participation in Balancing Services . . . 66
3. Imbalance Settlement . . . 66

VII. US: Western Interconnection . . . 67
A. Electricity System Overview . . . 67
1. Regulatory Institutions . . . 67
2. Electricity System Architecture . . . 68
3. Renewable Generation Policy and Implementation Mechanisms . . . 69
4. Transmission Network Overview . . . 70
B. Transmission Planning and Investment Processes . . . 71
1. The Planning Process . . . 71
2. The Investment Process . . . 72
C. Connection and Access to the Transmission Network . . . 72
D. Transmission Pricing . . . 72
1. Connection Charges . . . 72
2. Generation Transmission Use of System Charges . . .
E. Renewable Generation Operation . . . 73
1. Generation Forecasting . . . 73
2. Participation in Balancing Services . . . 74
3. Imbalance Settlement . . . 74

References . . . 75

About the Global Power Best Practice Series

Worldwide, the electricity sector is undergoing a fundamental transformation. Policymakers recognize that fossil fuels, the largest fuel source for the electricity sector, contribute to greenhouse gas emissions and other forms of man-made environmental contamination. Through technology gains, improved public policy, and market reforms, the electricity sector is becoming cleaner and more affordable. However, significant opportunities for improvement remain and the experiences in different regions of the world can form a knowledge base and provide guidance for others interested in driving this transformation.

This Global Power Best Practice Series is designed to provide power-sector regulators and policymakers with useful information and regulatory experiences about key topics, including effective rate design, innovative business models, financing mechanisms, and successful policy interventions. The Series focuses on four distinct nations/regions covering China, India, Europe, and the United States (U.S.). However, policymakers in other regions will find that the Series identifies best — or at least valued — practices and regulatory structures that can be adapted to a variety of situations and goals.

Contextual differences are essential to understanding and applying the lessons distilled in the Series. Therefore, readers are encouraged to use the two supplemental resources to familiarize themselves with the governance, market, and regulatory institutions in the four highlighted regions.

The Series includes the following topics:

1. New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China
2. Policies to Achieve Greater Energy Efficiency
3. Effective Policies to Promote Demand-Side Resources
4. Time-Varying and Dynamic Rate Design
5. Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed
6. Strategies for Decarbonizing the Electric Power Supply
7. Innovative Power Sector Business Models to Promote Demand-Side Resources
8. Integrating Energy and Environmental Policy
9. Policies to Promote Renewable Energy
10. Strategies for Energy Efficiency Financing
11. Integrating Renewable Resources into Power Markets

Supplemental Resources:

12. Regional Power Sector Profiles in the U.S., Europe, India, and China
13. Current Practices in Electricity Transmission: Case Studies

In addition to best practices, many of the reports also contain an extensive reference list of resources or an annotated bibliography. Readers interested in deeper study or additional reference materials will find a rich body of resources in these sections of each paper. Authors also identify the boundaries of existing knowledge and frame key research questions to guide future research.

Please visit www.raponline.org to access all papers in the Series.

This Global Power Best Practice Series was funded by the ClimateWorks Foundation www.climateworks.org

Foreword

The details of transmission policy and planning occasionally have drifted into the background of energy policy debates. This is understandable since the bulk transmission system in most regions represents only a small fraction of customer electricity bills and generally has performed well in delivering reliable electricity over long distances. Also, when debates do occur in the field, they usually involve relatively obscure issues of physics and economics. However, there is growing recognition of the need to focus more attention on transmission issues. Accordingly, transmission resources have begun to figure more prominently in policy discussions as regions move to adopt more ambitious goals for clean energy supply from variable energy resources, such as wind and solar generation. Transmission expansion and extension are among the enabling features through which we will manage access to and least-cost delivery of clean energy.

Current rules and laws have established a framework for network planning and cost-recovery that has, in most cases, encouraged investment in a reliable system. However, policy makers now face the challenge of creating a new supportive regulatory and planning environment to complement new public policy ambitions for renewables. Such movements in new directions typically require changes to the legal framework, including setting objectives for system expansion, forming rules around interconnection and cost-recovery, and making tariff arrangements for transmission services. Transmission expansion is part of a broader set of strategies for integrating renewables that includes more flexible resources, demand response, distributed resources, improved forecasting, and improvements to wholesale markets. Requirements for transmission expansion must be understood in the context of this broader set of strategies.

Of course, there is a growing body of experience around the globe related to expanding the transmission system to meet the need for renewables integration. While there are common challenges and opportunities across all regions regarding physical system requirements, there is wide variety around other features of the system, such as market versus central ownership, operation, and dispatch and payment for services provided to the system.

This report provides a summary of how seven regions have dealt with the opportunities and challenges of expanding the grid to serve public policy objectives for renewable energy. Many regions are making good progress and much can be learned from the variety of settings in which this transmission work has occurred.

Riley Allen
Global Research Manager

Introduction

This report, part of the *RAP Global Power Best Practice Series,* presents case-study examples of important transmission policies in different nations, along with two regions of the United States. Appropriate policies related to the transmission system are proving to be a key concern for the integration of variable energy renewables. Yet a review of regional practices reveals that current practices are quite varied between regions. The three key topics that are featured in this review include **grid policies for integrating renewables, transmission planning for carbon-free energy**, and **transmission cost-recovery practices**.

This report describes international experiences in transmission system organization, focusing on practices for planning, investments, cost recovery, and connection of renewable generation for the following countries or regions:

1. Brazil,
2. China,
3. India,
4. Spain,
5. Great Britain
6. United States: New York ISO, and
7. United States: The Western Electricity Coordinating Council (WECC).

These selected cases represent the main three organizational models of transmission activity, although each jurisdiction implements its general model in a slightly different way. These models include:

1. **Centralized electricity sector with a monopolistic and integrated utility**. With time, this model is being abandoned in favor of other organizational schemes that address the modern challenges of achieving an efficient and sustainable power sector.
2. **Integrated utility with some level of unbundling of the system operation and transmission activities**. In this model, the integrated utility coexists with independent power producers (IPPs) and some level of consumer liberalization. This scheme is presently functioning under different approaches in China, India, Mexico, and Vietnam, among others.
3. **Market model with multiple generators, suppliers, and liberalized end consumers**. In the market model, the transmission company and system operator are unbundled (accounting, legal, or fully) from generation and supply activities. Although there may be a number of variations on the general approach, this model is prevalent in almost all of the European countries, many US states and Canadian provinces, most Latin American countries, Singapore, Australia, New Zealand, Kazakhstan, and the Philippines.

The following are the most typical functional structures between the transmission and system operator:[1]

- **Transmission System Operator (TSO):** One company fulfills the role of system operator and owner of the transmission assets. In the majority of cases, market operation is separated from the system operation. This is the current model in EU countries, Ukraine, Kazakhstan, Panama, and Turkey. In the EU, the trend is for the incumbent TSO to have a monopoly on transmission activity, and asset ownership. Some asset ownership by third parties may be accepted in exceptional cases, subject to approval by the national regulator.
- **Independent System Operator (ISO):** System operation is unbundled from transmission asset ownership. The ISO is commonly a non-profit organization, managed by a technical staff and governed by a board in which market participants are represented. Variants of this scheme are:
  - The ISO also fulfills the role of market operator (sometimes with responsibility for planning), and there are several owners of the transmission assets.

1 Both ISOs and TSOs, in their function as System Operators, are normally responsible for long term transmission planning.

Examples include US pools (PJM, NY-ISO, Mid-West, NE-ISO), Argentina, Peru, and Guatemala;
- The market operator is independent from the ISO. An example is the Russian Federation; and
- There is an incumbent transmission company that owns the majority of the assets, but expansion can be carried out by independent transmission companies. Examples include Brazil, Argentina, and Peru.

In this paper we describe:

- Two cases (China and India) of the **integrated utility model**, with a TSO that has some level of unbundling from the integrated utility;
- Two cases of the **TSO model** (the UK and Spain);
- Two cases of the **ISO model**, one of a fully competitive market (NY-ISO) and the other with a single-buyer model, limited short-term market, using an innovative approach to transmission system expansion (Brazil); and
- The predominant model in the US area covered by the Western Electricity Coordinating Council (WECC), which is one of the nine regional electricity reliability councils operating under the North American Electric Reliability Corporation.[2]

In all the cases, the countries or regions described have exceptional policies to promote low-carbon energy production, a medium- or high-level deployment of renewable energy sources, and ambitious policies to substantially increase the penetration of carbon-free technologies.

See Table 1 below.

There are two significant notes on the structure and descriptions of the cases presented in this report:

- We set out to present a similar level of information and detail for all cases; but because transmission organization is different in each country, some sections may have more or less content.
- Depending on the countries' regulations, the same concept may be described with different wording. We prefer to maintain the original terms used in each country, rather than to homogenize the concept by using the same generic term across all cases. As a result, the same concept may be described with different words in different cases.

2 The area covered by the WECC is heterogeneous, including some competitive markets such as California.

Table 1

Summary of Renewable Policies

	Brazil	China	India	Spain	UK	Selected US markets
Priority of dispatch	Yes	Yes	Yes	Yes	No	No
Priority of access to networks	No	No	No	Yes	No	No
Exposed to balancing costs	No	No	Partially	Yes	Yes	Yes
Firmness of transmission access	No	No	No	No	Yes	No
Transmission charging	Deep	Shallow	Shallow	Shallow	Shallow	Shallow

Source: Mercados

I. Brazil

A. Electricity System Overview

1. Regulatory Institutions

The Brazilian Government has full sovereignty over energy policy. It has, however, signed some specific agreements with neighboring countries, and others are under study. So far, these agreements mainly involve the joint development and exploitation of hydro resources in the countries' border regions, along with some energy interconnections.

National regulatory functions in Brazil are performed by three different institutions, supported by several smaller advisory entities. The three main institutions are:

- The Energy Policy National Council,
- The Ministry of Mines and Energy, and
- The National Electric Power Agency.

At the highest level, energy policy is defined by the Energy Policy National Council (CNPE), an advisory board to the President made up of ministers and presidents of regulatory agencies, among others. CNPE's functions include:

- Proposing the national energy policy,
- Proposing the generation-supply reliability criteria, and
- Approving the auction of certain "strategic" power projects, which would otherwise not be developed.

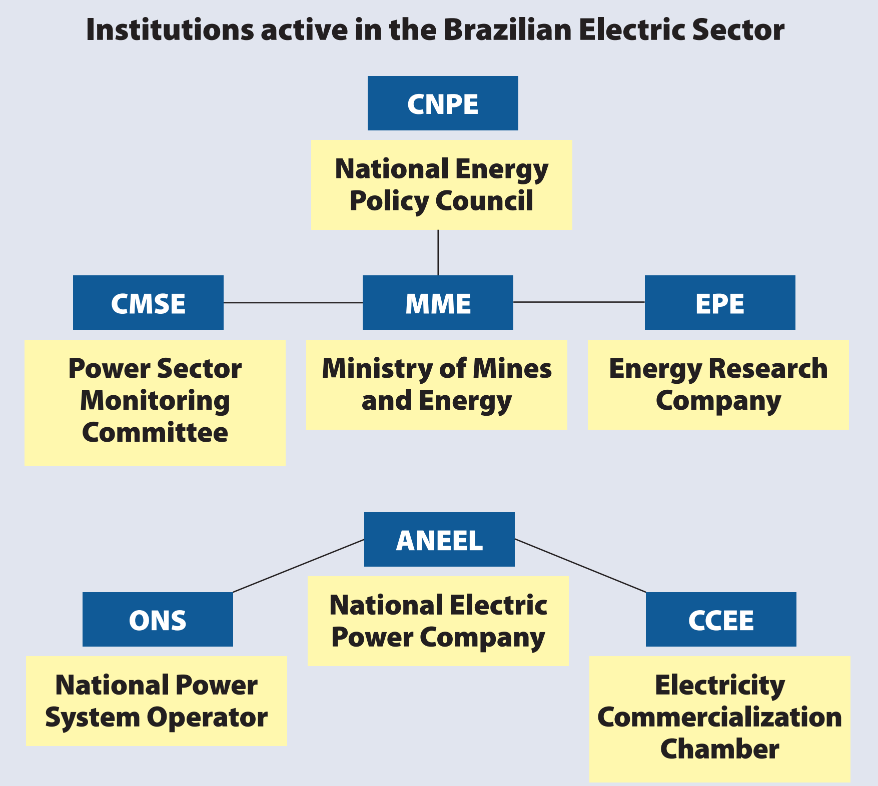
The Ministry of Mines and Energy both coordinates with the Energy Policy National Council and has the executive responsibilities for following its directives. The Ministry is responsible for planning, monitoring, and appointing main executives in the Market Operator and System Operator. It also has special intervention powers that can be used in the case of transitory supply shortages.

Finally, the National Electric Power Agency (ANEEL) is an independent regulatory entity responsible for pricing, setting the conditions for accessing the networks, auctioning, granting concessions, and supervising the Market Operator and System Operator.

Two smaller advisory institutions are the National Research Company (EPE), in charge of giving technical support to the Ministry in planning studies in the wider sense (generation, transmission, auctions, etc.) and the Electricity Sector Monitoring Committee (CMSE), which monitors short-term supply reliability.

Primary electricity regulation in Brazil is approved by the executive power by means of laws and decrees, while

Figure 1



Source: Chamber for the Commercialization of Electric Energy

ANEEL passes secondary regulation through resolutions. ANEEL is also responsible for approving market rules, grid codes, and concession contracts that contain an important part of the detailed regulation. The concession contracts set the basic rules on tariff formation, service quality and security, consumer rights and obligations, penalties, universal services, etc.

2. Electricity System Architecture

The current model of the Brazilian electricity sector was adopted in 2004, although major liberalization changes date back to previous reforms made between 1993 and 1998. The 2004 reform, prompted by supply shortages in 2001, meant the introduction of a long-term planning agency and the institutionalization of two segments in the retail market, one open to competition and the other supplied by distributors through energy purchase auctions.

Currently, wholesale trading is totally open to competition, although most generation assets remain in public hands. The retail market is partially open: only consumers with peak load over 3 MW are eligible, and they can contract freely with an electricity supplier.

The Brazilian electricity system is structured around the following participants:

- The generators,
- A regulated market operator, called CCEE for Câmara de Comercialização de Energia Elétrica (Electricity Commercialization Chamber), a non-profit association formed by the system agents (generators, distributors, and retailers),
- The national electric system operator, known as ONS, an independent nationwide system operator that is a non-for-profit, private right entity,
- The transmission companies,
- The distribution companies,
- Retail suppliers (retailers), and
- Electricity importers and exporters.

The system operator optimizes the entire generation-transmission electricity system through a centralized dispatch that precludes agents from signing physical bilateral contracts. Agents can, however, hedge against price variations by signing financial contracts. Parts of these contracts are negotiated in the periodic auction that the distribution companies hold to procure all the energy they require to supply captive customers. The market operator, CCEE, settles these contracts against short-term prices calculated using the system operator software, but not considering intra-zone transmission congestions, which results in zonal prices. In contrast to other electricity markets, where prices are determined for every hour or in shorter periods, prices in Brazil are calculated weekly.[3]

The Brazilian electricity sector has been only partially privatized. Federal and state-owned companies still account for most of the generation assets, with one public group, *Electrobrás*,[4] representing over 50% of total production. Private investor-owned companies have more presence in distribution activity. Because of this asymmetry, there is a limited degree of vertical integration.

3. Renewable Generation Policy and Implementation Mechanisms

Brazil´s renewable energy policy is clearly influenced by the country's large quantity of competitive renewable resources, such as hydro and biomass resources. Renewable energy already makes up 45.4% of 2010 total inland energy production, mostly thanks to sugar cane derivatives (such as bio-ethanol for transport) and hydroelectricity. The country´s renewable policy has been focused on developing these relatively cheap resources, and has not set up large-scale promotion schemes.

In the electricity sector, the contribution of renewable sources is even higher. In 2010, hydroelectricity alone represented more than 80% of electricity generation, with other renewable sources adding an additional 6.2%. Table 2 shows the Brazilian electricity balance.

3 Approximately 80% of electricity in Brazil is generated from hydropower resources. Electricity prices are therefore set according to the opportunity cost of the hydro resources, which does not vary hourly.

4 Electrobrás is a listed company controlled by the Brazilian federal government, which owns a direct 50.87% of the company's ordinary shares.

Table 2

Brazil Electricity Balance

	TWh 2009	2010	% in 2010
Total	514.1	463.0	100.0%
Non-renewable Energy	47.8	70.8	13.8%
Natural gas	13.3	31.9	6.2%
Oil derivatives	14.7	17.1	3.3%
Nuclear	13.0	14.5	2.8%
Coal and coal derivaties	6.8	7.2	1.4%
Renewable Energy	443.4	415.2	86.2%
Hydro	388.2	411.1	80.0%
Biomass	25.5	30.1	5.9%
Wind power	1.5	2.2	0.4%

Source: Ministry of Mines and Energy (2011). (draft results)

Table 3

Brazil Renewable Capacity Balance As of September 2011

	Number of Plants	MW Installed	Average MW per Plant	Percent of Capacity
Hydro	1,071	85,367	79	64%
Biomass				
Sugar cane waste	370	8,974	24	6.8%
Black liquor[7]	15	1,304	87	1%
Wood	48	417	8.7	0.3%
Biogas	19	74	3.9	0.1%
Rice waste	9	36	4	0.0%
Wind	96	2,109	22	1.6%

Source: ANEEL (2013).

Despite its abundance of resources, the country is actively encouraging electricity generation from alternative energy sources through ANEEL's energy procurement auctions for captive customers. Some auctions are reserved for energy generation from wind, biomass, or small-hydro power plants.[5] Winning bidders get a fixed price for the generated energy, based on their bids, and are subject to penalties if the plant is delayed.[6]

Apart from hydro plants, renewable generation is dominated by a group of biomass plants that is heterogeneous, both in the fuel used and in the size of the plant. Table 3 shows some of the characteristics of these plants.

According to public planning documents, prospects for renewable energy in Brazil are good. But those plans are not binding, and the country is finding new deposits of both gas and oil. This new oil and gas production guarantees Brazil's energy independence and is likely to reduce inland fossil fuel prices, making it harder for renewable energy to compete.

4. Transmission Network Overview

Brazil´s electricity transmission system has covered most of the country´s territory since the integration of the previously isolated northern and southern systems, although some small, isolated areas still have their own electricity systems.

Although planning for transmission expansion continues to be decided centrally, by the federal government through the Ministry of Mines and Energy, the country has chosen to create a market for transmission services as a mean of improving construction and operating efficiency. New transmission facilities are auctioned, and winning bidders are granted a 30-year concession contract. These contracts set the economic conditions of the concession, including the companies' allowed revenues, which is the result of the auction.

As a consequence, new private transmission companies are becoming important agents in the transmission system, accounting for most new concessions. Old public companies, however, still own most of the transmission grid.

5 Prior to the auction system, Brazil had in place a specific promotion program, the PROINFA (Programa de Incentivo às Fontes Alternativas de Energia Elétrica), which lasted until 2010.

6 Penalties may include a reduction of the price and the need to contract replacement firm energy during the delayed period.

7 Black liquor is the spent cooking liquor from the kraft process when digesting pulpwood into paper pulp.

B. Transmission Planning and Investment Processes

1. The Planning Process

a. Responsibility for Planning

The 2004 reforms resulted in the introduction of the Energy Research Company, EPE, as the main entity responsible for planning studies. But as an advisory body, EPE still requires approval from the Ministry of Mines and Energy for some plans, such as the basic long-term plan.

The system operator also participates in transmission planning. Together with EPE, it develops a medium-term plan and a three-year horizon document, which together communicate the expected transmission needs.

b. Planning Characteristics

There are three basic planning documents:[8]

- A ten-year horizon indicative plan, the Energy Expansion Decennial Plan (*Plano Decenal de Expanção de Energia*),
- A five-year horizon document, the Transmission Expansion Program (*Programa de Expansão da Transmissão*), and
- A three-year list of investments, the Expansion and Reinforcements Plan (*Plano de Ampliações e Reforços*).

The Energy Expansion Decennial Plan is an energy outlook document that provides high-level indications to energy agents and to governments. It covers interconnection between the different electricity regions, the connection of new hydro plants, and a projection of the required new investments and resulting transmission charges.

The five-year document, a list of required transmission facilities with their technical descriptions, is developed annually by the EPE as a summary technical guide for potential auctioning processes. It is prepared once the results of auctions for new generation are known, and incorporates their transmission requirements.[9] Among other details, it includes the project justification, the state where the project is located, the date by which it will be needed, the expected construction time, and the estimated budget.

Finally, the system operator prepares the Expansion and Reinforcements Plan, which includes all requests for access and connection to the network.[10] Based on all these documents, ANEEL approves the facilities that are to be auctioned.

c. Transmission Development Drivers

The Energy Expansion Decennial Plan does not provide much detail about the methodology to be used by the transmission expansion studies. It states that they are carried out using the demand and supply projections and the current planning criteria. These criteria include the following tasks:

- Coordinate different transmission regional plans, and plan new generation sites and international interconnections,
- Carry out a reliability assessment,
- Identify the needs for specific studies, and
- Update the transmission project pipeline.

Detailed transmission planning is closely related to the generation expansion auctions. The ten-year horizon study provides a first basis for estimating expansion costs and generation transmission charges. Detailed plans and transmission construction auctions take place once the generation sites become known.

2. The Investment Process

Once the construction of new transmission facilities is approved, ANEEL organizes a reverse auction (descending price, Dutch approach) for their construction. The concession is awarded on the basis of the lowest annual revenues, known as allowed annual revenue, requested by bidders for the construction and operation of the transmission facility. In exchange for licensing, building, and operating the transmission facility, successful bidders receive a monthly payment corresponding to the annual revenue requirement determined in the auction process. Each new facility investor forms a special purpose company (SPC) for the project development, which later becomes a

8 EPE issued some years ago the first integrated energy outlook with a 20-year horizon (*Plano Nacional de Energia 2030*). Although this plan includes the analysis of the electricity sector, we do not consider it as part of the transmission planning procedure. Available at: http://www.epe.gov.br/PNE/Forms/Empreendimento.aspx.

9 Energy Research Company (2013). To find the recent *Programa de Expansão da Transmissão:* http://www.epe.gov.br/Transmissao/Paginas/Estudos_9.aspx

10 National Electric System Operator (2013a). For the *Plano de Ampliações e Reforços* documents see: http://www.ons.org.br/plano_ampliacao/plano_ampliacao.aspx

transmission company (Transco).

Reinforcements for reliability and for system adequacy, including management of new requests for access and connection, are directly approved by ANEEL, which automatically concedes allowed annual revenue for the owner once the development is approved. No auctions are carried out for these transmission assets. Investment to improve service is also recognized by ANEEL. The revenue is, however, only guaranteed from the next allowed annual revenue revision process.

To guarantee open access, the transmission system is managed by the national system operator ONS, rather than by individual asset owners. ONS is responsible for centralized operation, supervision, and control of the transmission system. All transmission facilities are subjected to quality control, according to technical rules and to grid procedures regulated and approved by ANEEL. There are financial penalties in case of unavailability, although the total negative impact during the year is capped to 12.5% of the allowed annual revenue.

Finally, the concession term is 30 years for auctioned new assets, with one possible renewal for the same time span. Until September 2006, the allowed annual revenue of these assets auctioned was constant-fixed in real terms (i.e., adjusted by inflation) during the first 15 years, then reduced by 50% for the remaining 15 years. But after September 2006, ANEEL changed the rule and started to grant constant fixed revenue for all the concession period. However, the old criteria were kept for the contracts already signed. For directly authorized reinforcement investments, the period should respect the original concession contract term.

About the auctions: between 1998 and 2008, more than 70 high voltage transmission facilities (230 kV and above) were awarded totaling 31,800 km, with strong participation of both local and foreign investors and with an increasing number, over time, of competitors in the auctions.

a. Economic Regulation

Electricity transmission activities are regulated under concession contracts, which specify their economic regulation process. Transmission companies are entitled to receive the regulated monthly revenue that is set in the concession contracts, covering both capital and operating costs. This revenue is inflation-adjusted over time. For new concessions granted through auctions, revenue is set based on bidders' bids.

Due to this regulated revenue regime, transmission companies avoid facing demand or price risks. They do face some risks, however, since revenue is not adjusted over the life of the assets following changes in the cost of capital or in operating costs. Because generators can take these risks into account when bidding in the auction, this should not result in inefficient under-investment in transmission lines.

b. Responsibility for Building Projected Lines

Planned new transmission developments are allocated to different transmission companies by means of auctions (see Section 2 The Investment Process). Companies bid the annual revenue they are willing to accept for constructing and operating the asset during a pre-set useful life of 30 years. They then receive a concession contract for that period.

In the event that delays occur in construction, transmission companies are liable for penalties. These penalties include: no revenue until assets have been commissioned, and discounts to future rents spread over the first four months´ revenue. Concession contracts also provide for penalties in the case of delays in specific stages of the construction process.

Although private investors account for most of the new concession contracts granted, public infrastructure funding is still common, with the Brazilian Development Bank taking a very active role.

C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation

In Brazil, most allocation of transmission capacity is made jointly with the energy-procurement process for captive customers. Through the use of auctions, these procurement processes account for most new generation, and include implicit transmission access. Generators are provided with binding generation Transmission Use of System Charges for the next ten years, based on initial planning before the auction takes place, so they can internalize the transmission costs in their bids.

Connection of renewable plants is a greater challenge. In 2008, hundreds of renewable plants (small hydro and biomass), spread over 200,000 square kilometers, applied to participate in one of these auctions. Because new connections fall somewhere in between transmission and distribution responsibilities, it was not clear which entities owned responsibilities for planning, construction, and charging. Ultimately, a new approach was adopted and is still applied at this time.

This new approach is based on four principles:

- Generators, jointly with EPE, are in charge of transmission planning;
- They bear all the costs of connection assets, plus the transmission charges for the transmission assets;
- Transmission facilities are auctioned, even if they initially fall under the distribution company´s responsibility; and
- An iterative process decides the final network configuration and the cost for generators.

The first and last points are the most innovative. First, instead of individual connections to the grid, this approach planned for a layer of shared connection at different voltage levels. The generators pay for part of every line in relation to their usage.

The final point, the iterative process, is necessary because the final configuration of such connections—and the costs they would imply for the generators—depends on which generators are successful in the auction, and the bids depend on the connection costs. Generators are therefore provided with previous information so they can tune their bids. The generic process, as in the latest auctions, works this way:

- Generators receive information about preliminary planning, along with two sets of binding ten-year transmission charges depending on the final configuration of the connection network;
- After the auction, a more precise transmission planning process takes place. The details of such plans (but not estimates for charges) are handed to generators;
- Generators confirm if they still want to take a part of shared connections, and present a financial guarantee; and
- The final transmission assets are planned and auctioned. After that, the final transmission charges can be calculated.

2. Capacity Firmness and Congestion Management

Once the generator has been granted connection to the transmission system with a contractual capacity, it has the right to inject its specified amount of power into the grid. If the generator was constrained off due to a transmission system constraint, it has the right to receive a payment from the system for the reduction in the level of production, valued as the difference between the spot price and its price bid multiplied by the volume of energy.[11]

If the generator was constrained on, it has the right to receive a payment from the system for the additional energy produced. This payment is equal to the difference between the spot price and its price bid, multiplied by the volume of energy supplied.

D. Transmission Pricing

Generation *transmission use of system charges* are calculated as the long-run marginal cost of transmission expansion, adjusted to recover the 50% of the transmission total allowed revenue (the remaining 50% being recovered from load). These charges are nodal, so they vary depending on the generator's location, and are based on their contracted capacity (a fixed capacity charge), not their actual usage.

Transmission allowed revenue is the sum of the allowed revenues for all facilities. For most new assets this is the result of the auction, while ANEEL sets the revenue for old facilities and some reinforcements that have not been auctioned. There are also incentive schemes that offer some discounts on allowed revenue for increasing availability. Transmission companies do not receive any congestion rent for constraints in the transmission system.[12]

In recent auctions, ANEEL has offered fixed transmission tariffs to new power plants during the first years, with the aim of reducing generators´ risk by allowing them to

11 Chamber for the Commercialization of Electric Energy (2010b).

12 The application of the congestion rents are described in module 5 of the Market Rules. CCEE applies these amounts to fund a hydrological risk hedging mechanism and other specific contracts. See Chamber for the Commercialization of Electric Energy (2010a).

predict their transmission costs. Any difference between these pre-set tariffs and tariffs calculated later in time are absorbed by the load part of the transmission use of system charges.

E. Renewable Generation Operation

In Brazil, renewable power plants do not receive different treatment from conventional plants. The system operator's Network Procedures,[13] equivalent to a Grid Code, classifies power plants according to their impacts on the system and their ability to be centrally scheduled and dispatched.[14] For operational purposes, there are three types of plants:

- **Type I:** plants connected to the main grid or with a significant impact in the system.
- **Type II:** Non-type I plants greater than 30 MW in the case of thermal and hydro plants (or below 30 MW in some cases), 20 MW in the case of wind farms.
- **Type III:** remaining plants.

According to this classification, power plants have different roles in the operation of the power system. Type I plants have centralized scheduling and dispatch, while type II plants have centralized scheduling but are not dispatched: they do not need to respond to real-time orders by the system operator. While thermal renewable power plants, such as biomass plants, are equivalent to other thermal plants and can be classified as type I, wind farms are classified as type II or type III and do not actively participate in system operation.

Before 9 a.m. each day, wind farms and small hydro plants must provide a half-hourly generation schedule of their plants for the following day to the system operator, so that the daily schedule of the generating plants can be prepared.[15, 16]

13 The Network Procedures (*Procedimentos de Rede*) can be found at http://extranet.ons.org.br/operacao/prdocme.nsf/principalPRedeweb?openframeset.

14 National Electric System Operator (2013c). ONS, *Procedimentos de Rede*, sub-module 26.2, Criteria for Classification of the Power Plant's Operational Mode.

15 National Electric System Operator (2013b). ONS, Procedimentos de Rede, sub-module 8.1, Daily Schedule of the Electric Operation, art. 5.2 and 8.

16 This generation schedule is not a commitment to produce, but an information requirement imposed to the generators, and; therefore there is no imbalance charge if the final production is different. Infringement of this obligation to provide information may lead to penalties, but there are no imbalance charges for renewable generators in the CCEE market.

II. China

A. Electricity System Overview

1. Regulatory Institutions

The passing of the Electric Power Law in 1996 shaped China's power sector by setting out various provisions to promote the development of the industry and improve the assignment and protection of legal rights for consumers, investors, and managers. The Electric Power Law also brought major developments in the regulation of China´s electricity generation, distribution, and consumption.

China's electricity industry has become increasingly liberalized and competitive since 2002, mainly as a consequence of the government´s structural reforms and the country´s entry into the World Trade Organization. Before 2002 the market was dominated by vertically integrated utilities.

Major changes to the Chinese electricity market have included the following:

- In 1994, responsibility for the supply of electricity was transferred from provincial-level governments to independent corporations operating outside the government administrative framework.
- Independent power producers are now encouraged to finance projects using non-state capital, and they receive attractive rates of return on capital for such approaches.
- Six provincial or municipal electricity markets were established in 2004, and are operated by the electricity grid company that has jurisdiction in each respective region.
- Generation and transmission were unbundled and reformed in 2002, and a regulatory commission was formed.

Energy-related issues are addressed and administered by a variety of organizations, in particular the National Development and Reform Commission, the China Ministry of Commerce, and the National Energy Administration.

The National Energy Commission was founded in 2010 and is responsible for developing the country´s national energy development plan, considering major energy issues, addressing energy security issues, and coordinating domestic energy development and cooperation at the international level.

The Chinese State Electricity Regulatory Commission was established in 2002 as the first Chinese electric power industry regulator. The Commission was merged into the National Energy Administration (part of NDRC) in 2013.

China´s use of electricity has grown at an unprecedented rate in recent decades, fueling the country´s consistent and very rapid rate of economic development. The country is now regarded as the world´s largest user of electricity, having recently matched and then overtaken total electricity use in the United States. In some respects, the major growth in China´s electricity generation and demand has meant the country is now something of a victim of its own success: major sustained investments in infrastructure will be required to meet future electricity demand, which is forecast to continue growing significantly.

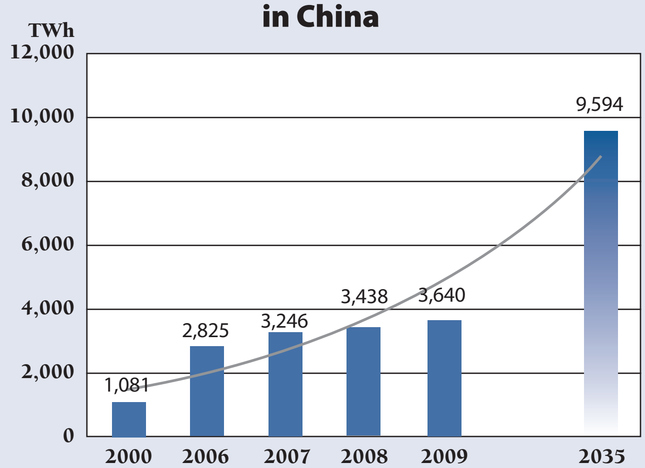
In the coming decade, China´s electricity industry is expected to maintain its high levels of growth and expansion, equivalent to a very significant level of capital investment. As shown in Figure 2, the IEA estimates that China´s electricity demand in 2035 will be around three times that of 2011 levels.

The Chinese government has stated that the development of a unified and connected national-level electricity transmission grid is a key economic priority for the country. This aim is related to the objectives of improving the efficiency of the country´s power system and addressing the risk of electricity blackouts. The transmission grid will also allow for the use of significant hydroelectric resources.

In terms of generation, China relies very heavily on coal-fired generation capacity, which currently provides around four-fifths of all generated electricity. Hydropower

Figure 2

Recent and Projected Electricity Demand in China



Source: IEA (2010).

is also a significant contributor to total generated electricity, with nuclear and wind power making a small but growing contribution. It is understood at present that China has approximately 900 GW of total generation capacity.

2. Electricity System Architecture

Electricity generation was reorganized in 2002 into five group companies, which incorporated independent power producers and these publicly listed companies:

- China Datang Corporation,
- China Guodian Corporation,
- China Huadian Group,
- China Huaneng Group, and
- China Power Investment Corporation.

These companies maintain similar asset portfolios, and can only have a maximum of 20% market share. Each company competes with other local generation companies, other small generation companies, and independent power producers backed by foreign investment.

Responsibility for China´s electricity transmission grid is shared between two companies:

- The China Southern Power Grid Company, which covers the south China grid, including five provinces in the south and southwest of the country—Guangdong, Guangxi, Yunnan, Guizhou and Hainan. The company is headquartered in Guangzhou; and
- The State Grid Corporation of China, which covers the remaining five regional grids. It is headquartered in Beijing and is the largest transmission company in the world.

These two companies are also responsible for the majority of electricity sold in the distribution and retail sector, equivalent to 80% in 2005.[17] Within its particular area, each retailer is also the only seller; it has a total monopoly within its own area.

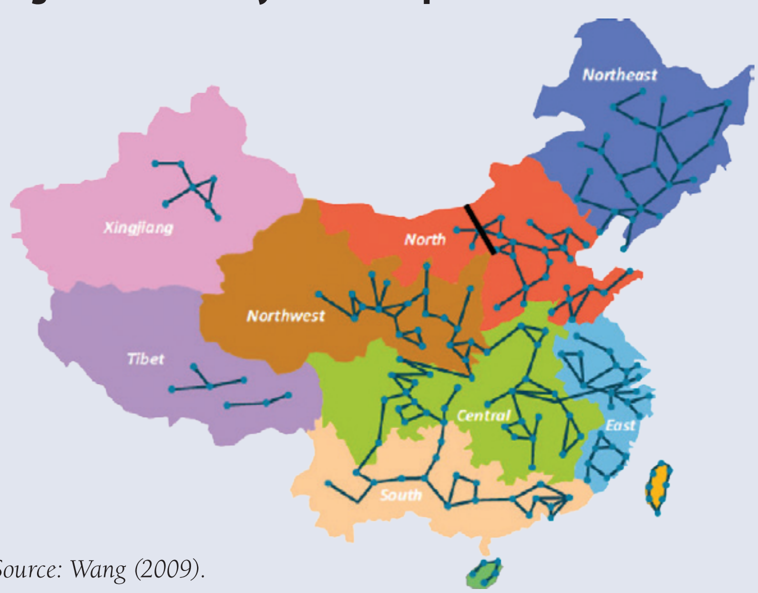
China´s electricity grids are fragmented. The system is grouped into six clusters of power-grid assets (Figure 3), with each group operating independently. The State Grid Corporation of China is responsible for managing four of these clusters (the northeast, northwest, central and eastern grids) as well as a portion of the north grid. In total, this jurisdiction spans 26 provinces. The southern grid is managed by the China Southern Power Grid Company.

Trade of electricity across regional boundaries is low: in 2009, it accounted for only 4% of total Chinese electricity production.[18]

An electricity market is operated within each regional grid. Within the regional grids, more than 80% of electricity demand is based on long-term bilateral

Figure 3

Regional Electricity Grid Groups and Clusters in 2009



Source: Wang (2009).

17 Zhang (2006).

18 Wang (2009).

contracts; the remainder is based on trades within the monthly and day-ahead markets. These monthly and day-ahead markets are operated by the designated Electricity Dispatch and Trading Center of each region. Thus, system operation and market operation are managed by the same company. Each Electricity Dispatch and Trading Center is typically responsible for generation scheduling, congestion management, and contingency analysis. These organizations are also responsible for settlement and ancillary services in the regional electricity markets. The first regional-level grids to establish their markets were those of northeast and east China in 2004.

3. Renewable Generation Policy and Implementation Mechanisms

The generation of electricity from renewable energy technologies has been declared a key priority for China´s energy future and economic strategy. China has become the world´s largest provider of renewable energy support funding through the use of state funds. In 2009, the country invested around $35 billion in renewable generation.

The government´s ambitions to make renewable energy a significant contributor to the country´s future electricity supply has been emphasized in the China Renewable Energy Law of 2005, in China´s twelfth five-year plan, and through incentive policies. The main policies related to renewable energy in China have focused on promoting investment, standardizing products, reducing environmental impacts, and regulating the price of renewable-generated electricity.

China´s Renewable Energy Law (2005) provides a feed-in tariff for some technologies, and explains the standard procedures and requirements of the grid feed-in tariff for generators. The law also sets out cost-sharing mechanisms for supporting the tariff, and creates various financing mechanisms and support schemes for the rural use of renewable energy. In addition, it sets out the basis for a long-term development plan, research and development, technology standards, geographic resource surveys, and requirements to integrate solar water-heating technologies in new buildings.

Various future targets for renewable energy generation have been discussed. The Chinese government has drafted plans to install 500 GW of grid-connected generation capacity by 2020. That would equal almost one third of the country´s projected 1.600 GW of generation capacity by that time—but this is currently a proposal. The target in place at present is 362 GW of grid-connected generation capacity.

Table 4 provides a summary of the electricity generation targets in China, both the current targets and the more ambitious proposed target.

Table 4

Renewable Energy Generation Capacity And Capacity Targets

Generation Technology	2006 Actual	2009 Actual	2020 Current Target	2020 Proposed Target
Hydro power	130 GW	197 GW	300 GW	300 GW
Wind power	2.6 GW	25.8 GW	30 GW	150 GW
Biomass power	2 GW	3.2 GW	30 GW	30 GW
Solar PV	0.08 GW	0.4 GW	1.8 GW	20 GW

Source: Martino & Junfeng (2010).

China now generates just under one-fifth of its total electricity from renewable energy resources. The vast majority of this generation is from established hydropower. In 2009, the country had a total installed hydropower generation capacity of 172 GW, generating around 16% of China´s total electricity generation.

There is considerable scope for expanding the country's installed hydropower generation capacity: China is understood to be using only around one quarter of the available hydro resource. The country´s National Development and Reform Commission has set the target of 300 GW of generation capacity to be installed by 2020. Hydropower has great appeal in China, due to the government´s strong preference for achieving and maintaining energy independence.

China also has significant resources in wind energy, particularly in offshore locations. In 2009, the country became the world´s largest manufacturer of wind turbines, setting the basis for a strong future in exporting wind turbines and supplying future domestic projects. China aims to have 100 GW of wind power installed by 2020, and has already met—and surpassed—its interim capacity targets for wind.

The currently regulatory framework for transmission appears at a first glance to be very advantageous for renewable energy generators. In particular, renewable energy generators do not pay for transmission connection. The planning process for transmission seems, however, to constrain the connection of these developments.

4. Transmission Network Overview

The Chinese government has the long-term goal of integrating the former 12 regional-level transmission grids into three much larger power grids, which would continue to be operated by the two transmission grid companies, China Southern Power Grid Company Limited and the State Grid Corporation of China. This is part of the government´s strategy of achieving a fully integrated transmission grid throughout the country by 2020.[19]

Both of the just-mentioned companies that share responsibility for China´s electricity transmission grid are regulated monopolies. The National Development and Reform Commission (NDRC), a public body responsible for formulating and implementing plans for national economic and social development, retains responsibility for regulating and controlling electricity transmission prices.

Electricity transmission grids are operated and managed at different geographic scales. Cross- or inter-regional grids are operated by the China Southern Power Grid Company Limited and the State Grid Corporation of China. Trans-province transmissions are operated and owned by regional-level grid companies, which are sub-companies of those two major transmission companies.[20]

Cross-regional and cross-province grids do not connect directly to electricity end-users. Their transmission costs are therefore passed to the companies operating province-level electricity grids, which recover the costs of transmission from the customers within their territory.

Major investment and expansion is planned for the transmission system to meet expected demand growth. The country´s electricity generation is geographically concentrated in the northwest, where significant reserves of coal, the dominant generation fuel, are located. This electricity must be transmitted to the south and east (coastal) areas of the country, where demand is highest. Major infrastructure investments are underway for this purpose.

B. Transmission Planning and Investment Processes

1. The Planning Process

a. Responsibility for Planning

The development of the Chinese transmission network is regulated and, to a large extent, driven by government pressure to both expand the transmission capacity and integrate regional grids. The country's two main transmission companies have formal responsibilities for planning transmission expansion projects.

Traditionally, the level of stakeholder engagement in China's transmission planning process has perhaps been lower, in terms of formal obligations and extent, than in many other countries. This is a consequence of China´s former centralized approach to planning and lack of democratic process frameworks. There are, however, some indications that engagement with stakeholders during transmission-network infrastructure planning is increasingly being recognized as an important part of the process. This is particularly true for planning to integrate renewable generation capacity in transmission infrastructure development.

As China raises its level of installed renewable-energy generation capacity, there is an increasing requirement to ensure both that renewable generation capacity can be successfully integrated into the transmission grid (connection), and that renewable electricity can be dispatched (reduced use of curtailment). To meet this objective, the IEA reported in 2011 that China is taking steps to ensure that stakeholders are given the "correct signals" within its technical standards-setting and policy frameworks.[21]

For instance, efforts are being made to encourage renewable energy project developers to invest in technologies whose technical characteristics allow them to be incorporated into the transmission grid system. This has not always been the case, and some project developers have invested in technologies that are not compatible with the grid, usually because those are the cheapest technologies on the market. That has resulted in situations where otherwise complete generation projects remain unconnected to the grid.

19 KPMG (2009).

20 Li et al. (2010).

21 Cheung (2011).

B. Planning Characteristics

The World Resources Institute (WRI) reported in 2011 that, despite the plans of the two Chinese transmission grid companies to develop grid infrastructure, the investments that have been made to date—most notably, in connecting wind energy generation in the northwest into the transmission grid—have been "plagued by poor planning and coordination."[22]

The National Development and Reform Commission maintains many of the responsibilities in planning, but the WRI concludes that it "has failed to ensure that generation and transmission planning are done in close cooperation." These are some of the WRI's key concerns related to China´s current transmission planning process:

- Considerable difficulties have been encountered during the supposedly easy task of "coordinating the transmission extension with the various phases of individual wind farm's build-out or ensuring the layout of a farm is conducive to transmission;"[23] and
- Grid companies appear to be preparing development plans based on wind energy generation targets that "are far lower than installation trends indicate."[24]

A further concern for transmission planning is that China, until recently, did not have standardized grid connection codes for wind energy installations. Its grid companies have reported that the installed wind-energy generation base is characterized by "serious technical constraints" related to grid connection codes. A standoff has ensued. Generators claim that transmission authorities reference inappropriate grid connection codes to evade their transmission connection responsibilities, while transmission authorities claim that generators entered the market unprepared and without a thought for connection codes. A solution appears to be on the horizon: in 2010, mandatory nationwide technical standards were drafted.

The State Grid Corporation of China´s plans to invest in ultra-high voltage electricity transmission capacity were announced in January 2011. Notably, the company did not provide a large level of detail regarding the project proposed, other than to state that it is:

- Planning a pilot project for a 1,100 kV DC line within the next five years, and
- It aims to complete key research into technology questions within a year and a half, and equipment manufacturing within two years.

The State Grid Corporation has earmarked around $75 billion to construct 40,000km of ultra-high voltage lines by 2015.[25]

Other major electricity transmission line developments have recently been completed, are under construction, or in the planning stages, including:

- Yunan: Guangdong DC line, in operation since June 2009;
- Xiang Jiaba: Shanghai DC line, in operation since July 2010;
- Sichuan: southern Jiangsu Province DC line, currently under construction;
- Jinping: Sunan DC line, currently under construction;
- Shanxi: Hubei AC line, in operation since January 2009;
- Sichuan: Shanghai AC line, under construction;
- Xi´men: Nanjing AC line, under planning; and
- Western Inner Mongolia: Shangdong via Beijing AC line, under planning.

The limited nature of the available information about proposed projects may be fairly typical, according to some industry players with experience at operating in the Chinese market. The country has historically used a centralized approach to infrastructure planning, with limited stakeholder engagement during project formation and a relatively low level of information-provision within the public domain (compared, for example, to Europe). On the other hand, many analysts and commentators have noted that the Chinese government has been congratulated for being fast-acting: it has a proven capability, in some sectors of China´s economy and industry, of being able to implement policies and plans relatively quickly.[26]

C. Transmission Development Drivers

The main driver of planned projects appears to be the need to introduce transmission capacity that will facilitate meeting the significantly increased forecast for future electricity demand in China. More specifically, a major driver of transmission planning decisions is the need to

22 Tawney, *et al*. (2011).

23 Jiang (2009).

24 Tawney, *et al.* (2011). Global Wind Energy Council (2010).

25 Clean Biz Asia.com (2011).

26 Schuman (2010).

develop an infrastructure that can allow for the transfer of very large volumes of power across large sections the country—i.e., from one geographic extreme to another.

Generation is highly concentrated in the northern and western regions, while the highest demand is in the southern and eastern regions, which include China's coastal areas of high population density and strong industry demand. This has shaped the requirement to develop major transmission capacity that runs both from the north to south, and from west to east. China is rapidly investigating the feasibility of improving the efficiency of electricity transmission over long distances; it aims to invest in long-distance and ultra-high voltage (above 800 kV) direct current transmission capacity. China is, in fact, the only country in the world seeking to construct ultra-high voltage transmission capacity.

Climate change mitigation, and the goal of greenhouse gas emissions reduction and limitation, also seems to be an important driver of transmission projects. The government has stated its ambition to build a comprehensive and ground-breaking smart grid within the country that will include technologies and applications related to both distribution and transmission systems.[27] Key components of China´s smart grid strategy include developing demand management (through real-time monitoring and control) systems and using long-distance DC transmission technologies, which have relatively high transmission efficiencies. On the other hand, China´s proposed development of ultra-high voltage direct current transmission lines is progressing with very little concession to concerns about environmental pollution.

China´s renewable energy resources, wind in particular, are also concentrated in its northern region. However, the country´s significant expansion in installed wind energy generation capacity, in the north, has not yet translated into a corresponding increase in the level of renewable generation electricity on its grid, for these reasons:

- Connection standards insufficiently describe the process to be followed by generators;
- Wind farm planning and transmission planning are not coordinated;
- The limited financial resources of grid operators means that they cannot purchase electricity generated by renewable energy technologies; and
- Electricity dispatch processes are inflexible.[28]

2. The Investment Process

A. Economic Regulation

The two transmission companies, the China Southern Power Grid Company and the State Grid Corporation of China, have overall responsibility for the economic regulation of transmission capacity investment. Within its jurisdiction, each company is responsible for the recovery of costs for transmission asset investment, and for transmission system management, construction, transformation, and electricity distribution. They recover transmission costs from the companies that operate province-level transmission grids, and those collect in turn from the users. The overall level of cost recovery is typically set by a combination of both electricity transmission capacity and quantity tariffs.

Different levels of cost recovery are levied and achieved in different regions. Tariff levels are set in accordance with each particular region´s level of economic development, as there is considerable variation between regions.

B. Responsibility for Building Projected Lines

The China Southern Power Grid Company and the State Grid Corporation of China share overall responsibility for ensuring that the necessary electricity transmission capacity is built. However, given the sheer scale of investment that has been required in recent years and will be required in the near future, the Chinese government has been very keen to ensure that transmission, and other power sector, investments use decreasing levels of state funding.

Foreign investment in China´s power system as a whole has been observed during recent decades. But according to an analysis of the insights and views of various industry players by KPMG, a financial consulting firm, Chinese laws related to foreign direct investment ensure that foreign parties do not have the opportunity to invest in, or own, power transmission (or distribution) assets.[29] This is a key part of the government´s plan to ensure that "key strategic assets remain under state control."[30] The same analysis also

27 Schwartz & Hodum (2008).

28 Tawney, *et al.* (2011).

29 KPMG (2009).

30 KPMG (2009).

concluded that there "will be no opportunities for foreign investment (in transmission and distribution infrastructure) in at least the next ten years."

c. Administrative Permits

The two transmission companies are both for-profit entities, and share control of issuing administrative permits for transmission asset development. These companies are closely affiliated with the Chinese government and other regional transmission system organizations.

The main difficulty in bringing projects to fruition is accessing the necessary capital to finance investment and development. There is clear intention on behalf of the Chinese central government to ensure that projects use private finance sources, moving away from state funding. Projects also encounter some objections on the grounds of environmental concerns or local population objections.

In general terms, however, many industry players and international observers have noted that the Chinese system for planning and development throughout the country tends to result in developments being initiated quickly. This is in contrast, for example, to the planning difficulties and resulting delays within the European Union and the United States. Coupled with this, there is little or no constraint on the available workforce to develop projects, and many of the required (raw and finished) materials for projects are sourced and developed in China.

C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation

There is some ambiguity surrounding the allocation procedures for connection capacity—in particular, around the decision-making processes for connecting generation capacity to the transmission grid.

An analysis of the available information suggests that decisions on whether to connect generation capacity to the Chinese transmission network are taken on a unilateral basis by the transmission companies, and are largely based on the objective of connecting large-scale, firm generation. A review of the State Grid Corporation's main website, for example, provides no information regarding the procedures, decision-making process, and obligations related to transmission system connections. Instead, the site provides descriptions of recently commenced or completed transmission line projects throughout the country, generally without detailing the process that was followed before project construction began).

Cost appears to play a considerable role in capacity connection decisions. In particular, wind energy output variability does not fit well with the inflexibility of electricity dispatch in China, and that may serve as a disincentive for grid companies to plan transmission capacity projects that connect renewable generation projects into the grid. Transmission owners/developers with limited financial resources believe they simply cannot afford to invest in transmission that connects renewable generation projects to grids, and prefer the lower cost of connecting firm load (i.e. coal-fired generation).

A key concern is the heavy concentration of wind farms being constructed in the north and northwest of the country, particularly in Mongolia, as shown in Figure 4. These are essentially considered to be too far from the areas of greatest electricity demand to warrant transmission connection investments.

The process for receiving a grid connection is also affected by the lack of planning coordination between generation projects and transmission projects. For renewable energy generation projects in particular, the two planning processes are not coordinated, which often leaves renewable capacity unconnected. This overall situation is not ideal from the perspective of renewable energy generators, who could reasonably claim to be discriminated against within the transmission connection decision-making process.

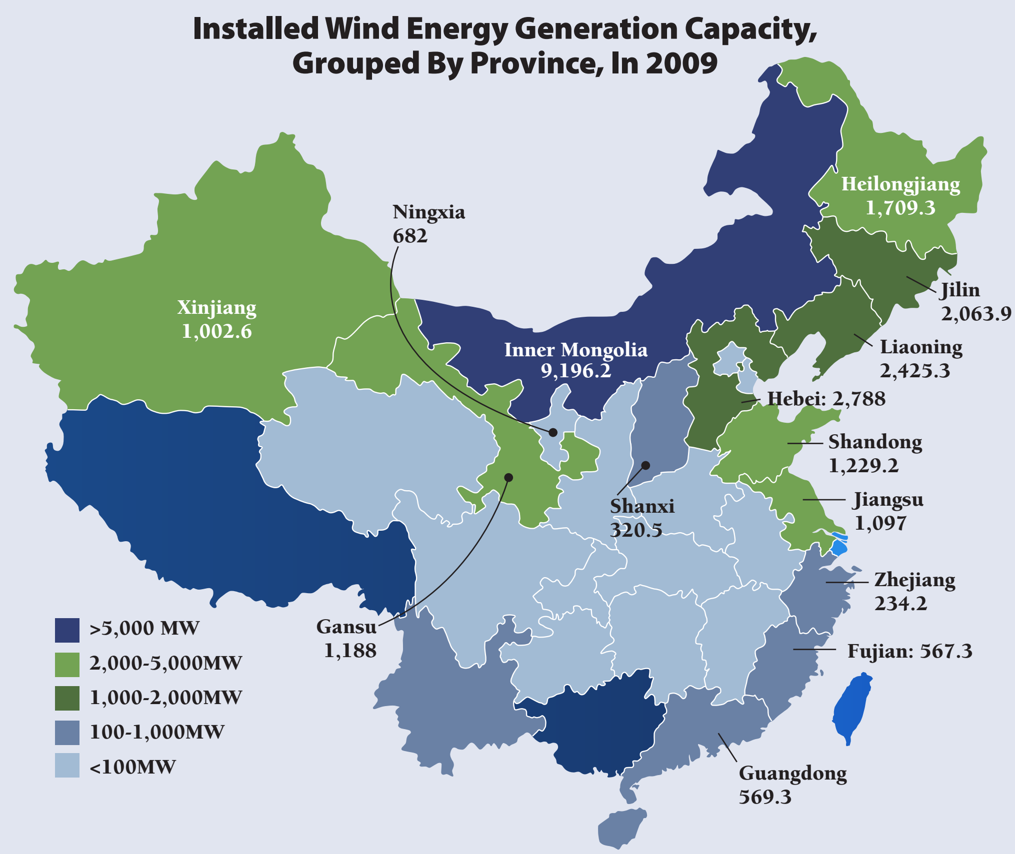
Renewable energy generators could improve their prospects for connection by taking steps to improve coordination of planning with transmission asset developers. Beyond this, however, it seems that the China Southern Power Grid Company and the State Power Grid Company have the greater influence over ensuring that renewable energy projects have a higher chance of obtaining a transmission grid connection, by optimizing where to locate transmission assets.

2. Capacity Firmness and Congestion Management

In theory, renewable generation projects have priority of dispatch. China´s Renewable Energy Law (2005) established the obligation on transmission grid companies to purchase all renewable energy generated within their operating region. Renewable energy generation technologies should be at the top of the generation scheduling merit order.

The reality is different. When congestion on the transmission grid is high, the IEA reports that renewable energy generators—particularly wind energy generators—receive especially harsh treatment. Even when existing wind generation capacity is grid-connected, the first choice of transmission system operators is typically to curtail wind power. As a result, wind energy generators operate over a lower total time period than they feasibly could, which can make wind projects economically unviable.[31] In 2009, nearly 15 TWh—equivalent to 12% of the total wind power generated—was curtailed.[32]

Figure 4



Source: China Wind Energy Association (2010)

In resolving congestion issues, regional grid companies typically employ a strategy with three main points for treating electricity supplied from renewable-energy grid-connected generators:

(1) Renewable-generated electricity is fully integrated if possible;

(2) If this is not possible, the surplus is curtailed; and

(3) The surplus energy is transferred to a neighboring grid. (A severe lack of inter-regional grid connections means, however, that this last measure is rarely undertaken in reality.)

The IEA reported in 2011 that a variety of factors appear to indicate that "China is taking steps to promote a new approach in which greater effort is made to accommodate and transmit more renewable electricity," as opposed to immediately taking the curtailment option. Specifically, the IEA drew attention to:

- Recent expansions of cross-regional power transmission capacity;
- The Chinese system increasingly bringing greater flexibility into its generation portfolio;
- Stronger promotion of more interactive demand response; and

31 Cheung (2011).

32 Even though grid companies are legally obliged to treat wind power as must-run generation, in many instances other generation types are treated as priority, notably coal-fired generation. This is due to the grid companies´ obligation to honour long-term and fixed-quantity delivery contracts with other generation plants (e.g. coal, CHP). Grid companies require official approval from local government in order to break these contracts, and obtaining this approval may be a time-consuming process.

- Policy-making and technical standards-setting that provide the correct signals to stakeholders.

To improve cross-regional electricity trading and thereby reduce major congestion risks, the State Grid Corporation of China is also planning to further strengthen and reinforce the interconnections of its grid jurisdictions in the south, east, and center of the country in the near future.

There are further signs that the Chinese approach to congestion management is changing, and moving toward a system that is more favorable to renewable energy generation. The Chinese National Development and Reform Council launched a trial process in 2007 that divided and prioritized the operation of power generation technologies in five provinces as follows:

- Wind, solar, ocean, and hydroelectric,
- Adjustable hydro, biomass, geothermal, and solid waste,
- Nuclear,
- Coal-fired combined heat and power units,
- Natural gas and coal-gasification combined cycle,
- Other coal-fired units, including cogeneration without heat loads, and
- Oil-based generation units.

There is no official report setting out how the trial finished and what were its conclusions. The IEA understands, however, that the trial order described above reduces coal-plant load factors, and thereby leads eventually to a reduction in their efficiency, causing a relative increase in the use of coal per unit output of electricity. Generation utilities' revenues would also be affected.[33]

D. Transmission Pricing

Renewable energy generators are not required to pay for the transmission infrastructure required to connect their generation capacity to load centers. Instead, transmission grid companies are required to:

- Directly cover the costs of transmission expansion to connect a renewable energy generator with the transmission grid; and
- Connect all renewable energy generation within their geographic jurisdiction that meets the minimum requirements (although these requirements have not yet been specified).[34]

Grid companies´ costs in connecting renewable energy generators to the transmission grid are partially reimbursed through the receipt of a government subsidy payment, which is set by the distance from the renewable generation site to the main grid infrastructure.

This incentive is part of China´s implementation of its Renewable Energy Law. The central government established a Renewable Energy Fund, one function of which is to subsidize grid companies for the costs of integrating renewable energy that they are unable to recover from electricity to customers.[35] This fund is supported through dedicated government funds and a surcharge on all electric consumers' bills. However, as discussed earlier, this does not seem to be sufficient to incentivize development.

The costs incurred by transmission system operators in transmitting electricity from generators to load centers are recovered through the use of two tariff types: capacity tariffs and quantity (volume) tariffs. The cost of transmission is collected by provincial-level transmission companies. The tariff levels are set by the National Development and Reform Commission, based on the recommendations of local pricing bureaus, which are answerable to local officials.[36]

E. Renewable Generation Operation

1. Generation Forecasting

Electricity generation forecasting is usually the responsibility of the various grid system companies, which operate on provincial and regional levels and are owned by the two major grid companies. These grid system companies operate the Electricity Dispatch and Trading Centers of different geographic jurisdictions. Along with developing generation schedules for the electricity market in question, including facilitating trading with generators in the monthly and day-ahead markets, the Electricity Dispatch and Trading Center is responsible for contingency analysis and congestion management.[37]

33 Cheung (2011).

34 Tawney et al (2011).

35 Tawney et al (2011).

36 Rosen & Houser (2008).

37 Wu & Fu (2005).

In March 2010, the Chinese National Energy Administration began a series of consultations to gather information and viewpoints on its draft "Standards on Wind Farm Connection." The document is specifically designed to develop a more robust and comprehensive approach to planning and operations for wind farm developments—by far the most significant renewable energy technology in China after hydropower, which is well-established. These draft standards set out the National Energy Administration´s proposed means of developing a wind forecasting system.

The proposed forecasting system is designed to improve the use of wind, in line with the government´s proposed strategy to prioritize wind energy above all other generation types (the government´s five-province trial is described earlier in this chapter). The draft standards propose a system that provides forecasts 48 hours ahead, and shorter-term, or more "real time," forecasts at a frequency of 15 minutes to four hours.

This system would be highly useful to system operators, allowing them to significantly lower the various costs associated with integrating renewable energy generation capacity into the transmission system through more efficient scheduling of ancillary units.

2. Participation in Balancing Services

China's regional-level electricity transmission grid companies are fully responsible for the overall provision of balancing services to the grid. These companies own and operate up to a maximum of 20% of the generation capacity on the grid within their jurisdiction; this allows them to ensure that the grid operates reliably.[38] The grid companies use their own generation capacity for frequency modulation (i.e., grid system frequency control) and peak-load following services.[39, 40]

The Chinese government has made a compelling case for extending the country's electricity (generation and transmission) market and balancing areas. At present, because of under-developed interconnection transmission capacity, only 4% of total generated electricity is traded between regions. Many industry analysts, transmission system operators, and, importantly, the government—which has the power to mandate change—have highlighted the benefits that would follow from widening the market and balancing areas (i.e., improving interconnections). The ability to smooth variable renewable generation, which is of particular relevance in this analysis, would be improved dramatically. Given the likely future obligation on system operators to ensure that renewable generation is prioritized over other generation types in the merit order, together with the national Renewable Portfolio Standard targets, a major extension of the market and balancing area appears to be crucial to China´s future electricity sector.

3. Imbalance Settlement

The grid companies operating the transmission grids at provincial and regional levels are responsible for generation scheduling. In addition, the grid company of the region or province in question has responsibility for managing settlement and ancillary services, as part of its operation of the monthly and day-ahead markets through the Electricity Dispatch and Trading Centers. Settlement and ancillary services are provided through both self-provision and purchase mechanisms.[41]

38 Wu & Fu (2005).

39 A *peak-load following power plant* is a power plant that adjusts its power output in accordance with demand for electricity, which varies throughout the course of a day.

40 Wu & Fu (2005).

41 Wu & Fu (2005).

III. India

A. Electricity System Overview

1. Regulatory Institutions

At the federal level in India, the main regulatory powers are shared between the Ministry of Power and the independent regulator, the Central Electricity Regulatory Commission. Some other institutions are also relevant to the electricity sector.

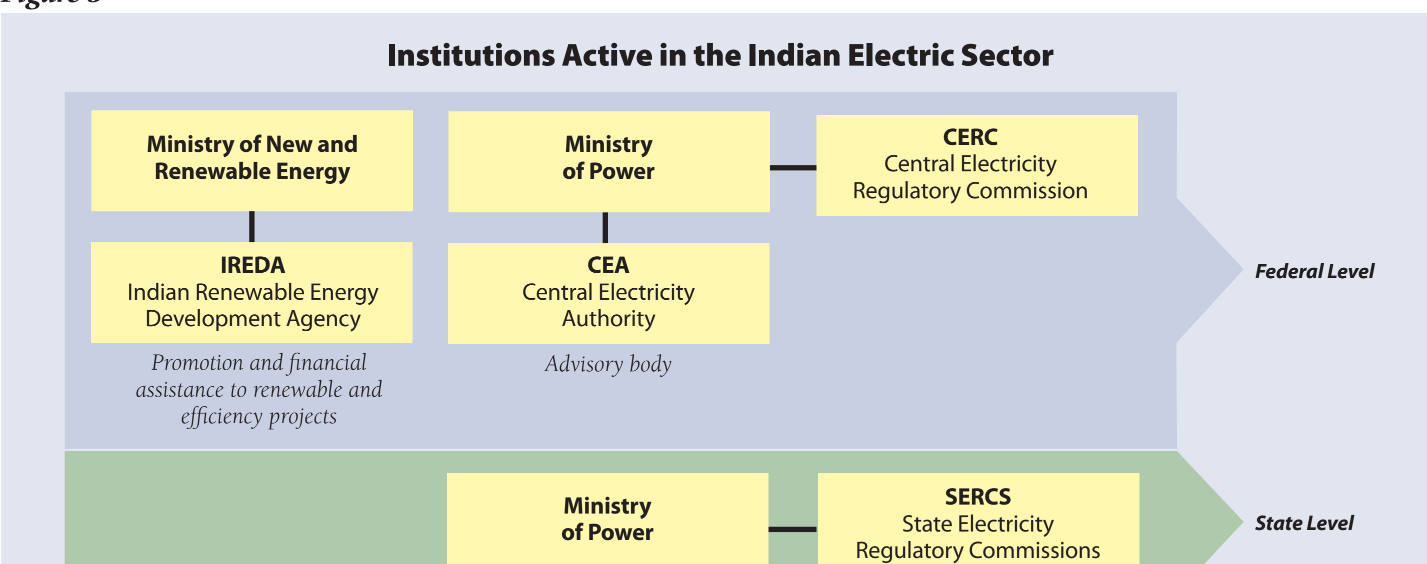
The Ministry of Power is responsible for the administration and enactment of legislation, for instance the Electricity Act of 2003. It is also in charge of overseeing electricity production and infrastructure development, and it acts as a liaison between the central government and state electricity operations, as well as with the private sector. Another federal agency, the Ministry of New and Renewable Energy (MNRE), deals specifically with renewable energy issues.

The Central Electricity Regulatory Commission (CERC), established in 1998, is a statutory body under the Electricity Act. CERC has both an advisory and a regulatory mandate on interstate issues such as setting tariffs, regulating transmission, licenses, dispute arbitrage, and formulation of National Electricity Policy and Tariff Policy. Apart from the federal CERC, each state has a State Electricity Regulatory Commission, with similar functions within its jurisdiction.

The Central Electricity Authority (CEA) is a technical and economic advisory body to the Ministry of Power, acting as an "attached office" of the Ministry. The CEA is responsible for advising the central government on matters relating to the National Electricity Policy, for formulating short-term and prospective plans for the development of the electricity system, for the technical coordination and supervision of programs, for electricity system planning, and for other statutory functions.

Under the administrative control of the Ministry of New and Renewable Energy, the Indian Renewable Energy Development Agency Limited (IREDA) is a public limited government company established to promote, develop, and extend financial assistance for renewable energy and energy efficiency/conservation projects.

Figure 5



Source: Mercados.

India's electricity system is governed by the Electricity Act. This law is the basis for several policy documents, such as Rural Electrification Policy and the National Electricity Policy, along with some subordinate legislation, rules, statutory orders, resolutions, and clarifications. CERC regulatory acts are approved by means of orders and regulations. Finally, transmission, distribution, and trading activities require a license.[42]

2. Electricity System Architecture

The Electricity Act introduced some features of a common market design aimed at introducing and encouraging liberalization and competition. These features include open access to the transmission and distribution network, identification of power trading as a distinct activity, the liberal definition of a captive generating plant, and provision for supply in rural areas. There is, however, still a heterogeneous degree of liberalization between the different states in India, making it difficult to paint a general picture of the country's electricity sector.

Overall, the country is divided into different control areas, each under a system operator responsible for keeping the system balanced within its area. Regional and national exchanges are coordinated by several regional and one national system operator, the Regional and National Load Dispatch Centers. The central government owns a nationwide transmission company, PowerGrid, which engages in interstate transmission and is the owner of the National and Regional Load Dispatch Centers. PowerGrid acts as the central transmission utility; this term describes its assigned institutional functions. Some power exchanges have been privately set up, to ease power trading and complement bilateral over-the-counter trading.[43]

States retain the power to determine the electricity system within their territory. Most have restructured their electricity sector, setting up different companies for generation, transmission, and distribution activities (and eventually privatizing them). In other states, integrated State Electricity Boards are in charge of the whole supply system. Currently, 69% of the country's generating capacity is owned by public companies (29.73% belongs to the central government through public sector undertakings, and 40.77% to state companies). Only 29.49% of the capacity is owned by private companies.[44]

3. Renewable Generation Policy and Implementation Mechanisms

Policies promoting renewables have been pushed at the federal level; India was the first country to set up a specific ministry for renewable energy development, the MNRE. Final implementation of most of the promotion policies depends, however, on the individual State Electricity Regulatory Commissions, and this has led to varying levels of promotion.

Since 2003, the Electricity Act has provided for the approval of renewable portfolio standards (RPS) by the different State Electricity Regulatory Commissions, and in 2005 the National Electricity Policy directed these state commissions to approve appropriate tariffs to incentivize renewable energy generation. Then in 2006, the Tariff Policy reestablished both mandates, but with similar lack of success. With no deadlines, minimum requirements, or penalties for noncompliance, the State Electricity Regulatory Commissions´ levels of commitment to renewable energy have been extremely variable.

In 2008, the National Action Plan on Climate Change suggested that:

- It is necessary to introduce a minimum renewable purchase standard (RPS[45]) that should increase over time, starting with a minimum 5% (excluding hydro plants with storage capacity and human food-fueled plants);
- The central government should establish requirements for verification mechanisms; and
- A tradeable certificate mechanism should be set up to enable utilities to meet their renewable requirements. This last suggestion became a reality in 2010, with the Central Electricity Regulatory Authority's renewable energy certificate regulation.[46]

42 Parliament of India (Electricity Act 2003), Part IV.

43 See, for instance, the Indian Energy Exchange (www.iexindia.com) and Power Exchange India Limited (www.powerexindia.com).

44 Ministry of Power (2013).

45 This acronym is the same as that for Renewable Portfolio Standard.

46 Central Energy Regulatory Commission (2010b). See the CERC Terms and Conditions for Recognition and Issuance of Renewable Energy Certificate for Renewable Energy Generation Regulations, 2010.

Table 5

India Generation Capacity Balance as of July 2011							
In MW	**Northern**	**Western**	**Southern**	**Eastern**	**N. Eastern**	**Islands**	**Total**
Coal	24,233	32,606	20,983	20,523	60	0	**98,403**
Gas	4,135	7,904	4,691	190	787	0	**17,706**
Diesel	13	17	939	17	143	70	**1,200**
Nuclear	1,620	1,840	1,320	0	0	0	**4,780**
Hydro	14,323	7,448	11,338	3,882	1,116	0	**38,106**
Renewable	3,510	5,938	10,129	356	224	6	**20,162**
Total	**47,833**	**55,752**	**49,400**	**24,969**	**2,329**	**76**	**180,358**

Source: Central Electricity Authority (2011)

At present, promotion of renewable energy is based on a combination of different instruments:

- Fiscal incentives: accelerated depreciation, concessional customs duty on specified items, excise duty exemption, sales tax exemption, income tax exemption for 10 years, etc.
- Financial support: the Indian Renewable Energy Development Agency (IREDA) provides loans for new projects.
- Renewable portfolio standards, with tradeable certificates for solar and other renewable sources.[47]
- Preferential tariffs.
- Capital subsidies based on installed capacity.

Renewable energy currently accounts for 32.3% of Indian generation capacity (hydro alone accounts for 21.3%). Table 5 shows the breakdown of recent generation capacity in India.

Although India´s renewable objectives are not binding, the National Action Plan on Climate Change aspires to achieve a 12% share of renewable electricity in the overall mix by 2016-17. This could mean the installation of another 35 GW of capacity, over the 20 GW now installed.[48]

4. Transmission Network Overview

The Indian transmission network has two layers: intra-state transmission networks, each of which is regulated by its State Electricity Regulatory Commission, and an interstate transmission network that is dominated by PowerGrid, the central government-owned company, although there are other interstate transmission licensees. As mentioned before, there are also regional system operators owned by PowerGrid.

For interstate transmission purposes, the country has been divided into five regions: Northern, North Eastern, Eastern, Southern and Western. The South Region remains unsynchronized with the other regions, although connected with direct current lines. The interconnected transmission system within each region is called a regional grid.

Transmission companies are subject to different regulatory regimes depending on the terms of concessions. The revenues of PowerGrid and other transmission companies are determined by the Central Electricity Regulatory Commission, based on actual investments and standard operating costs per type of line, similar to a revenue cap mechanism.

PowerGrid, in its role as the central transmission utility, is responsible for the central billing and collection of transmission charges, which are then disbursed to other interstate transmission licensees.[49]

47 Central Energy Regulatory Commission (2010b).

48 Ministry of New and Renewable Energy (2011).

49 Central Energy Regulatory Commission (2010c).

B. Transmission Planning and Investment Processes

1. The Planning Process

Transmission planning is carried out mainly by the Central Electricity Authority and the central transmission utility.

The Electricity Law states that the Central Electricity Authority is responsible for preparing a National Electricity Plan in accordance with the National Electricity Policy every five years. This planning is carried out in a coordinated manner with the central transmission utility.[50] The Planning Code (part III of the interstate Grid Code) adds that the Central Electricity Authority shall formulate its transmission plan for the interstate and intra-state transmission systems. The Planning Code also states that the central transmission utility shall carry out a periodic planning process and identify the system needs related to generation projects and reinforcement needs.

Additionally, the Central Electricity Authority holds periodic planning meetings of the Regional Standing Committees for Transmission Planning, constituted by the Central Electricity Authority, Regional Entities, Regional Power Committees, and National and Regional Load Dispatch Centers.

The Planning Code states that the basic planning criterion for the transmission network is the security of the system. It provides a list of events under which the system should remain stable, in terms of frequency, voltage, and overloading of the network elements, with no loss of load.

Besides this basic criterion, the Planning Code calls for detailed planning to take into account:

- The general planning guidelines issued by the Central Electricity Authority;
- Transmission planning criteria and guidelines issued by the Central Electricity Authority;
- The inputs provided by the stakeholders (Regional Power Committees, Load Dispatch Centers);
- Central Electricity Regulatory Commission regulation on connection and access to the interstate transmission network,[51] which implies taking into account new (firm) generation projects;
- The renewable capacity addition plan issued by Ministry of New and Renewable Energy, to meet the requirement for evacuating power from renewable energy sources;
- Minimization of congestion in system operation; and
- Revisions in load projections and generation scenarios (so that transmission plans should be continuously updated).

2. The Investment Process

New planned transmission projects may be auctioned or directly developed by the central transmission utility, another deemed licensee, or a state-owned or -controlled company.[52] When the projects have been auctioned, the transmission project revenues are determined by the auction. Alternatively, if the project is allocated directly to one of the aforementioned entities, annual revenues are specified by the Central Electricity Regulatory Commission. According to the tariff regulations, the revenue is derived from the actual capital invested plus standard operating expenses per type of line. Revenue is later adjusted based on the availability factor of the lines.[53]

C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation

Connection and access to the interstate transmission system is regulated in the CERC 2009 regulation, Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-state Transmission and Related Matters. The application is directed to PowerGrid in its role as the central transmission utility, together with a bank guarantee for Rs10.000/MW.

The central transmission utility studies the application jointly with other agencies involved in interstate transmission, and with any state transmission utilities whose transmission network is likely to be used. The central transmission utility also provides an estimate of the transmission charges payable based on prevailing costs, prices, and the methodology for sharing transmission charges.

50 Central Energy Regulatory Commission (2009a).

51 Central Energy Regulatory Commission (2009a).

52 Central Energy Regulatory Commission (2009b).

53 Central Energy Regulatory Commission (2009c).

The central transmission utility can require applicants to construct a dedicated connection line to the point of connection, except for big thermal (>500 MW) and hydro (>250 MW) plants, whose connection lines are part of the transmission lines. In the case of medium-term access, applicants can construct the connection lines at their own risk and cost.

2. Capacity Firmness and Congestion Management

There are four kinds of access contracts for accessing the transmission network:

- Long-term access (years),
- Medium-term open access (commencing after six months),
- Short-term open access, and
- Interconnection capacity, granted implicitly through power pools, called collective transactions.

Long- and medium-term access is granted on a first-come first-served basis, although longer-term applications have priority if received within the same month. Before granting long-term access, the central transmission utility takes into account the current capacity and reinforcement plans, while medium-term access can only be granted to spare capacity (not requiring any reinforcement).

Nevertheless, the capacity granted is not firm, since transmission users may be curtailed as a result of transmission constraints. Short-term access users are curtailed first, followed by medium- and finally long-term access users. The regulations do not provide for financial compensation in case of curtailment, so the access should not be considered as firm.[54]

Agents or power exchanges can require short-term access to the interstate transmission network to the central transmission utility. Short-term access may be applied for in advance, and involves spare transmission capacity and approval by the State Load Dispatch Center. If the central transmission utility identifies congestion (applications for capacity are higher than available capacity), then applications are normally accepted on a first-come, first-served basis.

D. Transmission Pricing

The State Electricity Regulatory Commissions are responsible for setting transmission charges within every state. Agents that are engaged in interstate trading also pay the transmission charges for interstate trades set by the Central Electricity Regulatory Commissions.

The charges for interstate transmission use are paid by network customers with long- and medium-term access.[55] Customers with short-term access pay the same charges, which vary according to the number of regions involved (intra-regional, adjacent regions, or trades that wheel across more regions).[56] Most costs are disbursed to customers with long-term access. In addition, regional utilities must make payments to a compensatory fund in the case of unscheduled exchanges.[57]

Interstate transmission charges are nodal and per MW/month (except for short-term access, which is charged per MWh). Charges are calculated according to a hybrid method: the slack buses are selected using the average participation method, and the burden of transmission charges or losses on each node is computed using the marginal participation method.[58]

E. Renewable Generation Operation

Although most renewable generation is connected to state transmission or distribution companies (and this will continue into the future), the importance of wind and solar energy sources, and other renewable plants, and the potential impact of variability of generation on the interstate electricity system's operation means that the scheduling requirements are incorporated into the interstate Grid Code.

The Grid Code sets the principles for renewable energy operation. It states that renewable energy should be treated as "must run" generation and are not subject to merit order dispatch, with the exception of dispatchable renewable plants (biomass and non-fossil-fueled cogeneration plants).[59]

54 Central Energy Regulatory Commission (2009a).

55 Central Energy Regulatory Commission (2009a).

56 Central Energy Regulatory Commission (2008). Articles 16 and 25.

57 Central Energy Regulatory Commission (2008). Article 20.

58 Central Energy Regulatory Commission (2010c).

59 Central Energy Regulatory Commission (2010a). Articles 5.2.(u) and 6.5.11.

The Scheduling and Dispatch Code (part 6 of the Grid Code) provides that the solar and large wind (> 10 MW) generators must provide the Regional Load Dispatch Center with a forecast of the schedule of the solar plants, based on availability, weather, and other factors. Wind schedules can be revised up to eight times during a day, every time for a three-hour block.

Energy imbalances are referred to as unscheduled interchanges. Solar generators do not pay any charge for imbalances, while wind generators will only pay for imbalances over ±30% of scheduled energy. The imbalance amount that is not met by generators is initially paid by states. From 2012, this cost will be shared between all states, through the Renewable Regulatory Fund, in proportion to their peak demand the previous month.[60]

60 Central Energy Regulatory Commission (2011).

IV. Spain

A. Electricity System Overview

1. Regulatory Institutions

Spain is a member state of the European Union, subject to European legislation on electricity markets. This is mainly contained in Directive 2009/72/EC Concerning Common Rules for the Internal Market in Electricity,[61] and secondary legislation, although other pieces of legislation and policies affect the electricity system, among them the Carbon Emission European Trading Scheme (EU ETS)[62] and the renewables directive.[63]

Spain also has an agreement with Portugal for the integration of their electricity markets. Since 2007, the two countries have had a common day-ahead market that allocates their available interconnection capacity. Despite the efforts of both regulators, harmonization between the markets is currently limited.

Nationwide regulatory functions are performed by two different institutions. The Ministry of Industry acts as the main regulator, since it defines energy policy goals, including renewable targets, along with the general framework for the electricity system that must receive consent by the Congress. The Ministry also issues all the secondary regulation, such as grid codes and energy exchange rules, and it determines the revenues and prices of regulated activities. The independent energy regulator, the National Energy Commission (CNE), does not have executive authority and acts mainly as an advisory body to the Ministry of Industry.[64] This situation is expected to evolve in the coming years, because new powers should be transferred to the CNE as required by the European Directive.

The general framework for the electricity system is set in the Electricity Sector Law, issued in 1997. Secondary regulations concerning specific activities (grid codes, market rules, settlement rules, etc.) are also contained in or approved by executive decisions by the Ministry, such as royal decrees (which are proposed by the Ministry of

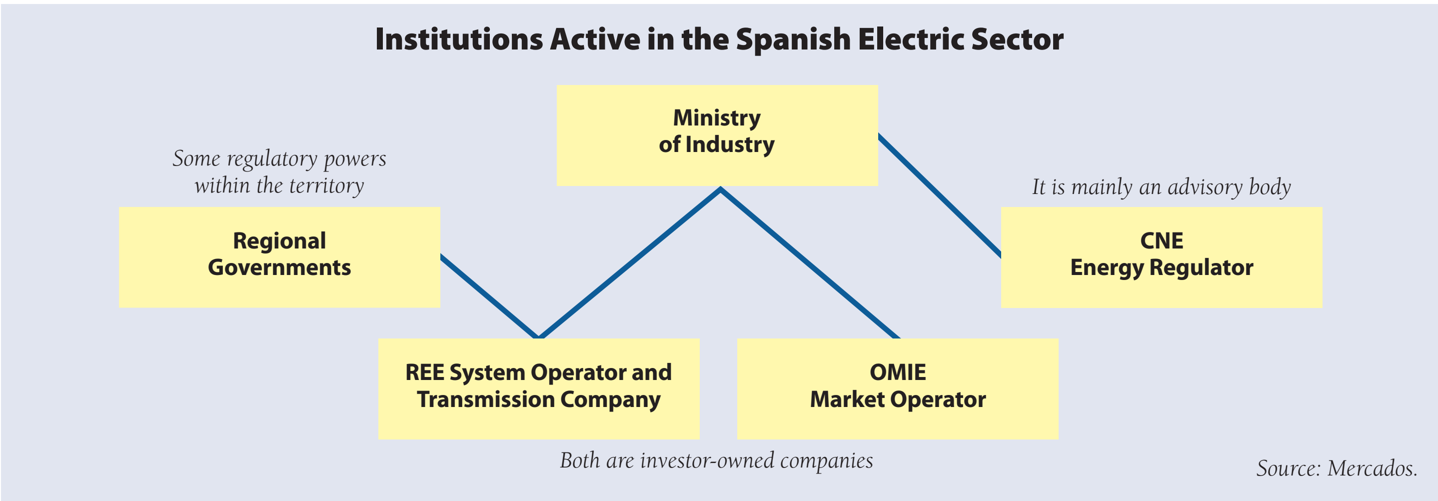
61 European Parliament (2009b).

62 European Parliament (2009a).

63 European Parliament (2009c).

64 Except for dispute settlement and power to decide in mergers and acquisitions of regulated energy companies.

Figure 6



Industry but ultimately approved by the government), ministerial orders, or resolutions (issued by the Ministry or other departments beneath it). The National Energy Commission can also issue regulatory norms by means of circulars giving directives about specific issues, or requiring agents to provide information.

The Spanish territory is divided into independent administrative regions called Autonomous Communities. The relationship between the national and regional governments is comparable to the relationship between the federal administration and state governments in the United States. In general, regional governments have power over infrastructure within their administrative regions, while the national government is responsible for general regulation and the remaining infrastructure. Regional governments should also be consulted before the most important policy decisions are taken, although their responses are not binding).

2. Electricity System Architecture

Spain´s electricity system restructuring started in 1986, when most of the transmission assets of private, vertically integrated companies were transferred to a newly created state company named *Red Eléctrica de España,* REE (Spanish Electricity Grid). REE was also in charge of the system operation in mainland Spain, pooling all the power plants in the territory into a centrally dispatched system (previously, each company was in charge of meeting the electricity demand in its territory). Generation and distribution assets were remunerated according to average unit costs set ex-ante by the government, and distribution companies were responsible for end-customer supply, so no retail competition was introduced.

In 1998, the electricity system was again restructured, this time in line with European energy policy. The wholesale market was opened to competition immediately, and a new regulated market operator, called OMEL, was created to manage an organized power exchange that ran day-ahead and intra-day balancing power markets. Retail competition was introduced gradually until 2003 (although distribution companies offered full-service regulated electricity tariffs until mid-2009); this required the creation of a third party access tariff system. Finally, REE, the main transmission company and system operator, was privatized.

It is worth noting that under the European convention, the market operator runs the day-ahead market, while the system operator runs the real-time balancing markets.

Currently, the electricity system is structured around the following agents:

- Generators,
- Market operator,
- System operator,
- Transmission companies,
- Distributors,
- Retail suppliers (retailers),
- Consumers, and
- System load managers (this role was introduced in 2010 to allow for the reselling of electricity in electric car charging stations).

Wholesale electricity can be freely traded until 11:00 a.m. of the day ahead of delivery in any of the available marketplaces: over-the-counter forward markets, an organized power future exchange in Portugal, or in the day-ahead market. After that moment, trading can only take place in intraday markets run by the market operator until two to three hours before electricity is delivered, or in the balancing markets held thereafter by the system operator.

Several unbundling provisions affect different participants in the sector. The market operator and system operator must be totally independent from any other agent (ownership unbundling), while the companies involved in transmission and distribution activities cannot have any other business, although they may belong to integrated companies (legal unbundling).

Retail supply was fully opened up to competition in 2003, but it was not until mid-2009 that the government removed the previous regulated tariff system (in mid-2008 for high-voltage customers). However, it introduced price caps to the retail tariffs that some retailers can charge to small customers (low-voltage customers with less than 10 kW maximum load). These price caps may be limiting retail completion. No new retailers have entered the domestic market, while they have in the industrial and commercial segments.

Today, five big vertically integrated companies, three of which belong to foreign groups, account for most of the electricity system in Spain. These companies generate most of the electricity and are the main distributor and retailers. Most newcomers have entered into the generation segments by building or buying renewable generation assets.

3. Renewable Generation Policy and Implementation Mechanisms

Spanish renewable energy targets are set in accordance with European objectives. Currently, the binding target is to achieve 20% of the gross final energy consumption from renewable sources by 2020. (There are also intermediate non-binding targets set between now and 2020.) Spain has allocated this overall target among the different energy sectors, and has set targets for different renewable energy generating technologies within the electricity sector. According to these targets, in 2020, 12,903 ktep of electricity (150 TWh) should be generated from renewable energy sources, accounting for 57.5% of the overall target and 36% of total gross electricity production.[65, 66]

Renewable energy generation in Spain is subsidized to compensate for the higher costs of its technologies. Generators can choose between receiving a feed-in tariff (a fixed price for all the energy injected into the network) or receiving a premium over the market price. Once they have chosen one of these options, they must stay under it for at least one year. Feed-in tariffs and premiums are technology-specific,[67] and are adjusted annually to account for inflation. Every four years on average, the government reviews the complete set of tariffs and premiums to reflect the evolution of investment and operating costs. Regardless of the option chosen, the energy produced is entered into the day-ahead market by the generators or their representative.

This general framework has undergone some adjustments in recent years due to the increasing costs imposed by the expansion of some technologies. In 2007, an attempt was made to remove subsidies for wind farms when market prices were high enough for them to recover costs. The government made premiums for wind farms variable: they increase when hourly market prices are low and decrease to zero when they are high. In 2008, in the midst of significant photovoltaic development, the government introduced an adjustment mechanism through which tariffs drop automatically for new plants when capacity reaches preset thresholds.

Currently, renewable energy generation in Spain accounts for approximately 27% of total gross generation. The exact figure varies according to the annual rainfall, since hydro production is very volatile.

Renewable generation is expected to continue growing due to Spain's commitments within the European renewable energy policy. There are, however, some uncertainties about how and whether the targets will be reached. The first is that so far, the targets set by government plans for most renewable generation technologies have hardly ever been met (although solar plants have exceeded them). The second is that past growth has meant increasing electricity bills to customers—so new developments may be limited by the extent of customers' willingness to pay for more renewable energy.

Table 6

Forecast: Renewable Energy Generation in Spain by 2020

	MW	GWh
Hydroelectric	**22,362**	**39,593**
Pumping storage	5,700	8,023
Geothermal	**50**	**300**
Solar:	**13,445**	**29,669**
Photovoltaic	8,367	14,316
Solar thermal	5,079	15,353
Tidal, wave, and other sea power tech	**100**	**220**
Wind:	**38,000**	**78,254**
Onshore	35,000	70,502
Offshore	3,000	7,753
Biomass	**1,587**	**10,017**
Solid	1,187	7,400
Biogas	400	2,617
Liquids	0	0
TOTAL (excl. pumping storage)	**69,844**	**150,030**

Source: Red Electric of Spain (2011) and AF-Mercados.

65 Ministry of Industry, Energy, and Tourism (2010a).

66 Targets are set for average weather conditions, given that hydro and wind generation are potentially very volatile.

67 For a whole breakdown of different tariffs and premium, see the last annual Ministerial Order adjusting such subsidies: Ministerial Order ITC/3353/20. http://www.boe.es/boe/dias/2010/12/29/pdfs/BOE-A-2010-20002.pdf

Table 7

Renewable Generation in Spain

Unit: GWh	2009	2010
Big hydro	23,862	38,653
of which pumping	-3,794	-4,458
Small hydro	5,474	6,811
Wind	37,762	43,692
Photovoltaic solar	6,140	6,311
Thermal solar	103	692
Other renewable	5,088	5,316
Total renewable energy	74,635	97,017
Total gross generation	291,386	300,593
% of renewable over total generation	25.6%	32.3%

Source: Red Electric of Spain (2011).

4. Transmission Network Overview

According to the Electricity Sector Law, transmission and system operation are different activities assigned exclusively to one company, REE, covering the whole country. The bundling of transmission and system operation functions into an independent entity results in the adoption of an unbundled transmission system operator model, as defined by the European Directive 2009/72/EC concerning common rules for the internal market in electricity.[68]

Electricity transmission and system operation remain regulated activities subject to revenue controls. While current transmission revenue control can be deemed as a revenue cap regulation, system operation remuneration is more similar to a cost-plus regulation, since its remuneration is adjusted every year to cover total costs.

The Electricity Sector Law states that transmission should be carried exclusively by the system operator; companies operating in the electricity sector cannot own more than 1% of the system operator capital. As a result, REE should remain independent from other agents in the electricity system apart from the state itself, which keeps at least 10% of the capital.

B. Transmission Planning and Investment Processes

1. The Planning Process

A. Responsibility for Planning

Development of the transmission network is still regulated. The government is responsible for approving the planning, based on a proposal by the Ministry of Industry, and it must present the resulting plans to the Congress. This planning is binding for the transmission company, which should develop the projected infrastructures.

The planning process has three stages. In the first stage, the system operator prepares a Proposal for the Development of the Electricity Transmission Network; then the Ministry prepares a Development Plan of the Electricity Transmission Network, which should be approved by the government (and submitted thereafter to the Congress). Finally, the Directorate General for Energy Policy (which depends of the Ministry of Energy) approves a detailed Infrastructure Program every year, with the list of new elements of the network that are expected to be commissioned that year.

In the first stage, as well as making their own forecasts, the system operator can ask other participants, such as developers of new generation plants, to submit their own forecasts and make their own proposals, although such involvement is not compulsory. The proposed plan includes a coordination plan with neighboring electricity systems. Finally, and before the final proposal can be submitted to the Ministry, it must also take into account the comments of the regional governments.

The system operator also prepares a report on the long-term evolution of the system. These reports are intended to give long-term guidance to participants. They are released every five years and have at least a ten-year horizon. The reports should contain:

- Demand forecasts,
- New generation plants that would be required to cover the demand,
- Identification of grid constraints and the need for reinforcement, and
- A high-level grid development plan.

68 European Parliament (2009d).

b. Planning Characteristics

The main transmission planning document, the Development Plan of the Electricity Transmission Network, is revised every four years, and is reviewed every year before the issuance of the annual Infrastructure Program. The plan is directed to cover the country's entire transmission system over a five-year horizon. Although the legislation does not provide for the plan's minimum content, it does state what should be included in the proposal on which it is built:

- A commissioning program for new transmission assets and reinforcement of existing assets,
- A transmission capacity adequacy report,
- A response to other agents' suggestions and proposals,
- A coordination program with other electricity systems (in neighboring countries), and
- A coordination program between transmission network development and new generation projects.

The Annual Infrastructure Program gives a more detailed picture of the state of development of the new lines, substations, and other assets due to come into operation.

c. Transmission Development Drivers

Legislation provides for a list of high-level planning principles that should guide the proposals submitted by the system operator. These principles include both technical and economic efficiency criteria:

- Reliability,
- Reduction of transmission energy losses,
- Mitigation of congestion on the grid,
- Efficient integration of new generators,
- Minimization of the energy non-supply,
- Minimization of global environmental impact,
- Coordination of the transmission development with the distribution network,
- Coordination with generation plants and new consumers, and
- Increasing the interconnection capacity with neighboring countries.

These principles leave considerable scope for discretion on the part of the system operator with respect to how planning is ultimately carried out, in particular where objectives conflict. Because the system operator is also the transmission company, there have been some claims of conflicts of interest (prioritizing of profitable projects, delaying socially controversial projects) in the planning process.

Despite not being clearly stated as principles, public policy goals such as energy efficiency and renewable energy promotion have been widely taken into account in the demand and generation modeling of previous and current plans. To date, in fact, the development plans have allowed for a considerable amount of renewable capacity being connected to the network. However, this lack of detail in the planning guidelines may create other issues. For instance, there is a lack of guidance on how to manage the interaction between transmission capacity availability and location decisions for generation plants, especially in the case of renewable energy plants. The current Development Plan acknowledges the difficulty of modeling future generation because of uncertainty about its location, and opts to make forecasts based on current applications to connect to the grid.[69]

2. The Investment Process

a. Economic Regulation

Electricity transmission remains a regulated activity and is subject to a revenue cap mechanism. The transmission company is entitled to receive fixed regulated revenue for those assets that are part of the public plan, regardless of the actual demand or level of use of the assets. Total revenue is made up from the revenue recognized for every single transmission network item (lines, substations, control rooms, etc.). The government uses a revenue formula to determine the revenues of the assets. This revenue will not vary during the remainder of the lifetime of the asset, apart from an adjustment for inflation, and is set based on an independent measure of investment and operation costs, including overheads.

In the current revenue formula, established in 2008, allowed investment costs are the average of actual investment costs and expected investments costs (set ex-ante by the Ministry based on historical values), although there is room for special remuneration linked to specific projects (such as submarine interconnections). Transmission company revenue is collected from all users through the distribution companies, regardless of their use of the infrastructure, and is centrally settled by the independent regulator.

69 Ministry of Industry, Energy, and Tourism (2010a). Ministry of Industry, Energy and Tourism (2008).

As a consequence of this regulatory framework, the transmission company faces relatively low risk in the development of the network, including when connecting renewable generation. Volume risks are transferred totally to electricity customers, the risks of demand or generation being lower than expected. There is a limited investment risk of actual building costs being higher than expected by the Ministry, which can delay expensive projects or cause project developers to ask for a special remuneration. The transmission company does face financial and operating-cost risks, since those are set for the entire useful life of every asset, and both operating costs and capital costs can vary to a great extent during the 40-year typical useful lifetime of a transmission line.

b. Responsibility for Building Projected Lines

Traditionally, two mechanisms existed for allocating transmission projects: the Ministry could auction the project development between different interested companies or appoint one of them directly. The latter mechanism was used in almost all cases. But in 2007 the government modified the Electricity Sector Law to grant exclusivity over the transmission activity to the main transmission company (except for some distribution-connected assets).[70] Since then, only the transmission company REE can develop new projects.

There are no special provisions regarding the funding of the new transmission lines. The transmission company is expected to internally finance the capital required for the projects included in the Development Plan, or to raise the money in the capital markets. Explicit ring-fencing provisions to safeguard the company's financial stability do not exist either, although corporate operations (acquisitions, mergers, etc.) that could jeopardize creditworthiness of the company are subject to approval by the regulator.

c. Administrative Permits

Before a transmission project begins operation, it needs to go through a series of administrative permit processes. The applications for these permits need to be filed with the national or regional administration, depending on whether the transmission line crosses more than one Autonomous Community. In general, these processes include:

- Administrative authorization,
- Environmental impact assessment, if required,
- Construction approval, and
- Authorization to begin operation.

The administration can, upon request by the transmission company, declare a transmission project as being of public interest. In such a case, the company can acquire the land for the project by eminent domain (compulsory purchase).

Currently, the difficulty in developing transmission projects is due to stakeholder opposition to some new projects, rather than the inherent complexity of the administrative permit process. Some long-awaited projects have been repeatedly delayed, especially in wooded mountain areas; these projects are, however, not related to renewable energy development.

C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation

Connection capacity is allocated on a first-come, first-served basis. The transmission company is not obliged to connect new generators upon request, but is expected to make connection easier.

The general procedure for allocating connection capacity to the transmission network starts with a generator that wishes to connect submitting an application to the system operator, which then assesses the transmission capacity available at that node. If enough capacity is available, the generator asks the transmission company for a connection works plan and budget. The generator bears the costs of shallow connection works (plus the cost of some minor reinforcements, if needed), although it can chose to contract another company to carry out the works.

The first-come, first-served approach has given rise to some connection conflicts, because of the great number of applications from small-scale renewable projects. In some cases, connection applications were submitted with the sole intention of "reserving" the transmission capacity in some nodes. As a consequence, in 2005 the connection regulation was amended to require renewable generators only to present a financial guarantee equal to 2% of the plant budget at the time of applying for connection.

70 National Energy Commission (2008), Article 35.2.

Later, in 2007, this obligation was restated as €500/kW of photovoltaic solar plants, and €20/kW for other generation technologies.

2. Capacity Firmness and Congestion Management

In Spain, all generators have equal rights of access to the available transmission capacity. This means there is no reservation of transmission capacity; and in the event of grid congestion, the system operator cannot discriminate between generators.

Instead, the system operator solves any congestion that arises by means of counter-trading. When there is an import-limited zone, this increases generation in that zone and reduces it in the rest of the country. When there is an export-limited zone, it does the opposite. The congestion may become apparent because of the schedules submitted by generators and consumers, in which case counter-trading is carried out by means of a market mechanism; or it may emerge in real time due to unanticipated changes in the electricity flows, in which case the system operator can give direct instructions to generators to reduce or increase production.

Applying a market mechanism to transmission congestion management is designed to ensure that renewable energy generators are not discriminated against, and that congestion issues are solved at minimum cost. In 2010, 88% of the energy re-dispatched due to congestions, and other network constraints, was bought/sold through market mechanisms.[71] The rest of the energy re-dispatched was due to real-time network congestions, where it is more difficult to monitor the system operator´s behavior. Nonetheless, the system operator has a formal obligation to curtail conventional generation plants before any renewable energy plant generation is reduced.[72]

Generators constrained-down due to exporting congestions—those generators whose production is reduced to solve the congestion—are not compensated. This is intended to discourage new generators from locating in constrained areas. Thus, the counter-trading mechanism in Spain is not equivalent to firm transmission access.

The cost of counter-trading activities by the system operator is recovered from the demand through a specific charge.

3. Generation Embedded in the Distribution Networks

In recent years, connection to distribution networks has been a more problematic issue than connection to the transmission grid, probably because of two major flaws in the regulation of distribution networks:

- Embedded generation is not appropriately regulated, because it is a relatively new phenomenon, largely resulting from the rapid increase in small photovoltaic plants and other new micro-generation technologies.
- The remuneration of the distribution activity does not explicitly take into account the costs of integrating variable generators into the network: for instance, the cost of increasing the capacity margin of the networks to allow for reverse flows.

At present, the main problem is the mechanism for calculating the available capacity in the low-voltage network. Generators are usually required to connect to medium- or high-voltage substations, which increases the connection costs. There are also some difficulties with the operation of the distribution networks when variable capacity is present and supply quality may be affected.

Legislation has been proposed that would make connection easier for small plants and to consolidate several pieces of legislation,[73] but it has been delayed several times. The proposal sets out different connection procedure, depending on the size of the power plant, but does not deal with other regulatory gaps, such as the lack of negative network tariffs or negative loss adjustment factors for embedded generators (which are common in other, more advanced regulations).[74]

71 Red Electric of Spain (2011).

72 Ministry of Industry, Energy, and Tourism (2010b). Section 3.4.1.1.5.2.

73 Real Decreto 1699/2011, "Regulation of Network Access for Small Generation Facilities.

74 At present, embedded generation does not receive credit for the loss reduction benefits of injecting energy into low-voltage grids.

D. Transmission Pricing

1. Connection Charges

Connection charges are not regulated, and vary on a case-by-case basis. Part of the reason for this is that, as previously explained, generation project developers only pay the costs of the assets required for connecting to the grid (plus some minor reinforcement), and not the costs of any overall reinforcement of the grid. They pay only the "shallow" connection charges, which are project-specific.

Moreover, generators can choose to contract any other building company apart from the transmission company to carry out the connections works, so the actual connection cost may result from negotiation with different contractors.

2. Generation Transmission Use of System Charges

In Spain, transmission use of system charges form one component of a much wider tariff. The costs of the transmission, distribution, renewable promotion mechanism, and other minor costs, such as system operator and energy regulator remunerations, are bundled into a single tariff. The government sets these tariffs, but does not explicitly state where the costs are allocated.

These tariffs were traditionally paid only by retailers, but the government introduced a generation network tariff in 2011. This is currently a flat €0.5 per MWh paid by all generators. Although this generation tariff does not explicitly discriminate against renewable generators, the ability of these generators to recover this (variable) cost from the energy price is less, since many will have opted for the fixed-price option of the renewable supporting scheme.

E. Renewable Generation Operation

1. Generation Forecasting

The system operator has two different sources of information on production from variable energy sources: the generators' forecasts and its own wind forecasts.

Renewable generators provide their own generation forecast through their plant schedules. Scheduling of renewable energy generation is no different from scheduling of conventional generation. Both can sell energy in the official Power Exchange, which in turn will communicate the resulting energy schedule to the system operator; or they can sell their production bilaterally in over the counter markets, then communicate the contracted energy schedule to the system operator.

Regardless of the trading method, the system operator should receive an initial energy schedule by 11:00 a.m. on the day ahead of delivery. If there are changes to their expected production, generators can still balance their positions by reducing or increasing their schedule in different intra-day markets until two to three hours before electricity is delivered.

The system operator´s own forecasts are used as a benchmark in order to correct possible system imbalances ahead of real time.

2. Participation in Balancing Services

In Spain, participants in the wholesale market trade freely until two to three hours before electricity is delivered. In other words, what is known as gate closure takes place two or three hours ahead of real time. After that moment the system operator takes over system control, in order to keep energy balance and system reliability through the purchase of ancillary services. The most important ancillary services are the balancing services, which are organized through a series of consecutive markets, which differentiate in the time remaining to the real time.[75] In those markets the system operator buys or sells electricity to close the gap between agents' energy schedules and actual consumption/generation, and thereby keeps the system balanced at all times.

Balancing services are organized nationally. Renewable energy generators are allowed to participate in the balancing services, provided that:

- They are actively participating in the power exchange,
- They have at least ten megawatts (generators can aggregate several plants in order to reach the threshold), and
- They show that they are dispatchable—that they can vary their generation following orders by the system operator.

In practice, these requirements limit the number and type of renewable energy stations that can provide such services to thermal plants (biomass, biogas, waste plants) and potentially some thermal solar plants.

75 These are the markets for capacity for secondary reserve (that can be activated in up to 15 minutes) and for tertiary reserve energy (that can be activated from 15 minutes onwards).

Renewable energy power plants also receive a premium payment for the generation of reactive power, although they are not required to do so.

3. Imbalance Settlement

All generators and consumers (apart from very small renewable power plants without hourly metering) are charged imbalance prices for the difference between their final energy schedule and their actual generation (their imbalance volume). The system operator applies a dual imbalance pricing system, which is common in Europe. Under this system, the prices applied to generators—the amount they have to pay for generating less than scheduled, or the amount that they receive for generating more than scheduled—depend on the imbalance position of both the generator and the system as a whole. If both are out of balance in the same direction, then the generator is contributing to the general imbalance and is charged/paid the average price of the energy sold/bought to solve the imbalance. If the generator's imbalance is in the opposite direction to the wider system, then the generator is helping to reduce the overall imbalance and is charged/paid the price of the day-ahead market, instead of the price of the energy sold/bought to solve the imbalance.

The system operator aggregates all the imbalances of individual power plants belonging to the same "settlement agent" into two groups: conventional and renewable plants. As a consequence the cost of imbalances is lowered, because opposite imbalances cancel each other out when they are aggregated. Every settlement agent normally corresponds to a generating company, but a settlement agent may pool plants from different companies in order to cancel out their respective imbalances.

Because they are subject to the same imbalance settlement as other power plants, renewable generators have an incentive to accurately forecast their expected production and to solve possible imbalances in the market ahead of gate closure.

V. The United Kingdom

A. Electricity System Overview

1. Regulatory Institutions

As a member state of the European Union, the United Kingdom is subject to European legislation on electricity. This is mainly contained in the internal market, in electricity Directive 2009/72/EC, and secondary legislation, although there are other pieces of legislation affecting the electricity market, such as the emissions trading scheme (EU ETS) and the renewables directive.

Within the UK, government policy is administered through the Department of Energy and Climate Change. DECC administers the formulation of policy, and primary and secondary legislation, on behalf of the Secretary of State for Energy and Climate Change, a Cabinet position in government, with significant changes to legislation being voted on by Parliament. DECC also has some specific functions in the energy sector: deciding on license exemptions, having the power of veto on any proposal by the regulator to modify licenses, wider social and environmental policy relating to energy, and international energy issues.

It is important to note that some UK legislation applies only to the electricity market in Great Britain, whereas in other aspects, such as European renewables, targets apply to the UK as a whole.[80] Some aspects of energy and planning policy are devolved to elected regional assemblies in Scotland and Northern Ireland. For example, the Scottish Government has its own renewable energy and CO_2 reduction targets, and unlike the UK Government it has taken a decision not to permit new nuclear development.

The electricity market in Great Britain is regulated by the Gas and Electricity Markets Authority, appointed by the Secretary of State for Energy and Climate Change, and operating through the Office of Gas and Electricity Markets (Ofgem). The Authority's powers and duties are largely provided for in statute, as well as arising from directly effective European Community legislation. It is accountable to Parliament directly, and is therefore independent of DECC and other government departments).

76 European Parliament and Council of the European Union (2009d).

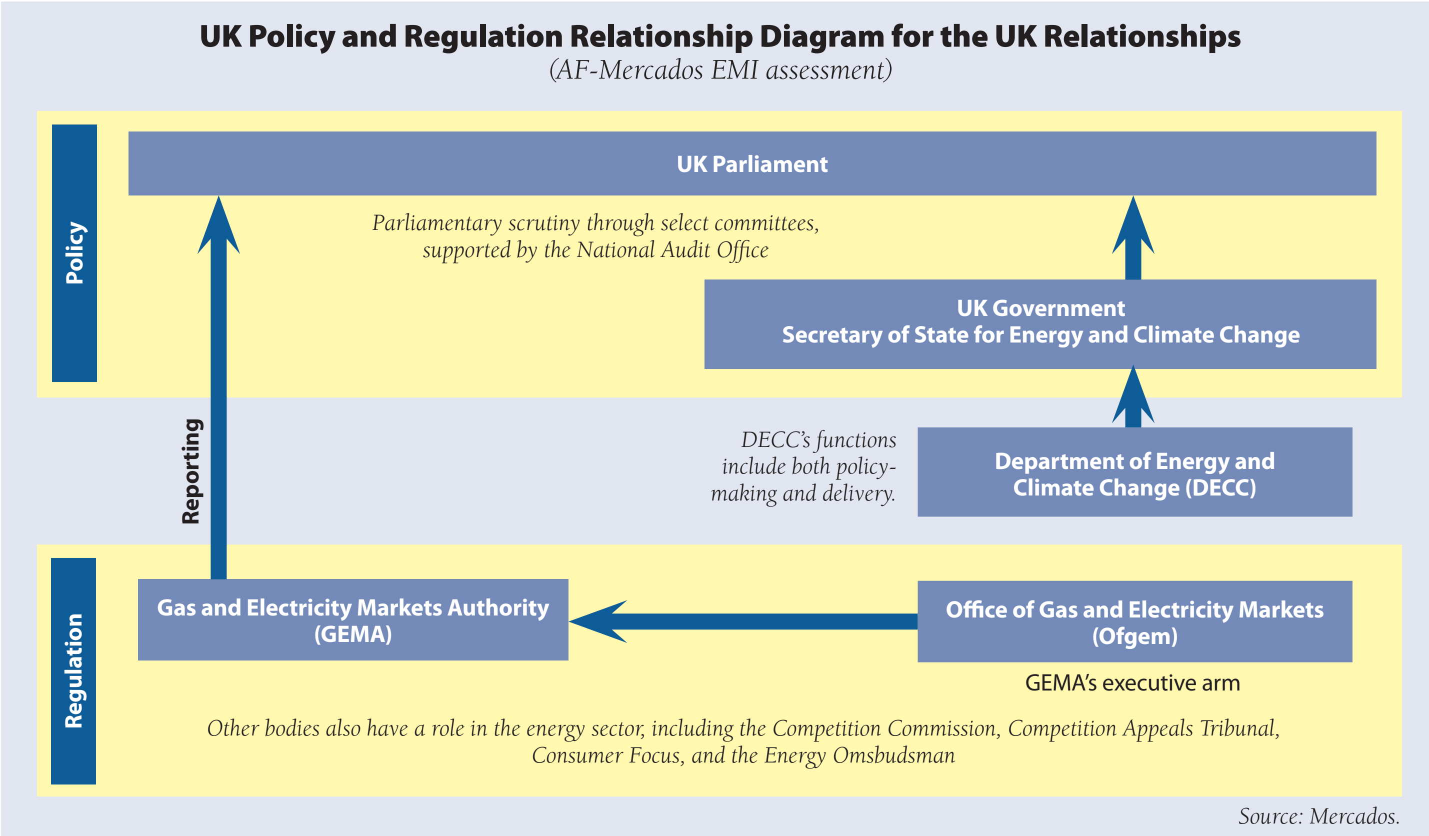
77 European Parliament and Council of the European Union (2009a).

78 European Parliament and Council of the European Union (2009c).

79 Generally, the requirements for primary legislation (Acts of Parliament) are initially decided by the Cabinet and entered into the Queen's speech, then a draft bill and final bill are debated in both Houses of Parliament (Commons and Lords), and once agreed by Parliament, will be presented to the Queen for approval, known as Royal Assent. There is a process for wider stakeholder consultations on primary legislation changes through Green papers (consultation on general principles) and White papers (consultation on more detailed proposals for the bill). Although this is not actually required, it is generally used for energy issues, with the consultation process managed by DECC. Secondary legislation, or statutory instruments, is made under the primary legislation, and does not normally require the same level of parliamentary scrutiny. In the case of energy, statutory instruments would normally be drafted and consulted on by DECC. In most cases, the Secretary of State can present the statutory instrument, and if no objections are raised within 40 days it passes into law, although in some cases the original act may require there to be a debate or a vote in Parliament before it passes into law.

80 The UK is a sovereign state, which includes England, Scotland, Wales, Northern Ireland, and smaller islands. Great Britain is a geographical description of England, Scotland and Wales. Great Britain has a single electricity market (called BETTA). The island of Ireland (Ireland and Northern Ireland) has a separate single electricity market (called the SEM), which we do not consider in this study.

Figure 7



Ofgem's role includes issuing licenses, ensuring regulatory compliance, and the regulating tariffs in the transmission and distribution networks.

The Electricity Act 1989 and Utilities Act 2000 are the main primary energy legislation, and have been amended by various subsequent legislation. Separately, the Climate Change Act (2008) sets an economy-wide target for reducing CO_2 emissions by 80% relative to 1990 levels.

To take part in the British gas and electricity markets, a business must have a license from Ofgem for any of these activities: generation, retail supply, distribution, transmission, and operating an interconnector.

Licenses require participants to conform to specified codes. Depending on the type of business, these may include the Grid Code, Distribution Code, Connection and Use of System Code (CUSC), Distribution Connection and Use of System Agreement, Master Registration Agreement, System Operator Transmission Owner Code, and the Balancing and Settlement Code (BSC). Key features of the code system include these:

- All power stations, regardless of whether they are directly connected or embedded, that are capable of exporting 100MW or more to the total system normally require a license;
- All transmission-connected power stations and directly connected distribution systems are required to accede to the CUSC;
- All holders of a license, regardless of whether they are directly connected or embedded, are required to accede to the CUSC and sign the BSC;
- If license-exempt, a user may choose to sign the BSC and accede to the CUSC;
- If registered within BSC, a user may choose to participate in the balancing mechanism;
- License-exempt embedded generation may be required to become party to the CUSC; and
- If party to the CUSC, a user must comply with the Grid Code and pay any relevant charges.

These codes are partly self-regulated by industry, with participants being able to raise modification proposals through industry panels. All final decisions on changes are made by Ofgem.

The electricity market is currently under review, with changes proposed to introduce a capacity mechanism, carbon price floor, emissions limits, and contracts for difference for low-carbon generation (renewables and nuclear). These proposed changes have yet to be passed into legislation. There are also other major reviews into transmission charging mechanisms and mechanisms for ensuring market liquidity. Unless otherwise stated, in this study we are referring to market mechanisms in place in September 2011.

2. Electricity System Architecture

All energy generation, transmission, distribution, and supply in the UK is now run by private sector companies. Price regulation by Ofgem only exists where there are natural monopolies—for example, in the transmission and distribution businesses.

Suppliers buy electricity from generators and sell it on to end consumers. Suppliers operate in a competitive market, and customers can choose any supplier to provide them with electricity. The domestic supply market contains six major suppliers, providing over 99% of electricity to households, as well as a few smaller ones. There are more suppliers that serve business and industrial customers. Many suppliers are vertically integrated, and own generation assets and distribution assets as well as retail supply. Scottish Power and Scottish and Southern Energy also own the Scottish transmission assets.

The overall Great Britain system is operated by National Grid. As system operator, it has responsibility for ensuring that the electricity transmission network remains in balance and within safe operational limits. Each of the parties that operate on the electricity transmission network has a responsibility to ensure that its position remains in balance, or it will be penalized according to the electricity imbalance arrangements.

The traded markets include both over-the-counter and exchange-based trading, which allows generators and suppliers to adjust their commercial positions ahead of real time down to a half-hour granularity. In the wholesale market, the majority of electricity (over 90%) is sold directly from generators to suppliers in bilateral contracts. Most of these contracts are made from a year or more ahead of delivery, up to a day ahead of delivery. The contracts can take any form and there is no formal obligation to disclose the prices contained within them. About 3% of electricity is sold through power exchanges.

Ofgem has reviewed the electricity market and concluded that there is insufficient liquidity, in part due to vertical integration. This illiquidity is perceived as a barrier to new entrants. Ofgem is therefore currently considering the introduction of a mandatory auction, which would require large retail suppliers to collectively provide a prescribed volume of electricity into each auction round; and mandatory market making, which would require large retail suppliers to submit a bid and offer a price for a narrow range of base-load and peak products on a continuous basis.[81]

The system operator has sole responsibility for balancing the system after gate closure (one hour before real time). The balancing mechanism operates from gate closure through to real time. It exists to ensure that supply and demand can be continuously matched or balanced in real time, including managing constraints through re-dispatch. The mechanism is operated with the system operator acting as the sole counter party to all transactions. ELEXON (the BSC Company) is responsible for managing and operating the systems that allow for balancing and settlement in the electricity market.

3. Renewable Generation Policy and Implementation Mechanisms

UK's renewable energy targets are set in accordance with European objectives. Currently, the binding target is to achieve 20% of gross final energy consumption from renewable sources by 2020. In 2010, renewable energy provisionally accounted for 3.3% of overall energy consumption, measured using the 2009 Renewable Energy Directive methodology, therefore including hydro.[82]

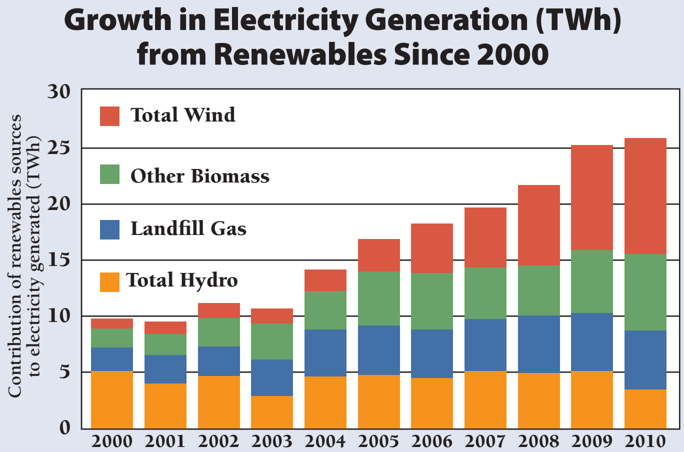
Electricity generation from renewable sources in 2010 was 25.7 TWh (6.8%). It is worth noting, however, that load factors for wind and hydro were low; the contribution of renewables to gross electricity consumption increased to 7.4% when using normalized load factors according to the 2009 Renewable Energy Directive methodology.[83] Historic contributions from renewable electricity are shown in Figure 8.

81 Wright (2011).

82 Department of Energy and Climate Change (2011).

83 Department of Energy and Climate Change (2011).

Figure 8



Source: Department of Energy & Climate Change (2011).

The government has indicated that to achieve the 15% renewable energy target, about 30% or more of electricity should come from renewable sources by 2020. This is because it is seen as more challenging to achieve the target in other sectors like heat and transport. The Climate Change Commission[84], in its initial advice to government in September 2010, agreed to a contribution from renewable electricity of 30% of total generation by 2020, and that there is a need to substantially decarbonize the power sector by 2030.

There are currently two mechanisms for supporting renewable electricity generation in the UK. The Renewables Obligation applies only to larger scale (>50kW) renewable electricity generation. The feed-in-tariff is limited to certain technologies under 5MW: wind, solar, photovoltaic, hydroelectric, anaerobic digestion, and non-renewable micro CHP (2 kW or less). Generators between 50kW and 5MW can make a one-off choice whether to take the renewables obligation or the feed-in tariff.

The Renewables Obligation is a green certificate-trading mechanism. Initially, all renewable generation received one Renewables Obligation Certificate (ROC) per MWh; but from April 2009, banding was introduced to support emerging technologies with potential for large-scale deployment. Eligible renewable electricity generation is banded according to the nature of the technology, and receives a defined number of ROCs for each unit of output (MWh) produced.

The Renewables Obligation requires licensed electricity suppliers to present a number of ROCs equivalent to a percentage of the electricity they have supplied, or pay a "buy-out" price for any shortfall. The buy-out price was originally set at £30/MWh in 2002/03, and is indexed. Funds accumulated from the buy-out are then recycled back to suppliers based on the number of certificates presented. Thus, the value of a ROC is the buy-out price plus the recycle price. This mechanism means that the market price for ROCs is set by the supply of renewable generation and demand, as defined by the obligation.

The government has announced its intention to replace the Renewables Obligation with a feed-in tariff that includes a contract for difference against the market price of electricity.

The feed-in tariff provides two guaranteed income streams (indexed at RPI): a generation tariff, which is paid for every kWh of electricity generated, whether or not exported; and an export tariff, which is paid for every kWh of electricity exported to the grid. The generation tariff differs depending upon the technology and the size of the project.

At present, the key barriers to higher renewable energy deployment are planning and finance. The government has proposed a Green Investment Bank, which may help to finance projects like offshore wind where significant conventional financing is not yet available. Perhaps the most significant barrier is the difficulty of obtaining planning permission for renewable projects, particularly onshore wind and transmission infrastructure.

4. Transmission Network Overview

The British electricity transmission network is owned by three transmission asset owners: National Grid Electricity Transmission, Scottish Hydro Electricity Transmission Limited, and Scottish Power Electricity Transmission Limited. National Grid is the overall system operator.

National Grid has gas and electricity transmission, gas distribution, LNG (liquefied natural gas) re-gasification and

84 The Climate Change Commission is an independent body established under the Climate Change Act (2008). It advises the UK Government on setting and meeting carbon budgets, and on preparing for the impacts of climate change.

storage interests, and some small generation interests[85] in Great Britain. (It also provides a small amount of energy as part of its property interests.) In the United States, National Grid has generation and supply interests.

Both the Scottish transmission systems belong to vertically integrated businesses. Scottish Hydro Electricity Transmission Limited is a wholly owned subsidiary of Scottish and Southern Energy plc (SSE). Scottish Power Electricity Transmission Limited is a wholly owned subsidiary of SP Limited, which is owned by Iberdrola. SSE and Iberdrola have significant generation and supply interests in Great Britain and elsewhere in the EU.

As the single system operator, National Grid operates the electricity transmission systems in Great Britain. National Grid is responsible for system operation tasks such as daily operation and providing access to the system. The Scottish asset owners still have responsibility for the maintenance and development of the transmission system, although there is some protection from conflicts of interest through the conditions set out in legislation and their license.

New offshore transmission lines connecting offshore wind projects will be built under a competitive tender process. Licenses to own and operate offshore electricity transmission assets will be granted on a competitive, non-exclusive basis under a competitive tender process administered by Ofgem. Offshore transmission licenses set out the obligations and rights of the licensee, and define the revenue stream that the offshore transmission owners (OFTOs) will receive. The first round of OFTOs involved bids to purchase partly or completely built transmission assets from the offshore wind developers, and then finance and maintain the assets over 20 years. Subsequent rounds intended to build the asset as well as owning and maintaining it, and this ongoing regime is still under development by Ofgem.

Because of their monopolistic nature, transmission asset owners are subject to transmission price controls. The regulator, Ofgem, is responsible for reviewing the price controls and determining the amount of capital expenditure over the period. Overall revenues are determined by a revenue cap. The cap was formerly based on an RPI-X regime, but the current price control is being conducted under a new RIIO (revenue = incentives + innovation + outputs) model. Detailed methodologies will be decided over the course of the price controls, although Ofgem has published a handbook on how it expects the process to work.[86]

Interesting features of the new regime include greater stakeholder engagement; greater "market testing" of the plans of network companies, with options for stakeholders (including third party providers) to suggest alternatives that offer greater value; an incentive for "network outputs," such as the health and loading of the network; and incentives for additional technical and commercial innovation by network companies.

As system operator, National Grid collects the transmission revenues and redistributes them among the other asset owners.

B. Transmission Network Planning and Investment Processes

1. The Planning Process

a. Responsibility for Planning

The transmission asset owners have ongoing and continually updated plans to reinforce the grid to allow for changing generation and demand patterns. Under the System Operator-Transmission Operator Code, all transmission asset owners are required to cooperate with National Grid as the system operator in producing their own annual transmission investment plans. They are required to take into account planning assumptions provided by National Grid. National Grid can comment on the investment plans of the Scottish electricity transmission businesses, and can either ask for additional work to be undertaken or refer the issue to Ofgem for a final determination.

National Grid has overall responsibility for managing requests from any party—power plants or users—to connect to the transmission system, including plants owned by SSE or Scottish Power. National Grid is prohibited from discriminating against users, and specific reasons for why

85 These are primarily part of its role as system operator (provision of electricity to its own transmission sub-stations and has, with stand-by generation in case of electricity supply failure at its own sites). However, National Grid is also part of a joint venture (Blue-NG Limited) to operate small rape seed oil -fired power stations at gas distribution pressure -reduction sites.

86 Office of Gas and Electricity Markets (2010b).

access may not be granted are set out in National Grid's license. To support this process, SSE and Scottish Power provide dates and costs for the work involved in facilitating the connection.[87]

Transmission owners are required to plan their networks to meet the National Electricity Transmission System Security and Quality of Supply Standards (SQSS),[88] which set out a coordinated set of criteria and methodologies that transmission licensees, both onshore and offshore, must use in the planning and operation of the transmission system. The SQSS are the minimum requirements for the planning and operation of the transmission system.

In 2008, a wide-ranging review of the SQSS was initiated in response to an increasing penetration of variable generation and significant changes taking place within the power industry. Recommendations from the review to date have included clarifying the use of dynamic ratings and more accurate and consistent consideration of the contribution of embedded generation to demand security.

To implement transmission system reinforcement proposals, transmission licensees need to have secured funding (e.g., as part of a price control) and to have secured landowner permissions and relevant planning consents.

An accumulation of connection requests or an increase in costs at capacity bottlenecks can trigger deeper grid reinforcements. By waiting for requests, transmission companies demonstrate that new lines are needed. However, this approach leads to long delays in cases where more strategic works are needed.

The need to connect large volumes of wind and other new low-carbon generation has required a more strategic and long-term vision is required. Scenarios of the potential transmission investments were developed by the Electricity Networks Strategy Group, a senior industry advisory group including the transmission companies, chaired by DECC and Ofgem.[89] The total value of these projects amounted to around £5bn. Ofgem as regulator has ultimate responsibility, and is working with the transmission owners on the regulatory approvals for these investments in light of the Electricity Networks Strategy Group's advice.

An initial tranche of money has been made available for projects in most urgent need of funding. Other aspects are likely to be funded as part of the next Transmission Price Control Review. All funding under the revenue cap for network companies is consulted on, and network companies are encouraged to get views from stakeholders in advance to improve the quality of their plans and increase the chance that Ofgem will approve them.

Once network companies have approval from the regulator to make a strategic investment, planning consents are required, and these also consider the opinions of stakeholders.

b. Planning Characteristics

Previously, price controls lasted five years, but the new RIIO-T1 price control will last eight years, with a mid-term review after four years. The four transmission companies have submitted and published their RIIO-T1 business plans. In April of 2013, the RIO-T1 price controls took effect. In September of 2013, Ofgem issued instructions and guidance to three electricity transmission owners to enable them to complete the reporting requirements associated with the transmission price control from April 2013 to March 2021. Within these plans, the three transmission asset owners consider the investments required in their own transmission system, in the context of the interconnected system.

As part of its responsibility as system operator, National Grid also produces seven-year statements that cover the whole Great Britain system. Produced annually to help users to recognize opportunities, these statements include demand forecasts, contracted generation capacity, plant margins, and boundary transfer analysis along with high-level information on likely connection timescales in each geographical area.

In terms of network operation for a particular half-hour period, planning work for system operation begins some five years ahead at an outline level and is then refined as time progresses. Figure 9 shows an example of how this process works for generation forecasting.

c. Transmission Development Drivers

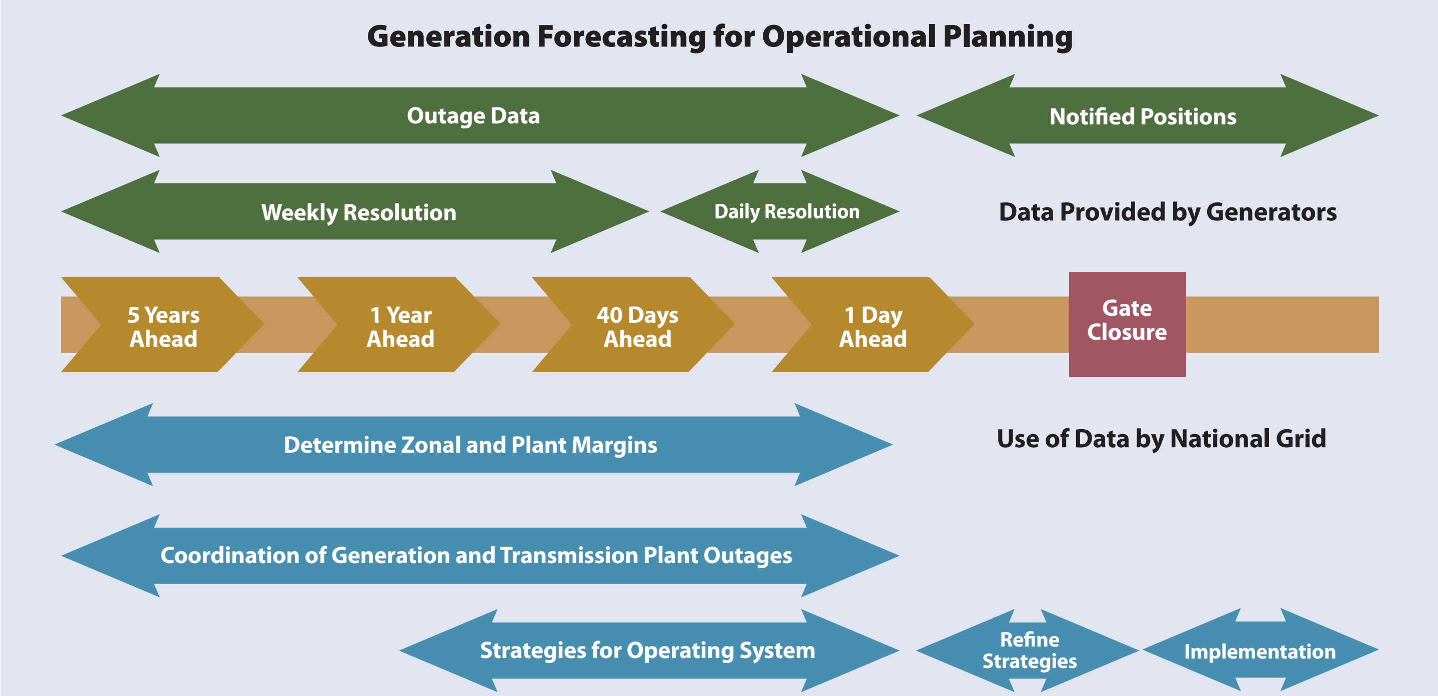
For planning, the SQSS defines the range of system conditions, including the demand and generation background to be assessed and the events for which the transmission system is required to be secure. These

87 Office of Gas and Electricity Markets (2010a).

88 National Grid (2009).

89 Electricity Networks Strategy Group (2009).

Figure 9



Source: Adapted by AF-Mercados EMI from System Operation Review Group (2007).

conditions must be applied when designing transmission network infrastructure and connections to it. Similarly, the operational criteria in the SQSS define the range of system conditions to be assessed and the events for which the transmission system is required to be secure. The operational criteria are closely related to the planning criteria, but also provide additional flexibility to manage actual system conditions, both approaching and during real-time operation of the transmission system (e.g., to accommodate planned or forced outages). The rules defining the system conditions and events to be secured in both planning and operational criteria are deterministic in nature.

More specifically, the events that are secured generally involve two pieces of primary transmission equipment being out of service. Therefore, the SQSS is commonly known to be based on N-2 deterministic criteria in planning and N'-D deterministic criteria in operation, where N denotes an intact network with all transmission equipment in service, N' denotes a network with prior outages of transmission equipment due to maintenance or faults, and D denotes a narrower definition of outage of two circuits—i.e., that of two overhead line circuits on the same towers.

All generators, including renewable generators, have financially firm access to the network. If a generator is constrained down for any reason, it will receive constraint payments. The cost of these payments is socialized, and National Grid as system operator has an incentive under its price control to keep the payments as low as possible.

The connection itself does not typically take into account the variability of the plant. Some offshore wind sites are taking an economic decision to have lower Transmission Entry Capacity (TEC) to reduce the cost of connection.

Variability is taken into account in the wider planning of the network. Significant effort has been made in determining the appropriate output from intermittent generation to be used during planning timescales.[90] National Grid as system operator collects data from all wind farms connected directly to the transmission system, and from a number of embedded wind farms connected to distribution systems. This data provides intelligence on the operation of individual wind farms and any correlation with geographically similar installations. Dynamic line

90 Transmission System Operation Review Group (2007).

ratings are used on some distribution networks.

Transmission licensees typically need to wait for connection requests before making transmission system reinforcements, to avoid the risk of stranded assets for which they cannot recover costs. More strategic investments, such as those required to connect renewables in Scotland, have been separately permitted by Ofgem. These more strategic decisions can take into account policy objectives, such as targets for renewables.

2. The Investment Process

A. Economic Regulation

The revenue cap was formerly based on an RPI-X regime, but the current price control is being conducted under a new RIIO (revenue = incentives + innovation + outputs) model.

The price control will remain an ex ante RPI-linked control. Ofgem will set an upfront price control, incorporating a return on the regulatory asset value and inflation indexing. The price control sets a revenue cap, without reference to an X factor. The revenue will be made up of:

- Base revenue to cover expected efficient costs, including financing costs, of delivering outputs and long-term value for money;
- Adjustments to reflect company performance (incentive schemes); and
- Adjustments made during the control period for specified uncertainties that are considered to be outside the company's control (e.g., price inflation), and changes to financial parameters during the period (e.g., pension adjustments).

There are a number of incentives that will be used under RIIO to ensure that network companies forecast the required expenditure appropriately (CAPEX and OPEX), and that they deliver agreed outputs. For example:

- Companies will be incentivized to meet certain output targets for the performance of the network, safety, customer satisfaction, connections, and environmental and social obligations; and
- Under the information-quality incentive, risks will be shared so that consumers bear some of the costs—or retain some of the savings—if the company's actual expenditure is more (or less) than envisaged at the price control review. Ofgem decides whether the plans submitted by DNOs are "well justified," meaning the DNOs have provided robust evidence that the measures they are proposing are needed and are good value. The level of justification perceived by Ofgem will decide the actual revenue allowed and the risk-sharing percentage.[91]

The aim of the new RIIO framework is to facilitate significant capital investment. Ofgem estimates that £32bn investment is required in the gas and electricity networks by 2020.[92] As a consequence of this regulatory framework, transmission asset owners face relatively low risk in the development of the network, as costs within the cap can be recovered from customers. They can, as a result, obtain relatively low-cost finance.

B. Responsibility for Building Projected Lines

Transmission asset owners are responsible for building and maintaining the transmission networks in their respective geographic regions. They raise the finance required for these projects from the markets, debt and equity, based on their regulated revenue allowances.

The transmission businesses must publish separated accounts and conform to other business separation rules. This is designed to protect the stability of network companies and prevent them using the relatively low-cost finance from regulated activities to finance more speculative activities.

C. Administrative Permits

Historically, planning permits have been a significant issue for major transmission works. For example, the Beauly-Denny line in Scotland (a new 400kV line replacing an existing 132kV line) has been very contentious. It was first proposed in 2001, and once Ofgem had approved the plan the planning process took a further five years before reaching approval in January 2010.

DECC administers the process for developers seeking development consents from the Secretary of State for the construction of overhead lines, electricity generating stations over 50 MW onshore or over 1 MW offshore up

91 Office of Gas and Electricity Markets. (2010c).

92 Office of Gas and Electricity Markets. (2010c).

to limits of territorial waters,[93] and associated permissions (necessary wayleaves, compulsory purchase orders, etc.)[94] in England and Wales. The Electricity Act 1989 requires DECC to take into account the views of the local planning authority, local people, statutory bodies (such as the Environment Agency), and other interested parties. In some cases, there may be a public enquiry before the Secretary of State makes a decision. Applications under the Electricity Act in Scotland are handled by the Scottish Government.

From 1 March 2010, the Infrastructure Planning Commission became responsible for processing new planning applications under the Planning Act 2008. On July 18, 2011 the House of Commons debated and approved the six National Policy Statements for Energy. These set out national policy against which proposals for major energy projects will be assessed and decided on by the Infrastructure Planning Commission.

Some new reinforcement works, to reduce the constraints between Scotland and England, are planned to be located offshore. This will avoid the issues of planning permission and wayleaves.

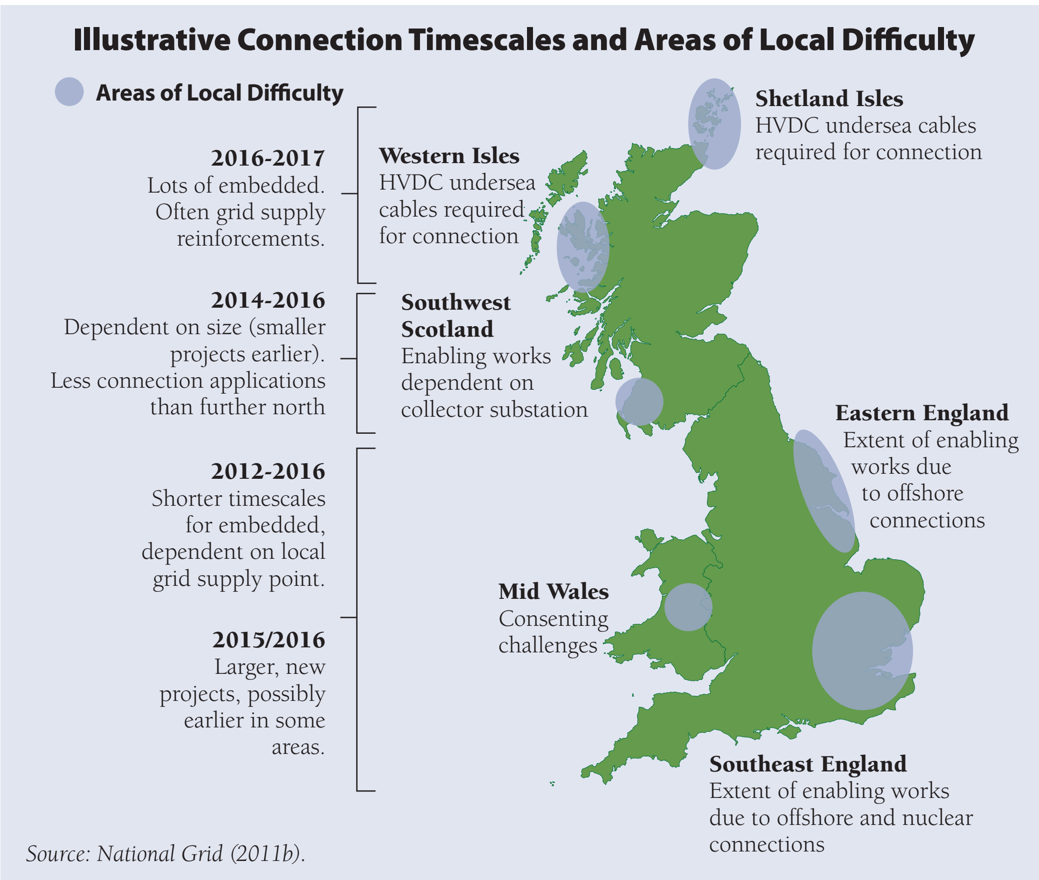
C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation

An applicant for transmission connection has to pay an initial application fee and provide technical details to get a quote. National Grid then has 90 days to prepare an offer, in conjunction with any other applicable transmission owner and distribution network operator. National Grid sends the offer to the applicant, which has another 90-day period to accept it.

Figure 10 provides an indication of the likely connection dates that National Grid expects to offer to new generation connection applications in 2011, in various geographical locations around the country. There is no difference in treatment between conventional and renewable generation. Capacity is normally allocated

Figure 10



Source: National Grid (2011b).

93 Section 37 of the Electricity Act 1989 specifies that, subject to certain exemptions, an electric line shall not be installed or kept installed above ground except in accordance with a consent granted by the Secretary of State. Generation plant over 50MW requires similar government approval (Section 36). Below this level, projects are assessed by local planning authorities.

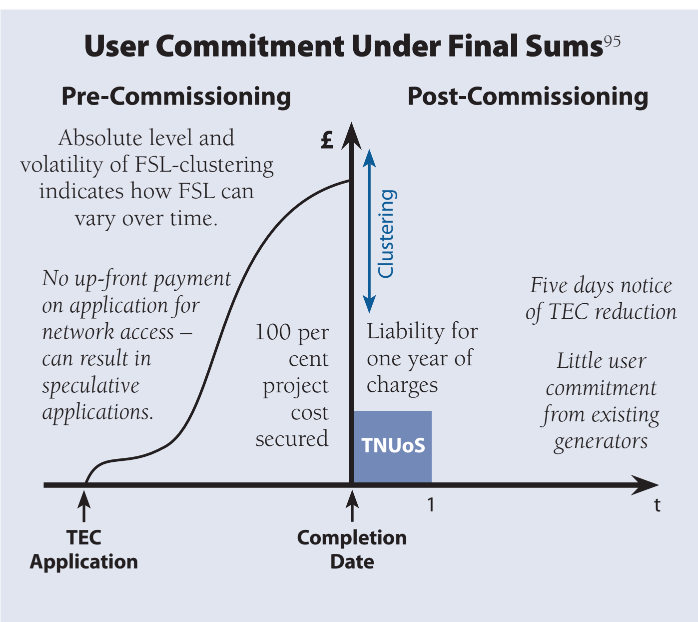
94 Most wayleave rights to install new transmission infrastructure are secured voluntarily. However, if a voluntary agreement cannot be reached, electricity companies have access to compulsory procedures. The electricity companies may seek a Compulsory Purchase Order under Schedule 3 to the Electricity Act 1989, or a "necessary" wayleave under Schedule 4 to the 1989 Act. DECC administers compulsory way leaves and purchase orders sought by electricity companies.

on a first-come, first-served basis. Under the old "invest then connect" access arrangements, all transmission reinforcement work had to be completed prior to connection. However, under the ongoing "connect and manage" arrangements implemented in August 2010, only enabling works need to be completed before a generator can have a guaranteed connection to the transmission network. A generator does not have to wait for wider reinforcement work to be completed. This move to connect and manage has significantly brought forward connection dates for renewable generators. However, enabling works can still be extensive in some circumstances.

Once a generator has entered into a connection agreement with the system operator, it may be required to provide financial security (user commitment) against the deep transmission system reinforcement works identified in its bilateral agreement. The financial security regime is designed to provide the transmission owner some protection from the risk of stranded assets if the project does not go ahead.

The abortive costs that could be incurred if a user terminates prior to connection are known as final sums. Figure 11 shows the key feature of final sums in the pre-commissioning period: that a generator's liability closely matches the expenditure profile of the transmission asset owner. At the point when an application for TEC is made, only a small administrative fee is levied. As construction

Figure 11



works commence, the generator is liable to provide security cover for the costs the relevant transmission owner has incurred, ramping up as construction progresses. At the point immediately before construction finishes, the generator is liable for 100% of the associated reinforcement costs.

This link to the full cost of wider reinforcements could be prohibitively high for some projects, particularly small renewable projects in remote areas that require significant reinforcement works. In August 2006, National Grid introduced a voluntary alternative approach for user commitment: Interim Generic User Commitment Methodology (IGUM). This was designed to maintain some protection from the risk of stranded assets, while reducing the burden on small individual projects by linking the liability to the scale of the project rather than the specific works.

Under IGUM, once a generator enters into a connection agreement with the system operator, it becomes liable for a charge, which increases from £1/kW in year one, £2/kW in year two, up to a maximum of £3/kW in year three. Following consents being granted, users are required to secure a cancellation amount, payable in the event that the generator terminates its connection agreement. The full cancellation amount is ten years' worth of transmission network use of system charges (TNUoS, which ramps up over a four-year period).

2. Capacity Firmness and Congestion Management

Once connected, TEC provides a generator with firm access to the transmission system. A generator cannot export more than its TEC. This is technology-neutral, so variable generators that may only achieve their TEC at certain times in the year will be charged their full TEC value irrespective of how often they are able to achieve TEC. A generator has to pay transmission charges based upon its TEC; but as long as it maintains payments, it is guaranteed to maintain its right to TEC.

Connection of generators under the connect-and-manage regime, ahead of the completion of wider reinforcement works, means that parts of the transmission system will not be compliant with the SQSS until these works are completed. This, in turn, means that National

95 Office of Gas and Electricity Markets (2010d).

Grid as system operator will be required to manage more constraints in the system.

There is no special treatment for renewable generation under constraint management rules. The UK complies with the Renewables Directive by providing guaranteed access for electricity produced from all types of generators, including renewables. If generators need to be constrained to ensure the reliability and safety of the grid system, market arrangements determine which generator reduces its output, and these generators are compensated.[96]

During operation, National Grid procures balancing services to manage system flows and alleviate constraints. Constraints can be managed by limiting or increasing the output of a generator, intertripping,[97] forward trading, or bilateral contracts to change or limit generator output. These all incur costs, which are recovered through balancing services use of system charges (BSUoS).

National Grid is incentivized to reduce constraint costs. BSUoS charges are subject to an incentive scheme where a target level of annual costs is agreed with National Grid. If actual costs are below the relevant target, National Grid is permitted to receive an incentive payment (although the benefits are also shared with generators and suppliers). Similarly, if actual costs exceed the target, National Grid faces an incentive penalty, although the full additional costs are shared with generators and suppliers.

The size of this payment or penalty is determined by the relevant sharing factors that are agreed as part of the overall incentive schemes. The sharing factors are in place to strike a balance between the risks and rewards faced by the system operator and customers. The maximum payment National Grid can receive under the incentive scheme framework is subject to an upper cap, and similarly the maximum penalty it can be liable for is bounded by a lower collar.

3. Generation Embedded in the Distribution Networks

Generators that are not registered within the BSC—those that are less than 100 MW, license exempt, embedded, and registered within a supplier's balancing unit—are exempt from TNUoS charges and payments. The output of these power stations is accounted for in the supplier's demand figures on which TNUoS charges are based. In these circumstances, an embedded power station may be able to reduce the TNUoS charges payable by the host supplier by generating in the Triad periods (three peak-demand periods). Normally there will be an agreement between the generator and the supplier to share the benefit of these negative charges. By being treated as negative demand, these generators avoid transmission losses as well.

Embedded generators are exempt from transmission connection charges, although they do have to pay distribution connection and daily use of system charges. Suppliers that contract with embedded generators receive a benefit, because this acts as negative demand and reduces their transmission charges. Embedded generators may receive a proportion of these benefits under their contract with a supplier.[98]

Net metering is not allowable. Some very small generators (such as household PV) may "spill" their excess generation onto the distribution system without metering. Most will have a half-hourly or non-half-hourly export meter, depending on their scale.

D. Transmission Pricing

Users of the transmission system are subject to three elements of transmission charges:

- Connection charges. These are for the provision and maintenance of connection assets.
- Transmission network use of system (TNUoS) charges. These are for the provision and maintenance of (potentially) shared transmission infrastructure assets—in other words, assets that cannot be solely attributed to a single user.
- Balancing services use of system (BSUoS) charges. These relate to the costs incurred by the system operator in its day-to-day operation of the network.

96 Department of Energy & Climate Change (2009).

97 Intertrip services are required as an automatic control arrangement where generation may be reduced or disconnected following a system fault event to relieve localized network overloads, maintain system stability, manage system voltages, and/or ensure quick restoration of the transmission system. There are two types of intertrip service: commercial intertrips, and system -to -generator operational intertrips.

98 Energy Networks Association (2009).

BSUoS charges include, for example, the costs incurred in resolving constraints. Imbalance charges are targeted at participants, but any residual element of balancing costs are passed through on a socialized basis through BSUoS, as are the costs of resolving congestion (constraint payments).

It was formerly National Grid's responsibility to propose and consult on changes to the charging methodologies. Since January 2011, charging methodologies have sat within the governance of the relevant industry code (CUSC), and changes can be proposed by a wider range of stakeholders.

Ofgem is currently carrying out an independent review of transmission charging and associated connection arrangements (Project TransmiT). In this study we have focused on the current arrangements.

To improve the accuracy of cost targeting, Ofgem's initial view is to move to improved investment cost related pricing. Under this methodology, tariffs would be based on a two-part peak and a year-round tariff, with the year-round element multiplied by a specific load factor (calculated ex-ante based on historical data). By taking into account lower load factors, this is likely to benefit variable renewable generation.

1. Connection Charges

National Grid calculates connection charges in accordance with the Statement of the Connection Charging Methodology, which is a methodology approved by Ofgem.

The capital costs, operation, and maintenance associated with the connection assets are charged to the generator, normally via a monthly fee (although users can choose to pay this as a capital fee). This only covers the shallow connection, with any reinforcement costs recovered through TNUoS charges. If the terms of National Grid's connection offer are not acceptable, the offer can be referred to Ofgem for review.

Some connection activities can be undertaken by the user, or by third parties employed by it. These include the construction, financing, and ongoing maintenance of connection assets. Where these options are taken up by the user, they should not have a detrimental effect on system integrity, security, and safety.

2. Generation Transmission Use of System Charges

TNUoS is the transmission owner charge for the transmission assets. Generators have to pay TNUoS based upon their TEC (normally generation capacity). TNUoS is charged on a zonal basis, with Great Britain divided into 14 zones for the purpose of demand TNUoS charging, and 20 zones for generation TNUoS charging. It is possible for generation charging zones to change each year. Demand charging zones do not change.

Twenty-seven percent of total TNUoS revenue is recovered from generators, the remaining 73% from demand customers. To get in line with EU tariff guidelines, this ratio is due to change to 15%/85% by April 2015.

All directly connected generation pays a local TNUoS tariff, representing the cost of the first transmission substation to which the generator is connected. If the generator is not connected to a substation that is part of the main interconnected transmission system, its local TNUoS tariff will also include an element representing the costs of the circuit linking the local substation to the main interconnected transmission system.

All generators are also levied a wider TNUoS tariff, according to the zone in which they are located.

Each year, National Grid calculates a TNUoS tariff for each generation and demand zone. These tariffs vary across Great Britain, and are designed to encourage demand and generation to locate in a manner that reduces peak power flows on the transmission system. This means the tariffs will vary year by year as the configuration of demand and generation in Great Britain changes. Because peak power flows tend to go from north to south, generation TNUoS is highest in Scotland and lowest in the south of England. The converse holds for demand TNUoS. A significant amount of the renewable resource is located in the more expensive TNUoS regions, increasing the costs associated with renewable generation. The locational differences in generation TNUoS are significant—ranging from £-7.04/kW to £22.93/kW for the period from April 2011[99] (a negative value indicating that generators are paid TNUoS).

Revenues from BSUoS are about half those from TNUoS.[100] BSUoS charges are calculated for each settlement period on a

99 National Grid (2011a).

100 Office of Gas and Electricity Markets (2010d).

£/MWh basis, and are charged equally to generation and demand (50/50) based on their metered volume in the relevant period. BSUoS charges do not vary by location.

E. Renewable Generation Operation

1. Generation Forecasting

Counterparties (generators and suppliers) decide individually how much power they physically plan to inject and withdraw from the system. Generators typically have firm transmission access rights, which mean that renewable generators will typically plan to inject all available generation onto the system.

The responsibility for balancing supply and demand is arguably split between the system operator and market participants.

Market participant balancing can only be undertaken through the traded market (bilateral and exchange trading), and through within-portfolio activities. At gate closure (one hour ahead), market participants must declare the physical operation of plant through the submission of final physical notifications. From this point, the system operator, National Grid, has responsibility for balancing the system, although due to the issues associated with plant dynamics it may take actions outside this one-hour timescale.

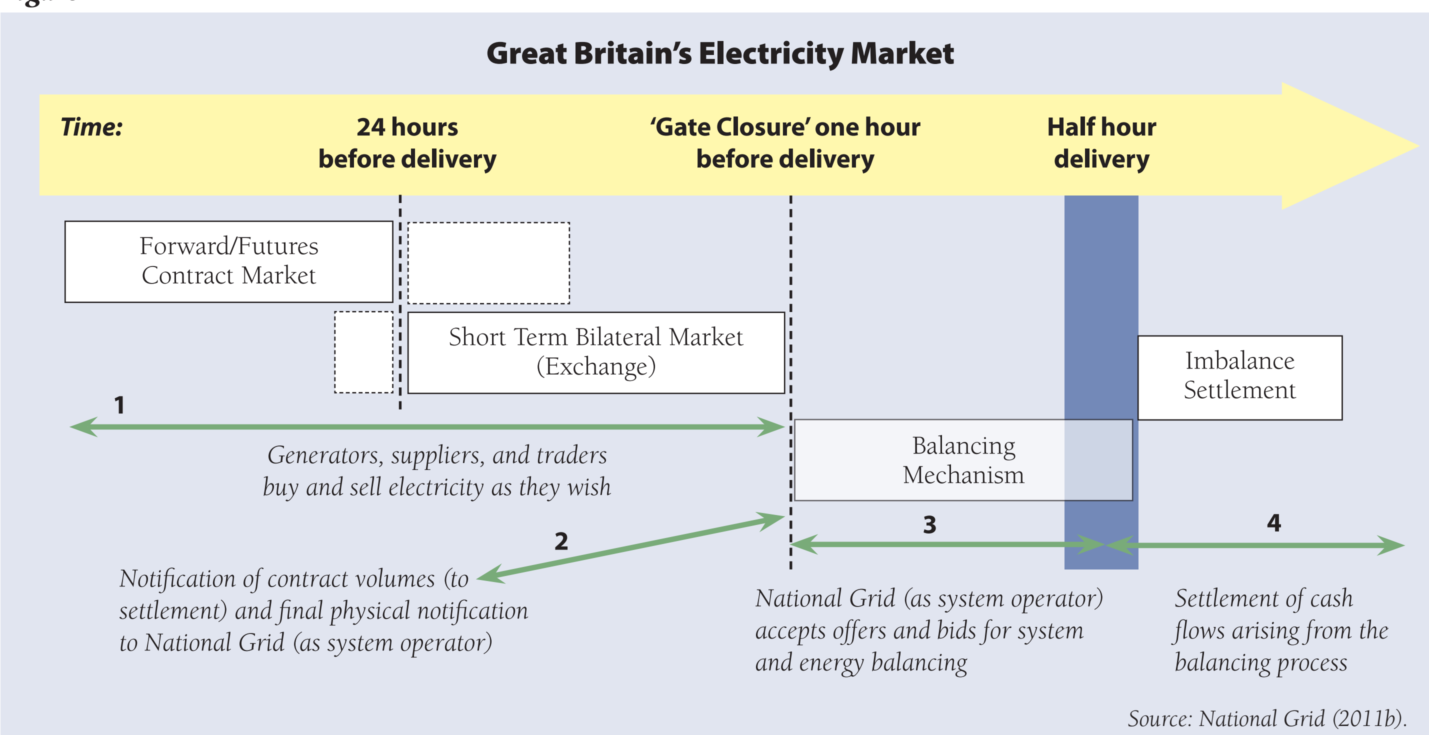
2. Participation in Balancing Services

The system operator is responsible for resolving any energy balancing, required as a result of differences between demand and generation final physical notifications, as well as any imbalances due to demand or generation fluctuations and unplanned outages that result in imbalances occurring after gate closure (differences between physical output and notifications). The system operator is also responsible for system balancing—maintaining supply quality (stable voltage and frequency) and supply security (transmission constraints).

The system operator has a number of tools for system and energy balancing. These include accepting bids or offers in the balancing mechanism, entering into contracts with market participants for energy or ancillary services, and energy trading in the power markets.

The balancing mechanism is the market that exists between gate closure and real time. The balancing mechanism is a monopsony market, with the system operator as the sole counterparty. Market participants—predominantly generators, but also large controllable loads—can submit bids or offers to decrease or increase their output from their final physical notification. The balancing mechanism is a pay-as-bid market, and is used as a balancing market and for the delivery of other system

Figure 12



operator actions such as ancillary services.

Although some flexible plant can derive significant revenues from the provision of ancillary services and flexibility to the system operator through balancing mechanism, participation from variable renewable generation is limited.

Participants in the balancing mechanism submit bids and offers to increase or decrease their generation. A negative price means that National Grid would have to pay the generator to reduce its output if the bid was accepted. Conversely, an offer represents a price, or range of prices, that the generator would be paid by National Grid to increase its output if its offer was accepted. So a bid or offer price would need to include fuel costs, variable operation costs, and, in the case of a renewable generator, the loss of renewable support (ROCs).

In areas where there are constraints, there may be significant balancing costs if there are negative bids. (These may not necessarily be priced based on market fundamentals: for example, high-priced negative bids, or "sleeper" bids, may be a signal that the party does not want the bid to be accepted.) Any plant can submit these high negative bids. This makes it possible for there to be situations where wind is constrained down before other plants.

Some wind generation has been constrained down under this mechanism to manage constraints. For example, National Grid was forced to curtail wind generation in Scotland due to localized constraint issues on April 5-6, 2011 and September 10-13, 2011, having first exhausted more economic options on conventional plant. During these periods, National Grid took actions on plant with high negative bid prices, and a number of Emergency Instructions were issued to reduce generation. These periods had high balancing costs and have led to a consultation on changes to the mechanism.[101]

3. Imbalance Settlement

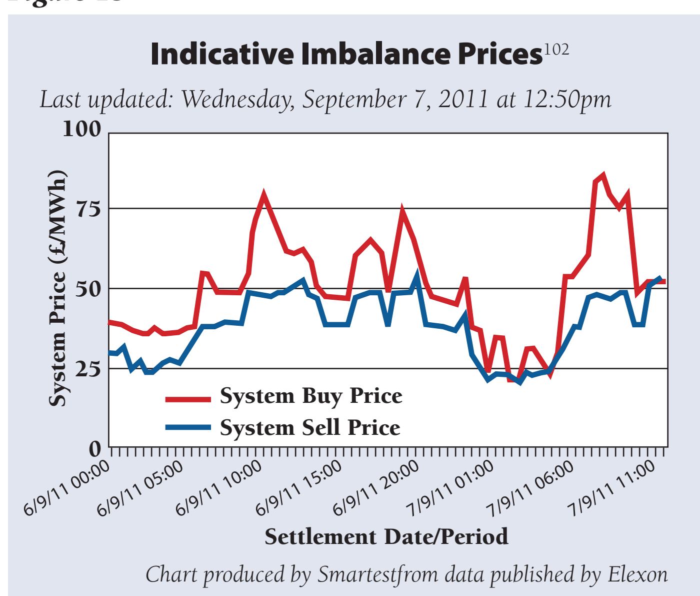
Market participants have financial incentives to manage the balancing of their position, since they will be charged imbalance prices on any differences between their notified commercial position and physical output over each half-hour period.

There is a dual imbalance price system: counterparties are exposed to System Buy Price (SBP) when their account is short and System Sell Price (SSP) when their account is long. Both prices are derived as a function of market prices and system operator costs. The imbalance cost is simply the imbalance volume multiplied by the imbalance price.

The methodology for calculating SBP and SSP varies depending on whether the system is long or short. There are two imbalance price methodologies, the main imbalance price (defined as a function of system operator costs) and the reverse imbalance price (defined as the half-hourly exchange market price). When the system is long, SSP is defined as the main imbalance price (and SBP is the reverse price). When the system is short, SBP is defined as the main imbalance price (and SSP is the reverse price). Imbalance prices can be extremely volatile, especially SBP.

Energy imbalances are calculated at an energy account level. Each market participant has a separate energy account for production, netting across all generation, and consumption, netting across all demand. However, it is not possible to net imbalances between these two accounts. Thus, market participants are exposed separately to imbalances on both the generation and demand side. However, vertically integrated companies can meet their own demand using their own generation

Figure 13



101 National Grid (2011c).

102 For more information see: http://www.smartestenergy.com/

without trading through the market, by notifying trades between their generation and consumption accounts, with volumes notified in both accounts before gate closure. Since portfolios can net balances across all of their generation (and separately demand) portfolio, this naturally leads to some advantage due to averaging effects. In addition, the ability of portfolios to trade between consumption and production accounts means that they are not as exposed to trading in relatively illiquid markets, especially approaching real time.

The variable and unpredictable nature of some forms of renewable generation—wind, for example—means that these are particularly exposed to imbalance charges. Since imbalances are calculated at an energy account level, this provides portfolio generators a considerable advantage compared to independent renewable projects. This is an additional factor that has influenced many generators to enter into long term off-take agreements with major utilities, passing them the imbalance exposure and allowing them to consolidate output from generation across the portfolio, reducing imbalance risks.

VI. US: NYISO

A. Electricity System Overview

1. Regulatory Institutions

The New York Independent System Operator, Inc. (NYISO) operates the New York region's electricity grid, administers the New York wholesale electricity market, and provides reliability planning for the New York region's bulk electricity system.

NYISO is subject to regulatory oversight, primarily by the Federal Energy Regulatory Commission (FERC). In this respect, it is like any other Regional Transmission Organization (RTO) or Independent System Operator (ISO) in the United States.[103] In certain aspects, the New York State Public Service Commission (NYPSC) shares some overlapping areas of regulatory oversight with FERC. However, NYPSC's main mandate is to regulate distribution utilities.

NYISO is also governed by the rules of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC).

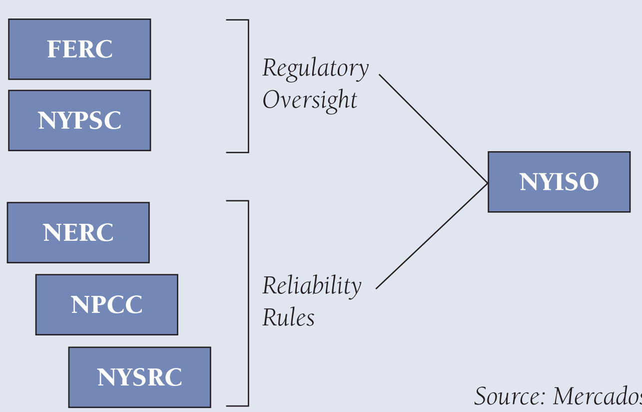
As with any ISO or RTO in the US, participation in NYISO is voluntary for all entities. Any entity that wishes to become a part of the ISO must meet certain minimum requirements and become a party to the ISO Agreement. All such parties are subject to charges as determined by the ISO, and may participate in the governance of the ISO. Any party may withdraw from the agreement with 90 days written notice to the ISO Board. Transmission owners must also sign the Transmission Owners Agreement, in which they give over operational control of their transmission assets in return for cost recovery through NYISO tariffs. Transmission owners may withdraw from the ISO upon 90 days' written notice to the ISO Board and the FERC.

Because of the voluntary nature of NYISO, its governance structure plays an important role in ensuring that the ISO continues to serve the needs of its participants. The governance structure is composed of three committees: the Management Committee, the Business Issues Committee, and the Operating Committee. These meet regularly, and each oversees its own set of working groups and subcommittees. NYISO members and stakeholders may also participate in planning processes, including reliability and economic planning. In the case of regulated economic transmission projects, load-serving entities that are potential beneficiaries of a proposed project are eligible to vote for or against implementation of the proposal.

Major decisions governing coordinated regional and interregional planning requirements that apply to most states are included in FERC Orders No's., 890 and 1000. FERC Order 1000 establishes significant new obligations on transmission utilities to coordinate planning efforts with neighboring regions, and to allocate costs to the intended beneficiaries of a line. The Order also establishes requirements to incorporate state policy objectives for clean energy resources in the planning efforts. (FERC, 2011)

Figure 14

Institutions Active in the Electric Sector in New York



Source: Mercados

103 With the exception of ERCOT – the Electric Reliability Council of Texas.

2. Electricity System Architecture

The New York Control Area (NYCA) is part of the Eastern Interconnection of the United States. The NYISO was formed in April 1997 as a non-profit organization by assuming the responsibilities of its predecessor, the New York Power Pool (NYPP), which was responsible for coordinating the reliability of New York State's electric power grid for more than 30 years.[104] NYISO formally started to operate the NYCA grid on December 1, 1999.

As a single-state ISO, functioning both as the transmission system operator and the market operator, NYISO is responsible for:

- Maintaining and enhancing regional reliability by managing its bulk electricity system;
- Operating and monitoring open, fair, and competitive wholesale electricity markets;
- Planning the NYCA's power system by conducting long-term assessments of resources and needs; and
- Providing factual information to policy makers, stakeholders, and investors in the power system.

NYISO is governed by an independent board of directors, as well as a committee structure that consists of market-participant representatives. In other words, it has a shared governing system with its stakeholders. NYISO's operating budget is financed by an "adder" on the transmission use of system charge (per MWh of power transmitted in the system) to market participants.

As a result of a series of restructuring acts that have been implemented since 1996, New York's electricity market has been completely unbundled in terms of generation, transmission, and distribution activities. Although vertically integrated utilities have previously been unbundled in terms of their assets, some distribution utilities also own transmission assets. There are both investor-owned and publicly owned distribution and transmission utilities in New York. Some generators are publicly owned, but most are privately owned and operated in the marketplace.

While the distribution rates are regulated at the state level by NYPSC, the transmission rates are set at the federal level by the FERC. The generation and transmission licensing, including site permitting procedures, involve both state and federal decision making.

The NYCA has nearly 10,900 miles of high-voltage transmission lines and serves approximately 425 market participants. The system includes more than 500 generating units, totaling 37,416 MW of capacity, and serves a peak load of 34,000 MW.

The NYISO runs energy, capacity, and ancillary services markets through hourly, daily, monthly, and annual auctions, depending on the nature of the product or service, by accepting bids (from buyers) and offers (from suppliers). In 2010, the total market volume of transactions was nearly $7 billion. The NYISO runs both day-ahead and real-time markets. In its *2010 State of the Market Report,*[105] Potomac Economics, which serves as the NYISO's external Market Monitoring Unit, assessed the NYISO's wholesale electricity markets to be competitive, comprehensive, and efficient.

3. Renewable Generation Policy and Implementation Mechanisms

The state of New York has set a rather ambitious Renewable Portfolio Standard (RPS) policy in 2004 that aims to obtain 30% of its electricity from renewable sources by 2015.

RPS energy targets are set for the following three groups:

- Main tier, or large-scale generators that sell power to the wholesale grid or generate power for onsite use;
- Customer-sited tier—small-scale generators such as household photovoltaic (PV) systems;[106] and
- Other market activities by individuals and businesses that choose to pay a premium on their electricity bill to support renewable energy. This group includes

104 New York ISO (2011a); also see Section 1.1, in part, is based on NYISO 2010 Annual Report and www.nyiso.com.

105 Potomac Economics serves as the Independent Market Monitor for the Midwest ISO and ERCOT, the Market Monitoring Unit for the New York ISO, and the Independent Market Monitoring Unit for ISO New England. (See http://www.potomaceconomics.com). Its *2010 State of the Market Report* for the New York ISO Markets states that "Overall, we conclude that the NYISO markets performed well in 2010, in part because the NYISO's systems are among the most advanced of any of the RTOs." (p. 154).

106 NYSERDA is administering the first two groups.

107 See http://www.nyserda.org/rps and http://www.nyserda.org/rps/index.asp. New York State Energy Research and Development Authority (NYSERDA) is a public benefit corporation that aims to promote the use of renewable energy sources.

108 Of these 53, one facility had its contract expired January 31, 2010.

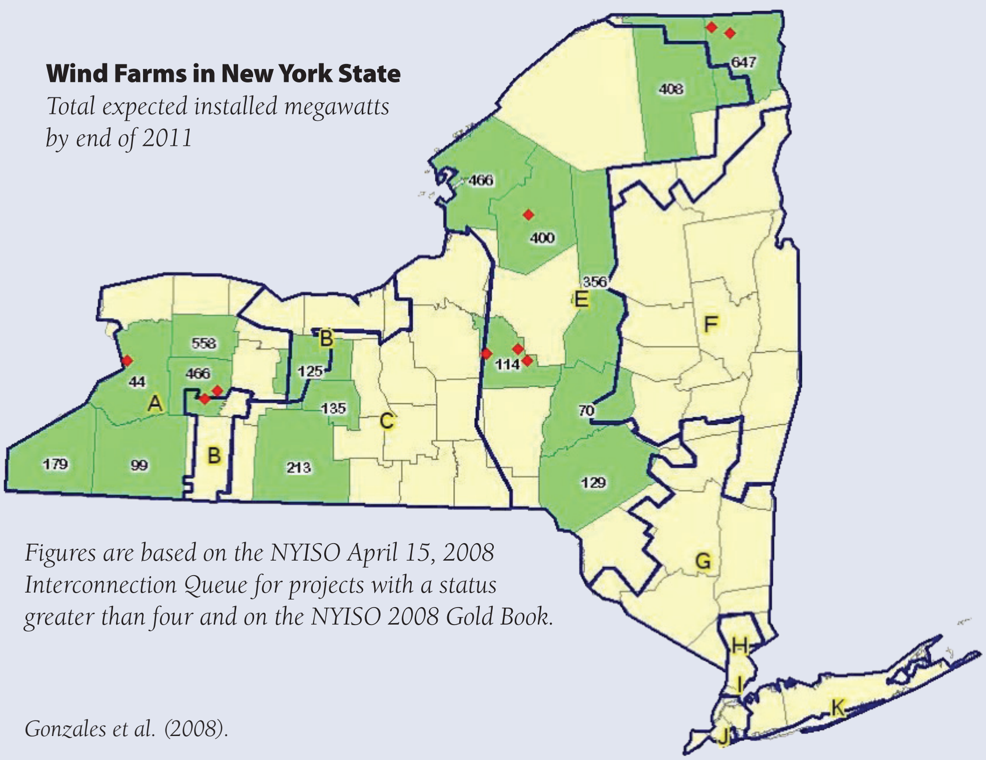
state agencies that are subject to renewable energy purchasing requirements.

As of August 2011, 53 large-scale electricity generators were participating in the RPS through NYSERDA.[107, 108] The remaining 52 facilities were under contract to provide 4.82 million MWh per year, or 49% of NYSERDA's 2015 main tier target of 9.77 million MWh per year.

Currently, 16% of installed capacity in NYCA is renewable. As of mid-2011, there were more than 1,300 MW of installed wind generation capacity and more than 7,000 MW of wind capacity had been proposed for grid connection.

Figure 15

Distribution of Wind Interconnection Forecast



Figures are based on the NYISO April 15, 2008 Interconnection Queue for projects with a status greater than four and on the NYISO 2008 Gold Book.

Gonzales et al. (2008).

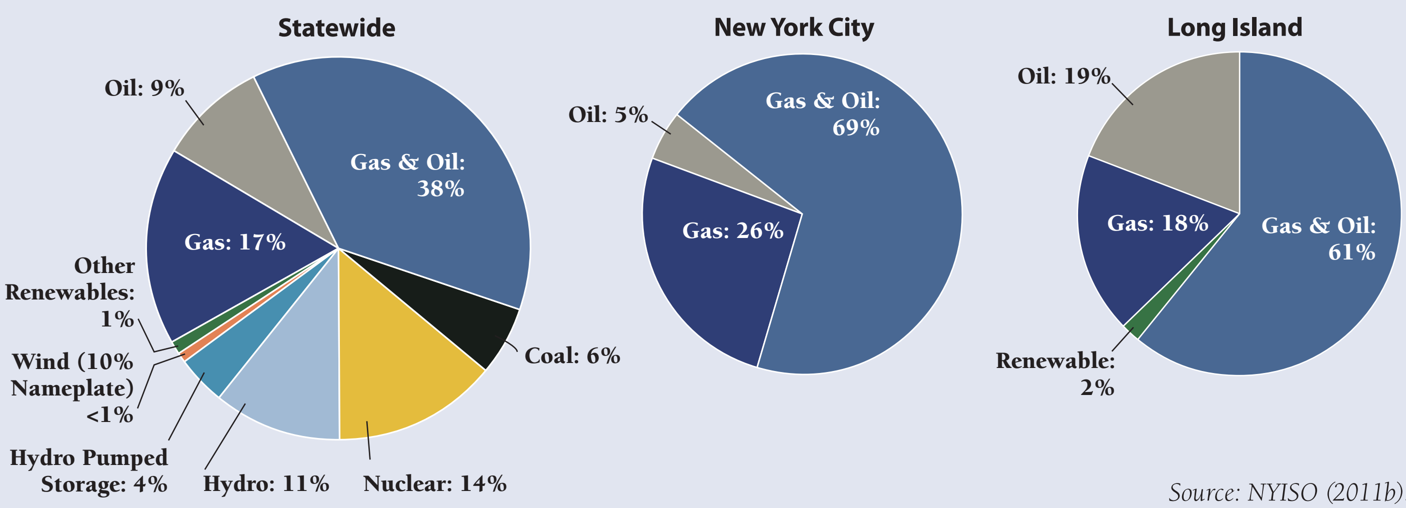
4. Transmission Network Overview

A. General Model

The NYISO serves nearly 19 million people in the NYCA; the system has 37,416 MW of generating capacity. The NYCA has three main areas: New York City (NYC), Long Island (LI) and the Rest of the State (ROS). The NYC is a congested area, and has different attributes for congestion management and market power mitigation measures. It must also meet a more stringent reliability standard than other areas of the state. The NYC's transmission

Figure 16

NYISO Electric Generation Capacity by Fuel Type, 2011



Source: NYISO (2011b).

system must be designed to meet Second Contingency Design Criteria, meaning that it must be able withstand the loss of two bulk electric assets. Most of the state, in contrast, must only satisfy First Contingency Design Criteria.

In 2010, the peak load was 33,452 MW, registered as the third-highest peak on record. The highest peak occurred in summer of 2006 as 34,000 MW. Approximately 50% of electric load is located in NYC and LI, while more than 60% of installed capacity is in the ROS area. NYC has approximately 10,000 MW of installed capacity —less than its load, which is more than 11,000 MW.

In NYCA, power flows are typically in the direction of from northern and western New York to the southeastern part of the state (i.e., NYC and LI), creating congestion on the system due to insufficient transmission capacity. Also, since it serves as a regional hub of power, substantial amount of wheeling occurs through NYCA, including from Canada to the PJM area.

Based on the usual ISO model in the US, the NYISO only operates the transmission network assets owned by either investor-owned or state-owned entities. In this case, the state-owned New York Power Authority (NYPA) owns the transmission (backbone) assets of NYCA. In total, there are seven transmission owners in the state.[109]

In 2010, the average cost of wholesale electricity in New York was $59 per MWh. Demand response resources added nearly 2,500 megawatts of capacity in the same year, with more than 4,000 customers registered to participate in these programs.

B. Geographic Scope

As stated above, the NYISO is a single-state ISO and operates the transmission network in the New York state area (i.e., NYCA), as shown in Figure 17.

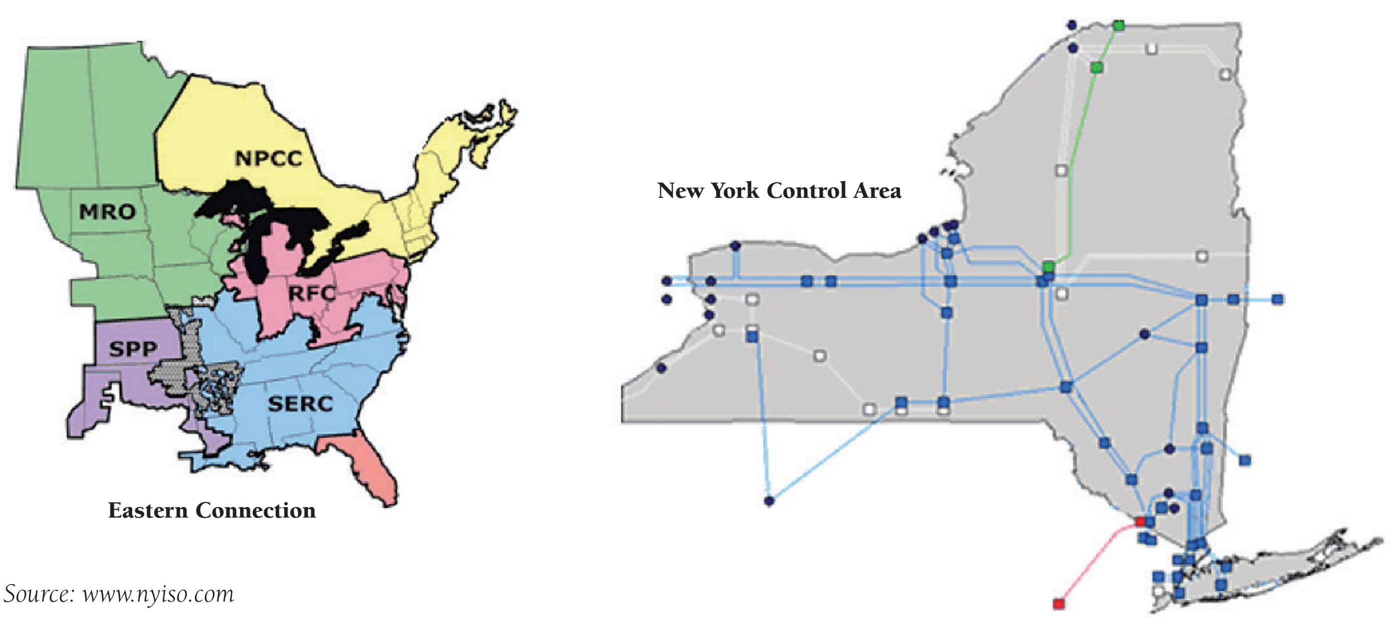
C. Transmission Network Regulatory Framework

The transmission use of system charges in the US are approved by FERC on the basis of a transmission district where a particular transmission-asset owner operates. Because these tariffs are determined based on the recovery of the cost of particular transmission assets, they vary between transmission owners. In general, transmission costs are recovered through a cost-plus (i.e., rate of return) regulation method.

109 Seven transmission owners are: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, Niagara Mohawk Power Corporation (doing business as National Grid), New York Power Authority, New York State Electric and Gas Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation.

Figure 17

The Eastern Interconnection and New York Control Area



Source: www.nyiso.com

In the NYISO region, transmission pricing is usually implemented in the form of "postage-stamp" pricing, which imposes a uniform usage-based charge within a particular area. This is generally the case in the US.

As will be discussed in more detail, transmission congestion pricing is also being implemented within the framework of organized wholesale electricity markets in the US. The congestion component of location-based marginal pricing of generation is also an additional form of transmission charge.

B. Transmission Planning and Investment Processes

1. The Planning Process

A. Responsibility for Planning[110]

The NYISO maintains the reliability standards of New York's bulk power system through its planning process, which is based on future demand forecast and the corresponding resource adequacy assessment. This Comprehensive System Planning Process has a ten-year horizon. Planning studies are conducted in collaboration with the NYISO's stakeholders, including regulators and market participants (suppliers, load serving entities, transmission owners, and electricity traders).

As a result of this planning process, potential needs and issues are identified in the Reliability Needs Assessment. All types of resources (generation, transmission, and demand-side management) are considered as potential solutions. The Comprehensive Reliability Plan is then developed, with plans and schedules to meet resource adequacy requirements.

If no market-based solution is available and there is a need for a regulated backstop solution to meet reliability needs, the costs of the project can be allocated through the NYISO's tariffs following FERC regulatory approval.

This reliability planning is followed by the process for economic planning. At that stage, the Congestion Assessment and Resource Integration Study is conducted to evaluate congestion on the transmission system and assess the relative costs and benefits of generic solutions to alleviate that congestion. In the second phase of economic planning, specific projects are evaluated. Eighty percent or more of the weighted[111] vote of beneficiaries (affected load-serving entities) is needed for a regulated economic transmission project to have its cost allocated. The costs are allocated to all beneficiaries through the NYISO's tariffs.[112]

The transmission studies and interconnection projects take into account the regional aspects of reliability, and so are conducted in coordination with neighboring system operators (i.e., PJM, ISO-NE, Midwest ISO, and the control areas of Hydro Quebec and Independent Electricity System Operator of Ontario, Canada).

B. Planning Characteristics

The following describes the NYISO's Comprehensive System Planning Process steps in detail:[113]

i. Reliability Planning Process

- ***Local Transmission Owner Planning Process:***
  - Each transmission owner is required to post on its website the planning criteria and assumptions currently used in its Local Transmission Planning Process for its own transmission district. Interested parties may review and comment on the planning process. Transmission owners must take any comments received into consideration.
  - Planning criteria must meet or exceed NERC, NPCC, or NYSRC criteria.
  - NYISO holds one or more stakeholder meetings in each planning cycle to discuss the transmission owner's current Local Transmission Plan.
  - Each planning cycle, the transmission owner submits the finalized portions of its Local Transmission Plan to NYISO for inclusion in the Reliability Needs Assessment.
  - Disputes related to the Local Transmission Plan are subject to a dispute resolution process determined by NYISO .

110 New York ISO (2011a); New York ISO (2012a).

111 As discussed above, load -serving entities defined as beneficiaries of a proposed project are eligible to vote on the project. The voting share of each LSE is weighted according to its share of the total project benefits.

112 If the project is implemented, all beneficiaries, including those voting "no," pay their proportional share of the cost of the project. See Section 31.4.3.6 of New York ISO (2012a). NYISO Tariffs–OATT Attachment Y.

113 New York ISO (2012a)This section is based on NYISO Tariffs–OATT Attachment Y. The Comprehensive System Planning Process refers to and covers reliability planning, economic planning, cost allocation and cost recovery, and interregional planning coordination.

- ***Reliability Needs Assessment:***
  - NYISO develops the Reliability Needs Assessment by evaluating the bulk power system needs over the ten-year study period, in consultation with market participants and all other interested parties.
  - The Reliability Needs Assessment identifies reliability needs, provides an analysis of historic congestion costs, and (if necessary) designates the transmission owner responsible for each reliability need.[114] Reliability needs are defined in terms of total deficiencies relative to reliability criteria.[115]
  - After its review, NYISO determines whether transmission owners' Local Transmission Plans meet the reliability needs, and recommends alternative ways to resolve the needs from a regional perspective.
  - The draft Reliability Needs Assessment is voted and commented on by the Operating Committee, the Management Committee, and the NYISO Board. The Market Monitoring Unit of the NYISO also considers whether market rules changes are necessary to address any identified failures in NYISO's competitive markets.
- ***Comprehensive Reliability Plan:***
  - When a reliability need is identified, the responsible transmission owner provides a proposal for a regulated solution.[116] At the same time, NYISO also requests market-based responses from the marketplace.[117] During this process, the NYISO and the transmission owners are required to provide access to necessary data.
  - When evaluating proposed solutions, NYISO considers all resource types on a comparable basis: generation, transmission, and demand resources.
  - Following NYISO's evaluation of the proposed solutions to reliability needs, the NYISO prepares a draft Comprehensive Reliability Plan.
    - If the NYISO determines that a market-based solution will not be available in time to meet a reliability need, and finds it necessary to take action to ensure reliability, it states in the plan that implementation of a regulated solution is necessary. The transmission owner then provides a description of the regulated backstop solution. This includes a non-binding preliminary cost estimate of that backstop solution, with the condition that a responsible transmission owner will be entitled to full recovery of all reasonably incurred costs related to the regulated backstop solution.
    - If the NYISO determines that neither market-based proposals nor regulated proposals can satisfy the reliability need in a timely manner, it will determine that a gap solution is necessary.[118] Gap solutions may include generation, transmission, or demand side resources.
  - The draft Comprehensive Reliability Plan is reviewed and commented on by committees and working groups.
  - The draft plan is voted and commented on by the Operating Committee, the Management Committee, and the NYISO Board. The Market Monitoring Unit of the NYISO also considers whether market rules changes are necessary to address any identified failures in NYISO's competitive markets.
  - The NYISO also provides the Comprehensive Reliability Plan to the regulatory agencies.

114 Responsible Transmission Owner is the TO designated by the NYISO, to prepare a proposal for a regulated solution, or to proceed with a regulated solution to a reliability need.

115 The reliability criteria refers to the electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules determined by the North American Electric Reliability Council. (NERC), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council (NYSRC).

116 There are detailed procedures for the qualification requirements of backstop solutions. See Section 31.2.4.2 of New York ISO (2012a).NYISO Tariffs–OATT Attachment Y.

117 Similar to that of backstop solutions, there are detailed procedures for the qualification requirements of valid market based solutions. See Section 31.2.4.4 of New York ISO (2012a).NYISO Tariffs–OATT Attachment Y.

118 Gap Solution is defined as a solution to a reliability need that is designed to be temporary and to strive to be compatible with permanent market-based proposals.

ii. Economic Planning Process

- ***Local Congestion Assessment and Resource Integration Study for Economic Planning:***
  - The NYISO prepares the Congestion Assessment and Resource Integration Study based on the most recently concluded and approved Comprehensive Reliability Plan. The study uses a ten-year planning horizon consistent with the reliability planning horizon.
  - As with the Comprehensive Reliability Plan, NYISO develops this study in consultation with market participants and all other interested parties.
  - The study assumes a reliable system throughout the study period, based on the Comprehensive Reliability Plan.
  - In conducting the study, the NYISO conducts a benefit/cost analysis of each potential solution to the congestion identified, applying a set of well defined benefit/cost metrics—such as the present value of the system-wide production cost reduction, estimates of reductions in losses, location-based marginal pricing load costs, generator payments, capacity costs, ancillary service costs, emission costs, and constraint payments.
  - The draft study is submitted to stakeholders for review and comment.
  - The draft Congestion Assessment and Resource Integration Study is voted and commented on by the Operating Committee, the Management Committee, and the NYISO Board. The Market Monitoring Unit of the NYISO also considers whether market rules changes are necessary to address any identified failures in NYISO's competitive markets.

C. Transmission Development Drivers

Transmission investment decisions are made on the basis of the predetermined reliability criteria and economic planning factors. The Reliability Needs Assessment process provides an assessment of resource adequacy and transmission security of the bulk power system over a 10-year planning horizon, and the Congestion Analysis and Resource Integration Study adds an economic planning aspect to the transmission planning process.

In developing solutions to reliability needs, the NYISO considers all resource types—generation, transmission, and demand response—on a comparable basis as potential solutions. More specifically, peak load reductions through energy efficiency and demand response are included in the calculations. In fact, a recent 2010 Reliability Needs Assessment states that the projected impact of these energy efficiency programs has increased relative to that expected in 2009. In the 2009 assessment, the cumulative energy savings were 10,235 GWh by the year 2018; in the 2010 assessment, this increased to 13,040 GWh by 2018.

NYISO does not own any of the bulk power transmission assets it operates, so the potential incentive for the preference for transmission investments over generation or demand response resources does not exist in the ISO model (in contrast to the Transco, model where transmission assets are owned *and* operated by the Transco).

For instance, in its 2010 Reliability Needs Assessment, the NYISO identified three reasons for not finding reliability needs for the next 10 years:

- Generation additions,
- A lower energy forecast as a result of the 2009 recession (which reduced the peak demand forecast for 2011 by 1400 MW) and statewide energy efficiency programs (which aim to lower electricity consumption by 15% of the 2007 forecasted levels by 2015), and
- Increased registration of demand response resources under Special Case Resource.[119]

2. The Investment Process

A. Economic Regulation

The revenue requirements of transmission assets owned by transmission owners are met through the transmission tariff set by FERC. The revenue requirements target the recovery of investment costs, which generally have long recovery periods.

As will be discussed later, the tariffs set by the FERC are called *transmission service charges* in NYCA. FERC usually uses a cost-plus method to set tariffs, where the investor earns a reasonable rate of return on dollars invested.

119 ***Special case resources*** are defined as end-use loads capable of being interrupted upon demand, and distributed generators, both of which must be rated 100 kW or higher and are invisible to the ISO's Market Information System. See Section 4.12 of New York ISO (2009).

b. Responsibility for Building Projected Lines

As discussed earlier, the responsibility for addressing the reliability of the transmission system is determined through the Comprehensive System Planning Process, as a result of which a transmission owner is given responsibility for implementing the solution through the transmission planning process.

If the NYISO then determines that a market-based solution is not available in a timely manner to meet a reliability need, and determines that it is necessary to implement a regulated solution by the responsible transmission owner, then that transmission owner becomes entitled to full recovery of all reasonably incurred costs related to the regulated backstop solution.

i. Cost Allocation Principles

Cost allocation for regulated transmission solutions to reliability needs are determined by the NYISO, based on the principle that beneficiaries should bear the cost responsibility.[120] This principle includes the following elements:

- The cost allocation methodology focuses on solutions to violations of specific reliability criteria. Potential impacts unrelated to addressing the reliability need are not considered for the purpose of cost allocation for regulated solutions.
- The primary beneficiaries are transmission districts that have been identified as contributing to the reliability violation.
- The cost allocation among primary beneficiaries is based on their relative contribution to the need for the regulated solution.
- To the extent possible, the cost-recovery methodology should provide cost recovery certainty to investors.

The NYISO has detailed methodologies and formulas for calculating the cost recovery of transmission projects depending on the classification of particular investment.

ii. Cost Recovery for Regulated Projects

The cost of transmission investments is recovered through FERC-approved tariffs. Transmission owners and other developers are entitled to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives related to the development, construction, operation, and maintenance of regulated projects, including short-term gap solutions to meet a reliability need.[121]

For a regulated economic transmission project, the transmission owner or other developer has the right to make a transmission tariff filing with FERC, for approval of its costs associated with implementation of the project. The filing must be consistent with the project proposal evaluated by NYISO. In transmission tariff filings, the period for cost recovery—if any is approved—will be determined by FERC, and will begin if and when the project starts commercial operation.

To the extent that *incremental transmission congestion contracts*[122] are created as a result of a regulated economic transmission project that has been approved for cost recovery under the NYISO tariff, those incremental contracts that can be sold are auctioned by the NYISO. The NYISO uses these contract revenues to offset the revenue requirements for the project.

3. Administrative Permits

Once a transmission project is identified as a result of Comprehensive Reliability Plan process in NYCA, site permits need to be obtained primarily at the state and federal levels. Strict regulatory codes for siting transmission facilities make transmission investments long and costly. Coupled with frequent local opposition to high-voltage lines, long cost-recovery periods, and the overall complexity of siting transmission,[123] the siting factor sometimes deters transmission investments. Sometimes there is a tradeoff for consumers between consuming less-expensive power to be transmitted from long distance via new lines to populated areas, and continuing to consume expensive power with the existing, congested transmission infrastructure. Local decision making plays a relatively larger role, compared to state and federal administrations, as the laws and regulations regarding transmission siting are shaped by the will of the local population, though authority ultimately rests with the state.

120 See Section 31.4.2.1 of New York ISO (2012a).NYISO Tariffs–OATT Attachment Y.

121 See Section 31.4.4 of NYISO (2012a).Tariffs–OATT Attachment Y.

122 Transmission congestion contracts are equivalent to *financial transmission rights.*

123 For a more detailed discussion on transmission siting and permitting issues in the United States see Meyer et al. (2002).

C. Connection and Access to the Transmission Network

1. Connection Capacity Allocation[124]

In the New York transmission system, a new load or generation plant *(eligible customer)* can begin an interconnection request process by submitting an interconnection proposal to the NYISO. The process starts with an Interconnection Study, which actually involves two studies: a Design Study and a System Reliability Impact Study.

The Design Study determines how the load or generation would interconnect to the current system, and identifies the facility additions and modifications required to complete the interconnection. The transmission owner whose system the customer proposes to interconnect with has primary responsibility for the Design Study.

The System Reliability Impact Study determines whether the proposed interconnection may negatively affect reliability or adversely affect the operation of the New York Power System. The NYISO holds the primary responsibility for the System Reliability Impact Study.

NYISO does not apply any prioritization of projects grouped based on the technology. Each project shares in the cost required to interconnect its respective project.[125]

To summarize the steps of an interconnection application and completion process:

- Load or generation customer submits an interconnection proposal and requests an Interconnection Study.
- The NYISO, in coordination with the TO with whose system the customer proposes to interconnect, tenders an Interconnection Study Agreement (ISA) to the customer within 30 days of receipt of that proposal, including the scope of work, estimated cost, and time for completion of the study.
- Within 15 days, the customer executes the ISA and returns it to the NYISO to go ahead with the study, including agreeing to fund the cost of the study.
- NYISO and the transmission owner should complete the study within 60 days (extension of this time is allowed).
- NYISO may reject the interconnection proposal if the System Reliability Impact Study concludes that the proposed interconnection negatively affects system reliability or adversely affects the operation of the New York Power System. In this case, to mitigate the negative impact, the customer may request a Reinforcement Options Study or System Impact Study to pursue a transmission expansion as an alternative to the interconnection proposal.

According to NYISO, the typical time to complete the interconnection studies and Interconnection Agreement is three years.[126] NYISO maintains an interconnection queue as an overview and real-time queue of interconnection items. As of March 2013, 83 projects were in the queue. The earliest interconnection request date for queued projects was April 24, 2002.[127]

2. Capacity Firmness and Congestion Management

The NYCA generators have a right to export capacity to neighboring control areas—such as PJM, New England, etc.—within the installed capacity (ICAP) market rules of NYISO and other control areas. The settlement occurs in accordance with mutually agreed rules, in addition to the bilaterally agreed rules between capacity exporters from NYCA and capacity importers of the receiving control area. Note that NYISO has developed ICAP markets, and the ICAP prices are determined on the basis of monthly capacity requirements, annual supply requirements, and auctions which include (summer/winter) capability-period auctions.

The NYISO energy markets implement congestion management through location-based marginal pricing (LBMP).[128] LBMPs are calculated both in the day-ahead and real-time energy markets. On the load side, LBMPs are calculated on a zonal basis and load pays zonal LBMP.

124 This section is based on New York ISO (1999).

125 See New York ISO (2013a). See Section V of the NYISO OATT Attachment S, Rules To Allocate Responsibility for the Cost of New Interconnection Facilities.

126 New York ISO (2012b)

127 For more information see http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/NYISO_Interconnection_Queue/NYISO_Interconnection_Queue.xls. NYISO. Planning Services & Requests.

128 LBMP are equivalent to Locational Marginal Pricing, LMP, used in other US regions.

On the generation side, the LBMP calculation is made on a nodal basis, where generators are paid nodal LBMPs. Zonal prices are the weighted averages of nodal prices within that particular zone. An LBMP is composed of three components: energy + loss + congestion.

The NYISO treats all generators equally in the context of congestion management and related charges. This is of particular interest since the state, through NYPA, owns 6,635 MW of generation, nearly 20% of the total generation capacity.

D. Transmission Pricing

1. Connection Charges

According to NYISO rules, every developer is responsible for the cost of the new interconnection facilities required for the reliable interconnection of its generation or merchant transmission project.[129] These costs cover all costs and overhead associated with the design, procurement, and installation of the new interconnection facilities.

The rules for estimating and allocating the cost of the interconnection facilities are set separately for the Energy Resource Interconnection Service (ERIS) and the Capacity Resource Interconnection Service (CRIS).

Also, different rules are in place for projects larger than 20 MW (these are called Standard Large Facility Interconnection Procedures), and for small generating facilities no larger than 20 MW (interconnected to the New York State Transmission System or to the Distribution System).

The developer pays the actual cost of the Interconnection Study. If more than one Interconnection Study is conducted at the same time as a combined study,[130] then each developer pays an equal share of the actual cost of the combined study. If a developer elects to be evaluated only for ERIS, it will not be responsible for any cost of any CRIS evaluation in the combined study. The developers pay a processing fee or deposit associated with the interconnection request.

A developer with an interconnection proposal for a new *large generating facility or merchant transmission facility* to the system submits the interconnection request to the NYISO with a non-refundable application fee. The application fee is divided equally between NYISO and connecting transmission owners. With the interconnection request, the developer also submits a refundable study deposit for the Interconnection Feasibility Study.[131]

Throughout the interconnection request process, NYISO, in consultation with the connecting transmission owner, may determine that the interconnection request cannot be approved without a supplemental study. A supplemental review process can then be initiated.

If the interconnection customer agrees to do supplemental review, it then submits a deposit to the NYISO for the estimated costs. The customer becomes responsible for the actual costs to the NYISO and the connecting TO for the supplemental review conducted by NYISO. The customer also pays any review costs that exceed the deposit. If the deposit exceeds the invoiced costs, the NYISO returns the amount in excess without interest.[132]

2. Generation Transmission Use of System Charges

The NYISO provides *firm* and *non-firm* point-to-point transmission service over the transmission facilities of the parties that signed the ISO/transmission owner agreement.[133] For firm point-to-point transmission service, the transmission customer pays congestion charges. This is not the case for customers of non-firm point-to-point transmission service. A customer may hedge the price of day-ahead congestion charges associated with its firm point-to-point transmission service, by acquiring sufficient transmission congestion contracts with the same points of receipt and delivery. Customers submit their requests for

129 This section is based on New York ISO (2013a, b.) NYISO OATT Attachment S, NYISO OATT Attachment Attachment X, Standard Large Facility Interconnection Procedures, and c).NYISO OATT Attachment Z, Small Generator Interconnection Procedures.

130 Except for a Facilities Study.

131 New York ISO (2013b). See Section 30.3 of NYISO OATT Attachment X.

132 See Section 32.2.4 of New York ISO (2013c). NYISO OATT Attachment Z.

133 NYISO Tariffs–OATT Section 3, Point-To-Point-to-Point Transmission Service (2011). Point-to-point transmission service is defined as the service for the receipt of capacity and energy at designated point(s) of receipt and the transfer of such capacity and energy to designated point(s) of delivery. See New York ISO (2011c).

transmission services to the NYISO via the dedicated Open Access Same-Time Information System (OASIS).

The NYISO markets have the following characteristics:

- Location-based marginal pricing (LBMP) that reflects the value of the energy at the specific time and location that it is delivered;
- A two-settlement (day-ahead and real-time) energy market.
- Those transactions that take place in the day-ahead market are only financially binding—i.e., no physical exchange of power takes place. After the acceptance and rejections of offers and bids, the day-ahead market results in posting of:
  - Commitment schedules for generators,
  - Schedules for load serving entities,
  - Transaction schedules (based on LBMP and bilateral agreements), and
  - Day-ahead market LBMP.
- Next day in real-time, only generators submit offers to sell. After the acceptance and rejections of offers, the real-time results in posting of:
  - Commitment schedules for generators,
  - Schedules for load serving entities,
  - Transaction schedules (based on LBMP and bilateral agreements), and
  - Real-time market LBMP.

The objective of the commitment software is to minimize the as-bid production cost subject to satisfying all system constraints and reliability rules. In the day-ahead market, this is called the *security constrained unit commitment procedure*.

The day-ahead market settlement price (the LBMP) is made up of energy + loss + congestion components.

The energy component of the LBMP is calculated with respect to a reference bus—called the Marcy Bus, actually a substation in the NYCA—and congestion and losses are considered zero at that node. In other words, the reference bus serves as the price point for calculating the marginal cost of energy in the NYCA. In the absence of congestion and losses, all energy prices at every node at the NYCA would be equal to the reference bus energy price.

The congestion component reflects the cost of transmission congestion calculated at each node with respect to the reference bus. Congestion is formally defined as the difference between congestion at the sink and the congestion at the source nodes.

In total, there are three components to transmission charges in NYCA:

1. *Transmission usage charges*. These include the congestion charges and the charges for marginal losses,[134] and are paid to NYISO.
2. *Transmission Service Charges*:[135] These are set by FERC for the recovery of the cost of transmission asset, and are paid to the transmission owner located in the transmission district to which load is delivered.[136]
3. *NYPA transmission adjustment charge*. Paid to NYPA, this is for the recovery of the costs of NYPA that are not recovered through transmission service charges due to restructuring.[137]

There are two types of transactions in NYISO energy markets: LBMP-based transactions and bilateral transactions. For the purposes of transmission pricing, both LBMP and bilateral transactions are charged all three of the transmission charges (for use, service, and adjustment charges).[138]

E. Renewable Generation Operation

1. Generation Forecasting

The NYISO uses its own forecasting procedures to generate a load forecast,[139] with a separate procedure for obtaining wind generation forecast.

Since its very beginning, the NYISO has had special market rules that exempt wind and run-of-river hydro units from financial penalties for deviations from expected schedules.[140] In June 2008 the NYISO started to implement

134 Note that the transmission usage charge is equal to the product of the LBMP at the point of withdrawal minus the LBMP at the point of injection (in $/MWh), and (2) the scheduled or delivered energy (in MWh). See New York ISO (2002).

135 The "Transmission Service Charges" concept corresponds to Transmission Use of System Charges used elsewhere.

136 In general, FERC sets transmission rates based on the cost plus (rate of return) method of regulation.

137 NTAC is billed by NYISO but paid to NYPA.

138 Note that bilateral transactions are also charged for the replacement of energy originating from their energy contracts.

139 See New York ISO (2010).

140 The following part is based on Gonzales, et al. (2008).

a centralized wind forecasting system, to forecast the amount of energy expected to be produced by each wind plant for use in the NYISO's day-ahead and real-time Security Constrained Economic Dispatch systems.

In this system, wind plants collect data on wind speed and direction and transmit that data to the NYISO's forecast vendor. Accurate wind power forecasts in the day-ahead unit commitment process minimize the potential to over- or under-commit other generation resources to meet forecast load. This allows the NYISO to produce more efficient commitment decisions in real time.

2. Participation in Balancing Services

The reserve requirement of NYCA is set through the determination of *installed reserve margin*, which is based on reliability criteria and resource adequacy standards. As a first step, NYSRC sets the installed reserve margin, then the NYISO determines the necessary minimum level of installed capacity needed to meet the reliability criteria of NERC, the New York Public Service Commission, and the NYSRC.

Within the framework of NYISO's ICAP market rules, the load-serving entities are obligated to procure ICAP, either through ICAP auctions or bilateral contracts or by owning certain amount of ICAP in proportion to their load obligations. Load obligations of load-serving entities are determined by the NYISO in accordance with the set installed reserve margin.

The following services are defined as ancillary services by the NYISO:[141] scheduling, system control and dispatch, voltage support, regulation, energy imbalance, operating reserve (i.e., spinning and non-spinning reserves), and black start capability services.

Market participants can either self-supply certain ancillary services or procure them through the NYISO. The cost of scheduling, system control and dispatch, voltage support, and black start capability services is considered an embedded cost of ancillary services. However, the other ancillary services (regulation, operating reserves, and energy imbalance services) are provided as market-based services through offers and are priced accordingly. Reactive power provision/absorption is handled within the voltage support service. There are certain requirements for providing ancillary services, depending of the nature of the services to be supplied.

3. Imbalance Settlement

Based on the two-settlement system of the NYISO markets, settlement is carried out in both the day-ahead market and real-time market. In the day-ahead market, the NYISO receives offers from suppliers and bids from load.

The day-ahead market is only financially binding, and no physical exchange of power takes place. However, in the real-time market, market participants buy and sell energy based on the differences during the actual day, to provide balancing amounts of energy for deviations from the day-ahead market schedule. Therefore the real-time market serves as the balancing market.

As discussed earlier, the NYISO has special market rules that exempt wind and run-of-river hydro units from financial penalties for deviations from expected schedules.[142]

141 See New York ISO (2011d).

142 Gonzales, et al. (2008).

VII. US: Western Interconnection

A. Electricity System Overview

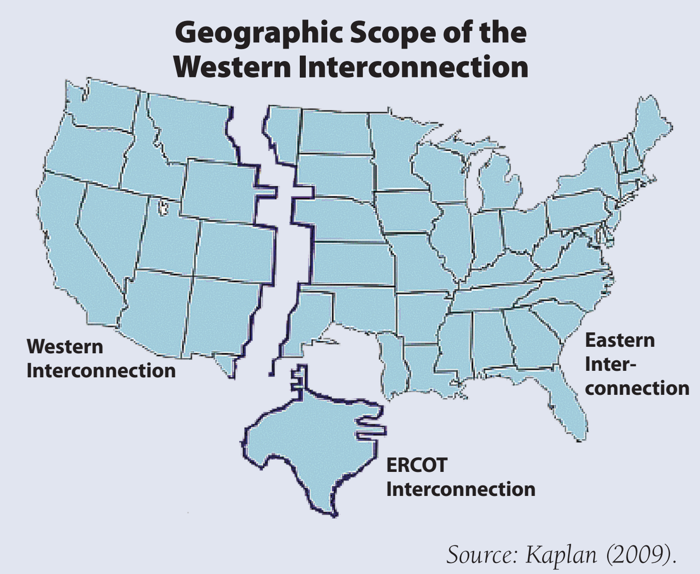
1. Regulatory Institutions

The Western Interconnection includes all or part of 13 US States, two Canadian Provinces, and part of northern Mexico.[143] The geographic extent of the Western Interconnection is shown in Figure 18, within the context of the wider United States systems. The region provides an example of how in the US a wide variety of power-sector policies can coexist in a coordinated system.

The electricity sector restructuring process, which was begun at a federal level with the Energy Policy Act of 1992, has made limited progress in the Western region, whose electricity sector is still mostly run under the vertically integrated structure that prevailed before the Act. With the exception of California, few states have undergone the restructuring process by requiring utilities to divest generation, or have taken the steps toward further liberalization beyond opening access to transmission networks, which is required by federal law.

Major issues are covered by federal and state regulation.

Figure 18



Source: Kaplan (2009).

The Federal Energy Regulatory Commission (FERC), an independent agency, is in charge of regulating the interstate transmission of electricity. The state Public Utilities Commissions (PUCs) are responsible for regulating the parts of the industry not regulated by FERC. Additionally, the Bonneville Power Administration and Western Area Power Administration, federal non-profit agencies not subject to FERC or state regulation, operate large generation fleets and transmission systems in several western states. The Western Interconnection also contains large publicly owned power systems. In addition to the entities discussed below, this variety makes the Western Interconnection a complex area, with many diverse entities capable of influencing the regulation of the western grid.

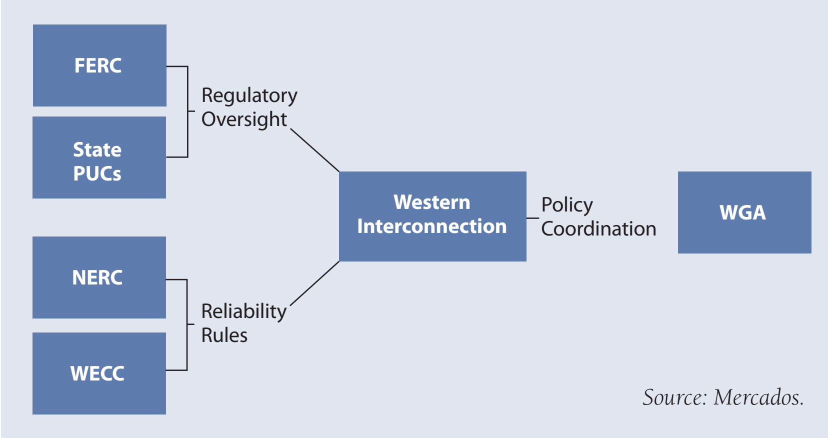
The Western Governors' Association (WGA) has become significant in the region's electricity sector, through its initiatives on transmission planning and other aspects of the sector. The WGA is a nonpartisan organization whose members represent 19 western states. Its purview is broad, covering a variety of policy issues in the areas of the environment, natural resources, economic development, human services, international relations, and state-level governance.

The Western Electricity Coordinating Council (WECC) is one of the eight regional electricity reliability councils[144] operating under the North American Electric Reliability Corporation (NERC), and sharing its mission in the Western region. WECC and NERC oversee reliability standards applicable to the transmission system by delegation from the FERC. WECC was formed in 2002 by

143 These include parts of Montana, New Mexico, South Dakota, Texas, Wyoming and New Mexico, and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, and Washington. Source: Transmission Agency of North California (2010).

144 Some sources include the Alaska System Coordination Council (ASCC) as the ninth reliability council.

Figure 19



Institutions Active in the Western Interconnection

Source: Mercados.

the merger of the Western Systems Coordinating Council (WSCC) and two regional transmission associations.

Just like the New York System, the WECC transmission utilities are subjected to the same requirements for coordinated planning and cost allocation.

2. Electricity System Architecture

The extension and political diversity of the area covered by the Western Interconnection explains the significant variation in the degree of liberalization of the electricity sector in this area.

Wholesale competition is assured at a federal level through open access to the transmission system (Energy Policy Act 1992). Individual states, however, have jurisdiction over retail competition policy.

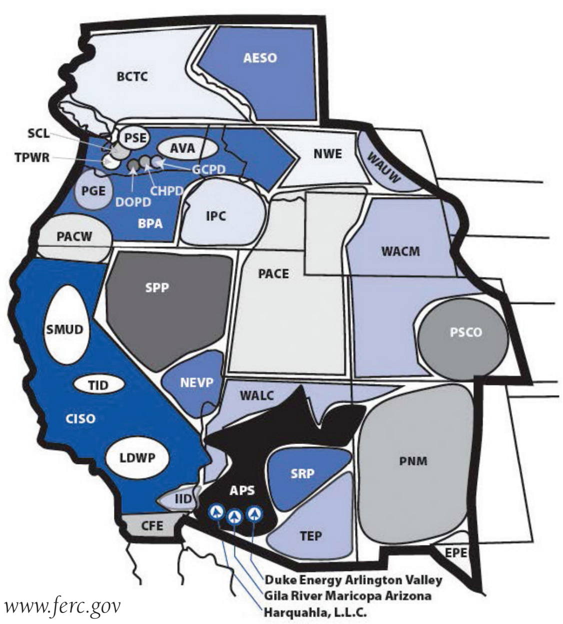
The electricity sector is still mostly run by vertically integrated companies, although these coexist with other entities that have different degrees of vertical integration and ownership structures, including unaffiliated single-activity companies. Supply to final customers is carried out by a combination of self-generation (sometimes requiring long-term transmission contracts with other utilities), long-term generation agreements, and medium- and short-term energy transactions. California is the only state in the region where an Independent System Operator (ISO) has been set up.

Proposals have been made to create larger balancing regions managed by new ISOs or Regional Transmission Organizations (RTOs). At least two entities have filed applications to the FERC, WestConnect[145] and RTO West.

The Western Interconnection area is managed by 38 balancing authorities, which act as system operators within their respective areas. Coordination of exchanges between these areas ensures the balance of the Western Interconnection as a whole.

Figure 20

Western Interconnection Balancing Authorities



Source: www.ferc.gov

Figure 21

Westconnect Proposed RTO Planning Area

Source: www.westconnect.com

145 See WestConnect webpage at http://westconnect.com.

3. Renewable Generation Policy and Implementation Mechanisms

Prospects for renewable energy are positive throughout the United States. But because individual state governments are responsible for renewable energy policy, the development of renewables within the Western Interconnection system will depend on the final combination of federal and state targets and policies.

Table 8 summarizes the government and utility rules, regulations, and policies that promote renewables in Western Interconnection states, allowing a quick comparison of the number and types of programs in each state.

California is one of the most ambitious states in terms of renewable energy generation targets. In 2011, the state passed legislation requiring that, by the target year of 2020, 33% of all electricity sold by retailers must be sourced from renewable energy generation.[146]

Transfers of renewable energy generation can be tracked throughout the Western Interconnection by the Western Renewable Energy Generation Information System (WREGIS),[147] an independent tracking system administered by WECC and governed by a seven-member committee consisting of representatives from various stakeholder groups.

WREGIS was developed through a collaborative process between the Western Governors' Association, the Western Regional Air Partnership, and the California Energy Commission, with extensive stakeholder input from more than 400 participants. Generators that register in the WREGIS system are monitored and tracked using verifiable data. Renewable Energy Certificates (RECs) are created as proof of generation, and can be used to verify a generator's compliance with different regulatory requirements, whether at the state or regional levels. RECs can also be used within some voluntary market programs as proof of renewable generation.

WREGIS reports an increasing number of renewable plants (wind, hydro, solar and biogas/ biomass) being approved in the region (Table 9).

146 California Energy Commission (2011).

146 See http://www.wregis.org/links.php.

Table 8

Number of Rules, Regulations, and Policies for Renewable Energy

State	Public Benefit Funds			Renewable Portfolio Standards			Net Metering			Inter-connection			Contract. License			Equip. Certific.			Access Laws			Constr. & Design			Green Power Purchasing			Required Green Power		
	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility	State	Local	Utility
Federal											1												1							
Arizona				1			1		1	1			1			1			1			3	5							
California	1			1			1		1	1			1						1	7		4	17							
Colorado		1		1			1			1									1	1		3	4					1		
Idaho									3										1											
Montana	1			1			1		1	1									1									1		
Nevada				1			1		1	1									1			1	1							
New Mexico				1			1		1	1									1									1		
Oregon	1			1			1		1	1			1						1	2		4	2					1		
South Dakota				1						1									1			2								
Texas				1	1	1			3	1									1			2	5							
Utah				1			1		3	1			1						1	1			1							
Washington				1			1		1	1									1			1	1					1		
Wyoming							1			1												1								

State Local Utility

Sources: U.S. DOE (2011); US Department of Energy, DSIRE, Database of State Incentives for Renewable & Efficiency http://www.dsireusa.org/summarytables/rrpre.cfm

Table 9

WREGIS-approved Generating Units						
	October 2008		October 2009		September 2010	
Generation Technology	Approved Units	Generation (MWh)	Approved Units	Generation (MWh)	Approved Units	Generation (MWh)
Wind	134	5,126	195	8,805	221	10,774
Hydro-electric	285	2,091	365	5,432	447	7,347
Solar	150	440	370	529	553	756
Biogas/Biomass	98	1,126	142	2,814	178	3,700
Geothermal	44	2,136	65	2,670	65	2,670
Total	**711**	**10,919**	**1,137**	**20,250**	**1,464**	**25,247**

Source: Western Renewable Energy Generation Information System (2010).

There is technical potential for higher levels of renewables. In a 2010 study on the potential to integrate wind and solar power levels at 35% of the energy requirement on the Western Interconnection system, the United States' National Renewable Energy Laboratory (NREL) concluded that the 35% level could be achieved without the requirement for investing in extensive transmission infrastructure (new or upgrades).[148] Achieving this potential will depend on some changes in the operation of the system. Among others, these changes include shorter than one-hour generation scheduling, substantial increases in balancing area cooperation or consolidation, increased use of transmission capacity, additional operating reserves committed as appropriate, and demand response programs, both existing and new.

4. Transmission Network Overview

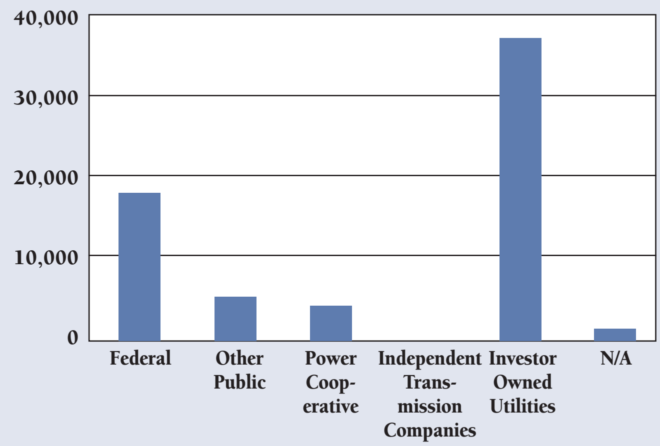
There are a variety of ownership structures in the Western Interconnection region. Many owners of transmission assets also act as system operators in the same area, although not in all cases. High-voltage transmission lines (230kV and above) in the region are under the ownership of a variety of industry players, as shown in Figure 22.

While investor-owned utilities own the largest total distance of transmission lines (56%), 27% are under federal ownership. 8% is owned by other public bodies and 7% by power cooperatives. Information is not available on ownership of the remaining 2%.[149]

Figure 22

Ownership of Transmission Lines of 230kV and Above

(Distance in miles)



Source: Mercados adaptation of Kaplan (2009).

148 GE Energy (2010).

149 Kaplan (2009).

B. Transmission Planning and Investment Processes

1. The Planning Process

A. Responsibility for Planning

Transmission owners have responsibility for transmission planning. This planning is coordinated at regional or sub-regional levels by different entities.

At a regional level, the WECC is the most relevant because it is coordinated with the Western Governors' Association, which conducts regional-level transmission planning policy and resource assessments within the Western Interconnection region.

Within WECC, four main groups are involved with the transmission planning process in the region:

- Transmission Expansions Planning Policy Committee,
- State/Provincial Steering Committee,
- Scenario Planning Steering Committee, and
- Sub-regional Coordination Group.[150]

The 2009 American Recovery and Reinvestment Act resulted in the WECC receiving $14.5 million to undertake Interconnection-wide electricity transmission system planning studies.

B. Planning Characteristics

As mentioned above, transmission utilities are formally responsible for planning, which typically leads to many planning efforts being decentralized. To ensure coordination, the Federal Energy Regulatory Commission's Order Nos. 890 and 1000 require transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level as well as on to interregional planning and coordination.

The planning principles identified in this order are:

- ***Coordination:*** the process for consulting with transmission customers and neighboring transmission providers;
- ***Openness:*** planning meetings must be open to all affected parties;
- ***Transparency:*** access must be provided to the methodology, criteria, and processes used to develop transmission plans;
- ***Information exchange:*** the obligations of and methods for customers to submit data to transmission providers must be described;
- ***Comparability:*** transmission plans must meet the specific service requests of transmission customers, and otherwise treat similarly situated customers (e.g., network and retail native load) comparably in transmission system planning;
- ***Dispute resolution:*** an alternative dispute resolution process must be included, to address both procedural and substantive planning issues;
- ***Regional participation:*** there must be a process for coordinating with interconnected systems;
- ***Economic planning studies:*** study procedures must be provided for economic upgrades to address congestion or the integration of new resources, both locally and regionally; and
- ***Cost allocation:*** a process must be included for allocating the costs of new facilities, such as regional projects, that do not fit under current rate structures.

Within the Western Interconnection, transmission network expansion needs are analyzed on an annual basis, through a process developed and administered by the WECC's Transmission Expansion Planning Policy Committee. During the process of developing this plan for undertaking transmission expansion studies, the committee draws on the inputs of a wide range of stakeholders, including transmission operators and developers, public interest groups, and government organizations.[151]

In addition to and complementing assessments of potential transmission system expansions at the regional level, the following organizations complete transmission planning analyses at the more localized, sub-regional levels:

- California Independent Service Operator,
- Sierra Sub-regional Planning Group,
- Southwest Area Transmission,
- Colorado Coordinated Planning Group,
- Northern Tier Transmission Group,
- Columbia Grid,
- British Columbia Transmission Corporation, and
- Alberta Electric System Operator.

C. Transmission Development Drivers

Transmission expansion analyses take into account a range of factors and variables, including generation resources (available capacity), electricity demand,

150 Western Electricity Coordinating Council (2011a).

151 Western Electricity Coordinating Council. (2011b).

technology costs, energy policies, the impacts on transmission reliability of different developments, and greenhouse gas emissions.

The opinions and inputs of a wide range of stakeholders are canvassed and taken into account during the analysis process. In particular, the WECC seeks guidance, advice, and input from state-level representatives, provincial-level representatives, utilities, agencies, energy-generation project developers, non-governmental organizations, and consumer advocates/consumer rights groups.

The Regional Transmission Expansion Planning (RTEP) project is funded by the US Department of Energy and focuses on expansion planning in the Western Interconnection and other regions. The RTEP project will only consider potential transmission expansion plans. It will initially develop 10 year expansion plans, and a 20-year expansion plan in 2013. It does not analyze project developments, policy decisions, or policy goals.

The four key objectives of the expansion plans developed by RTEP include supporting:

- Improved coordination between players within the Western Interconnection,
- An increased awareness of how energy policy decisions affect transmission costs and reliability,
- Increased ability to answer key policy questions at the state, provincial, and federal levels, and
- Leveraging additional information to be used by decision makers in siting cost-allocation proceedings.[152]

The direction and focus of the RTEP project is guided and managed by an organization called the Scenario Planning Steering Group.

2. The Investment Process

While most electric transmission projects are approved by the states in which they are located, the Energy Policy Act 2005 granted FERC the authority to consider applications for projects, and to issue a construction permit for proposed facilities in the event that a state withholds approval for more than one year, does not have the authority to site transmission facilities, or cannot consider interstate benefits of a proposed project located in a National Interest Electric Transmission Corridor (NIETC).[153]

This gives FERC the power to approve nationally important projects that are consistent with sound national energy policy, enhance energy independence, can be used to increase interstate trade or reduce congestion, or more generally are in the public interest. The Department of Energy has identified one NIETC in the west, including seven counties in Southern California and three in western Arizona. But FERC has not yet used its authority to issue permits in this corridor, or in the other designated NIETC in the mid-Atlantic region.

C. Connection and Access to the Transmission Network

Transmission operators are obliged to provide two different network services:

- Point-to-point transmission (either firm or not firm), where the transmission customer designates specific points for the receipt and delivery of the energy.
- Network integration transmission, which allows the customer to integrate, economically dispatch, and regulate its generation to serve its load (within the transmission area) in a manner comparable to that of the transmission company.

The detailed connection conditions and firmness of the transmission capacity depend on the specific transmission service contracted. Capacity in point-to-point transmission services is granted, subject to the availability of capacity, in a first-come, first-served basis for long-term services.[154] For network integration services, capacity is considered firm (subject to the realization of the necessary reinforcements).

D. Transmission Pricing

1. Connection Charges

Connection charging policy varies from one transmission owner to another. For example, PacifiCorp, a major electricity company[155] operating in various states throughout the Western Interconnection, has developed

152 Western Electricity Coordinating Council (2011b).

153 FERC (2010).

154 Priority arrangements for short -term services are more complex.

155 PacifiCorp is one of the major utilities operating the Western Interconnection region, with approximately 1.7 million customers across six U.S. states.

its Pro Forma Open Access Transmission Tariff guidelines, which set out the organization's approach to levying connection charges. The guidelines explain that when a connection request is received, the transmission provider will complete an Interconnection Feasibility Study. Two of the key outputs of this feasibility study are to provide "a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct."[156]

The tariff guidelines provide the following information on connection charges:

- ***Connection charges for interconnection facilities:*** The interconnection customer (the generator) pays for the costs of interconnection facilities identified in the feasibility study, with a detailed itemization of each cost. The costs associated can be shared by agreement with other entities that might benefit from the facilities.[157]
- ***Charges for network upgrades:*** Unless the transmission provider chooses to pay for the wider network upgrades, the actual incurred costs of any network upgrades is initially paid for by the interconnection customer (the generator). The interconnection customer is, however, later entitled to receive an equal cash payment to the total amount paid for network upgrades. An interconnection customer may assign these repayment rights. An alternative payment schedule may be adopted if it is more agreeable and mutually acceptable, on the condition that one of the following actions is taken no more than five years following the beginning of commercial operation:
    - Return to the interconnection customer any remaining amounts advanced for network upgrades that are not yet repaid; or
    - Declare in writing that the transmission operator will continue to provide payments (on a dollar-for-dollar basis) for the non-usage-sensitive portion of transmission charges. Full reimbursement cannot extend beyond 20 years after the date of commercial operation commencement.

If a generating facility that has requested a system upgrade fails to achieve commercial operation, but is later brought to completion—or if a different generation facility requires use of the upgraded network—the transmission provided must, at that time, reimburse the generating facility for the amounts initially advanced for the network upgrades.

Broadly speaking, this is equivalent to a generator paying for shallow connection charges, but having to provide a full up-front payment (which is later repaid) as security for the deep reinforcements. This could be a barrier to smaller or more remote renewables projects, where the deep reinforcement costs are likely to be more significant.

2. Generation Transmission Use of System Charges

In the United States, transmission services include some system operation services—such as frequency control, reactive power, and balancing services—whose costs do not arise directly as a consequence of the use of the network. Transmission tariffs include specific schedules for the recovery of these costs.

Regarding network-only costs, federal legislation does not provide guidance about the allocation of transmission costs between the different types of transmission services. As a result, final tariffs depend on the transmission companies' criteria.

In any case, generators—specifically, renewable generators—could only be subject to (network only) transmission charges under point-to-point services, given that under network integration services the charges are paid by the load in proportion to its monthly maximum demand. Under point-to-point services, the allocation of transmission costs between the load and the generators will depend on specific agreements between them.

E. Renewable Generation Operation

1. Generation Forecasting

Scheduling of plants under point-to-point transmission services for delivery of energy during one day should be done by about ten in the morning for the previous day. Under network integration transmission services, the network customer schedules its power plants in order to cover its load.

At present there is an issue with renewable energy not being dispatched. In 2009, WECC calculated that increased use of generated renewable electricity could

156 PacifiCorp (2010).

157 PacifiCorp (2010).

provide an economic benefit of between $323 million and $3.6 billion within 40 years. As a result, WECC is currently implementing a new approach called the Western Interconnection Synchrophasor Program, which is due for completion in 2013 and an extension phase in 2014.

This program is expected to be a major tool in improving the Interconnection's use of installed renewable generation capacity. The intention is that a series of measures for improving the quality of monitoring transmission, generation, and load conditions on the transmission system will significantly reduce the requirement to "spill" renewable electricity from the system.

WECC also expects that implementation of the WISP project will help address the issue of variability in renewable energy generation, by encouraging an increase in the diversity of renewable generation resources connected to the grid, thereby enabling a reduction in the system's peak capacity and operational reserves.

2. Participation in Balancing Services

Ancillary services in the Western Interconnection are broadly divided into the following six categories:

- Scheduling, system control, and dispatch services,
- Reactive supply and voltage control from generation sources services,
- Regulation and frequency response service,
- Energy imbalance service,
- Operating reserve—spinning reserve service, and
- Operating reserve—supplemental reserve service.

The transmission customer (e.g., generator or vertically integrated utility) is obliged to acquire these services from the transmission operator directly, except in the case of regulation and frequency response, imbalance, and operating-reserve services. Those are open to competition, so it is possible to procure them from a third party or to self-supply.[158]

No specific provisions prevent renewable energy power plants from providing balancing services and other ancillary services, but a basic requirement for such services is the ability to increase or decrease the production as mandated by the system operator (control area authority).

3. Imbalance Settlement

The FERC Open Access Transmission Tariff Order 888 sets out the procedures to be followed in the provision of imbalance settlement services. Transmission service providers must offer energy imbalance services, and transmission customers (including generation) must either purchase this service from the transmission provider or make alternative comparable arrangements to satisfy its energy imbalance obligations.

According to the federal regulation (FERC Order 890, Appendix C, Schedule 9, Generator Imbalance Service),[159] if the service is provided by a Control Area operator, the transmission company can only pass through the costs to the transmission customer.

The transmission provider cannot charge at the same time for generator and load imbalances of the same transmission customer, unless the imbalances are in the same direction. Therefore, load can be used to counterbalance generation imbalances.

Charges of imbalances increase with the size of the imbalance (bands are defined as first ±1.5%, ±1.5-7.5%, > ±7.5% imbalance). Intermittent sources (such as a non-dispatchable generator) have a partial relief, as they are exempt from this progressive charging.

158 FERC (2007).

159 FERC (2007). Appendix C, Open Access Transmission Tariff.

References

ANEEL. (2013). Energy Matrix. www.aneel.org. Retrieved from http://www.aneel.gov.br/aplicacoes/capacidadebrasil/OperacaoCapacidadeBrasil.asp.

California Energy Commission. (2011). Renewables Portfolio Standard (RPS) Proceeding. www.energy.ca.gov. Retrieved from http://www.energy.ca.gov/portfolio/index.html.

Central Electricity Authority. (2011). All India Regionwise Generating Installed Capacity (Mw) Of Power Utilities Including Allocated Shares In Joint And Central Sector Utilities. www.cea.nic.in. Retrieved from http://www.cea.nic.in/reports/monthly/executive_rep/jul11/8.pdf.

Central Energy Regulatory Commission. (2008). Open Access in Inter-State Transmission. New Delhi, India: Central Energy Regulatory Commission. Retrieved from http://110.234.20.122/docs/CERC_Open-Access-in-inter-State-Transmission_Regulations-2008.pdf.

Central Energy Regulatory Commission. (2009a). Grant of Connectivity, Long-term Access, and Medium-term Open Access in Inter-State Transmission and Related Matters Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from http://cercind.gov.in/Regulations/Final-version-of-Long-term-and-Medium-term-Regulations-2009.pdf.

Central Energy Regulatory Commission. (2009b) Procedure, Terms, And Conditions For Grant Of Transmission Licence And Other Related Matters Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from: http://cercind.gov.in/2009/June09/Transmission-Licence-Regulations-2009.pdf

Central Energy Regulatory Commission. (2009c). Terms and Conditions of Tariff Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from: http://cercind.gov.in/Regulations/Terms-and-Conditions-of-Tariff-Regulations_2009-2014.pdf

Central Energy Regulatory Commission. (2010a). Indian Electricity Grid Code Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from http://cercind.gov.in/Regulations/Signed-IEGC.pdf.

Central Energy Regulatory Commission. (2010a). Terms and conditions for recognition and issuance of Renewable Energy Certificate for Renewable Energy Generation Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from https://www.recregistryindia.nic.in/pdf/complete_rec_procedures.pdf.

Central Energy Regulatory Commission. (2010b). Sharing of Inter State Transmission Charges and Losses Regulations. New Delhi, India: Central Energy Regulatory Commission. Retrieved from http://cercind.gov.in/Regulations/Transmission_Regulations_on_transmission_charges_and_losses_2010.pdf.

Central Energy Regulatory Commission. (2011). Approval of detailed "Procedure for the Implementation of the Mechanism of Renewable Regulatory Fund" under Regulation 6.1 (d) of Central Electricity Regulatory Commission (Indian Electricity Grid Code), Regulation 2010. New Delhi, India: Central Energy Regulatory Commission. Retrieved from http://www.cercind.gov.in/2011/February/Detailed_Procedure_IEGC.pdf.

Chamber for the Commercialization of Electric Energy. (2010a). Market Rules, Module 5. www.ccee.org. Retrieved from http://www.ccee.org.br/StaticFile/Arquivo/biblioteca_virtual/Regras/05_excedente_financeiro_.pdf.

Chamber for the Commercialization of Electric Energy. (2010b). Market Rules, Module 6. www.ccee.org. Retrieved from http://www.ccee.org.br/StaticFile/Arquivo/biblioteca_virtual/Regras/06_encargos_de_servicos_do_sistema_.pdf.

Cheung, K. (2011). Integration of Renewables: Status and Challenges in China. Paris, France: International Energy Agency. Retrieved from http://www.iea.org/publications/freepublications/publication/Integration_of_Renewables.pdf.

Clean Biz Asia.com. (2011). China plans ultra-high voltage transmission network. www.cleanbiz.asia. Retrieved from http://www.cleanbiz.asia/story/china-plans-ultra-high-voltage-transmission-network.

China Wind Energy Association. (2010). Outlines Prepared by CWEA for the China 2050 Wind and Grid Integration Roadmap. Beijing, China: China Wind Energy Association.

Department of Energy & Climate Change. (2009). National Renewable Energy Action Plan for the United Kingdom. London, UK: Department of Energy & Climate Change. Retrieved from: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47871/25-nat-ren-energy-action-plan.pdf.

Department of Energy & Climate Change. (2011). National Renewables Statistics 2010. London, UK: Department of Energy & Climate Change. Retrieved from: https://restats.decc.gov.uk/cms/national-renewables-statistics/.

Electricity Networks Strategy Group. (2009). Our Electricity Transmission Network: A Vision For 2020. London, UK: Department of Energy & Climate Change. Retrieved from: http://webarchive.nationalarchives.gov.uk/20100919181607/http:/www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf.

Energy Networks Association. (2009). Report on the Draft Common Distribution Charging Methodology. London, UK: Energy Networks Association. Retrieved from http://media.lsiutilitybroker.co.uk/media/downloads/Common_Distribution_Charging_Methodology.pdf.

Energy Research Company. (2013). Studies for Bidding Transmission Expansion – 2013-2017. Rio de Janeiro, Brazil: Energy Research Company. Retrieved from http://www.epe.gov.br/Transmissao/Documents/PET%202013-2017.pdf.

European Parliament and Council of the European Union. (2009a). Amending Directive 2003/87/EC so as to Improve and Extend the Greenhouse Gas Emission Allowance Trading Scheme of the Community. Official Journal of the European Union, 5.6.2009. Retrieved from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:en:PDF.

European Parliament and Council of the European Union. (2009b). Directive Concerning Common Rules for the Internal Market in Electricity and Repealing Directive 2003/54/EC. Official Journal of the European Union, 14.8.2009. Retrieved from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF.

European Parliament and Council of the European Union. (2009c). Directive on the Promotion of the Use of Energy From Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC. Official Journal of the European Union, 5.6.2009. Retrieved from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:en:PDF.

European Parliament and Council of the European Union. (2009d). Directive Concerning Common Rules for the Internal Market in Electricity and Repealing Directive 2003/54/EC. Official Journal of the European Union, 14.8.2009. Retrieved from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF.

FERC. (2007). Order 890. Final Rule. Washington, D.C.: FERC. Retrieved from http://www.ferc.gov/whats-new/comm-meet/2007/122007/E-1.pdf.

FERC. (2010). A Guide to the FERC Electric Transmission Facilities Permit Process. Washington, D.C.: FERC. Retrieved from: http://www.ferc.gov/for-citizens/citizen-guides/electric/guide-transmission.pdf.

FERC. (2011). Order 1000. Final Rule. Washington, D.C.: FERC. Retrieved from http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

GE Energy. (2010). Western Wind and Solar Integration Study. Golden, CO: NREL. Retrieved from http://www.nrel.gov/electricity/transmission/western_wind.html.

Global Wind Energy Council (2010). "New In-Depth Analysis of the Renewable Energy Law Amendment."

Gonzales, R., Mukerji, R., Swider, M., Allen, D., Pike, R., Edelson, D., Nelson, E., & Adams, J. (2008). Integration of Wind into System Dispatch. Rensselaer, NY: New York ISO. Retrieved from http://www.ferc.gov/EventCalendar/Files/20090303120334-NYISO%20Wind%20White%20Paper%20October%202008.pdf.

IEA. (2010). World Energy Outlook 2010. Paris, France: International Energy Agency. Retrieved from http://www.worldenergyoutlook.org/publications/weo-2010/.

Jiang, L. (2009). Integration of Wind Power in China—Status and Future Requirements. Presentation at International Workshop on Large Scale Wind Power Grid Integration, Beijing, October 22–23, 2009.

Kaplan, S. (2009). Electric Power Transmission: Background and Policy Issues. Washington, D.C.: Congressional Research Services. Retrieved from http://assets.opencrs.com/rpts/R40511_20090414.pdf.

KPMG. (2009). Think BRIC! China. Los Angeles, CA: KPMG Global Energy Institute. Retrieved from http://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/Think-BRIC/Documents/Think%20BRIC_China.pdf.

Li, Han, Gao, and Guan. (2011). Allocation Method Of Cross-Region (Trans-Province) Electricity Transmission Security Costs. Beijing, China: State Grid Research Institute, North China Electric Power University, and DBCCA.

Martinot, E. & Junfeng. L. (2010). China's Latest Leap: An update on renewables policy. www.renewableenergyworld.com. Retrieved from http://www.renewableenergyworld.com/rea/news/article/2010/07/renewable-energy-policy-update-for-china.

Meyer, D. H. & Sedano R. (2002). Transmission Siting and Permitting. National Transmission Grid Study: Issue Papers. Washington, D.C.: U.S. Department of Energy. Retrieved from www.raponline.org/document/download/id/496.

Ministry of Industry, Energy and Tourism (2008). Planificación de los Sectores de Electricidad y Gas 2008-2016: Desarrollo de las Redes de Transporte, section 3.4.3.c, "Modelo de Generación." http://www.mityc.es/energia/planificacion/Planificacionelectricidadygas/Desarrollo2008/DocTransportes/planificacion2008_2016.pdf

Ministry of Industry, Energy, and Tourism. (2010a). National Action Plan for Renewable Energy in Spain. Madrid, Spain: Ministry of Industry, Energy, and Tourism. Retrieved from http://www.minetur.gob.es/energia/desarrollo/EnergiaRenovable/Documents/20100630_PANER_Espanaversion_final.pdf.

Ministry of Industry, Energy, and Tourism. (2010b).Resolution of Technical Restrictions. Madrid, Spain: Ministry of Industry, Energy, and Tourism. Retrieved from http://www.ree.es/operacion/pdf/po/BOE-A-2010-16441.pdf.

Ministry of Mines and Energy. (2011). National Energy Balance 2011 (draft results). Rio de Janeiro, Brazil: Empresa de Pesquisa Energética. Retrieved from https://ben.epe.gov.br/downloads/Resultados_Pre_BEN_2011.pdf.

Ministry of New and Renewable Energy. (2011). Grid Connected Renewable Power Draft Sub-Group Report. New Delhi, India: Ministry of New and Renewable Energy. Retrieved from http://www.eai.in/club/users/Romila/blogs/6884.

Ministry of Power. (2013). Power Sector At A Glance "ALL INDIA." www.powermin.nic.in. Retrieved from http://www.powermin.nic.in/indian_electricity_scenario/introduction.htm.

National Electric System Operator. (2013a). Expansion and Reinforcement Plan. Rio de Janeiro, Brazil: National Electric System Operator. Retrieved from http://www.ons.org.br/plano_ampliacao/plano_ampliacao.aspx.

National Electric System Operator. (2013b). Network Procedures: Sub-module 8.1, Daily schedule of the electric operation, art. 5.2 and 8. Rio de Janeiro, Brazil: National Electric System Operator. Retrieved from http://extranet.ons.org.br/operacao/prdocme.nsf/principalPRedeweb?openframeset.

National Electric System Operator. (2013c). Network Procedures: Sub-module 26.2, Criteria for classification of the power plants operational mode. Rio de Janeiro, Brazil: National Electric System Operator. Retrieved from http://extranet.ons.org.br/operacao/prdocme.nsf/principalPRedeweb?openframeset.

National Energy Commission. (2008). Law54/1997, Spanish Electric Power Act. Madrid, Spain: National Energy Commission. Retrieved from http://www.cne.es/cne/doc/publicaciones/NE009_08.pdf.

National Grid. (2009). National Electricity Transmission System Security and Quality of Supply Standard. Warwick, UK: National Grid. Retrieved from http://www.nationalgrid.com/NR/rdonlyres/149DEAE1-46B0-4B20-BF9C-66BDCB805955/35218/NETSSQSS_GoActive_240609.pdf.

National Grid. (2011a). The Statement of Use of System Charges. Warwick, UK: National Grid. Retrieved from http://www.nationalgrid.com/NR/rdonlyres/0F5FBFA1-A94C-45DD-BAC0-C9A676737176/46235/UoSCI7R0Draft_Issued_FINAL.pdf.

National Grid. (2011b). 2011 NETS Seven Year Statement. Warwick, UK: National Grid. Retrieved from http://www.nationalgrid.com/NR/rdonlyres/A693C979-18C8-4A56-A6F2-F1FA601B6031/46996/NETSSYS2011.pdf.

National Grid. (2011c). Managing Intermittent and Inflexible Generation in the Balancing Mechanism. Warwick, UK: National Grid. Retrieved from http://www.nationalgrid.com/NR/rdonlyres/FD02238E-6168-4BAA-8F15-F3147CED1EE0/49115/ManagingIntermittentandInflexibleGenerationintheBMConsultationfinal.pdf.

New York ISO. (1999). Transmission Expansion and Interconnection Manual. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/FERC_Form_715_Filing/Planning_Assessment_Practices/ARCHIVE/tei_mnl.pdf.

New York ISO. (2008). FERC Electric Tariff, Third Revised Sheet No. 73. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/FERC_Filings/2011-1999/2002/Oct/services_tariff_udr_icap_revisions/ARCHIVE/attachment_1_services_tariff_clean.pdf

New York ISO. (2009). NYISO Installed Capacity Manual. Rensselaer, NY: New York ISO.

New York ISO. (2010). Load Forecasting Manual. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/load_fcst_mnl.pdf.

New York ISO. (2011a). Annual Report 2010. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Annual_Reports/Annual_Reports/NYISOAnnual2010_final.pdf.

New York ISO. (2011b) Power Trends 2011: Energizing New York's Legacy of Leadership. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/Power_Trends_2011.pdf.

New York ISO. (0211c). NYISO Tariffs: OATT Section 3, Point-to-Point Transmission Service (2011). Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Tariff_Documents/NYISO_OATT_3_Point_to_Point_Transmission_Service.pdf.

New York ISO. (2011d). NYISO Ancillary Services Manual. Rensselaer, NY: New York ISO.

New York ISO. (2012a). NYISO Tariffs: OATT Section 31, Attachment Y New York ISO Comprehensive System Planning Process. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_y.pdf.

New York ISO. (2012b). NYISO Transmission Expansion and Interconnection Manual. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/tei_mnl.pdf.

New York ISO (2013a). NYISO Tariffs: OATT Section 25, Attachment S – Rules To Allocate Responsibility for the Cost of New Interconnection Facilities. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_s.pdf.

New York ISO. (2013b). NYISO Tariffs: OATT Section 30, Attachment X - Standard Large Facilities Interconnection Procedure. Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_x.pdf.

New York ISO. (2013c). NYISO Tariffs: OATT Section32, Attachment Z – Small Generator Interconnection Process .Rensselaer, NY: New York ISO. Retrieved from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_z.pdf.

Office of Gas and Electricity Markets. (2010a). Certification of Transmission System Operators Under the Third Package - consultation. London, UK: Office of Gas and Electricity Markets. Retrieved from http://www.ofgem.gov.uk/Europe/Documents1/3rd%20pk%20unbundling%20con%20doc_FINAL.pdf.

Office of Gas and Electricity Markets. (2010b). Handbook for Implementing the RIIO Model. London, UK: Office of Gas and Electricity Markets. Retrieved from http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf.

Office of Gas and Electricity Markets. (2010c). RIIO: A new way to regulate energy networks. Final Decision. London, UK: Office of Gas and Electricity Markets. Retrieved from: http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Decision%20doc.pdf.

Office of Gas and Electricity Markets. (2010d). Project TransmiT: A Call for Evidence - Technical Annex. London, UK: Office of Gas and Electricity Markets. Retrieved from: http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Project_TransmiT_A_Call_for_Evidence_Technical_Annex.pdf.

PacifiCorp. (2010). FERC Electric Tariff, Volume Number 11. Portland, OR: PacifiCorp. Retrieved from http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Services/Approved_Open_Access_Transmission_Tariff.pdf.

Parliament of India (2003). Act No. 36 of 2003. Retrieved from http://www.powermin.nic.in/acts_notification/electricity_act2003/pdf/The%20Electricity%20Act_2003.pdf.

Potomac Economics. (2011). 2010 State of the Markets for the New York ISO Markets. Fairfax, VA: Potomac Economics. Retrieved from http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2010_Final.pdf.

Real Decreto 1699/2011, "Regulation of Network Access for Small Generation Facilities.

Red Electric of Spain. (2011). The Spanish Electric System in 2010. Madrid, Spain: Red Electric of Spain.

Rosen, D. & Houser, T. (2008). China Energy: A Guide for the Perplexed. Washington, D.C.: Peterson Institute for International Economics. Retrieved from http://www.iie.com/publications/papers/rosen0507.pdf.

Schuman, M. (2010). India vs. China: Whose Economy is Better? www.time.com. Retrieved from http://www.time.com/time/world/article/0,8599,1957281,00.html.

Schwartz, L. & Hodum, R. (2008). ´Smart´ energy management for China´s transmission grid. www.renewableenergyworld.com. Retrieved from http://www.renewableenergyworld.com/rea/news/article/2008/11/smart-energy-management-for-chinas-transmission-grid-54061.

Tawney, L., Greenspan Bell, R., & Ziegler, M. (2011). High Wire Act: Electricity Transmission Infrastructure And Its Impact On The Renewable Energy Market. Washington, DC: World Resources Institute. Retrieved from http://pdf.wri.org/high_wire_act.pdf.

Transmission Agency of North California (2010). http://www.tanc.us/chap2_picture.html

Transmission System Operation Review Group. (2007). Final Report v1.0. London, UK: Department of Energy & Climate Change. Retrieved from: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/071005%20TSORG%20Final%20Document.pdf.

U.S. Department of Energy. (2011). Rules, Regulations & Policies for Renewable Energy. www.dsire.org. Retrieved from http://www.dsireusa.org/summarytables/rrpre.cfm.

Wang, Z. (2009). Market Potential and Technology Transfer - Experience and Expectations from a Chinese Perspective. Presentation made on Nov. 9, 2009, Berlin, Germany. Retrieved from http://www.cwpc.cn/cwpc/en/system/files/documents/ERI_WangZY_WindPowerinChina_Nov09.pdf.

Western Electricity Coordinating Council. (2011a). Regional Transmission Expansion Planning. www.wecc.biz. Retrieved from http://www.wecc.biz/committees/BOD/TEPPC/Pages/RTEP.aspx.

Western Electricity Coordinating Council. (2011b). Frequently asked questions about transmission planning in the Western Interconnection. www.wecc.biz. Retrieved from http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/Transmission%20Planning/RTEP%20FAQs.pdf.

Western Renewable Energy Generation Information System. (2010). WREGIS Annual Report 2010. Salt Lake City, UT: Western Electricity Coordinating Council. Retrieved from http://www.wecc.biz/WREGIS/Documents/2010%20WREGIS%20Annual%20Report.pdf.

Wright, A. (2011). Open Letter: Ofgem's Retail Market Review – update and next steps (liquidity proposals). London, UK: Office of Gas & Electricity Markets. Retrieved from: http://www.ofgem.gov.uk/Markets/RetMkts/rmr/Documents1/Liquidity_Annex%20One_Open%20letter.pdf

Wu, F. & Fu, S. (2005). China´s future in electric energy. IEEE Power & Energy Magazine. July/August 2005. Retrieved from http://www.eee.hku.hk/people/doc/ffwu/China%20pub%20version.pdf.

Zhang, Q. (2006). Regulatory Framework For The Electricity Industry In China. Paris, France: Organization for Economic Co-operation and Development. Retrieved from http://www.oecd.org/dataoecd/46/39/41888874.pdf.

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability, and the fair allocation of system benefits among consumers. We work extensively in the US, China, the European Union, and India.
Visit our website at **www.raponline.org** to learn more about our work.

The Regulatory Assistance Project

Beijing, China • Berlin, Germany • Brussels, Belgium • Montpelier, Vermont USA • New Delhi, India
www.raponline.org