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and
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STUDY ON LEGAL AND REGULATORY FACTORS AFFECTING CROSS-BORDER TRADE IN ELECTRICITY BETWEEN MEXICO AND THE UNITED STATES

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Acronyms

Unless otherwise noted, all organizations with English names in the following list are based in the U.S., and those with Spanish names are based in Mexico.

AC	Alternating Current
ACC	Arizona Corporation Commission
APP	Affiliated Power Producer
ATC	Available Transmission Capacity
BIA	U.S. Bureau of Indian Affairs
BLT	Build-Lease-Transfer
BOOT	Build-Own-Operate-Transfer
BOT	Build-Own-Transfer
BPA	Bonneville Power Administration
CAMMESA	Compania Administradora del Mercado Mayorista Electrico Sociedad Anónima (Argentina) (Administrative Company of the Wholesale Electricity Market)
CCGT	Combined-Cycle Gas Turbine
CDEC	Center of Economic Load Coordination (Chile)
CfD	Contract for Differences
CFE	Comisión Federal de Electricidad (Federal Electricity Commission)
CMVE	Competitive Market Value Estimate
CND	Centro Nacional de Despacho (Columbia) (National Dispatch Center)
CNE	Comisión Nacional de Energía (Chile) (National Energy Commission)
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
CPUC	California Public Utilities Commission
CRE	Comisión Reguladora de Energía (Energy Regulatory Commission)
CREG	Comisón Reguladora de Energía y Gas (Columbia) (Energy and Gas Regulatory Commission)
CRT	Capacity Reservation Tariff
CTC	Competition Transition Charge
DAS	Deputy Assistant Secretary for Fuels Programs, Department of Energy
DC	Direct Current
DDF	Departamento del Distrito Federal (Department of the Federal District)
DdP	Documento de Prospectiva (Prospectus Document)

DOE	Department of Energy
DSM	Demand-Side Management
EA	Environmental Assessment
EdF	Eléctricité de France
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPMI	Enron Power Marketing Incorporated
ERA	Economic Regulatory Administration
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
EWG	Exempt Wholesale Generator
EXIM	Export-Import Bank
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPC	Federal Power Commission
GATT	General Agreement on Tariffs and Trade
GW	Gigawatt
gWh	Gigawatt-hour
HCP	Habitat Conservation Plan
IBWC	International Boundary and Water Commission
IFC	International Finance Corporation
IIC	Inter-American Investment Corporation
IPP	Independent Power Producer
IRP	Integrated Resource Planning
ISO	Independent System Operator
kV	Kilovolt
KW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LFC	Luz y Fuerza del Centro (Central Power and Light)
LO	Length of Obligation
LOLP	Loss-of-Load Probability
LOU	Letter of Understanding
M&A	Mergers and Acquisitions
ME	Ministry of Economics (Chile)
MIGA	Multilateral Investment Guarantee Agency
mVA	Mega-voltamperes
MW	Megawatts

mWh	Megawatt-hour
NAFTA	North American Free Trade Agreement
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NHPA	National Historic Preservation Act
NIE	Northern Ireland Electric
NOPR	Notice of Proposed Rulemaking
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NUG	Non-Utility Generator
NWRTA	Northwest Regional Transmission Association
NYMEX	New York Mercantile Exchange
NYPA	New York Power Authority
OASIS	Open Access Same-Time Information System
OFFER	Office of Electricity Regulation (England and Wales)
OPIC	Overseas Private Investment Corporation
PMA	Power Marketing Administration
PPA	Power Purchase Agreement
PUC	Public Utility Commission
PUHCA	Public Utilities Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
REA	Rural Electrification Administration
REC	Rural Electric Cooperative
REC	Regional Electricity Companies
ROR	Rate of Return Regulation
RSE	Revenue Stream Estimate
RTG	Regional Transmission Group
SCO	Stranded Cost Obligation
SEC	Securities and Exchange Commission
SECOFI	Secretaría de Comercio y Fomento Industrial (Ministry of Commerce and Industrial Development)
SEMIP	Secretaría de Energía, Minas, y Industria Paraestatal (Ministry of Energy, Mines and Parastatal Industry)
SEN	Sistema Eléctrico Nacional (National Electric System)
SHCP	Secretaría de Hacienda y Crédito Público (Ministry of Treasury and Public Finance)
SIC	Sistema Interconectado Central (Chile) (Central Interconnected System)
SING	Sistema Interconectado del Norte Grande (Chile) (Interconnected System of the North)

SMARNP	Secretaría del Medio Ambiente, Recursos Naturales y Pesca (Ministry of the Environment, Natural Resources and Fisheries)
SO_X	Sulfur Dioxide
SPP	Southwest Power Pool
SRE	Secretaría de Relaciones Exteriores (Ministry of Foreign Relation)
SRMC	Short-Run Marginal Cost
SRP	Salt River Project
SWPA	Southwestern Power Administration
SWRTA	Southwest Regional Transmission Association
TDA	Trade and Development Agency
TPUC	Texas Public Utilities Commission
TSP	Total Suspended Particulates
TTC	Total Transmission Capacity
TVA	Tennessee Valley Authority
TW	Terawatt
tWh	Terawatt-hour
USAID	U.S. Agency for International Development
USBR	U.S. Bureau of Reclamation
VAT	Value Added Tax
WAPA	Western Area Power Administration
WEPEX	Western Power Exchange
WRTA	Western Regional Transmission Association
WSCC	Western Systems Coordinating Council

Foreword

In 1994, USAID identified key environmental activities related to the energy sector in its report to the U.S. Congress on Global Climate Change. In 1996, at the Conference of the Parties to the Framework Convention on Climate Change, the U.S. announced its support for establishing binding domestic targets and timetables for reducing greenhouse gas emissions. In addition to these initiatives, the U.S. has also committed to collaborating with other countries to address Global Climate Change issues.

USAID's Center for Environment, as part of the U.S. contribution to the International Climate Technology Initiative announced by Organization for Economic Cooperation and Development (OECD) countries in April 1995, has launched several regional programs having the potential of reducing the threat of Global Climate Change. These programs are aimed at exploring reductions in greenhouse gases by promoting technologies and approaches that accomplish economic development goals and increased trade and investment while reducing the negative climate change-related impacts. In this context, the increase of electricity trade across the border of the U.S. will enhance the efficiency of the power sector in the U.S. and its neighboring countries and defer the need to build new generation capacity. Within this framework, USAID supported and collaborated with the Comisión Federal de Electricidad and the Salt River Project Agricultural Improvement and Power District in the preparation of *Study on Legal and Regulatory Factors Affecting Cross-Border Trade in Electricity Between Mexico and the United States.*

Executive Summary

Introduction

The electricity sectors of both Mexico and the U.S. are undergoing a process of significant structural change. Traditional industry frameworks in both countries are being exposed to new market structures and greater competition, both of which are being introduced by changing regulations on who can generate, transmit, distribute and sell electricity.

In April of 1996, the U.S. Federal Energy Regulatory Commission (FERC) issued a set of broad-reaching rulemakings -- Orders 888 and 889 -- which will have a tremendous impact on the U.S. electricity sector. Among the main issues addressed in those orders are open access to transmission services for all wholesale buyers and sellers, reliability safeguards and the treatment of "stranded investments" created by increased competition.

In Mexico, the electric sector has been undergoing a process of deregulation throughout the 1990s. The sector has been opened to private participation in generation, and policymakers and industry participants are studying various power sector structural models that have been implemented in other countries in order to help shape the future of the Mexican power sector. Due to the proximity and increasing inter-relatedness of the Mexican and U.S. economies, it is likely that changes in one country will have repercussions in the other. Interest in deregulation and restructuring is therefore high on both sides of the border.

One area in which there is particular interest is the potential for increased cross-border trade in electricity. Such an increase would provide economic benefits to both countries, which is of course the primary reason for engaging in trade. Moreover, it could also generate substantial environmental benefits -- in terms of reduced emissions of global pollutants such as carbon dioxide and regional pollutants such as sulfur oxides and nitrogen oxides -- depending on the composition of available capacity (the mix of renewable and fossil-fired generation resources), the size and direction of the energy flows, and the time frame under consideration. Over the long term, structural changes in Mexico's resource base, especially, will provide substantial environmental benefits.

These environmental and economic benefits would be made possible by the increased integration of the two power grids, which would allow more efficient investment in generation resources, as well as slow the need for new generation capacity. Although international interconnections are now in use, the total amount of energy exchanged between the U.S. and Mexico is relatively limited. Industry participants on both sides of the border are interested in understanding the steps necessary to increase trade in electricity, and how the evolution of the legal and regulatory regimes of both countries will affect the development of such trade.

In order to address these issues, an agreement was reached between the Comisión Federal de Electricidad (CFE) and the United States Agency for International Development (USAID) during the summer of 1996. This agreement authorized the implementation of a study on the environmental, legal and regulatory factors affecting future cross-border trade in electricity between Mexico and the U.S., to be conducted by CFE, a consortium of contractors working on behalf of USAID and the Salt River Project (SRP), a public power utility in Arizona. This document is the result of that effort.

The objectives of this study are:

- To analyze current legal and regulatory frameworks of the Mexican and U.S. power sectors and their potential evolution, especially in light of the proposed changes in the U.S.
- To assess the impact and repercussions of the legal frameworks and regulatory changes on the cross-border trade in electricity between Mexico and the United States.

As indicated by these objectives, the focus of this study is on legal and regulatory issues, although technical and economic factors are addressed as well. The latter were addressed in detail as part of the last examination of cross-

border electricity trade, the 1991 *United States/Mexico Electricity Trade Study* (the DOE-SE Study) undertaken by the U.S. Department of Energy (DOE) and the Mexican Secretaría de Energía, Minas e Industria Paraestatal (SEMIP, or Ministry of Energy, Minas and Parastatal Industries).[1]

As is also indicated by the objectives above, this study places relatively more emphasis on developments in the U.S. This emphasis reflects the very rapid pace of change in the U.S. electricity industry, which will have an impact on cross-border trade and investment. Significant changes have also been undertaken in the Mexican electricity sector, as noted above, but it is generally expected that further changes will be at a different pace than in the U.S. Over the near-to-medium term, therefore, the restructuring events in the U.S. will likely have more impact on cross-border trade and investment opportunities than will the continuing evolution of the Mexican electricity sector. Regulatory changes in the Mexican power sector were also examined in detail in a recent USAID report, the 1995 *Private Power Opportunities in Mexico*, and are therefore not described in detail in this study.

The study is organized into three parts. Part I is an introduction. Part II describes electricity sector restructuring developments in the U.S., in order to provide a context for the discussion of specific issues that is contained in Part III. Part II begins with an overview of the regional electricity market, followed by discussions of restructuring efforts in the U.S. The final section provides a review of the restructuring efforts of other countries, in order to put the current process in perspective.

Part III focuses more specifically on opportunities for cross-border trade and investment. The first section identifies a range of regulatory, legal, technical and economic factors on both sides of the border that will affect trade and investment. The second section then examines a set of cross-border trade and investment options, and develops a scenario analysis methodology that incorporates many of the issues detailed in the first section.

Appendix A contains a glossary of electricity industry restructuring terms.

Conclusions

This section presents some of the conclusions that can be drawn from the analysis presented in this study, which can be organized into four broad categories.

Gains from Increased Trade and Integration

One of the most important and robust conclusions to emerge from this study is that there are significant potential gains available from increasing the coordination and integration of the Mexican and U.S. power systems. This conclusion is borne out by previous experience on the border, as well as by international experience with increased system integration and cross-border trading.

- The long history of cross-border coordination and trading between Mexico and the U.S. has already yielded substantial benefits for each country:
    - Excess geothermal capacity in Baja California Norte has served the large demand in southern California at a relatively low cost, while at the same time providing revenue to service the capital costs of those facilities until demand in Baja increases sufficiently to utilize their full capacity.
    - Similarly, regions of Mexico remote from the SEN have been served by interconnection with neighboring U.S. utilities at a fraction of the cost required to extend service from the SEN.
    - Existing agreements between CFE and neighboring utilities in the U.S. have provided valuable backup and emergency capacity.

[1] DOE/IE-0020P, March 1991. The Secrataría de Energía (SE, or Ministry of Energy) subsequently assumed the energy-related responsibilities of SEMIP.

  - CFE purchases of power from U.S. utilities have allowed it to meet WSCC stability criteria in the Baja California Norte power grid without the need for substantial new investments.

- While benefits to date have been substantial, the recent changes in both countries discussed in this study have made their electricity markets more diverse and competitive, creating additional opportunities for cross-border coordination, trade and investment. It must be emphasized, however, that these opportunities are made available not as a result of the regulatory and legal changes themselves, but rather as a result of the increased integration and coordination between systems that such changes make possible. Moreover, as noted in the study and in other conclusions below, regulatory and legal changes are responses to other developments, and in particular to the dramatic increases in generating efficiency made possible by continuing technological advances.

- The potential magnitude of these additional opportunities is suggested by previous international experience. Benefits from increased system coordination and trading have been primarily of three types, as is illustrated by the experience of various Western European countries:

  - Reduced need for new capacity, as has been the case in England and Wales, through its interconnection with France, and in Scandinavia, where the integration of three national systems has reduced the need for new generation capacity in each.

  - Operational benefits, as in the case of Northern Ireland, where a strong interconnection with the Republic of Ireland has reduced the amount of spinning reserve required to be carried by each of its small number of generating stations.

  - Reduced need for additional transmission investment, as in England and Wales, where interconnection with France has relieved the capacity constraints caused by a predominantly one-way flow of energy toward London from the rest of the country.

- Additional benefits are available from increasing the integration of the larger energy markets in Mexico and the U.S. These opportunities are made possible by the integration of electricity and other energy markets that is already occurring on each side of the border. This trend is the most visible in the case of electricity and gas, where mergers between electric and gas utilities have speeded the convergence of those markets. Such convergence is likely with other fuels as well, however, such as coal and fuel oil, although the extent of convergence will depend ultimately on how substitutable one fuel is for another, as well as the alternative uses of each.

Investment Opportunities

In order to realize the benefits of increased integration and trade, investments in transmission, generation and system coordination will likely be necessary. While such investments are in general desirable, the analysis of specific opportunities in the context of different competitive scenarios undertaken in this study illustrates that no general conclusions can be reached regarding the attractiveness of particular types of investment without considering the broader environment in which those investments will be made. Similarly, the specifics of each project are unique, and will ultimately determine its viability; they must therefore by carefully analyzed on a project-specific basis.

- In the case of transmission, the viability of a specific project will depend very much on factors such as the loads and resources in each region and the resulting market price of power, the terrain over which the line is routed, and the need for DC converters, as well as a variety of other variables that will depend on which competitive scenario is realized. Due to the changing nature of the power systems on both sides of the border, additional routes should be continuously investigated and evaluated.

- In the case of generation, the factors determining the viability of a specific project will include loads and resources in the region, fuel prices, and technological developments, as well as the scenario-specific variables described above. Generation projects will often be linked to new transmission capacity, as well, as was emphasized in the description of investment opportunities in this study.

- In order to achieve true integration, however, generation and transmission projects should not be analyzed in isolation, but rather as part of a larger analysis that includes all potential resources in both countries. Such coordination offers the best opportunity to maximize the benefits of cross-border trade and investment.

- As private and/or non-utility investment plays a greater role in the financing of generation, the type of financial arrangement used will have different impacts on the cost of energy. The financial impact of different arrangements should be evaluated, and used to formulate policies that lead to an equitable sharing of risks between utilities and independent generators while ensuring the lowest possible cost of electricity.

Legal and Regulatory

Although this study described a variety of important legal and regulatory changes in both countries that have taken place in the last several years, many important cross-border issues have not been resolved by the regulatory bodies and/or courts of Mexico and the U.S.

- The status of a non-U.S. entity under the Federal Power Act and FERC Order 888 is not yet defined. A resolution of that issue would facilitate the integration of the two countries' power grids.

- Regulatory and legislative changes continue to occur in both countries, which will impact the attractiveness of various cross-border trade and investment opportunities, and the possibility of greater integration and coordination. Developments in both countries should therefore be closely monitored by market participants and official agencies. As a way to increase communication between these entities, informal discussions regarding general developments and specific issues in each country could be held on a regular basis.

Technical, Financial and Economic

As noted above, the legal and regulatory changes described in this study are in general responses to more fundamental underlying technical, financial and economic forces, which will continue to play a key role in the evolution of the Mexican and U.S. power systems.

- Advances in technology will be particularly important. Further increases in generation efficiency will bring down the price of energy, while advances in metering, communications and information technologies will increase the potential benefits from cross-border trade and integration and speed the process of fuel convergence.

- High retail electricity prices and the pressure to reduce costs will remain strong forces for change in the U.S. power industry. Whatever course restructuring efforts take, therefore, will likely include measures that respond to these concerns. This is especially true in the case of retail electricity prices, which must fall along with commercial and industrial rates to avoid strong resistance to change on equity grounds.

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Suggested Next Steps

In order to build on the bi-national effort undertaken for this study, the following list summarizes suggestions for additional steps that could be taken to facilitate the process of cross-border trade and investment.

- Identify forums to improve communications and cooperation among CFE, other relevant Mexican government entities (such as CRE), and FERC. This dialog should include discussion of the "safe harbor" provisions of FERC Order 888.
- Explore additional transmission interconnection opportunities. This should include a re-examination of the technical feasibility of additional AC interconnections between CFE, WSCC and ERCOT.
- Undertake a joint study of gas/electricity links for cross-border activities.
- Analysis of optimal project finance "modes" to facilitate cross-border activity.
- Continued monitoring of legislative and regulatory developments in both countries.
- Investigation of ways to standardize contractual arrangements.
- Identification of those transmission routes leading to and from the border that lack complete information on available or potential transmission capacity, and the determination of that capacity.

I. Introduction

This section provides the background for the present study, defines its objectives, and outlines the structure of the remainder of the study.

A. Background

The electricity sectors of both Mexico and the U.S. are undergoing a process of significant structural change. Traditional industry frameworks in both countries are being exposed to new market structures and greater competition, both of which are being introduced by changing regulations on who can generate, transmit, distribute and sell electricity.

In April of 1996, the U.S. Federal Energy Regulatory Commission (FERC) issued a set of broad-reaching rulemakings -- Orders 888 and 889 -- which will have a tremendous impact on the U.S. electricity sector. Among the main issues addressed in those orders are open access to transmission services for all wholesale buyers and sellers, reliability safeguards and the treatment of "stranded investments" created by increased competition.[2]

In Mexico, the electric sector has been undergoing a process of deregulation throughout the 1990s. The sector has been opened to private participation in generation, and policymakers and industry participants are studying various power sector structural models that have been implemented in other countries in order to help shape the future of the Mexican power sector. Due to the proximity and increasing inter-relatedness of the Mexican and U.S. economies, it is likely that changes in one country will have repercussions in the other. Interest in deregulation and restructuring is therefore high on both sides of the border.

One area in which there is particular interest is the potential for increased cross-border trade in electricity. Such an increase would provide economic benefits to both countries, which is of course the primary reason for engaging in trade. Moreover, it could also generate substantial environmental benefits -- in terms of reduced emissions of global pollutants such as carbon dioxide and regional pollutants such as sulfur oxides and nitrogen oxides -- depending on the composition of available capacity (the mix of renewable and fossil-fired generation resources), the size and direction of the energy flows, and the time frame under consideration. Over the long term, structural changes in Mexico's resource base, especially, will provide substantial environmental benefits.

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[2] "Stranded investments" generally refer to generation facilities that, due their relatively high costs, would not be economic if in a competitive environment -- i.e., where they would not be dispatched. Such facilities are considered to be "stranded" by competition, and their owners, which are generally investor-owned utilities, are generally acknowledged to be entitled to recover some or all of their fixed costs, which were usually incurred with the regulatory promise of such recovery. As described in later sections of the study, other types of "investments" have also been deemed to be stranded, particularly in California. Stranded investments are also referred to as stranded costs or stranded assets.

B. Objectives

The objectives of this study are:

- To analyze current legal and regulatory frameworks of the Mexican and U.S. power sectors and their potential evolution, especially in light of the proposed changes in the U.S.
- To assess the impact and repercussions of the legal frameworks and regulatory changes on the cross-border trade in electricity between Mexico and the United States.

As indicated by these objectives, the focus of this study is on legal and regulatory issues, although technical and economic factors are addressed as well. The latter were addressed in detail as part of the last examination of cross-border electricity trade, the 1991 *United States/Mexico Electricity Trade Study* (the DOE-SE Study) undertaken by the U.S. Department of Energy (DOE) and the Mexican Secretaría de Energía, Minas e Industria Paraestatal (SEMIP, or Ministry of Energy, Minas and Parastatal Industries).[3]

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C. Structure of the Study

The study is organized into three parts. Part I is this introduction. Part II describes electricity sector restructuring developments in the U.S., in order to provide a context for the discussion of specific issues that is contained in Part III. Part II begins with an overview of the regional electricity market, followed by discussions of restructuring efforts in the U.S. The final section provides a review of the restructuring efforts of other countries, in order to put the current process in perspective.

Part III focuses more specifically on opportunities for cross-border trade and investment. The first section identifies a range of regulatory, legal, technical and economic factors on both sides of the border that will affect trade and investment. The second section then examines a set of cross-border trade and investment options, and develops a scenario analysis methodology that incorporates many of the issues detailed in the first section.

Appendix A contains a glossary of electricity industry restructuring terms.

[3] DOE/IE-0020P, March 1991. The Secrataría de Energía (SE, or Ministry of Energy) subsequently assumed the energy-related responsibilities of SEMIP.

II. Electricity Sector Restructuring Developments

As noted above, this part of the study is focused on recent developments in the U.S. electricity sector.[4] In order to provide the reader with some background for the discussion of these developments, the first section provides a brief overview of the regional electricity market. The second section describes the existing U.S. electricity sector, its historical evolution, alternative approaches to restructuring, and the activities now underway. The third section puts U.S. restructuring activities into context by examining the restructuring experience of selected other countries.

A. Overview of Regional Electricity Market

This section provides a quick overview of the regional electricity market, which is defined for purposes of this study to include the Electric Reliability Council of Texas (ERCOT); those parts of Mexico, the U.S. and Canada that are in the Western Systems Coordinating Council (WSCC); and the non-WSCC areas of the Sistema Eléctrico Nacional (SEN, or National Electric System) of Mexico. The WSCC and ERCOT are two of the "reliability councils" that comprise the North American Electric Reliability Council (NERC), a non-profit corporation that promotes the reliability of North America's interconnected electricity systems. Both Councils are discussed in detail in later sections. The WSCC encompasses the Baja California North section of the CFE grid, all or part of 14 western states in the U.S., and British Columbia and Alberta in Canada. ERCOT, as its name suggests, covers most of Texas, although parts of that state are also in the WSCC and the Southwest Power Pool (SPP), another of the NERC reliability councils.

Market participants from each country are described, followed by summary statistics on regional generation capacity, energy production and wholesale electricity prices.

1. Market Participants

a) Mexico

In recent years many electric utilities in the world have started implementing important changes in their organization in order to promote efficiency and improve their financial situation. Most of these changes in the power industry are related to the introduction of competition and the disaggregation of electric services.

In some countries this process has been combined with a total or partial privatization of services in state-owned utilities; as a result, new participants in the power industry have appeared with particular business objectives. This opening of the power market will produce important changes in system planning and operational procedures and will add additional uncertainty to an already complex task.

This process has started in Mexico. This study summarizes some of the changes already undertaken and presents some of the challenges foreseen for the future.

(1) The Mexican Electric System

(a) Generation Structure

At the end of 1996, the SEN has an estimated total of 166 power plants -- 79 hydro, 88 thermal, and 1 wind-powered -- with 511 units. The estimated installed generation capacity is 34,790 MW; 51.7 percent of this total is conventional steam units, combined-cycle units and gas turbines burning fuel oil, natural gas and diesel; 28.8 percent is hydro units, most of them located in the Southeast of Mexico; 7.5 percent is steam units using domestic coal as fuel; 6 percent of the capacity is dual units burning fuel oil or imported coal; 2.1 percent is geothermal plants; 3.8 percent is nuclear power plants; and less than 1 percent is wind power stations.

[4] " Electricity sector", "electricity market" and "electricity industry" are used interchangeably throughout this Study. Although this treatment might be somewhat confusing, it accurately reflects the transitional nature of current circumstances.

(b) Electric Energy

Total estimated energy production in 1996 was 153 terawatt-hours (tWh), with a maximum load demand of 23 gigawatts (GW); 54.8 percent of this total was sales to industrial and high voltage customers, 24.7 percent was to residential users, 8.4 percent to commercial customers, 5.8 percent for agricultural irrigation, 4.6 percent for municipal services such as street lightning and water pumping, and the remaining 1.7 percent was exports to electric utilities in the U.S. and Belize. The average number of customers served in 1995 was 15.4 million.

(c) Transmission Structure

The national grid is formed by a transmission system based on 400 kV, 230 kV and 115 kV lines that cover most of the country . Today, only the Baja California Peninsula remains isolated from the main electric network.

The main transmission system consists of 66,674 kilometers of high voltage lines, and total installed substation capacity is 114,701 mega-voltamperes (mVA). The bulk transmission system is made up of 400 kV transmission lines (16.5 percent), 230 kV (27.8 percent) and 161 to 69 kV lines (55.7 percent). The SEN has several interconnections with electric systems of various utilities along the Mexico-U.S. border, which are described later in the study. Some of these ties have been used for permanent interchanges of energy, while others are used only for emergency assistance or short-term area-dedicated economic transactions. At the southern border, energy is exported to Belize at distribution voltages and in the near future at 115 kV.

(2) Power Industry Organization

The Comisión Federal de Electricidad is the electric utility in Mexico responsible for the public supply of electricity, which includes power system planning, power generation for public service, and transmission and distribution of electric power.

Power system planning is part of a national energy planning process, which in turn defines fuel policies and diversification strategies to coordinate the execution of alternative projects, such as hydroelectric, geothermal and nuclear power plants.

Under this process, investment programs are subject to the government budget process, which considers economic goals, financial resources and retail electric rate policies. The Mexican government manages the energy sector, including electricity, through the SE and the Comisión Reguladora de Energía (CRE, or Energy Regulatory Commission).

Although CFE is by law the electric utility responsible for the electric public service in Mexico, another utility, Luz y Fuerza del Centro (LFC, or Central Power and Light) distributes electric energy in the central part of the country. Both CFE and LFC are state-owned utilities. The CFE and LFC boards are headed by the Minister of Energy, but they are each self-governing companies with an appointed general director.

LFC is mainly devoted to the distribution of electric energy, although it has some generation capacity which currently meets only 5 percent of its load requirements. LFC serves 4.8 million customers; to meet that demand, it imported 27.2 tWh from CFE in 1995, equivalent to 20 percent of CFE's total generation.

The two utilities combined distribute electric energy to almost 20 million customers, covering 95 percent of the country's inhabitants. The remaining 5 percent of the population lives in small villages of less than 100 inhabitants located far away from transmission and distribution lines. CFE serves 99 percent of Mexico's territory (2 million square kilometers) and 75 percent of electricity customers.

(a) Structural Model

At present, Mexico's power industry is changing to a competitive integrated model. The generation of electric energy is open to private investment for external (i.e., non-utility) production, through the ownership, design, construction, maintenance and operation of power plants. It is expected that a large portion of the generating capacity additions required to face future load demand will be met by non-utility generators. Specific aspects of private participation in electricity generation are described in detail in later sections of the study.

b) United States

More than 3,000 entities are engaged in the generation, transmission, distribution or sale of electricity in the U.S. These entities include investor-owned utilities (IOUs), publicly[5] owned utilities, cooperatives, non-utility generators NUGs) power marketers, power brokers and load aggregators.

(1) Investor-Owned Utilities

Investor-owned utilities have historically been vertically integrated, regulated monopolies with exclusive service areas. As their name implies, they are private, joint-stock companies that are traded on U.S. stock exchanges. Although the activities of IOUs are now considerably more complex than in previous decades, as is described below, the name is used today to differentiate these regulated entities from other private generators in the U.S. electricity sector, such as affiliated power producers (APPs), co-generators and independent power producers (IPPs).[6] IOUs have the largest share of the generation market in the region and in the U.S. as a whole, and as Table 1 illustrates, a small number in each region account for a large share of total activity.

(2) Publicly Owned Utilities

There are publicly owned electricity entities at the federal, state and local level in the U.S. Federal entities include the Power Marketing Administrations (PMAs), which sell power produced by federal projects, and the projects themselves, which are built and operated by the Bureau of Reclamation (USBR), the Bureau of Indian Affairs (BIA), the Army Corps of Engineers (COE) and the International Boundary and Water Commission (IBWC) of the Department of State. As Table 1 illustrates, PMAs play a particularly important role in the WSCC, due to the large amount of federally owned and operated hydropower capacity in the western U.S. state entities are typically public utility districts or authorities that serve a specific state, such as the New York Power Authority (NYPA), or state agencies that operate state and/or federal assets, such as the Salt River Project Agricultural Improvement and Power District. Local publicly owned entities are generally municipal utilities, which own distribution, and sometimes transmission and generation assets used to serve their citizens.

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[5] The term "public" has several meanings within the U.S. electricity sector, which can be the source of some confusion. A "public utility" is a regulated IOU that falls under the jurisdiction of the FERC. A "publicly owned" utility is one that is owned and operated by a federal, state or local government body. Finally, any private company can be "publicly held", meaning that it is a joint-stock company whose shares are publicly traded on a stock exchange -- or "privately held", meaning that its shares are controlled by one or more shareholders and not publicly traded. Thus, although IOUs, EWGs and IPPs are all private, non-government enterprises, they can all be described differently using this nomenclature: IOUs are publicly held, public utilities subject to FERC jurisdiction; EWGs are publicly held generators that are not public utilities; and IPPs can be either publicly or privately held, and are not public utilities.

[6] These terms are explained in detail in later sections.

Table 1: Market Shares in WSCC (U.S.) and ERCOT

Region & Entity	Share of Net Generation & Purchases	Region & Entity	Share of Net Generation & Purchases
WSCC (1993)		ERCOT (1995)	
IOUs		IOUs	
Arizona Public Service	4%	Central Power & Light Company	7%
Pacific Gas & Electric	15%	City Public Service	8%
Pacificorp	11%	Houston Lighting & Power Company	27%
Puget Sound Power & Light	4%	Texas Utilities Electric Company	40%
Public Service of Colorado	4%		
Southern California Edison	14%		
Total IOUs	**52%**	**Total IOUs**	**82%**
Federal		Federal	
Bonneville Power Administration	15%	Lower Colorado River Authority	4%
Western Area Power Administration	4%		
Total Federal	**19%**	**Total Federal**	**4%**
Other Government		Other Government	
Salt River Project	4%	City of Austin	5%
Los Angeles Dept. of Water & Power	4%	Texas Municipal Power Pool	4%
Total Other Government	**8%**	**Total Other Government**	**9%**
Other	**19%**	**Other**	**5%**

Sources: HISTCDR.XLS Spreadsheet from ERCOT Bulletin Board System, 1995 data, 07/29/96
Energy Information Administration, IOU's 1993, January 1995
Publicly Owned Electric Utilities 1993, February 1995

(3) Rural Electric Cooperatives

Rural Electric Cooperatives (RECs) are a specialized form of publicly owned utility. They are non-profit entities run by their customers and incorporated under the laws of the states in which they are located. RECs use low-interest loans provided by the Rural Electrification Administration (REA) for system expansion and other capital needs.

(4) Non-Utility Generators

NUGs are private companies that generate electricity for sale in the wholesale market and for their own use. As explained in detail below, this term includes several different types of private generators, some of which sell their output under legislatively mandated power purchase agreements (PPAs), while others use bilateral, negotiated contracts.

(5) Intermediaries

The final category of participants in the U.S. electricity market are those that do not own generation: power marketers, power brokers and load aggregators. Power marketers are approved by the FERC to sell wholesale electricity at market rates, and are becoming an increasingly important component of the overall market. Brokers arrange transactions between buyers and sellers, but do not take title to the power themselves. Load aggregators, as their name implies, join together the loads of many relatively small customers in order to buy electricity at the more attractive rates that are available for large purchases.

c) Canada

Like the U.S. and Mexico, Canada has a mix of public and private ownership in the electricity sector. Unlike either, however, government-owned enterprises at the provincial level are the principal providers of electricity in most parts of the country, accounting for 80 percent of total electricity revenues in 1992.

This general pattern is true in British Columbia, where the British Columbia Hydro and Power Authority, which is a provincial "crown corporation" generates and sells most of the provinces electricity. An IOU, West Kootenay Power, also serves part of the province.

Alberta is distinct from the rest of Canada in two important ways. First, IOUs provide the majority of the electricity generated. TransAlta Utilities supplies 63 percent of the province's electricity, with most of the balance provided by Alberta Power, a smaller IOU, and Edmonton Power, a municipal utility owned by the City of Edmonton. There are also three other small municipal utilities. Second, since January 1, 1996 Alberta has operated a power pool into which all electricity, whether generated in Alberta or imported, is sold. All of the province's electricity distributors then purchase the power sold to their customers from the pool, at an hourly price set by supply and demand.

2. Capacity and Energy Statistics

As illustrated in Table 2, WSCC, ERCOT and CFE have a combined installed capacity of about 242 GW, which serves a combined peak demand of 171 GW. Both CFE and ERCOT have installed reserve margins of about 24 percent, while the WSCC margin is considerably higher, approximately 33 percent. The WSCC average, however, masks wide variation within sub-regions. Margins in the Northwest Power Pool, the Rocky Mountain sub-region, and the Arizona-New Mexico sub-region are all very high, ranging from 38 to 59 percent, while the margin in the California-Southern Nevada sub-region is only 4.5 percent. This disparity reflects the regional flow of power within the WSCC, which moves from the less populated and resource-rich areas in the northwest and mountain states to meet the very large demands of California.

The resource profile of the three areas in the region differ significantly. Hydro accounts for almost 40 percent of WSCC generation capacity, as a result of the system of large dam projects in the U.S. northwest and western Canada, but only one percent of ERCOT, which is heavily dependent on oil and gas, of which Texas has abundant supplies. Mexico lies between these extremes, with slightly more than half of its generation capacity fired by gas and oil, and almost 30 percent in hydro. Nuclear capacity is less than 10 percent of the total in all three areas.

Retail energy sales in the region total 934,000 gWh, most of which goes to industrial customers. Both the WSCC and ERCOT have similar sales profiles, with roughly one third of all energy consumed by industry, while in Mexico industry's share is close to 60 percent.

Table 2: Regional Electricity Markets -- 1995

	WSCC	ERCOT	CFE*	Total
Total Peak Demand (Non-coincident GW)	102	44	25	171
Total Retail Energy Sales (gWh)	531,000	262,000	141,000	934,000
Residential	32%	35%	25%	
Commercial	31%	26%	8%	
Industrial	33%	34%	55%	
Other	4%	5%	12%	
Total Installed Capacity (GW)	152	58	32	242
Hydro	39%	1%	28%	
Coal	24%	28%	7%	
Gas/Oil	29%	62%	52%	
Nuclear	7%	9%	4%	
Other	1%	0%	9%	
Installed Reserve Margin	33%	24%	24%	30%

Source: World Energy Service U.S. Outlook, Fall-Winter 1995-96
Electric Power Annual, 1995, Vol. I
DOE/EIA-0348(95)/1, July 1996
CFE, Desarrollo del Sector Eléctrico de México: 1996-2006, Documento de Trabajo, August 20, 1996

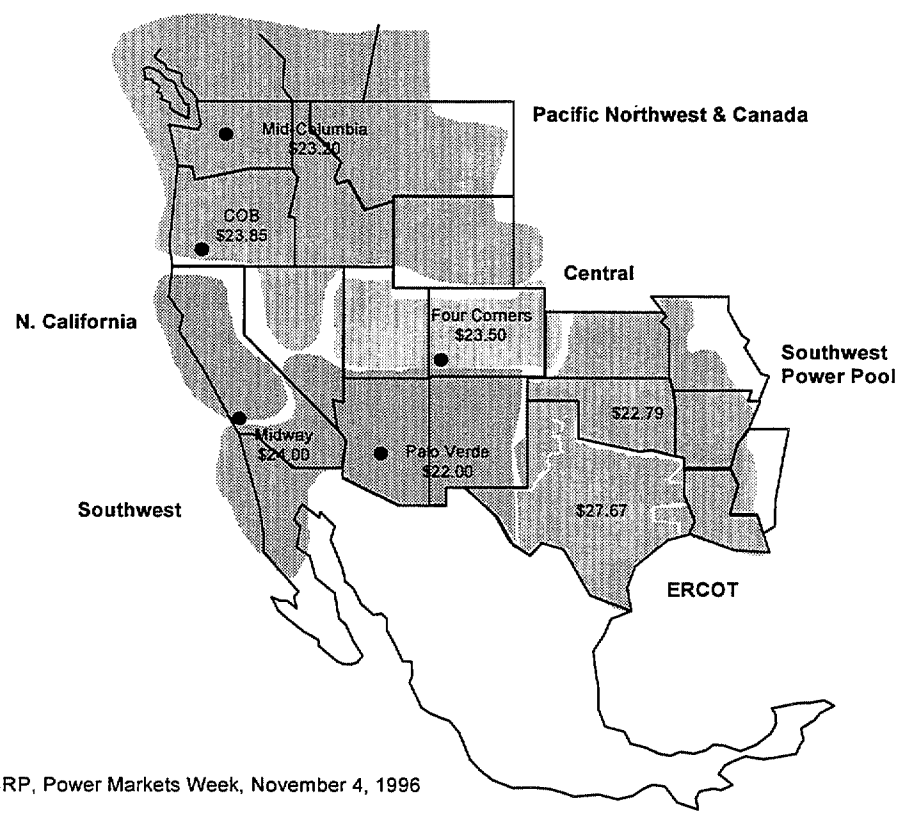
*Energy sales percentages not directly comparable to WSCC/ERCOT due to classification differences with regard to end-users

3. Wholesale Prices

The generation market in the U.S. and western Canada is essentially free of price regulation. As a result, the wholesale prices of electricity are relatively low in the WSCC and ERCOT. As illustrated in Figure 1, the region can be divided into several trading areas, based on the location of loads, resources and transmission constraints. These factors create some differences in prices among the regions, which are which are tracked by published indices.[7] Two of these indices, Palo Verde and the California-Oregon Border (COB), are based on the trading of futures contracts for delivery of electricity at those points according to the terms specified by the New York Mercantile Exchange (NYMEX), where the contracts are traded. The other prices illustrated in Figure 1 are based on surveys of trades at either the specific trading points illustrated (e.g., Midway and Four Corners), or in the region as a whole (e.g., ERCOT). Although the SPP is not defined as part of the regional market for purposes of this study, it is included in Figure 1for informational purposes.

Wholesale prices in Mexico are determined by CFE's economic dispatch of CFE and private generators, both of which submit daily bids for energy only. Energy from surplus capacity of 20 MW or less is purchased by CFE if the price offered is less than CFE's marginal cost of generation in the region, which is calculated and published each year by the SE based on information submitted by CFE.

Figure 1: Wholesale Prices at Major Trading Points ($ per mWh)



Sources: SRP, Power Markets Week, November 4, 1996

[7] The periodical *Power Markets Week* is the standard source of prices for these indices. The prices used in Figure 1 represent the weekly index values for each trading point or area published in the November 4 issue of *Power Markets Week.*

B. Overview of U.S. Restructuring

This section provides a detailed discussion of the restructuring process currently underway in the U.S. The current structure of the U.S. electricity sector is first described, followed by an explanation of its historical origins, which is necessary to put current developments in context. Various types of alternative structures are then presented, followed by a description of federal and state restructuring activities. The end of the section provides some observations and conclusions regarding this process.

1. Historical and Current Structure in the U.S.

This section describes some of the various market participants discussed above in more detail, focusing on those that will likely be the principal players in the restructured market and their relationships to each other.

a) Vertically Integrated Utilities

Approximately 260 vertically integrated IOUs dominate the U.S. electricity sector by most measures, as illustrated in Table 3. These utilities were created from the merger of many small private and municipal systems during the period when increasing economies of scale in generation gave significant advantages to larger companies.

Table 3: Summary of 1995 U.S. Electricity Sector (excluding NUGs)

Ownership	Generating Capacity (MW)	Share of Total	Generation (gWh)	Share of Total	Number of Entities	Share of Total
IOUs	577,405	77%	2,340,482	78%	249	8%
Federal	66,333	9%	263,205	9%	10	0%
Cooperatives	27,220	4%	134,103	4%	937	29%
Other Publicly Owned	78,766	11%	256,739	9%	2015	63%
Total	749,724		2,994,529		3,211	

Source: Edison Electric Institute: Advance Release of Data for the 1995 Statistical Yearbook of the Electric Utility Industry, June 1996

IOUs are owned by equity shareholders who can trade their ownership shares on public stock exchanges. IOUs share several key characteristics, some of which may change as a result of the current restructuring process. First, they are granted service areas by the regulatory bodies that oversee them. Within this service area, the IOU is granted monopoly rights to provide its services, although competing products -- such as natural gas -- can be sold by other businesses within the service area. Second, the IOU incurs an "obligation to serve" in return for this monopoly privilege. It must provide service to all customers that request it, regardless of whether they are profitable customers. Third, the electricity provided is considered to be a necessary public service, or one for which there is no substitute. Fourth, the provision of electricity service has historically been considered to be a natural monopoly, or an industry in which the incremental cost of providing one unit of output declined continuously as the level of output increased. Generation, transmission and distribution were observed -- or assumed -- to exhibit such apparently infinite economies of scale. As is now widely known, the natural monopoly assumption has proven to be incorrect in the case of generation, and distribution has been separated from the concept of "supply", or the purchase of electricity as distinct from its delivery over distribution wires, which remains a natural monopoly. The restructuring process in the U.S. and elsewhere in the world is to a large degree a reaction to this change in thinking, which in turn was brought about by the forces discussed elsewhere in this study.

As a result of the natural monopoly characteristics of electricity, and the desire to avoid the potential abuses that are created by providing a private company with a legal monopoly, IOUs have been heavily regulated in the U.S. at both the federal and state levels. Federal regulations have been concerned with limitations on ownership and control of interstate commerce, while state regulation has been used to control the prices and expenditures of IOUs. The

principle mechanism used to accomplish this has been rate-of-return (ROR) regulation. Under a ROR system, an IOU is allowed to charge tariffs sufficient to recover its "revenue requirement", which is defined as operating costs, including depreciation, plus a return on its assets. This return is a weight average of the IOU's interest rate on outstanding debt and its return on equity, which is used to pay shareholder dividends. A state public utility commission (PUC) or similar regulatory body controls the activities of the IOU by regulating each component of this equation. It approves which operating expenses can be recovered, the level of the allowed return on equity, and which capital expenditures can be included in the assets on which a return will be earned.

IOUs have always had commercial relations with other sector participants. They enter into "economy interchange" agreements with other IOUs to take advantage of different generation and/or load profiles, and to dispatch generation capacity on an economic basis over a larger geographic region. IOUs also sell wholesale electricity to municipal utilities and RECs, and purchase available power from PMAs. These commercial relations have been expanded considerably with the creation of a true wholesale electricity market in the U.S. Some of the newer types of commercial arrangements now being utilized are described in later sections.

b) Power Marketing Administrations

The U.S. Congress has established by statute a number of federal multi-purpose water projects throughout the U.S. The purposes of these federal water projects are varied -- flood control, navigation, agricultural irrigation, generation of hydroelectric power and recreation. These projects have been constructed and operated primarily by two federal agencies: the U.S. Bureau of Reclamation, which is an agency of the U.S. Department of Interior, and the U.S. Army Corps of Engineers. The power generating facilities at these water projects are controlled by the USBR and the COE.

The electric power generated from the projects is marketed by five federal PMAs, which are part of the DOE. The PMAs include the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Alaska Power Administration, the Southeastern Power Administration and the Southwestern Power Administration (SWPA). The PMAs sell electricity within 34 states, primarily on a wholesale basis. In 1994, PMAs sold about 3 percent of the total U.S. electricity output. By law, they are required to give priority in the sale of federal hydroelectric power to public power entities, such as public utility districts, municipalities, and customer-owned cooperatives. These customers are referred to as "preference customers."

BPA, WAPA and SWPA own and operate high-voltage power transmission lines and also make use of other utilities' transmission systems in order to deliver power from federal dams to their customers' power grids. Under the Energy Policy Act of 1992 (EPAct, discussed in detail below), FERC, which is also an agency of DOE, can order BPA, WAPA and SWPA to provide wholesale transmission services to eligible requesters. While the PMAs are not directly subject to FERC Order 888, the Secretary of Energy has stated that the PMAs will support the principles of open transmission access and comparability set forth by the FERC in Order 888 and will develop open access transmission tariffs.

The Tennessee Valley Authority (TVA), another federal multipurpose water project authorized by the U.S. Congress in 1933, is not classified as a PMA but does market hydroelectric power produced by TVA dams, does own transmission facilities, and is subject to FERC for the provision of wholesale transmission service under the EPAct.

This following sections describe the two PMAs that are within the WSCC region: BPA and WAPA.

(1) Bonneville Power Administration (BPA)

BPA was created by the U.S. Congress in 1937 to market and transmit the hydroelectric power produced at Bonneville Dam on the Columbia River in the U.S. Pacific Northwest. Today, BPA markets the power from 29 federal dams and one non-federal nuclear plant. In fiscal year October 1994-September 1995, BPA sold just over 131,000 MW of capacity and 80,390 gigawatt-hours (gWh) of energy to municipalities, public utility districts, cooperatives, federal agencies, investor-owned utilities and direct-service industries. Of this power, 3,147 MW of capacity and 6,782, gWh of energy were sold outside of the Pacific Northwest to other utilities and power marketers in the WSCC region.

BPA's service territory covers about 300,000 square miles (775,000 square kilometers) and it sells about 46 percent of the electricity consumed in the U.S. Pacific Northwest. It maintains over 300 substations and nearly 15,000 miles of transmission lines (nearly three-fourths of the grid) in the Pacific Northwest. BPA has transmission links to the north (Canada), south (California) and east (eastern Montana). The largest is the Pacific Intertie, which carries power between the Pacific Northwest and California. Utilities up and down the west coast of the U.S. use BPA's high-voltage grid to help deliver electricity to their customers.

BPA is a significant market player in the wholesale electricity market in the WSCC region. During high water years, BPA's surplus hydro generation coupled with its strategic interconnections with the Pacific Intertie and California load centers can push down electricity spot market prices in the WSCC significantly. Conversely, during low water years, the absence of BPA's surplus hydro generation from the WSCC market has historically resulted in higher electricity spot market prices.

BPA faces many conflicting issues in its joint role with the USBR and COE in managing the Columbia River system. Such issues include mitigation of damage to fish and wildlife habitat, support of commercial and tribal fishing industries, support of recreational uses of the Columbia River, and consumer pressures to keep electricity costs low.

BPA is an active member of the WSCC, the Western Regional Transmission Association (WRTA), the Northwest Regional Transmission Association (NWRTA), and the Northwest Power Planning Council.

(2) Western Area Power Administration (WAPA)

WAPA was established in 1977 under the U.S. Department of Energy Organization Act to assume power marketing responsibilities previously managed by the USBR. WAPA markets and transmits hydroelectric power from 55 power plants operated by the USBR, the COE and the International Boundary and Water Commission. WAPA also markets the federal government's entitlement (547 MW) in the coal-fired Navajo Generating Station near Page, Arizona.

WAPA's current maximum operating capability is approximately 10,600 MW. In fiscal year October 1994-September 1995, WAPA sold approximately 36,000 gWh of energy to municipalities, cooperatives, public utility and irrigation districts, federal and state agencies and IOUs.

WAPA's service area covers 1.3 million square miles (3.38 million square kilometers). WAPA's wholesale power customers, which number close to 600, provide electric service to millions of consumers in 15 western states in the U.S. -- Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming. It operates an extensive high-voltage power transmission system to deliver federal power to its customers, maintaining nearly 300 substations and nearly 16,700 miles of transmission lines.

In recent years, the federal PMAs, including WAPA, have been the target of much public debate in the U.S. Such issues as whether and how the federal multipurpose water projects should be privatized, whether or not the costs of building and operating the federal power generation facilities have been subsidized by the federal government, whether or not "preference laws" -- which give priority in the sale of federal hydroelectric power to the preference customers described above -- should be overturned, have been of great interest in this era of increasing electric utility industry competition. In the past, the Clinton Administration has expressed interest in privatization of the PMAs and the U.S. Congress may see proposed legislation regarding the issue in its upcoming term.

As does BPA, WAPA faces complex environmental issues related to the generation and marketing of electric power from the multi-use federal projects that it helps to manage. For example, the U.S. Congress passed the Grand Canyon Protection Act in 1992 in response to environmental and recreational concerns regarding effects of operation of the Glen Canyon Dam on fish, wildlife and habitat in the Grand Canyon. Implementation of the Act affects the amount of power that can be generated at the Glen Canyon Dam and thus affects WAPA's marketing and delivery of that power under existing long-term power contracts with its customers. WAPA is an active member of the WSCC, the WRTA and the SWRTA.

c) Other Publicly Owned Utilities

As illustrated in Table 3, non-federal government utilities owned 105,986 MW of generation capacity in 1995. Of this total, 27,220 MW was owned by cooperatives, and 78,766 by other government utilities. Cooperatives are not described in this section, because their unique form of member ownership makes it unlikely that they will become major participants in the wholesale power market.

In addition to cooperatives and federal entities, there are a variety of local and state utilities. Most are municipalities, which accounted for 42,169 MW of capacity in 1995. This category includes such major utilities as the Los Angeles Department of Water and Power (LADWP), with an installed generation capacity of several thousand MW, as well as small distribution municipals with several hundred MW of distribution capacity only. Municipal utilities are permitted by federal law to issue bonds for which the dividends are tax-exempt.

State-owned electricity utilities entities are typically public utility districts or authorities that serve a specific state, such as the NYPA, or state agencies that operate state and/or federal assets, such as SRP. Like the federal generation projects, the NYPA owns hydro and other generation capacity, the generation from which is sold based on legislatively determined preferences. Industrial companies, for example, compete for NYPA electricity by promising a certain number of jobs per megawatt-hour (mWh) purchased, and then sign contracts with the Authority holding them to those obligations. In contrast, SRP is actually a combination of two entities: the Salt River Project Agricultural Improvement and Power District, which provides power to more than 600,000 customers in the Phoenix area; and the Salt River Valley Water Users' Association, which delivers water to eight cities as well as agricultural and urban irrigators.

d) Non-Utility Generators

NUGs are private companies that own and operate generating capacity, but are not IOUs as defined above. Such entities -- usually in the form of industrial facilities that engage in self-generation -- produced more than half of all electricity generated in the early years of the century. This capacity had all but disappeared by the 1960s, due to increasing economies of scale in generation that made it uneconomic for all but the largest industrial facilities to self generate. Several changes in the 1970s made non-utility generation more attractive -- both for self use and to sell to IOUs -- as explained in later sections, but by that time several impediments limited the amount of NUG capacity that could economically be built. First, the IOUs often refused to buy NUG energy, or offered uneconomic prices for it when they did. Second, the IOUs sometimes charged very high rates for backup power and other ancillary services. Finally, a NUG that sold to an IOU ran the risk of being considered a "public utility" under the Public Utilities Holding Company Act of 1935 (PUHCA), which would subject it to a variety of restrictive regulations.[8] These problems were partly alleviated by the Public Utility Regulatory Polices Act (PURPA) of 1978, and by the EPAct of 1992. As a result, there are currently there are several categories of NUGs, which correspond to their regulatory status:

- *PURPA Qualifying Facilities (QFs)* -- Two types of NUG were designated by PURPA to be QFs, a status which required that IOUs purchase the facility's energy at the IOU's "avoided cost", and that the IOU provide backup service at non-discriminatory rates. In addition, QFs were not considered to be public utilities, and were therefore exempted from the regulatory requirements of PUHCA. QFs must meet requirements regarding ownership, fuel and size. The ownership provision requires that QFs not be owned by a person whose primary business is the generation or sales of electricity, which effectively prohibited IOUs from ownership of QFs. Fuel and size requirements are contained in the definitions of the two types of QFs:
    - *Cogeneration* -- To meet the QF criteria, a cogenerator must produce both electricity and another form of useful thermal energy from the same primary energy source. In addition, it must meet specified efficiency criteria. Any type of primary fuel may be used, but most cogeneration plant use fossil fuels.

[8] The Public Utilities Holding Company Act (PUHCA) and other laws discussed in this section are explained in detail in later sections.

- *Small Power Production* --To meet the small power producer criteria, a facility must use primarily renewable resources -- i.e., biomass, solar, geothermal, wind and water. The original regulations required that the capacity of such facilities also not exceed 80 MW, but modifications to the law in 1990 removed this restriction for any of the above fuels except water, provided that the application for QF status was received before December 31, 1994 and that construction commence before December 31, 1999.

- *Exempt Wholesale Generators (EWGs)* -- In order to encourage the development of the wholesale electricity market, EPAct created EWGs as a new class of NUGs that were also free from PUHCA regulation. Any generator that sells wholesale electricity can qualify as an EWG, subject to a determination by FERC that the generator lacks market power. The two principal types of EWGs are affiliated power producers, which are affiliated with an IOU, and independent power producers, which have no such affiliation.

- *Self Generators* -- Any business may own and operate generation facilities for its own use without regulation by FERC or state regulatory bodies, except regarding technical issues such as required facilities for interconnection with the grid, etc.

Capacity owned by NUGs has increased dramatically since the passage of PURPA, reaching 68,461 MW in 1994, or almost 9 percent of total installed capacity in the U.S. This percentage is likely to increase, since NUGs have built more capacity than IOUs every year since 1992, a trend which is forecast to continue for the foreseeable future.

NUG capacity is dominated by cogeneration QFs, which account for 66 percent of the total. Small power producer QFs account for an additional 14 percent, followed by cogeneration non-QFs (11 percent) and non-cogeneration EWGs (8 percent). Natural gas accounts for 41 percent of the installed capacity, followed by oil or oil/gas (18 percent), wood waste (15 percent), coal (15 percent) and other renewables (i.e., hydro, geothermal, solar and wind, which account for 12 percent).

e) Regional and Sectoral Institutions

(1) Reliability Councils

The North American Electric Reliability Council was formed in 1968 in the aftermath of the November 9, 1965 Blackout that affected the northeastern U.S. and Ontario, Canada. NERC is a not-for-profit corporation owned by the ten regional reliability councils whose purpose is to promote the reliability of North America's interconnected electric systems. Its functions are to review and learn from operating history; to monitor current operations for compliance with reliability council operating and planning policies, criteria, standards, principles and guides; and to assess the future reliability of bulk electric systems.

NERC has been actively working with the FERC to make sure that reliability issues are recognized and incorporated in formulation of rules for open-access transmission and increased competition in wholesale power markets. It has worked to open membership in NERC and the regional councils to all segments of the electric supply industry, including IOUs, publicly owned utilities, NUGs and power marketers.

This following sections describe the two regional reliability councils that are contiguous with Mexico: the WSCC and ERCOT.

(a) Western Systems Coordinating Council

The WSCC, geographically the largest of the ten regional electric reliability councils, was formed in 1967. WSCC's 1.8 million square mile (4.7 million square kilometer) service territory is equivalent to more than half of the contiguous area of the United States. WSCC currently has almost 80 members (including CFE's Baja California Norte region) and 15 affiliate members. WSCC's members serve over 59 million people in 14 states in the U.S., two provinces in Canada, and the northern part of one state in Mexico.

In 1994, the WSCC membership approved changes to WSCC governance that revised the structure of its Board of Trustees. The Board of Trustees now includes representation from three membership categories: major transmission utilities; transmission dependent utilities; and NUGs/power marketers. This structure provides for all member

classes to have an adequate voice and role in WSCC activities. Additionally, advisory positions on the Board for three regulatory representatives were created. Changes in membership were also approved in 1994. Affiliate memberships are now open to, for example, power brokers, environmental groups, and state and federal regulatory agencies.

The WSCC Operations Committee is responsible for reviewing and analyzing operating procedures and problems related to the reliable operation of the interconnected bulk power system. It has implemented a compliance monitoring process designed to assess member systems' compliance with the WSCC Minimum Operating Reliability Criteria; WSCC operating policies, procedures and guidelines; and the NERC Operating Guides for Interconnected Systems Operation.

The WSCC Planning Committee is responsible for recommending system planning criteria for the guidance of the member systems, compiling and disseminating information pertaining to planned generation and transmission facilities, and performing regional studies to assess the reliability of the interconnected system. All WSCC committees are made up of representatives from its members.

The WSCC region experienced two significant and widespread blackouts in July and August of 1996. WSCC staff and members participated in investigative teams, which also included industry experts and representatives from the DOE, the California Public Utilities Commission (CPUC), and NERC, to determine the causes for the outages and recommend corrective action. Recommendations from the investigations include reduction of power transfers over the Pacific Intertie pending further review; development of a process to increase monitoring and exchange of information required to enhance system security; increased emphasis on adequate study of operating conditions and compliance with WSCC and NERC criteria; member review of tree trimming programs; etc.

(b) Electric Reliability Council of Texas

ERCOT is a non-profit corporation in the state of Texas created to insure that the interconnected generation and transmission facilities of its members are planned and operated in a reliable manner. Membership in ERCOT is entirely voluntary and is currently open to electric utilities, non-utility generators and power marketers. Membership in ERCOT by power marketers was allowed after ERCOT revised its bylaws in 1995.

ERCOT has 86 members, including 47 electric cooperatives, 16 municipalities, 10 power marketers, 6 investor-owned utilities, 5 non-utility generators, and 2 agencies of the State of Texas. The service area of ERCOT members is over 200,000 square miles (517,000 square kilometers) in Texas. ERCOT has about 32,000 miles (52,000 kilometers) of transmission lines, of which 7,000 miles (11,000 kilometers) are 345 kV (kV). The installed capacity in the ERCOT region is about 58,000 MW, which serves about 11 million people.

ERCOT has accomplished its reliability mission through three main mechanisms; Information and Data Collection and Analysis, Operating Guides and Security Centers. ERCOT's Operating Guides contain operating requirements that pertain primarily to operation of the nine Control Areas within ERCOT. The Control Areas, which must be certified by ERCOT for compliance with all applicable ERCOT and NERC planning and operating guides, are ultimately responsible for the reliability of the ERCOT interconnection. Additionally, there are two Security Centers in ERCOT which ensure that the Control Areas comply with the ERCOT Operating Guides and coordinate their actions during unusual or emergency operating conditions.

Pursuant to a Texas Public Utilities Commission (Texas PUC) order issued in February 1996, an Independent System Operator (ISO) Working Group made up of ERCOT members filed a proposal for an ERCOT ISO and an electronic transmission information network with the Texas PUC on June 10, 1996. The PUC approved the ISO plan on August 21, 1996. Target date for completion of implementation of the ERCOT ISO is June 1997.

(2) Regional Transmission Groups

Shortly before Congress began consideration of proposed legislation that ultimately was approved as the Energy Policy Act of 1992, electric utilities in several regions of the U.S. initiated discussions regarding facilitation of wholesale transmission access through formation of regional transmission organizations. Such voluntary organizations would set forth mandatory procedures for their members for requesting and providing transmission access, coordinating transmission planning, and resolving transmission disputes. Membership in these organizations,

which became known as "regional transmission groups" or "RTGs", would be open to all segments of the wholesale electric industry, including transmission-owning utilities, transmission-dependent utilities, independent power producers and power marketers.

While EPAct 92 did not specifically address rules for formation and regulation of RTGs, FERC quickly took on that responsibility through issuance of a Policy Statement on RTGs in 1993.[9] The RTG Policy Statement concluded that pursuant to FERC's authority under the Federal Power Act, RTGs must be approved by FERC and must comply with seven requirements in order to be approved:

1. Broad membership from all wholesale electric industry segments within a geographic region
2. Involvement of or participation by state public utility commissions or energy offices
3. Obligation of transmission-owning members to provide transmission to other members, including the obligation to enlarge facilities if required to provide the requested transmission
4. Periodic development of a regional transmission plan
5. Procedures for fair and non-discriminatory governance and voting
6. Procedures for resolution of transmission disputes between members
7. Procedures specifying the obligations of departing members

Subsequent to the issuance of the RTG Policy Statement in 1993, FERC began to develop the principle of "comparable transmission access" through a series of merger, market pricing, and RTG approval cases. FERC first defined "comparability" in *American Electric Power Service Corp. (AEP)*[10], as follows:

> *An open access tariff that is not unduly discriminatory or anti-competitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's use of its system.*

In 1994, FERC incorporated the principle of comparability as an eighth requirement for approval of RTGs. FERC said that an RTG governing agreement must require all transmission-owning members of the RTG to develop and offer an open access transmission tariff that met the comparability standard developed under the AEP case and subsequent cases. FERC finally made the comparability standard a requirement for all transmission-owning utilities subject to its jurisdiction through the issuance of Order 888 in 1996.

Three RTGs are active in the WSCC region: the Southwest Regional Transmission Association (SWRTA), the Western Regional Transmission Association (WRTA), and the Northwest Regional Transmission Association (NWRTA). FERC approved these RTGs in 1995. Membership in all three RTGs includes representatives from transmission-owning utilities, transmission dependent utilities, and non-utility suppliers, such as independent power producers and power marketers. The utility members include investor-owned utilities, public power entities, and federal power marketing administrations.

The western RTGs were developed largely in parallel but independent of each other. They have declined to set specific geographic boundaries for membership eligibility, so members are free to join whichever organization(s) most closely align with their transmission and market interests. All three RTGs have committed to FERC to coordinate their activities, which focus primarily on transmission planning and commercial/economic issues, and to work cooperatively with the WSCC on reliability issues, so that efforts are not duplicated unnecessarily.

While the western RTGs do not have firm geographic boundaries, interests of members that own specific transmission resources or serve specific retail areas fall somewhat naturally into general geographic areas. Membership in SWRTA generally includes entities with transmission interests in New Mexico, Arizona, southern

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[9] 64 FERC ¶ 61,138.

[10] 67 FERC ¶61,168.

Nevada, southern California, and southern Utah. Membership in WRTA generally includes entities with transmission interests in California, Colorado, Idaho, Utah, Montana, Washington, Oregon, and British Columbia. Membership in NWRTA includes entities with transmission interests in British Columbia, Washington, Oregon and Montana. Power marketers have generally joined all three RTGs.

Much of the purpose for formation of RTGs—development of rules of open transmission access—has been subsumed by FERC Orders 888 and 889, which mandated that transmission-owning utilities develop and implement open access transmission tariffs by July 1996. However, FERC clearly expressed its continued support for the development of RTGs in Order 888, encouraging RTGs to develop regional open access transmission tariffs and innovative regional transmission pricing proposals.[11] FERC also confirmed that it would continue to give deference to the planning, dispute resolution and decision-making processes of approved RTGs.[12]

f) Existing Wholesale Trading Arrangements

This section examines the functioning of the current wholesale market in the U.S. It begins with a description of new intermediaries in that market and their role. The two types of wholesale trading that now take place -- exchange and off-exchange, or bilateral -- are then explained, with an emphasis on some of the new "products" that have emerged in the wholesale market.

(1) New Intermediaries

Purchases and sales of electricity have traditionally been conducted by participants in the "supply chain" -- i.e., entities that engaged in generation, transmission or distribution. Intermediaries, or entities that own no physical generation, transmission or distribution assets, have only been participants in the sector since the advent of market-based wholesale rates and increased access to transmission, which the FERC began encouraging in the 1980s.

(a) Marketers and Brokers

Power marketers buy and sell wholesale electricity at market rates. Brokers arrange wholesale transactions, but do not take ownership of the energy traded. As a result, they come under considerably less regulatory scrutiny than do marketers.

Power marketers are required to file an application with the FERC that contains a market-based rate schedule and other information necessary to determine the entity's affiliations with any IOU. This information is designed to address the FERC's concern that a marketer that is affiliated with an IOU could be used to help the IOU charge monopoly rates for wholesale power by dominating the local wholesale market. If the applicant is an affiliate of an IOU, the application will only be approved if the applicant can show that it and its affiliate either do not have market power in generation and transmission or have already mitigated it. In practice, this means that if the affiliated IOU provides open-access transmission services that meet the FERC's standards, the application will be approved.[13]

Although the first power marketer was approved in 1986, the number of marketers and their sales have increased significantly in the last two years. As of September 1996, 285 companies had filed power marketer applications with the FERC, including 26 affiliates of IOUs. Of these, 242 had been approved, including 19 IOU affiliates, 47 applications were still pending, and the remainder had been denied. Sales by power marketers have increased from 7 million mWh for the entire year of 1994 to more than 70 million mWh in the third quarter of 1996. As illustrated in Figure 2, this growth has been essentially exponential. Another indication of the level of activity is the fact that some blocks of power are delivered only after reaching the end of a trading "chain" that may include six to eight marketers.

Sales volumes among marketers are heavily concentrated in the largest companies. During the third quarter of 1996, for example, the top ten marketers accounted for more than 70 percent of total sales by power marketers.

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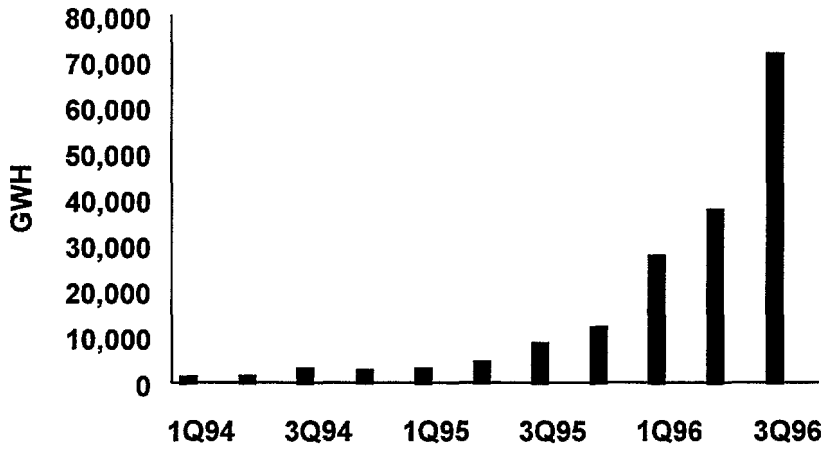
[11] 61 Fed. Reg. 21539 at 21667.

[12] 61 Fed. Reg. 21539 at 21667.

[13] The FERC's rulings on open-access transmission will be discussed in detail in later sections.

Figure 2: Quarterly Power Marketer Sales for Resale

1994 through 3rd Quarter 1996



Sources: Edison Electric Institute, Power Marketers Yearbook-1995
Edison Electric Institute, Regulatory Briefing Service, October 1996
Power Markets Week, November 25, 1996

(b) Load Aggregators

Load aggregators consolidate the requirements of multiple customers, or multiple sites owned by the same customer, in order to increase bargaining leverage and reduce the cost of purchasing electricity. This type of activity can only be undertaken if retail competition is allowed, which currently means only a few states with pilot programs. In anticipation of more widespread retail competition, however, various aggregators have signed agreements with businesses that have facilities in several states or utility service areas.

(2) Exchange Trading

On March 29, 1996, the New York Mercantile Exchange began trading electricity futures and options contracts for delivery to two locations: the California/Oregon border and the Palo Verde switchyard in Arizona. NYMEX officials recently announced that a contract for delivery at an unspecified eastern site will be announced in early to mid 1997, with trading to begin in the autumn of that year.

A futures contract is binding on both buyer and seller, and specifies delivery of the commodity in question on a specified date. In the case of electricity, the unit sold is one "contract", which requires the delivery of 736 mWh over a one-month period. The electricity is delivered at a rate of 2 MW per hour for the sixteen-hour period from 7 am to 10 p.m., for 23 days of the month (corresponding to a five-day work week). Futures contracts are available with delivery dates up to 18 months from the month of purchase, and can be purchased through the fourth business day prior to the first day of the delivery month.

Options contracts give the buyer the right, but not the obligation, to purchase a specified future contract. This right is valid until the expiration date, which is the day preceding the expiration of the underlying futures contract, or five

business days before the first day of the delivery month. In return for the right to buy the specified futures contract, the buyer pays an option premium, which is determined by supply and demand on the exchange. Options are available with delivery dates up to 12 months from the month of purchase.

Futures and options are financial contracts, in the sense that they are usually used to manage risk, or to speculate on price movements in the market, rather than to actually purchase the commodity in question. Only about one percent of the energy futures sold on the NYMEX result in actual delivery. Both buyers and sellers of electricity use futures and options to manage risk. A buyer might want to purchase a futures contract to avoid unexpected price increases, while a seller might want to sell the same contract to lock in a sale price for power generated. Power marketers will often use futures to mitigate both types of risk, since they are exposed by both their purchases and sales of electricity.

Exchange-traded financial instruments require both price volatility and liquidity -- i.e., a sufficiently large number of transactions to make prices transparent. While there have been concerns regarding the liquidity of the COB and Palo Verde contracts at various times since the start of trading, those concerns have eased recently as the overall wholesale market matures and deepens. The level of price volatility in electricity futures is illustrated by trading data for November 1996. For the week ending November 8, prices for December delivery at Palo Verde fluctuated from a low of less than $17 per mWh to a high of almost $26. The range of fluctuation for individual days of that week ranged from $2 to $5. As liquidity in these contracts has increased, price volatility has declined somewhat, one of the signs of a maturing market. Such decreased volatility gives traders confidence in the accuracy of the prices revealed on the exchange -- in the sense that they represent "the market", rather than isolated trades that may not reflect the general balance of supply and demand. This type of increased confidence makes it more likely that non-exchange transactions will start to use the exchange prices as a contractual reference point, such as occurs in the U.K. power pool, where "contracts for differences" define payments between parties based on the published pool price. This type of contract is described in a later section.

(3) Off-Exchange or Bilateral Trading

Most physical -- as opposed to financial -- trading of electricity in the U.S. is still done through bilateral transactions. This will of course change if the state-wide power exchanges or "pools" planned for California and New York are implemented. Trading arrangements that have arisen around the U.K. power pool are discussed later in the study to provide an idea of how exchange and off-exchange transactions can be related. This section describes some of the trading arrangements, or "products", that have become commonplace in the current U.S. wholesale market.

(a) Standard Products

A series of standard electricity contracts have emerged over the past year in the WSCC. Interestingly, blocks of energy, such as the 6x16 product described below, are increasingly popular, while traditional products that include demand charges with capacity factor restrictions (0 to 100 percent) are losing favor. Standard products are defined by three characteristics which are combined in different way for each product: reliability, time-of-day and term. Each of these is discussed below:

- Reliability
  - *Firm*: a firm product or contract will not be curtailed, or "cut", for economic reasons. It can be cut for *force majeure* (i.e., an act of god or other uncontrollable event) reasons, but these provisions are defined and limited under a firm contract. During the summer in Arizona, firm product prices are higher than other products. If the supply is curtailed, the supplier is usually forced to pay an economic penalty (i.e., liquidated damages).
  - *One hour firm*: this product can be curtailed for any reason, economic (i.e., *price majeure*) or otherwise, on one hour's notice. It is unlikely, however, that this product will be cut solely for economic reasons. This product is considered to be less reliable than a firm product.
  - *Non-firm*: a non-firm product can be cut for any reason, economic or otherwise, without advance notice, and without economic penalty on the part of the supplier. This is the least reliable product offered.

- Time-of-day
  - *6 x 16*: a 6 by 16 contract (6 days per week, 16 hours per day) is a standard on-peak product. The schedule is defined as the hours ending 0700-2200 Monday through Saturday.
  - *5 x 16*: a 5 by 16 contract (5 days per week, 16 hours per day) is a standard on-peak product. The schedule is defined as the hours ending 0700-2200 Monday through Friday. The NYMEX futures contract closely resembles this product.
  - *7 x 8*: a 7 by 8 product (7 days per week, 8 hours per day) is a standard off-peak product. The schedule is defined as the hours ending 2300-0600 Monday through Sunday.
  - *7 x 24 (commonly known as a "flat" product)*: a 7 by 24 product (7 days per week, 24 hours per day) is scheduled all day.

  Suppliers will sell these products as firm, one hour-firm and non-firm.

- Term

  Products with various reliability and time-of-day characteristics can be purchased for different lengths of time, although many of the time-of-day products offered are by definition for terms of one week or more:

  - Hourly
  - Daily
  - Weekly
  - Monthly
  - Quarterly
  - Annually

(b) Other Products

A variety of other products are also offered, but on a less frequent basis than the standard products described above.

Options are offered on a bilateral basis, as well as on the NYMEX exchange. Unlike the NYMEX options, which are for energy only, bilateral options are available on capacity and/or energy. On capacity, it becomes an option on an option. That is, the buyer may exercise the option to purchase capacity and then have the option to purchase energy from that capacity. On energy, the buyer has an option to purchase a block of energy (e.g., 6 x 16) at a certain price. To date, option transactions have been fairly infrequent.

Under a gas tolling arrangement, a gas supplier pays the generator a fixed fee to convert natural gas to electricity. An interesting variation on this arrangement has been used by Oglethorpe Power (Oglethorpe). Under this arrangement, Oglethorpe has agreed to lease specified generation assets to power marketers, which then operate them and sells the energy generated. In return, the marketers provide a specified quantity of electricity to Oglethorpe at a fixed price. The implicit risk sharing arrangement in this contract is that Oglethorpe is able to benefit from the marketers' expertise at electricity trading by receiving electricity at a price that presumably is lower than its own cost of generation using the assets in question, but without the additional risk from such trading. Although it has no downside risk from this transaction, it also has no potential for additional benefits if market conditions should change or the marketers are particularly successful in selling the power produced. These potential benefits belong to the marketers, who also assume the additional risk.

There have also been contracts signed which use electricity prices based on indexation to another commodity. This type of economic arrangement is already commonplace in the form of fuel adjustment clauses used for the retail tariffs of regulated IOUs, which allow fluctuations in fuel prices to be passed through directly to customers. What is different about the new contracts is that they are indexed to commodities not used in the production of electricity. One example of this type of contract is an arrangement between Pacificorp, an Oregon IOU, and Roseburg Forest

Products. Pacificorp sells electricity to Roseburg at a price that is indexed to the price of wholesale lumber, allowing Roseburg to link its revenues and production costs in order to reduce its business risk.

2. Evolution of the Current Structure

This section provides a brief description of the evolution of the current electricity sector in the U.S., focusing on the underlying forces that have created pressure for change at different times, and the legal and regulatory responses to those changes. The section ends with a discussion of perceived problems with the current structure.

a) Driving Forces

The current electricity sector in the U.S. is the result of a long evolutionary process with many participants and key events. Several forces have been important in this evolution:

- Technology, and its impact on generation costs
- Fuel costs and the international events that have impacted them
- Environmental concerns regarding fossil fuel emissions and nuclear plant safety
- Legal and regulatory developments

The following narrative describes how these forces have shaped the U.S. electricity industry. It should be noted that legal and regulatory developments are both causes of change and responses to pressure for change from other sources. This dual role is fundamental to an understanding of the restructuring process currently underway.

b) Historical Evolution

(1) 1900 to 1978

In the first 35 years of this century, the production of electricity was gradually consolidated from the large number of small municipal and private companies that existed at the turn of the century into a small number of huge holding companies. Part of the reason for this change was due to technological advances in generation: the amount of coal required to generate one kWh declined from 6.5 lbs. in 1902 to 1.5 lbs. in 1935. Other economies of scale in transmission, distribution, raising finance, etc. were also realized. Much of the consolidation, however, was attributable to the rise of holding companies, which used financial pyramid arrangements to enrich their owners and drive up the operating costs of the actual utilities, which were already regulated at the state level in the 1930s. By 1932, the eight largest holding companies controlled 73 percent of the IOU business in the U.S. The response to this situation was passage of two pieces of federal legislation that still provide much of the framework of the U.S. power sector: the Public Utilities Holding Company Act of 1935[14]; and the Federal Power Act of 1935 (FPA).[15]

PUHCA was designed to address the problem presented by the holding companies, which had made effective regulation impossible. Authority was given to the Securities and Exchange Commission (SEC, which regulates U.S. stock markets) to break up the holding companies, to limit utilities to the jurisdiction of a single state, to restrict their activities to the operation of a utility and to regulate the industry in order to prevent holding companies from returning. One of the most important provision of PUHCA was the restriction of activities to those necessary for the operation of a single vertically integrated utility. This provision had the effect of almost eliminating non-utility generation in the U.S. The FPA was originally passed in 1920 but modified when it became part of PUHCA. Its purpose was to bring interstate transactions under federal authority, which it did by prohibiting states from regulating interstate pricing and trade of electricity and assigning that responsibility to the Federal Power Commission (FPC, which later became the FERC), which had been created as part of the original FPA in order to regulate federal hydropower licenses. The FPA has been the key legislative vehicle for federal regulation of electricity ever since.

[14] Public Law 74-333.

[15] Title II of PUHCA.

The period before World War II also saw the construction of large federal hydropower projects as part of President Roosevelt's New Deal, and the creation of the Rural Electrification Administration and many municipalities which took advantage of the cheap federal hydropower.

The period from 1945 to 1965 was one of relative stability, and also large increases in the operating efficiencies of generating plants, which were accompanied by continually increasing economies of scale. As a result, the nominal price of electricity actually declined during this period, even though fuel prices increased by 40 percent and prices in the economy as a whole rose 75 percent.

Events after 1965 were less positive for the electricity industry. The Northeast blackout in that year led to the creation of the NERC, and raised new concerns about reliability and falling reserve margins. In response, investment expenditure programs were implemented to improve reserve margins and interconnections between systems. There were also other large requirements for capital expenditures. Rising environmental concerns and new regulations led to the addition of new equipment, the conversion of some generating plants to cleaner fuels, and increased delays in permitting and construction. Utilities also embarked on a program to construct even larger fossil-fuel units, even though generating efficiencies seemed to have reached their peak, and new nuclear stations, both of which were very capital intensive and introduced new operating problems that had not previously existed. One important impact of these developments and their related capital expenditures was a reversal of the price trend of the previous 20 years. This reversal was magnified by the oil price shocks of the 1970s. As a result, residential electricity rates tripled and industrial rates quadrupled from 1970 to 1985 in nominal terms. From this point forward, price has played a key role in the development of the sector.

(2) PURPA and the Introduction of Competition

The federal response to the rising prices and general energy insecurity produced by the events described above was the National Energy Act of 1978, which included five different laws. This Act had several objectives, the most important of which was to maintain economic growth while allowing the economy to make a transition from low to high energy prices. Due to concerns regarding the environment and the security of foreign-supplied oil, the Act was also meant to foster the development of renewable and other alternative energy sources, and to reduce dependence on foreign oil.

Of the five laws that comprised the National Energy Act, the most important for the electricity industry was the Public Utility Regulatory Policies Act of 1978.[16] PURPA led to a significant change in the structure of the industry, and laid the foundation for some of the changes now underway. Most importantly, it defined several classes of non-utility Qualifying Facilities -- small producers or those that use renewable or other alternative technologies -- which were independent generators from which IOUs were required to purchase electricity at the IOU's own marginal or "avoided" cost of generation. The result was a new type of generator with a guaranteed market for their production. To ensure that QFs were able to produce at low cost, PURPA also exempted them from virtually all of the regulations governing IOUs. Ironically, the QF provision of PURPA may have contributed to price increases. Requiring IOUs to purchase power at their own avoided cost, rather than at a price submitted under competitive bidding, has resulted in power purchases by IOUs at prices well above what they might have been. In addition, some states required IOUs to sign contracts with QFs regardless of whether they needed the power.

Nevertheless, PURPA was without doubt a key element in the introduction of a wholesale electricity market. Another contributing factor was increased regulatory scrutiny of IOU investments. As a result of increasing prices and large cost over-runs at nuclear facilities, regulatory bodies began to force IOUs to write off large investments that were not considered to be "prudent". These write-offs totaled $22.4 billion for nuclear plants alone between 1985 and 1992. As a result of these write-offs and forced purchases from QFs, IOUs became reluctant to invest in new generation facilities if their cost would have to be recovered under ROR regulation. At the same time, technological advances in combined-cycle and fluidized-bed generating units reduced both the optimal size of a generating plant and the total cost per kWh produced. Gas-fired combined-cycle units reach their maximum generating efficiency in the 150 to 200 MW range and can provide electricity to the grid for less than 4 cents per kWh. This is in comparison to the large coal and nuclear plants built in the last 15 years, which deliver power at 4 to 7 cents per kWh for coal and 9 to 15 cents for nuclear.

[16] Pub. L. No. 92 Stat. 3117, codified in U.S.C. Sections 15, 16, 26, 30, 42 and 43.

As a result of these developments, an opening was created for non-QF generators -- which are called IPPs to differentiate them from QFs -- who were able to sell into the growing wholesale market. IOUs were still interested in generation, but not under a regulated framework, so they began to invest in affiliated power producers (APPs) to compete in this market, and power marketers began to appear. Both IPPs and APPs were constrained, however, by the restrictions of PUHCA and a lack of transmission access. In order to address these problems the FERC began to grant authority to sell wholesale power at market-based rates in the late 1980s, and to increase access to the transmission system. These measures were only partly successful, however.

(3) The Energy Policy Act of 1992

Congress addressed developments in the wholesale market with the passage of the Title VII of Energy Policy Act of 1992.[17] There are two key provisions of the EPAct that further encouraged development of the wholesale market. The first removed some of the ownership restrictions of PUHCA by creating a new class of generating company, Exempt Wholesale Generators, that are exempt from PUHCA. This allowed IPPs and APPs to receive the same regulatory treatment as QFs without the QF size and technology restrictions. The second provision expanded the FERC's authority to approve applications for transmission services. A more general impact of the EPAct was to signal electricity industry participants that wholesale competition was coming, and to provide the FERC with the authority to enact its open-access transmission rule, Order 888, which is discussed in detail below.

The current electricity industry structure in the U.S. can be broadly summarized as follows:

- A large number of participants of various types and ownership, but dominated by traditional vertically integrated IOUs
- Generation capacity being added primarily by NUGs, rather than regulated IOUs, and able to produce electricity at prices significantly below large IOU plants built in the last 20 years
- A series of competitive regional competitive wholesale markets separated by transmission constraints
- An increasingly open market for transmission services, which will further stimulate wholesale competition once fully implemented
- A general trend toward increasing deregulation and its replacement with market-based determination of prices and profits in the generation sector

c) Remaining Problems

The evolution described above is in all likelihood still incomplete. Some of the major issues currently being debated include the following:

- Even with the full implementation of FERC Orders 888 and 889 (described below), transmission services will not be universally available under transparent and fair rates and terms, due to the large amount of transmission capacity that belongs to entities exempt from direct FERC jurisdiction.
- New low-cost generation facilities have not led to large reductions in retail prices, primarily because all of the "uneconomic" generation capacity built by IOUs is still being paid for by their customers. Introducing competition in the retail market is being examined at the federal and state level as a way to address this problem, but this raises the question of who should pay for the unecoomic IOU generation facilities, which are also referred to as "stranded costs".
- The transition from relatively isolated, self-sufficient IOUs with distinct service territories to regional and perhaps national markets has pointed to the need for coordination and planning mechanisms to ensure reliable operation of the transmission system.

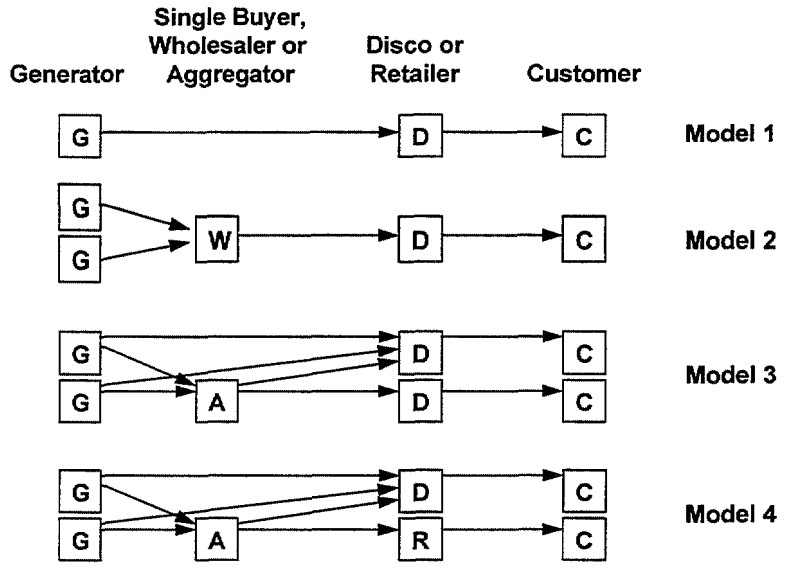
[17] Pub. L. No. 102-486, 106 Stat. 2776 , codified at, among other places, 15 U.S.C. §79z-5a and 16 §§796 (22-25), 824j-l.

3. Proposed Alternative Approaches

In order to provide some context for the discussion of restructuring efforts in the U.S., this section outlines a framework for examining different sector structures.[18] Four models are introduced, corresponding to different levels of competition. There are of course many variations on each of these basic models, and there are also other ways to categorize industry structure, such as by the amount and type of regulation. Competition is a particularly useful way to categorize current and potential U.S. industry structures, however, since most recent activity has in fact focused on that topic, as explained above. Competition is also preferable in some regards to regulation as a way to broadly describe future structures, since the regulatory picture in the U.S. is exceedingly complex, and will likely remain that way due to the large number and many types of sector participants. The four models are the following, and are illustrated for comparison purposes in Figure 3:

[18] This framework was developed by Sally Hunt and Graham Shuttleworth in their book *Competition and Choice in Electricity*, John Wiley & Sons, 1996.

Figure 3: Models of Industry Structure

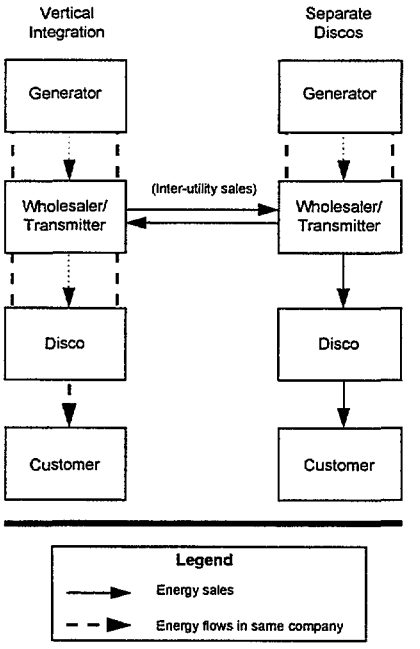


Source: Hunt and Shuttleworth, *Competition and Choice in Electricity*

- *Model 1 -- Monopoly.* This corresponds to a traditional vertically integrated IOU or other utility. The monopoly is responsible for generation, transmission and distribution of electricity to its customers, who are required to buy from it.
- *Model 2 -- Single Buyer or Purchasing Agency.* This model is characterized by competition in generation only, and corresponds to the type of competition introduced by PURPA. A single buyer purchases all the output from various generators, acting essentially as the regional wholesaler, to encourage competition in generation. Generators are not allowed access to transmission wires, and the buyer retains a monopoly over transmission and distribution.
- *Model 3 -- Wholesale Competition.* In this model, which corresponds to the direction in which the U.S. is currently moving, distribution companies (discos) are allowed to buy electricity directly from a generator, or from marketers, aggregators, or any other legitimate wholesaler, and to have that energy transmitted for them over the grid.
- *Model 4 -- Retail Competition.* This model corresponds to the structure proposed for California, in which all customers are allowed to choose their supplier. It requires access to both transmission and distribution wires by generators and customers, and the separation of "supply" -- the contractual sale of energy -- from distribution -- the delivery of that energy over the distribution system.

Each of these models is described in more detail below, along with some of the key considerations that accompany their implementation.

Figure 4: Model 1 -- Monopoly



Source: Hunt and Shuttleworth, *Competition and Choice in Electricity*

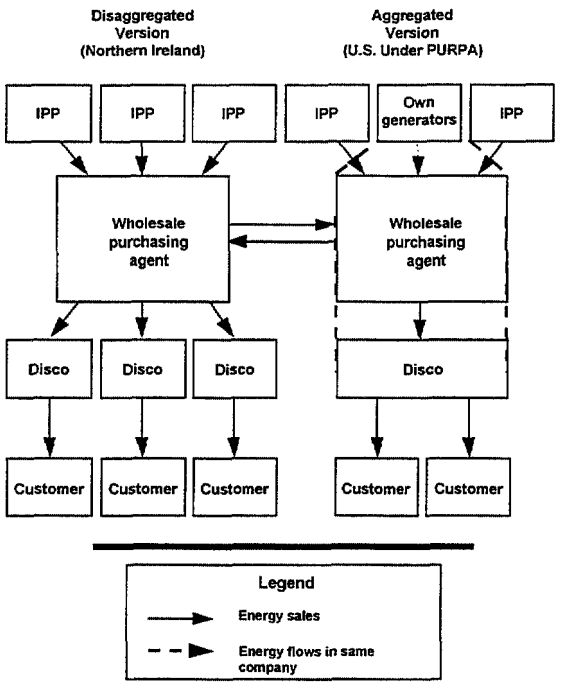
a) Model 1 -- Monopoly

Under this type of system, the vertically integrated utility has a monopoly over its service area, along with the obligations that go along with that monopoly that were described above. There can also be multiple discos, but the economic relations remain the same so long as they have monopoly franchises to serve their customers, and in turn are required to buy from the transmission and generation monopoly. Both versions of this model are shown in Figure 4.

There can be sales between integrated utilities, as there has been for some time in the U.S., but these arrangements are generally short-term, and based on the relative costs of the two systems, rather than a market-determined price. There is no competition for either the dispatch or construction of generation, and transmission access is not an issue.

This has historically been the standard form of utility organization, and has only been challenged since the 1980s. Most countries still use this system, although many are starting to move toward the other three models. Countries often move on from this model when the marginal cost of new generation is significantly less than prices charged by the utility, as is now the case in the U.S.

Figure 5: Model 2 -- Single Buyer



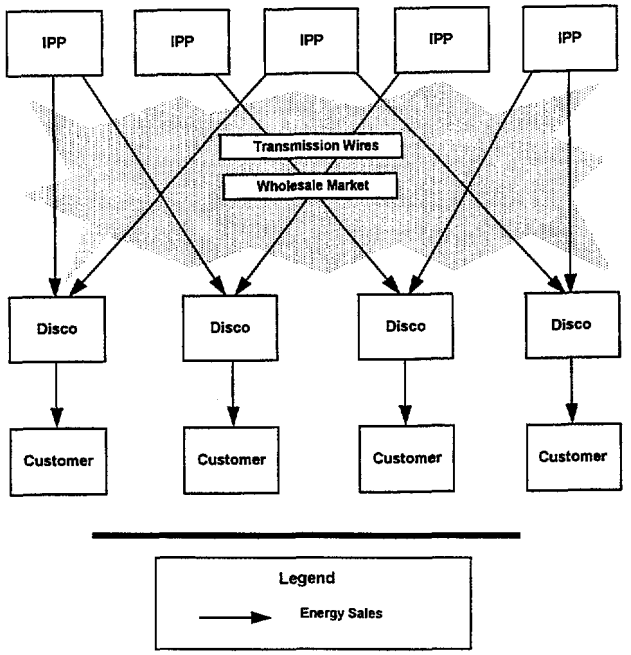
Source: Hunt and Shuttleworth, *Competition and Choice in Electricity*

b) Model 2 -- Single Buyer or Purchasing Agency

Model two allows independent generators to build capacity and sell that capacity and its associated energy to the single buyer. This buyer can then either sell the electricity to its own customers if it is an integrated utility, or to other discos, as illustrated in Figure 5. So long as all generation is required to be sold to this buyer, the economic relations of the model remain intact. Generators in this model compete to win contracts to construct new plants, as is the case under PURPA or CFE solicitations.

The contract between the independent producer and the single buyer is typically a PPA, which may or may not require economic dispatch of generation units. Prices paid to the generators are set contractually in the PPA. The price charged by the single buyer to the disco is usually regulated, and contains a component that will fluctuate with the price of purchased power, fuel, inflation or other costs outside the control of the single buyer. Transmission access is not "sold" by the single buyer to generators, but the issue does arise of how to ensure that new generation built by independents does not increase transmission bottlenecks or otherwise increase system costs unnecessarily. This can be done by the buyer specifying the location of new generation, or by incorporating transmission costs into the price paid by the buyer.

Figure 6: Model 3 --Wholesale Competition



Source: Hunt and Shuttleworth, *Competition and Choice in Electricity*

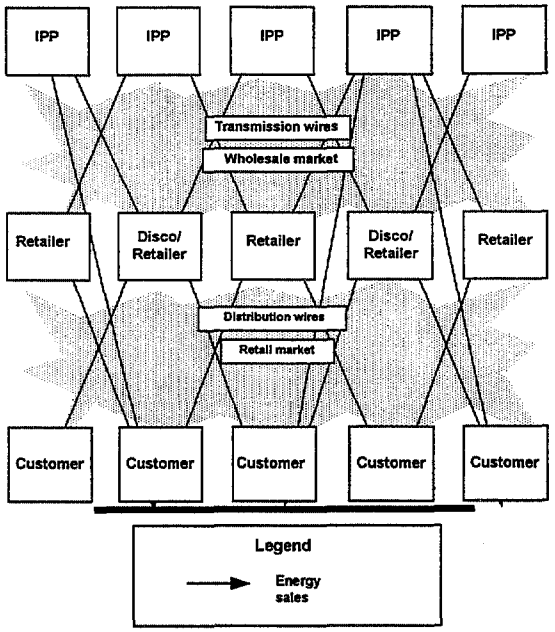
c) Model 3 -- Wholesale Competition

Model 3 represents a somewhat radical departure from traditional industry structures. Under this system, which is illustrated in Figure 6, generators sell their output to discos and other wholesale customers in a market with multiple buyers and sellers. Transmission and distribution are still regulated monopolies, but open access to the transmission grid provides wholesale market participants with the opportunity to buy from and sell to whomever they please.

Trading in a Model 3 structure is usually done through a combination of a "pool" or exchange into which generators sell and from which wholesale customers buy, and bilateral contracts that are entered into outside of the pool for purposes of hedging the price risk associated with the pool. Generators bid a price at which they are willing to supply electricity. The dispatching entity then schedules generators on an economic basis, and the pool price is set by the last generator required to meet demand for a given time period. This type of system is already functioning in England and Wales, as well as several other countries, and is being implemented in California, where the pool corresponds to the Western Power Exchange (WEPEX), and the dispatch entity corresponds to the ISO that are part of the California plan. The ISO is responsible for dispatch as well as for frequency and voltage control, and therefore must be independent from the trading that occurs in the pool.

This Model can also be implemented without a central pool mechanism, as is being planned in Texas, which will use an ISO but no trading exchange. Model 3 can also be implemented without an ISO, but this is only feasible if there are a relatively small number of wholesale market participants, and requires strong regulation to ensure that the transmission provider does not hinder market performance. The transitional nature of the U.S. industry is illustrated by these three alternative versions of Model 3: California is moving ahead with a pool and ISO; Texas is forgoing the pool in favor of bilateral contracts and an ISO; and the FERC is trying to move the rest of the industry closer to a true wholesale market by strictly regulating transmission access and tariffs. The coordination problems that might occur as a result of this multi-path approach are also evident, which explains the increasing emphasis of industry observers on regional and/or national solutions.

Figure 7: Model 4 -- Retail Competition



Source: Hunt and Shuttleworth, *Competition and Choice in Electricity*

d) Model 4 -- Retail Competition

Model 4 brings competition all the way to the ultimate consumer. Retail customers can purchase directly from a generator, from their distribution company, or from any other participant in the wholesale market, as illustrated in Figure 7. This Model requires the introduction of a "supply" function, which concerns only the actual sale of power to customers, rather than its delivery over distribution wires. As in all the other Models, transmission and distribution continue to be regulated monopolies. In fact it is a requirement of Model 4 that the transmission system be consolidated, since the transmission operator needs to measure the delivery of electricity in order to facilitate the settling of accounts for bilateral transactions. Open access is required for transmission and distribution wires, and both must be priced. Stranded costs are a potentially major problem in this Model, as is indicated by the lengthy debate on this topic in California and the attention it received in FERC's Order 888.

In both Models 3 and 4, several decisions must be made about the specific mechanisms that will be used to establish the wholesale and retail markets. These decisions do not affect the level of competition in most cases, but they can have a large impact on how well the market functions and on the size of its transaction costs. Two of the most important are discussed in the following paragraphs.

The first such issue is whether to create a pool, or to use bilateral contracts alone. Under a pool system, as described above, generators submit supply bids to the pool, purchasers submit demand bids, and the system operator dispatches the generators in economic order.[19] The resulting pool price is the price submitted by the most expensive plant required for that period, or the lowest demand bid. Market participants make financial contracts with each other to manage the price risk of the pool, but they do not contract for physical delivery, and the system operator is unaware of these contractual arrangements. Using bilateral contracts alone, participants make deals for the physical delivery of electricity, and then schedule those deliveries with the system operator. The information requirements and

[19] It is not actually a requirement that purchasers submit demand bids. The alternative is have demand estimated by the system operator, which transfers some risk from the purchasers to the operator, but also reduces the likelihood of forecast errors therefore of overall costs.

number of transactions processed by the system operator are significantly greater using bilateral contracts, but the system is also easier to understand.

A second issue that must be addressed is the type of transmission pricing that will be used. Under the "transport" method, a user of transmission services pays a fee for a specified transmission service. This service is often referred to in the U.S. as being "unbundled" from the energy it is associated with -- i.e., there are separate prices for the energy itself and the transmission service required to deliver it. Transmission prices of this type can be "postage stamp" -- i.e., a single price for delivery from and to any point on the system -- or dependent on distance. In either case, the tariff to be paid is generally known in advance, and is considered as a separate cost. An alternative to the "transport" method is to use nodal pricing, under which the seller or buyer simply pays the spot price prevailing at his "node" of the transmission grid, and does not pay an explicit transmission charge. The cost of transmission is assumed to be incorporated into the price differentials between nodes, eliminating the need to schedule and pay for transmission service. This system has the advantage of incorporating transmission constraints into the implicit price of transmission on a continual basis.

4. Federal Restructuring Issues

In response to the recent developments outlined above, there has been significant legislative and regulatory activity regarding restructuring, although legislative efforts to date have not been successful. The following discussion summarizes the most important aspects of each.

a) Legislative Initiatives

Two important bills have been introduced in the U.S. Congress that would significantly accelerate the restructuring now underway. The first was the Electric Consumers' Power to Choose Act of 1996, introduced by Representative Schaefer of Colorado. This bill would require retail competition throughout the U.S. by 2000. The FERC would be required to implement this competition if a particular state has not established a timetable for implementation by December 15, 2000. Retail competition would affect both regulated and unregulated utilities, and there is no requirement in the bill for the recovery of stranded costs, although states are directed to consider such recovery. The bill was ultimately defeated, but served to provide a reference point for future legislation on this topic.

A potentially more important bill was introduced by Representative DeLay of Texas. This was introduced just before Congress adjourned in 1996, but is meant to influence the debate in 1997, when Congress is expected to address electricity industry restructuring. This bill would require retail competition nationally starting on January 1, 1998, and would *prohibit* the recovery of stranded costs. In terms of regulation, the bill would repeal both PUHCA and PURPA, and give the FERC broad authority to regulate all aspects of utility behavior, taking much of that authority from state regulators. Vertically integrated utilities would be required to separate organizationally, and the FERC would be able to order that utilities divest any assets that might give them monopoly power in their service areas.

Both Representatives have indicated a willingness to work together on this issue in 1997, so it is likely that legislative activity will increase at the same time that FERC's open-access rules are starting to take effect. Those rules are discussed in the following section.

b) Regulatory Issues

This section discusses several recent FERC final and proposed orders that affect industry structure. FERC's general regulatory responsibilities are first reviewed, and each relevant order is then described in detail, focusing on those issues of most relevance to this study.

(1) FERC Authority

Federal regulation of electricity is handled by FERC, with the exception of some relatively narrow DOE authority over international issues, which are discussed in later sections. The FPA gave FERC a number of broad regulatory responsibilities, including utility mergers and acquisitions, accounting practices, power purchase contracts and interconnection agreements and wholesale rates and services. As part of its encouragement of increased competition,

FERC has clarified and expanded its authority over the wholesale market through a number of recent orders and proposed orders. These new rules are discussed in detail below.

(2) The Mega-NOPR

When it is considering new rules and regulations, the FERC issues Notices of Proposed Rulemaking (NOPRs) on specific issues. In a NOPR, the FERC states its proposed rules and invites commentary . Following an evaluation of the responses received, the Commission issues its final orders, which are binding.

In March 1995, the FERC issued two NOPRs: "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities," and "Recovery of Stranded Costs by Public Utilities and Transmitting Utilities."[20] These documents together came to be referred to as the "Mega-NOPR." In the Mega-NOPR, the FERC proposed to require utilities to provide open access to the interstate transmission network in the U.S. in order to facilitate a more competitive wholesale electric power market. FERC's goal in proposing these rules was to ensure that wholesale buyers and sellers could reach each other without the high transmission costs imposed by monopolistic or discriminatory transmission practices. The Mega-NOPR proposed several requirements for both open access and the recovery of stranded costs. After receiving comments, FERC issued Orders 888 and 889, the final rules on open access, stranded costs, and real-time information system requirements. Because the NOPR was a proposal rather than a final rule, and was revised in subsequent official regulation, its explicit details are not discussed here.

(3) Order 888

In Order 888, issued April 24, 1996, FERC published a final rule, predicated on the Mega-NOPR, designed to restructure, deregulate, and unbundle the electric power industry. The two main goals of the rule are to create competition through mandatory open access of wholesale transmission, and to encourage states to adopt retail competition plans which provide for the recovery of stranded costs. Key provisions of each of these goals are outlined below. Jurisdictional issues are addressed in a later section of this report.

(a) Open Access

To comply with Order 888, utilities under FERC jurisdiction must file a single open-access tariff for network, load-based service as well as point-to-point, contract-based service (these terms are defined below). Order 888 became effective July 10, 1996, at which point utility filings of initial pro forma tariffs were due. The filings must comply with FERC minimum terms and conditions, but utilities were also able to propose their own rates.

According to Order 888, any entity participating in the wholesale electricity market -- whether as a buyer or a seller -- is an eligible customer for pro forma tariffs. An important feature of this open access is that a public utility must offer transmission services that it is reasonably capable of providing, not just services it is currently providing. Thus, a utility may be required to build transmission to meet a request for transmission services that it cannot currently provide. It must offer services whether or not other utilities in the region could offer the same service and regardless of whether such services are generally available in the region. The reciprocity clauses in 888 specify that utilities who own, control or operate transmission and receive open-access service must in turn provide open-access service to the transmitting utility. This topic is discussed in detail in later sections of the study.

(b) Tariff Parameters and Procedures

In Order 888, FERC provides certain guidelines and procedures to which utilities must adhere in creating their transmission tariffs. These rules address price, reservation priority, reserving capacity, curtailment, and reassignment. In order to provide utilities with a model on which to base their tariffs, the FERC provided a pro forma tariff as an appendix to Order 888. A brief description of the main guidelines is outlined below.

- *Price*: The pro forma tariff does not specify an exact pricing structure, but rates charged for transmission services are required to conform to the parameters contained in the FERC's Transmission Statement of

[20] Docket No. RM95-8-000, Docket M94-7-0001, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, Mar. 29, 1995.

Pricing Policy, which detailed the different types of rate structures that would be allowed, and how they are to be calculated.[21] In cases where transmission is constrained, the transmitting utility is permitted to charge a user of that constrained capacity a rate sufficient to cover its opportunity costs, providing that those opportunity costs do not exceed the incremental cost of expanding the transmission capacity.

- *Reservation Priority*: Reservations for short-term (less than one year) firm point-to-point[22] service will be conditional until one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. These conditional reservations may be displaced by competing requests for longer-term point-to-point service.

- *Reserving Capacity*: Firm transmission customers, including network customers, will not lose their rights to firm capacity simply because they do not use that capacity for certain periods of time. In the absence of evidence of hoarding or other anti-competitive practices, FERC will not limit the amount of transmission capacity that a customer may reserve. Utilities may reserve their existing transmission capacity for load growth among their own customers reasonably forecast within the utility's current planning horizon. Any capacity reserved for future growth that is not currently needed must be posted on the Open Access Same-Time Information System (OASIS, discussed under Order 889 below) and be made available to others until such time as it is actually needed and used. Existing customers should have a right of first refusal to capacity they previously used if they are willing to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by another potential customer.

- *Curtailment*: The transmission provider will have discretion to curtail service, whether firm or non-firm, to relieve a transmission constraint. Curtailment will be made on a nondiscriminatory basis, including curtailment of the transmission provider's own use of the system. The tariff allows the transmission provider to curtail service for reliability or economic reasons.

- *Reassignment*: Point-to-point service is reassignable. Network transmission service is not reassignable. The assignor does not have to return its capacity entitlement to the original transmission provider, but may deal directly with an assignee without involvement of the transmission provider. The rate for any capacity reassignment must be no greater than the highest of: 1) the original transmission rate charged to the purchaser (assignor); 2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment; or 3) the assignor's own opportunity costs, capped at the cost of expansion.

(c) Stranded Costs

In Order 888, FERC restates its commitment to allow recovery of stranded costs, which was first proposed in the Mega-NOPR. The Commission's primary justification for this decision is that a utility should not be penalized in a newly competitive environment for decisions it made before such an environment was viable. Order 888 declares that the appropriate means for recovering these stranded costs is through direct assignment of such costs to the departing wholesale customer, either through an exit fee or a surcharge on transmission. Thus, a departing customer will be required to pay for investment that was incurred to serve it when it was a bundled requirements customer. The Order further details rules for recovery of costs associated with both new and existing wholesale contracts:

- *New Contracts*: Utilities will be allowed to recovery stranded costs associated with new wholesale contracts (executed after July 11, 1994) only if the new contracts contain explicit stranded cost provisions. Such an explicit provision is defined as one that "identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate."

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[21] 61 Fed. Reg. 92 at 21601.

[22] Point-to-point service is defined as the receipt of capacity and energy at designated point(s) of receipt and transmission of such capacity to designated point(s) of delivery. Point-to-point contrasts with network service, which allows the user to vary the schedule, points of delivery and receipt without incurring an extra charge for each change.

- *Existing Contracts*: For contracts executed before July 11, 1994, FERC ordered that utilities may seek stranded cost recovery for a limited set of existing wholesale contracts which do not already contain exit fees or other explicit stranded cost provisions. However, utilities may not recover costs through transmission rates.

In addition, Order 888 provides two other alternatives suppliers may pursue when seeking to recover stranded costs:

- Either or both parties to an existing contract may seek to amend it before it expires, even if the contract contains a clause barring a change. Such amendments might include, but are not limited to, stranded cost issues.
- A supplier also may attempt to recover stranded costs through departing generation customer transmission rates by filing a claim under Sections 205-206 or 211-212 of the FPA before the contract expires.

(4) Order 889

For a competitive transmission market to be viable, utilities need regular access to information on transmission pricing and available transmission services. To address this issue, FERC issued Order 889 on April 24, 1996. Order 889 established an Open Access Same-time Information System and prescribed rules of conduct for the system. The rule applies to any public utility that offers open-access transmission services under the pro-forma tariff established through Order 888, including both wholesale transmission customers and retail transmission customers that are able to receive unbundled retail transmission services

Under Order 889, transmitting utilities are required to participate in an OASIS that will provide open-access transmission customers with electronic information about available transmission capacity and prices. The rule also requires affected utilities to implement standards of conduct to separate transmission functions from those of wholesale power sales within their organizations.

Although compliance with Order 889 was originally required to be complete by November 1, 1996, FERC agreed to requests for a delay. Basic OASIS implementation is now scheduled to begin on a test basis on December 2, 1996, and for commercial operation effective January 3, 1997.

Order 889 contains five major components, dealing with standards of conduct, obligations of transmission providers and responsible parties, information to be posted on an OASIS, auditing transmission service information, and a phased implementation schedule for OASIS requirements. The first three of these are discussed below.

(a) Standards of Conduct

The standards of conduct are designed to prevent employees of a public utility or its subsidiaries/affiliates engaged in marketing functions from obtaining preferential access to OASIS-related information or from engaging in discriminatory business practices. They primarily address appropriate employee conduct, and are supplemented with a separately issued code of conduct.

(b) Obligations of Transmission Providers and Responsible Parties

FERC defines "Transmission Provider" as "any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce." A "responsible party" is the transmission provider or any agent delegated to meet the provider's responsibilities.[23] The Commission outlines three main obligations:

- Every Transmission Provider must provide for the operation of an OASIS, either by itself or in conjunction with other providers; it may delegate this responsibility to a Responsible Party.
- A Responsible Party must provide access to an OASIS providing standardized information relevant to the availability of transmission capacity, prices, and other information (described in the following bullet point)

[23] 61 Fed. Reg. at 21764.

related to the transmission system for which it is responsible, and must operate the OASIS in compliance with the standardized OASIS Standards and Communications Protocols published separately by FERC.

- Transmission Providers must provide "read only" access to the OASIS to Commission staff and state regulatory agency staff at no cost.

(c) Information to be Posted on an OASIS

This portion of the rule is perhaps most specific. FERC requires that information posted on an OASIS must be comprehensive enough to allow customers to: request transmission services; view and download information necessary to make business decisions; post, view, upload and download information regarding available products and services; clearly identify the degree to which their transmission service requests or schedules were denied or interrupted; and obtain electronic access to information that supports available transmission capability calculations and historical information for audit purposes.

The rule requires Transmission Providers to post the transmission capacity expected to be available on their system (available transmission capacity, or ATC), as well as the total transmission capability (TTC) of that system for each "posted path", which includes any transmission path that a customer might want to use.[24] In the case of a customer request, the posting must continue for 180 days, and thereafter until 180 days have elapsed from the most recent request for service over the requested path. FERC also defines a "constrained" path as a posted path having a ATC less than or equal to 25 percent of TTC at any time during the previous or upcoming 168 hour period. Responsible Parties must make the data used to calculate ATC and TTC for constrained paths available if requested. In addition, they must make publicly available any system planning or network impact studies performed for customers.

(5) Capacity Reservation Tariff

In addition to Orders 888 and 889, FERC also issued new NOPR on April 24, 1996. The Capacity Reservation Tariff NOPR[25] proposes to replace the pro-forma tariff in Order 888 with a capacity reservation tariff (CRT). If the NOPR's proposals are all approved, replacement would take place on December 31, 1997.

In Order 888 prices for network service are based on customer load. The Order allows the transmission customer to use the provider's entire grid to serve designated loads from designated resources without having to pay a separate charge for each pairing of resource and load. Network service therefore enables the customer the flexibility to integrate its resources and loads efficiently, and to realize economic dispatch in the same way as the system owner. By contrast, point-to-point service sets prices based on transmission capacity reservations. The user designates points of delivery and points of receipt and reserves each.

The CRT is proposed to replace the network and point-to-point services outlined above, creating a new tariff based solely on point-to-point service. Under the proposed CRT, utilities and all other power market participants would reserve firm rights to transfer power between designated receipt and delivery points. FERC explained that the proposed reservation-based service appears to be more compatible with the open-access requirement that market participants know how much transmission is available for electric power purchases and sales. It may also better accommodate competitive changes occurring in the industry, including more flexible transmission pricing. FERC also believes that the requirement to reserve transmission capacity by all users will give transmitting utilities more certainty in planning for future system needs, and will place the burden on transmission customers to forecast those needs and commit to them in the transmission reservation process.

In order to evaluate this proposal, FERC sought comments on its content and also convened a technical conference in September of 1996. Assuming a CRT seems viable, a final rule will be issued sometime in 1997, early enough to allow utilities the necessary time to develop new CRTs by the December 31, 1997 proposed deadline. Currently, utilities continue to abide by the provisions contained in the Order 888 pro forma tariffs.

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[24] The definition of "posted path" is "any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have an ATC or TTC posted".

[25] FERC Docket No. RM96-11.

5. State-Level Restructuring Activities

In addition to the federal legislative and regulatory activities described above, 47 states and the District of Columbia are currently in the process of examining or implementing some form of electricity sector restructuring. The following sections summarize these activities in states that share a border with Mexico.

a) California

Of the four border states (California, Texas, Arizona and New Mexico) the transition to full competition at the retail level is most advanced in California. The California Public Utility Commission issued three orders, on December 20, 1995, January 10, 1996 and March 14, 1996, that laid out a comprehensive plan for the restructuring of the California power industry. The goal of this plan is the phasing in of full retail competition starting on January 1, 1998. These decisions, with some important modifications, were written into law by the California Legislature with the passage of Assembly Bill 1890 (AB 1890), which received the unanimous approval of both houses of the Legislature in August of 1996 and was signed by the Governor on September 23, 1996. The principal relevant features of AB 1890 and the restructuring process that it authorizes are as follows.

(1) Market Structure

Two new entities will be created to manage the competitive electricity system. An Independent System Operator will operate the high-voltage transmission system which will be available to all generators and all customers on a non-discriminatory basis. The Western Power Exchange (WEPEX) will be created to perform the market function of matching purchase and sale bids for those suppliers and buyers that choose to participate. Regulated California distribution utilities will be required to buy energy for all of their full service customers from the WEPEX for the five years beginning in 1998, and regulated California generating utilities will be required to bid all of their generation into the WEPEX for the same period. Participation by others is optional, although AB 1890 contains various incentives to encourage participation by municipal utilities in particular.

The ISO will exercise operational control, but not ownership, of the transmission assets of regulated utilities and others that choose to join on a voluntary basis. Operational control has been defined to include:

- Administration of transmission tariffs to ensure open and non-discriminatory access to ISO grid facilities
- Authority to direct operation of all ISO grid facilities that affect reliability in accordance with NERC and WSCC guidelines
- Authority to approve requests to take transmission equipment out of service
- Authority to set priorities for restoring transmission facilities after an emergency

The transfer of operational control from transmission owners to the ISO will be made under contracts, tariffs and protocols to be filed with FERC during 1997.

WEPEX will be responsible for operating a forward market (day-ahead and hour-ahead) for energy, into which any participant that meets specified criteria (defined below) can buy and/or sell on a free-entry and free-exit basis. It will be an independent, non-profit entity which administers an open, competitive market for energy. WEPEX will also be a scheduling coordinator representing, initially, utility generators and loads in the areas of bidding, scheduling, billing and settlements, and dealing directly with the ISO on matters of grid operations and ancillary services. Its responsibility as a scheduling coordinator is to aggregate generation and load in order to submit balanced schedules of supply and demand to the ISO.

The criteria for participation in the WEPEX have been defined as follows:

- An entity must be registered and qualified as one or more of the following market participants, or be represented by a registered and qualified market participant:
  - Scheduling Coordinator

  - Generator (generating unit located inside ISO control area)
  - Load (end use customer within ISO control area)
  - Import/Export Scheduler (sending/receiving entity located outside ISO control area)
  - Retailer
  - Aggregator
- The registration process requires that Market Participants provide the PX/ISO with a Master File of certain business and operating information. The purpose of this file is to establish the identity of the market participant, its eligibility to bid into the WEPEX/ISO, and to establish the basic operating parameters that the WEPEX will use in validating that participant's bid. Market participants may update their master data file at any time, and may submit bids based on updated master file data after five normal working days. The Master File data requirements for an importer/exporter are as follows:
  - Name of sending/receiving entity
  - Name of control area
  - Scheduling interconnection point(s) (bus name and voltage level)
  - Name of load aggregator or retailer
  - Name of party with financial responsibility (address, fax & phone)
  - Name of party with scheduling responsibility (address, fax & phone)
- An entity must meet financial responsibility criteria as described in appropriate section of the settlement protocols for the WEPEX

The California plan allows retail customers to purchase energy directly from the WEPEX or from suppliers other than the utility which operates the distribution system to which they are connected. This "direct access" to the market is to begin for large customers on January 1, 1998 and be available to all customers by January 1, 2002, although customers that purchase at least half of their energy needs from a renewable resource provider can obtain immediate direct access.

To mitigate the exercise of market power by the existing three IOUs in the state, the plan calls for 50 percent of the California fossil-fuel generating capacity of Southern California Edison and Pacific Gas and Electric to be divested (an inventory of generating assets owned by the CA IOUs is provided in later sections). Nuclear and hydroelectric generation, as well as distribution operations, will remain regulated under "performance-based regulation" concepts.

(2) Transmission Pricing

The transmission pricing plan proposed by the three California IOUs[26] has three parts: an access charge, a usage charge and a charge for line losses. The access charge is designed to recover the transmission owners' transmission revenue requirement, and will be levied on all entities withdrawing power from the ISO grid. Each owner will file an access charge that will apply to customers located in its service territory, so that customers will only pay only a single access charge. Market participants wheeling power through the ISO grid will pay the charge in effect where the power leaves the grid.

The usage charge is designed to manage transmission congestion between zones, which will be pre-determined areas of the ISO within which transmission congestion is expected to be minimal. Zones will be created based on historic paths where congestion occurs, so that these paths are between, rather than within, zones. In order to account for the costs imposed on the system by such congestion, the ISO will assess market participants the marginal value of that transmission over the congested path via a usage charge. The usage charge will equal the difference between the

[26] Final decisions on transmission tariffs will be made by FERC in 1997.

spot price in each of the zones over which the transmission interface congestion occurs. Revenues collected through the usage charge will be credited against the access charge in order to avoid double billing.

Another locational pricing feature related to the usage charge will be Transmission Congestion Contracts (TCCs). TCCs will ensure price certainty for grid users by providing a financial hedge against variable congestion charges. A TCC entitles its holder to the congestion revenues on a specified path for a fixed period of time, in return for a single payment equal to the future stream of congestion revenues over that same path. TCCs provide for the price equivalent to long-term transmission rights. The ISO will administer the TCCs to grid users until an independent market for them develops.

The charge for transmission losses will be allocated to grid users by the ISO via a marginal loss factor. Grid users may provide for losses either in kind or by purchase from other grid users.

(3) Recovery of Stranded Costs

AB 1890 provides for the full recovery of stranded costs incurred by the three California IOUs, as well as by any public power agencies that choose to participate in the competitive market. These costs will be paid for by a non-bypassable "competition transition charge" (CTC) that will be assessed on all current California retail customers. The CTC will pay for the following categories of stranded costs:

- Uneconomic generation assets
- "Regulatory Assets" – i.e., investments required by regulators, that the utility would not otherwise have made
- Nuclear settlements with regulatory bodies
- Power purchase contracts with prices above market levels

Subject to rate constraints, most of these costs must be collected by December 31, 2001. A novel feature of the California plan is its use of Rate Reduction Bonds (RRBs) to fund an immediate 10 percent reduction in the rates of residential and small commercial customers. These bonds will be collateralized with a portion of the expected stream of payments generated by the CTCs. Proceeds from the sale of RRBs will be used to retire existing debt and equity of the three IOUs, allowing them to pass on the savings in the form of the required rate reductions. Revenues from the CTC will then be used to service the RRB debt. Net savings from this arrangement are possible because the RRBs will have a longer term than existing utility debt, a lower rate than utility equity, and may also qualify for tax-exempt status, depending on the details of how and by whom they are issued. Because debt service on the RRBs will be required after the deadline for recovery of stranded costs, a reduced CTC will continue to charged from that date until the RRB debt is retired. Certain other specific transition costs will also be charged to customers after 2002.

b) Texas

The focus in Texas has been on increasing competition at the wholesale level, although retail competition will be debated seriously in 1997. Senate Bill 373, passed in 1995, substantially deregulated the Texas wholesale market, but did not address retail competition. The bill authorizes EWGs and power marketers to operate in the state for the first time.[27] Significant progress is also being made to transform ERCOT – currently a NERC regional reliability council with no operational responsibility – into an ISO. The PUC approved, on August 21, 1996, a joint application from the state's IOUs and other wholesale market participants to establish an ERCOT ISO and an Electronic Transmission Information Network. Under this plan, the current ERCOT Board will be transformed into the governing body of the ISO. Three functions will report to this body: policy (the Technical Advisory Committee); administration; and operations (the director of the ISO). Membership will be "open and available to any entity that desires to participate in the wholesale electric market." New members can join one of six market groups, but they may only join one as a voting member. The six groups are: 1) IOUs; 2) municipally owned utilities and river

[27] Because ERCOT has only DC interconnections with other states, Texas utilities that have operations only in that state are not within the jurisdiction of the FERC.

authorities; 3) electric cooperatives and river authorities; 4) transmission dependent utilities; 5) independent power producers; and 6) power marketers. The implementation of the ISO will be phased in over several months and should be operational by June 1997.

Although all references to retail competition in Senate Bill 373 were eliminated before the bill was passed, a new coalition of industrial, commercial and residential users has been formed to pursue retail competition legislation, which is expected to be introduced during the 1997 legislative session. This expectation was strengthened by the PUC's release in mid-January 1997 of two reports to the state legislature on competition and stranded investment. These reports are based on t he premise that retail competition in Texas is inevitable, and offer the legislature four options for dealing with the transition: 1) adopt the goal of retail competition but take no further action in the current legislative session; 2) allow voluntary restructuring activities by utilities consistent with a set of consensus principles; 3) expand the wholesale competition regulatory framework begun in 1995 to encompass all wholesale markets in the state; and 4) expand retail competition to all of Texas[28]. The PUC observed that the options are not necessarily mutually exclusive, but recommended the fourth option as a goal and asked the legislature for guidance regarding timing and other details.

c) Arizona

Although there has been significant regulatory activity in Arizona, the ultimate parameters of competition are not as firmly established as in California. The Arizona Corporation Commission (ACC) opened a generic investigation on restructuring and competition in May 1994.[29] An ACC working group on restructuring and three separate task forces began meeting in January 1995 to identify policy options for retail electric competition, to investigate the benefits and disadvantages of competition in electric markets, and to describe implementation policy options.

On October 5, 1995, ACC staff issued a progress report on the working group and task force findings. On February 22, 1996, the Commission mailed a request for comments on how to implement various approaches to restructuring, focusing primarily on how to develop a restructuring pilot program.[30]

On October 9, 1996, the ACC gave preliminary approval to rules which would provide for retail competition for ACC regulated utilities and would allow other utilities to voluntarily participate under certain conditions. The rules would require regulated utilities to make 20 percent of their 1995 peak load available for competition effective January 1, 1999, with competition fully implemented by January 1, 2003. In parallel with the activity of the ACC, the legislature has established a study committee which is expected to report in 1997 on the need for legislative action to fully implement retail competition.

d) New Mexico

A state legislative committee investigating electricity restructuring found that neither retail competition nor industry restructuring was in the best interests of the state and recommended no legislative action. While supporters of retail competition claim the issue is not dead, it cannot be revived until the next legislative session in 1998.

On November 28, 1995, the New Mexico PUC issued a notice of inquiry into retail competition and sought comment on how the state's electricity industry should be restructured. As evidence of the PUC's outlook, Lawrence Ingram, Chair of the New Mexico Public Utility Commission is quoted as saying, "I doubt we will see retail wheeling in the near future in New Mexico."[31]

In El Paso, the U.S. Army and Air Force have notified El Paso Electric that they intend to seek competitive bids for retail service to bases in New Mexico. This issue is currently before the PUC.

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[28] Retail competition currently exists in limited areas of the state in which either two or three traditional utilities are licensed to provide service.

[29] Docket No. 11-000-94-165.

[30] NARUC State-by-state summary, August 7, 1996.

[31] Ibid., p. 26.

6. Conclusions

Several observations can be made about the process described above:

- Current restructuring efforts reveal a strong preference for market-based solutions, replacing cost-based regulatory oversight with the price discipline of the market.
- Retail price levels, as well as differentials among regions and customer classes, have been a key driver for change, and will likely continue in that role since retail prices have not declined with wholesale prices.
- Considerations of "equity" among customer classes -- i.e., whether all customers will benefit from retail competition -- may force the pace of change to accelerate, as illustrated by current Congressional efforts.
- Stranded costs are a major hurdle that must be overcome to successfully introduce retail competition. Although many challenges remain, the states, and potentially Congress, are moving forward with proposed solutions.
- State restructuring activities tend to be synergistic, since state regulatory bodies follow events in other states closely, and also have strong institutional bonds and a sense of shared interests.
- The restructuring process in the U.S. is not unique, and in fact it has relied heavily for ideas on the efforts already taken by a variety of countries. What may be unique about the U.S. is the combination of an extremely large and geographically diverse area, and a similarly large and diverse number of industry participants. These challenges will likely require adjustments to structures already implemented, however, rather than the creation of an entirely new model.

C. Overview of Relevant Experience in Other Countries

This section describes the characteristics of several countries that have already undertaken restructuring, and one, France, that has initiated only limited reforms. It also describes the regional efforts underway in western Europe. This discussion is meant to provide some context for the changes now underway in the U.S. Specific lessons learned from international experience in cross-border trade and investment are covered in a later section.

1. United Kingdom

The electricity industry in the U.K. is split into three separate structures, covering the three different countries within the U.K. These are:

- England and Wales, which operates a competitive electricity pool
- Scotland, where two vertically integrated IOUs compete
- Northern Ireland, where there is competition in generation, with power purchases and limited competition in supply

a) England and Wales

The electricity industry in England and Wales was privatized in 1990, except for nuclear generation, although some newer nuclear generation was privatized in 1996. The only remaining state-owned interest is older nuclear generation facilities.

There are currently a large number of participants in the generation market, including three "portfolio generators" with various types of generation capacity, two nuclear generators, one peaking generator, numerous IPPs -- many of which are under multiple ownership -- and interconnectors with both France and Scotland. Virtually all new generation built since privatization has been gas fired.

Transmission is a private, regulated monopoly, and distribution is split into twelve regional monopolies known as RECs (Regional Electricity Companies). Supply is partly competitive (for all customers with a maximum demand greater than 100 KW) and part franchise, where the twelve RECs have a monopoly within their own area. The industry is regulated by the Office of Electricity Regulation (OFFER), which issues licenses and uses price controls to provide cost-cutting incentives to the monopoly parts of the industry. OFFER can regulate the companies themselves, but cannot directly regulate prices in the market.

Although there is no vertical integration within the industry, there is significant cross-ownership of companies. Many of the generators (including the Scottish interconnectors) participate in the competitive supply market, and the RECs have stakes in various IPPs. One REC even purchased a significant amount of coal-fired generation to become a portfolio generator in its own right.

The electricity pool trading mechanism begins with centralized merit order (i.e., economic) dispatch by a system operator. Generators submit price and availability bids to the operator one day ahead, and the resulting dispatch schedule is used to determine an energy price based upon the bid of the marginal plant, without taking account of any system constraints. A capacity price is set at the same time to indicate when there are shortages of available capacity and to give signals when new capacity may be required. The price paid to generators therefore is the sum of the energy price and the capacity price and is set one day ahead. The price paid by wholesale consumers combines the price paid to generators with the costs of changes made on the day of dispatch due to operational requirements. Generators that are required to operate out of merit receive full compensation -- i.e., the amount of their bid times their available capacity -- and generators that are scheduled but not required to operate are paid lost profit as compensation. This profit is calculated as the difference between the system marginal price and their bid for each kWh they were scheduled to produce.

As noted in previous sections, various financial instruments have grown up around the pool to manage the risk of spot market prices. Much of the energy traded is therefore not traded at pool determined prices, but via contracts for differences (CfDs). These contracts are struck between two parties in order to maintain a stable income stream, and are generally related to expected pool price. Differences between the actual pool price and a contractual strike price are paid by the two parties, so that the total price paid for energy procured from the pool is equal to the sum of the pool price and payments made or received via CfDs.

The key changes in the market since privatization have been as follows:

- The market share of the two major generators has fallen from 73 percent to 57 percent
- New gas-fired IPPs have captured 10 percent of the market, and the figure is continuing to rise
- Significant amounts of older (mainly coal-fired) plant have been closed or mothballed as they could not compete with the newer, more efficient, non-coal capacity
- New generation has entered the baseload market, making it more competitive and displacing existing baseload generation
- There was little competition among the marginal generating units until the two portfolio generating companies were forced to divest 6,000 MW of capacity
- Lenient price controls and the lifting of the Government's "golden Share" (which prevented takeovers) has led to significant interest in the market from overseas investors, and the takeover of a number of RECs

Further changes are still to come in the market:

- Full competition in supply is planned for 1998
- The role of coal as a generation fuel is uncertain after 1998, when government contracts with above-market prices expire
- Arbitrage between the gas and electricity markets is expected to grow as the two markets become progressively more competitive
- Environmental pressures and an emphasis on clean technology will impact the construction of new generation

The major problems faced in England and Wales have been:

- The ability of the two major generators to influence prices in both the pool and the contract market
- Excessive profits made by the RECs and the regulated transmission company (National Grid), which were caused by lenient price controls and a lack of effective cost-cutting incentives
- Anomalous price spikes caused by limitations of the price-setting software used by the pool
- Generators have moved away from bidding strictly on their marginal costs of generation, and have included strategic considerations that distort the merit order
- IPPs with take-or-pay fuel contracts have bid a price of zero to ensure they are dispatched, thereby distorting the merit order

b) Scotland

The Scottish electricity industry was privatized in 1991 as two vertically integrated companies (the nuclear generator was not privatized until 1996) with interconnection to England and some second-tier supply. There are plans for an interconnector with Northern Ireland, but these have been held up under planning legislation. The two companies operate under a number of public and private long-term PPAs, many of which were set in place at privatization. Transmission, distribution and supply follow the pattern of the England and Wales market and are regulated in the

same manner. Scotland does not give the same level of access to Scottish customers for generators from England and Wales as it enjoys in the England and Wales pool.

c) Northern Ireland

The key points to note about the electricity industry in Northern Ireland must be put into context. It is a very small island system, which has four major power stations and an interconnector with the Republic of Ireland. Due to this small size, there is a need for a high level of spinning reserve to be maintained and hence a high loss of load probability. The small size of the system and the sparse population lead to relatively high transmission and distribution costs.

Its principal features are:

- Competition in generation
- A power procurer (Northern Ireland Electric, or NIE) which purchases under long term contracts from the generators
- A supply business (integrated with the power procurer and the grid operator)
- A wholesale tariff to enable competition between suppliers
- Limited second-tier supply

Northern Ireland has considered the possibility of operating under a pooling arrangement and discarded it as unlikely to be cost effective. There remains controversy over whether the proposed interconnector with Scotland is the most suitable means of providing the country with new generation. NIE has rejected the regulator's price control proposals which are currently being assessed by the competition authorities.

2. France

The electricity industry in France remains a state-owned, vertically integrated company (Eléctricité de France, or EdF). There is limited competition in generation through:

- Renewable plants (e.g. waste-to-energy)
- Cogeneration

In addition there is very limited competition in distribution via a small number of municipalities.

EdF exports significant amounts of energy to neighboring countries, including England. Its exports to its continental European neighbors (Switzerland, Germany, Italy, Spain and Benelux) are based on volumes required rather than commercial, market based mechanisms. Currently only England and Wales, of all its counterparts, operates under competitive arrangements. This will change as the European Union directive on electricity takes effect.

EdF itself will need to make changes over the next few years to ensure it complies with the EU directive. It is expected that it will move towards a single buyer model, thereby enabling it to remain in state ownership and minimizing the extent of any required changes.

3. Scandinavia

The electricity industries in Norway and Sweden operate under a multi-country trading framework (similar to a pool). In each country, there is competition in generation and distribution/supply. Generation is characterized by a large number of small and medium producers, but dominated by a few large producers. Distribution is fragmented, with many small municipalities involved. Much of the generation is hydro, with a significant amount of nuclear and combined heat and power generation also available.

Norway reorganized its markets in 1991, regulating interconnector trade and building on the generation trading exchange which had operated since 1971. In 1996 a common power pool was established for Norway and Sweden,

with Finland due to join in January 1997. Denmark is in a position more similar to that of France vis-a-vis the England and Wales pool in that Danish producers have almost full rights in the pool while having full protection in their home market (Finland and Denmark still have to pay border tariffs on their trades).

Key features of the market include:

- Significant amounts of interconnector trading
- A fragmented industry with many participants
- The breaking up of state-owned monopolies through reorganization rather than privatization
- Free access to the power pool and to all grids
- Power pool prices heavily dependent on level of rainfall in year (low in wet years, high in drought years)
- Medium-term contract prices moving towards the level of spot prices
- Weak competition in the household market in Norway as energy costs are a small proportion of overall household expenses
- The return of hydro assets to the state without compensation after 60 years in Norway
- The dominance of the Swedish state-owned producer Vattenfall

There are several differences between the structure established in Scandinavia and that of England and Wales that illustrate the possible variations of a pool-based industry structure. One of the most important is that the objectives of the reforms in Scandinavia were to reduce price differentials between regions and sectors and to improve efficiency in the sector through lower prices, while the England and Wales privatizations were the result of an economy-wide effort to reduce state ownership. In addition, competition is international in Scandinavia, making it unique in the world in terms of a pool. Transmission tariffs in Scandinavia are point-to-point transport tariffs, while those in England and Wales are a combination of a nodal charge for the use of the system and a charge for ancillary services based on the customers proportion of total system usage. The Scandinavian system also has interconnections with a large number of countries, with additional interconnections likely. The power exchange in Scandinavia also offers several products: a day ahead physical market; a weekly futures market; and a very short-term (same day) spot market that is used to balance actual supply and demand. The England and Wales pool offers only day ahead purchases and sales. Finally, despite the existence of the pool, there is still heavy reliance on long-term contracts.

4. European Union Directive

The countries of the European Union agreed in 1996 on a plan for the liberalization of electricity trading throughout the union. It does not apply to the U.K. or to Scandinavia since those countries have already liberalized further than the directive requires. The key requirements of the directive are as follows:

- Clear public service obligations for all utilities
- Transparent procedures for the procurement and construction of new generating capacity
- Independent system operator
- Separate accounts for each activity -- i.e., generation, transmission, distribution and supply
- Open access or single buyer model for use of the transmission system
- Identification of customers eligible for competitive supply
- A phased timetable to open market for competition in supply
- Mechanisms for regulation, control and transparency

- The option to apply for a transitional regime if necessary (given to Belgium, the Republic of Ireland and Greece).

5. Argentina

The electricity industry in Argentina was restructured in 1992. Generation, transmission and distribution were separated and each is now regulated separately under the supervision of the Secretary of State for Energy. The new market permits trading between generators, transmission operators, distributors and large users.

The ultimate objective of restructuring was to use competition to reduce tariff rates and to improve the quality of service. To achieve this, goals were established to minimize the need to store energy (in hydroelectric storage plants) and to avoid the practice of energy being traded from a particular generator to a specific customer.

A power pool is managed and run by the Compania Administradora del Mercado Mayorista Electrico Sociedad Anónima (CAMMESA, or Administrative Company of the Wholesale Electricity Market), a non-profit organization in which all participants in the market are members. CAMMESA operates the scheduling and dispatch of generation on the basis of marginal costs and reliability. Marginal cost for dispatch purposes is defined according to fuel type:

- For thermal generation, marginal cost is the cost of fuel to produce one kWh of electricity
- For hydro storage plant, the marginal cost is based on a model which looks at current levels of storage and predicted rainfall over the next six months
- For run-of-river hydro, the marginal cost is zero and these plants are dispatched first

Generators advise CAMMESA on a weekly basis of their expected availability and CAMMESA schedules the resulting dispatch to minimize total system cost. Hourly spot prices are calculated based on the marginal cost of energy (the marginal cost of the plant which would produce the next kWh of electricity required), a capacity component and a standby capacity component.

Sales and purchases can take one of three forms:

- At spot prices in the pool
- Via negotiated contracts
- Under seasonal (6 monthly) prices set by CAMMESA based on the expected generation to be used

On average the seasonal price should be equal to the spot price over a six month period but in practice there will be differences. CAMMESA also runs a stabilization fund to compensate generators when the seasonal price is lower than the spot price.

There are three distribution companies which are designated as public service monopolies and regulated accordingly. They operate with controlled rates and have quality of service specifications. The distribution companies are required to satisfy demand on their networks (as long as there is sufficient capacity available) and are obliged to allow third party access for energy being supplied to customers connected to their network.

The transmission business is designated as a public service monopoly and regulated. It has been run by Transener under a concession agreement (95 year agreement, subdivided into a number of management periods) since 1993. Transener is required to offer open access (given available capacity) and is not allowed to participate in the buying or selling of electricity.

The Argentinean market is more strictly regulated than that of England and Wales and many other countries with competitive industries. This is at least partly the result of a generation mix that combines significant amounts of hydro and thermal capacity. With such a resource mix, a straightforward merit order dispatch cannot work without some additional safeguards. In a competitive generation market, owners of hydro plant would not necessarily find it in their interests to conserve water at certain times of the year or to offer it at others, as would be required to lower overall system costs. With a price formula taking account of the countrywide need, a more optimal allocation can be

made. The rules on marginal cost bidding also make the regulation of the competitive market more strict. There is no opportunity, for example, for generators to inflate price bids for strategic reasons.

6. Chile

Chile pioneered the Southern Cone model, which other Latin American countries, including Argentina and Columbia, have recently adopted. The model has its roots in the Electricity Law of 1982, which restructured the power sector. Utilities were privatized between 1986 and 1989, after financial and corporate restructuring.

Chile's diverse geography drove the creation of its two main power systems. The first, the Sistema Interconectado Central (SIC, or Central Interconnected System) covers the central regions and has 4000 MW of installed capacity. Eighty-six percent of the SIC is privately owned. SIC's main generating companies are ENDESA S.A, which owns 65 percent of generating capacity and Chilgenor, which owns an additional 14 percent.

The second system, Sistema Interconectado del Norte Grande (SING, or Interconnected System of the North) covers the northern regions and has predominantly thermal (oil and coal) generation, with less than two percent hydro and approximately 1,200 MW of capacity. Eighty-nine percent of SING's generating capacity is owned by mining companies to cover their own demand, and 11 percent is owned by EDELNOR S.A., which also owns the transmission system. EDELNOR S.A. belongs to private investors (53.5 percent) and the state.

Regulatory and advisory bodies include the Comisión Nacional de Energía (CNE, or National Energy Commission), the Center of Economic Load Coordination, the Ministry of Economics (ME), and the Superintendent of Electricity and Fuels. CNE regulates the industry, carries out generation planning, determines the hydro/thermal mix, and develops pricing policy. The ME reviews and decides on final tariffs.

The Southern Cone model, adopted by Argentina in 1992 and by Columbia in 1995, was pioneered by Chile in the early 1980s. The model divides the sector into five divisions -- generation, dispatch, transmission, distribution wires and distribution supply -- and deregulates utilities at the wholesale and retail levels. Open access to the wholesale market, an energy pool for generating facilities and least-cost centralized dispatch form the model's core.

Another key element of the model, the introduction of competition into the power sector, is accounted for in the following ways:

- It allows large consumers to purchase from any generator or distribution company, giving suppliers an incentive to lower costs in order to capture more of the market.
- It links the regulated price to the market price, so that small consumers share in the efficiencies resulting from competition.
- It uses the unregulated price as a signal for investment, so that expansion decisions reflect market forces.

Since a new pricing policy was established in 1980 and since the passage of the 1982 Electricity Law, tariffs have been regulated and adjusted to reflect generating costs, and costs are separated between generation/transmission ("node" prices) and distribution ("added value" prices). Negotiated rates are available to customers with demands above two MW, but these prices cannot differ by more than 10 percent from node prices. Average incremental generation costs are reset every six months, and are currently about 5.3 cents per kWh. Average rates are 6.3 cents for industrial users, 10.2 cents for commercial customers, and 11.1 cents for residents.

The effect of the Southern Cone model on Chile's power sector has been largely beneficial. It has stimulated the entry of many new generators into the power sector, improved efficiencies and the quality of power supply and caused prices to fall in real terms.

Despite its obvious successes, however, the model has given rise to several problems in the following sectors.

Generation: Predominance of one generator in SIC. One investment group controls most of the system's generating capacity, the largest distribution company and transmission assets. Cross-ownership and conflicts of interest have resulted, curtailing competition in the generation market.

Transmission: Equitable access to transmission. Even though the Electricity Law of 1982 sets rates for transmission charges, the method for calculating the cost and the cost-sharing formula for transmission assets has proved contentious. Cross-ownership of transmission and distribution assets has led to extremely difficult toll fees negotiations between generation and transmission companies. The disagreements center around calculations of each generator's "influence areas," (which are necessary to set toll fees), the allocation of the load served by it and other generators, the price of toll fees (which are set and raised by transmission companies), and the replacement value of transmission lines.

Some industry analysts maintain that the transmission system also lacks incentive to encourage optimal new investment in transmission. The recent decision of new entrants to install additional generation near consumption centers, despite additional capacity in the system, reinforces this belief.

Distribution Wires and Supply: Competition for retail customers has been slow to develop. This has probably occurred because the largest distribution company is also the largest consumer, which may have suppressed competition for customers in its market area. Distribution utilities have also found it difficult to improve efficiency. Electricity theft has remained high and it has been difficult to collect overdue payments. Provincial companies, which are still not privatized, also are finding it difficult to maintain a balance between increasing efficiency and maintaining employment.

7. Colombia

The Colombian Government initiated in the early 1990s a restructuring initiative designed to rehabilitate, reorganize and privatize the electricity sector. Prior to restructuring (and to a lesser extent today), virtually all electricity in Colombia was generated, transmitted and distributed through eight vertically integrated organizations. Five state-owned utilities dominated the sector. The Electricity Law of July 1994 created an unbundled and competitive industry with competition in generation and third-party access in transmission. The industry was largely disaggregated into generation, transmission, distribution and power brokering entities. Vertically-integrated companies still exist, but are required to keep separate records for activities in each area. Generators can enter negotiated and unregulated power-purchase agreements with large end users, brokers and other generators and can sell power to brokers in the energy exchange market at pool prices. Sales to end users with demand in excess of two MW are not regulated.

An energy exchange for sales between generators and power brokers has been operating since July 20, 1995. All generation facilities in excess of 20 MW must be connected to the Centro Nacional de Despacho (CND, or National Dispatch Center) and post offer prices for the following day. CND ranks the offers by price, matches total supply with demand and then schedules the amount of power it will take from each generator. Approximately 70 percent of electricity traded on the exchange is for contract terms of six months to one year.

Sales to small end users are regulated by the Comisón Reguladora de Energía y Gas (CREG, or Energy and Gas Regulatory Commission). Under the Electricity Law, CREG will set tariffs for retail or unregulated sales for a three-year transitional period. During this time, sales to end users will be based on an energy charge, a charge for power used during periods of peak demand, a fixed capacity charge and a connection charge.

Other key features of the regulatory environment are:

- CREG does not regulate sales to end users with demand in excess of two MW
- Starting in January 1997, CREG will not regulate sales to consumers with demand greater than 1.0 MW
- Starting in January 1998, CREG will not regulate sales to consumers with demand greater than 0.5 MW
- All transmission companies must guarantee open access subject to regulated transmission rates

In the wake of these restructuring efforts, the Government is actively encouraging private investment in the electricity sector. A total of 4,231 MW of generation capacity along with several distribution companies are planned for privatization in 1996 and 1997. The Government is also encouraging the private sector to undertake most of the 2,700 MW of new generation capacity scheduled for development between 1996 and 2001.

The most significant problem faced by the sector today is caused by weather: Colombia's high dependence on hydro leaves its generation susceptible to seasonal variations and droughts which have caused great volatility in pool prices. To alleviate the problem, the Government will introduce in December 1996 a new firm capacity price of $5.25 per KW per month to be included in the total cost paid to generators.

III. Opportunities for Cross-Border Trade and Investment

This part of the study moves from the general discussion in Part II to a more detailed examination of issues relevant for cross-border trade and investment between the U.S. and Mexico. Part III is divided into two large sections. The first examines a set of specific regulatory, legal, technical and economic issues, while the second identifies four categories of trade and investment opportunities and evaluates them within the context of a scenario analysis designed to incorporate the topics discussed in this study.

A. Specific Issues Affecting Cross-Border Trade and Investment

1. Regulatory

This section examines the regulatory treatment of cross-border trade and investment by each country, for both generation and transmission projects. Relatively more attention is given to generation regulations in Mexico because regulations governing non-utility generation in the U.S. have been discussed in previous sections, and because there are no restrictions on foreign ownership of that generation. Conversely, relatively more attention is given to transmission regulations in the U.S. because those regulations are very complex and still evolving.

a) Generation

(1) U.S.

As discussed in detail in other sections of this study, the generation sector in the U.S. has a large number of privately owned generation plants that operate under several types of regulation. There are currently no restrictions on foreign participation in those plants.

(2) Mexico

(a) Legal and Regulatory Framework

The supply of electricity for public service is regulated by the 1992 Electric Energy Public Service Law[32] (the 1992 Energy Law), and its implementing Regulations[33] enacted in May 1993 (the 1993 Implementing Regulations).

Under the 1992 law and its regulation, private investors are allowed, as external producers, to participate in the generation process; they may generate electric power for any of the following reasons:

- Sell all capacity and associated energy to CFE
- Self consumption through self-supply or cogeneration projects
- Sell energy surpluses to CFE (self-suppliers and cogenerators)
- Use in emergency conditions
- Export to other countries

[32] Decreto que Reforma, Adiciona y Deroga Diversas Disposiciones de la Ley del Servicio Público de Energía Eléctrica, Diario Oficial, 23 Diciembre 1992.

[33] Reglamento de la Ley del Servicio Público de Energía Eléctrica, Diario Oficial, 23 Mayo 1993.

In addition, under the new regulation consumers are able to import electric power, though appropriate permits, for the exclusive use of the importer. These activities may involve wheeling and capacity back-up services provided by CFE. There are specific procedures to define the associated charges when private power producers require any of these services. Self-producers and cogenerators are allowed to build and operate their own transmission lines, but they may not be connected to the national transmission grid.

At present, the open access transmission model is a limited option, only to be used by self-producers and cogenerators, as well as for imports or exports. A self-supply power plant can have consuming partners located in different areas of the public service transmission grid. Consuming partners are allowed to use electric energy at remote locations from the self-supply power plant using the public service transmission network.

(b) Power Market Opening

Under the short term dispatch procedure, CFE accepts external production offerings with energy prices lower than the system's short-term marginal cost. Through this process competition with CFE's generating units and other external producers is introduced.

In the long term, CFE is required by regulation to buy firm capacity and associated energy through a bidding process, which allows CFE to select the best option based on a least-cost criterion. In addition, CFE can acquire, without a bidding process, capacity from private producers that offer power and energy surpluses (20 MW or less) from their cogeneration and self-supply projects.

There are two goals achieved with the new regulation: 1) redefinition of functions performed by the government as a regulatory body; and 2) creation of significant opportunities for private investors in the generation business.

Some of the important factors related to the participation of private investors in electric energy production are:

- Short and long term competitiveness of energy generation costs
- Competition with CFE's power plants and other private producers in the dispatch process
- Use of wheeling and back-up services from CFE

In all circumstances it is required that permit be obtained from the Energy Ministry to develop a private generation project.

(c) Contracts and Services

CFE has established standard format contracts and procedures for several services approved by the authorities: including facilities interconnection; wheeling; capacity and energy purchases; and back-up services. The contracts were designed and coordinated by a team including personnel from the national control center, the system planning unit and the legal department of CFE.

The interconnection contract is the master contract between CFE and a non-utility generator. Other contracts are incorporated under this basic document according to the transactions to take place between CFE and the private producer and/or consumer.

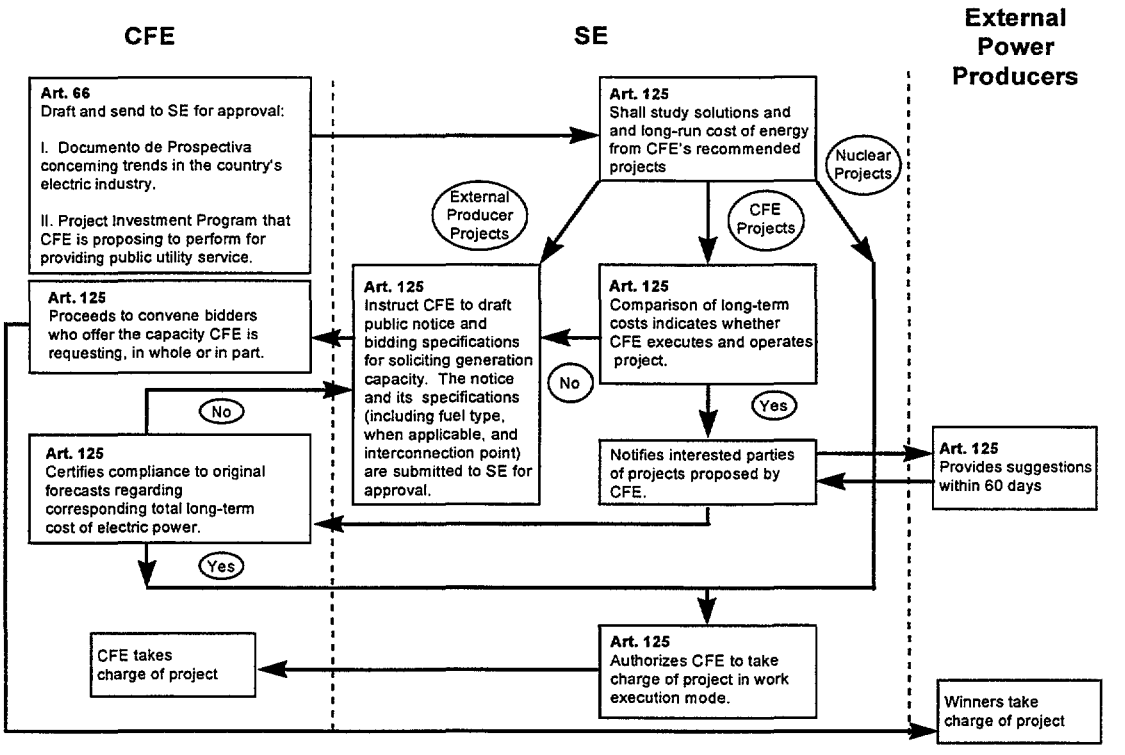
(d) Procedure for Generation Capacity Additions

Participation as Independent Power Producer is open to foreign investment, as long as the company is founded according to Mexican law and domiciled within the country.

Figure 8 shows schematically the procedure foreseen by the 1993 Implementing Regulations to cover the generation capacity additions which SEN expansion requires.

Figure 8: Procedure for Generation Capacity Additions

(According to the 1992 Energy Law and its 1993 Implementing Regulations)



Source: CFE

(e) Capacity and Energy Purchases

As defined in the 1992 Energy Law and the 1993 Implementing Regulations, CFE uses a bidding procedure to obtain firm capacity and energy from private producers. To promote efficiency, the law allows the right to build, own and operate power plants, and to sell capacity and energy to CFE as long as the associated cost is competitive according to the terms of the law (i.e., the cost is consistent with long-term least-cost planning).

When CFE contracts for a power purchase from an external power producer, CFE retains control over the quality and reliability of the services by means of economic dispatch and real-time operating controls. Accordingly, private plant owners will control personnel, procurement of fuel and other costs.

CFE and non-utility power plants will make daily competitive bids to supply load demand on a short-term least-cost basis. For the external power producer selected by the bidding process, the day-by-day competitive dispatch framework of the regulation does not represent a risk for long-term investment, as firm contracts are based on a reference value for power plant efficiency and current fuel prices. Through a capacity contract, CFE will pay private plant owners the amount needed to recover investment and a fair return, according to the availability of the generating capacity.

(f) Capacity & Energy Surpluses

This agreement covers purchases from non-utility generators, without a bidding process, when a small surplus (20 MW or less) of capacity and energy is offered. The payment is determined by the methodology described by regulations enacted in November 1994. Under this agreement, CFE will accept proposals for sale of surplus capacity

and energy if and only if the equivalent price for capacity and energy is lower than the short-term marginal cost in the region where the generator is located.

(g) Other Services

The contract for economy energy is focused on non-firm energy that a private producer can eventually offer to CFE. Its price must be competitive in order to be dispatched every day.

CFE's back-up service at high and medium voltages allows self-producers and cogenerators better operational flexibility. This service guarantees that their processes will not be interrupted in case of failure or maintenance of generating equipment. Back-up rates are available for high and medium voltage interconnection points.

b) Transmission Access

(1) U.S.

As described above, FERC Orders 888 and 889 have provided open access to much of the U.S. transmission grid. The mechanics of that access and specific provisions of the Order 888 pro forma tariff were described in previous sections. This section describes three other provisions of those Orders that are particularly relevant for cross-border transactions.

(a) Eligibility

Under Order 888, "any entity engaged in wholesale purchases or sales of energy" is eligible to receive open access transmission service from a transmission provider under FERC jurisdiction. This includes generators, integrated utilities, distribution utilities and marketers, but not brokers, since they do not take title to the electricity. Regarding foreign entities specifically, the Order states that foreign entities that are eligible for transmission services under Section 211(a) of the FPA are also eligible to receive service under the non-discriminatory open access transmission tariffs. The Order then goes on to note that this statement does not mean that the FERC has determined whether foreign entities are in fact eligible under Section 211(a).[34] Discussions with FERC attorneys indicate that no such determination has been made because no foreign entity has ever requested service under Section 211(a).

(b) Reciprocity

As noted in the description of Order 888 in Part II, the FERC included a reciprocity clause in the pro-forma tariff. The purpose of this provision is to ensure that non-jurisdictional[35] utilities are not able to take advantage of open access transmission service offered by jurisdictional utilities without opening their own transmission grids to others.

The reciprocity clause in the Order 888 pro-forma tariff states that:

[34] The relevant part of Section 211(a) states that "Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission [FERC] for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant".

[35] As explained in other sections, many different utilities -- and in particular those that are publicly owned -- do not fall under the direct jurisdiction of FERC, although certain activities they may engage in, such as requesting transmission services from a jurisdictional utility, may give FERC jurisdiction over those specific activities.

> A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates.....This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

Reciprocity is not granted automatically, but is rather triggered by a request to the entity receiving open-access transmission services from a jurisdictional utility. If the utility receiving open-access services does not make such a request, reciprocity is not required. Reciprocity is also granted only to the non-jurisdictional entity that is providing transmission services, rather than to any entity that requests it. The exact nature of the service that must be granted is determined by the Order 888 pro-forma tariff. Although the non-jurisdictional utility purchasing transmission services need not file such a tariff with the FERC, the service it offers to the jurisdictional utility must conform to all the terms of the pro-forma tariff, including the requirement that the rate charged must conform to the FERC's Statement of Pricing Policy. The non-jurisdictional utility would also be required to demonstrate to the FERC that it takes its own transmission service under the same terms being offered to the jurisdictional utility. Finally, reciprocity requires that the non-jurisdictional utility meet all the requirements of Rule 889, described in an earlier section.

(c) Waivers and "Safe Harbor"

Non-jurisdictional utilities have the option of requesting a waiver from some or all of the reciprocity provisions contained in the pro-forma tariff. This application may be filed with the FERC at any time, for "good cause shown." Non-jurisdictional utilities also have the option of filing a tariff with the FERC along with a request for a declaratory order that the tariff meets the FERC's comparability standards. This option is called the "safe harbor" provision, because it allows a non-jurisdictional utility to take pro-active measures to ensure that it is not denied open-access transmission services based on a claim that it does not offer reciprocal services. The use of the safe harbor provision is of course completely voluntary. To date, only one U.S. utility, South Carolina Public Service Authority, has filed a tariff under this provision.[36] After comparing the proposed tariff to the Order 888 pro-forma tariff on a point-by-point basis, the FERC requested that various changes be made, and granted the requested declaratory order contingent upon those changes. The resulting tariff was therefore equivalent to the pro-forma tariff in almost all respects.

(2) Mexico

For the interconnection of private power plants to CFE's electric system, it is necessary to sign a contract that contains the conditions which must be fulfilled by non-utility generators and their remote loads connected to CFE's electric system. It also establishes the procedure for energy supply measurements; this supply could be from a private power plant to CFE's system or from a private power plant to its own loads through the CFE electric system. In addition, the contract determines the capacity and energy amounts associated with each of the possible services or transactions needed by the users, based on available measurements.

The interconnection contract also includes provisions for back-up requirements for self-suppliers and cogenerators, independent of the transaction type. This contract establishes common clauses – mainly legal and procedural -- for all transactions, which are referenced in all other contracts.

[36] FERC RM93-19.

The procurement from CFE of wheeling services for self suppliers requires a contract that determines wheeling charges. It takes into consideration the capacity and energy to be transmitted, and the charge is calculated in accordance with the methodology described in regulations enacted in November 1994. This methodology establishes a calculation procedure for the following concepts: 1) fixed and variable wheeling costs; 2) fixed management cost; and 3) ancillary services costs.

Fixed wheeling cost includes charges for the use of transmission infrastructure and the capacity (transmission and generation) required to cover power losses. These charges depend on the maximum positive value or zero of the weighted sum of the differences of the maximum values of active power flows registered for each transmission element, with and without the wheeling service in the transmission grid. The simulations are performed with maximum and minimum demand scenarios.

The charges for transmission and generation capacity associated with power losses could be positive or negative, depending on whether wheeling service losses are greater or lower than in the case without the transaction.

Variable wheeling costs are determined by simulating the operation of power plants with and without the wheeling transaction, taking into account energy losses and re-dispatch costs indicated by the simulation.

The fixed management cost takes into account charges related to commercial processes. Additional charges are imposed to cover CFE's costs due to frequency and voltage control services.

c) Jurisdiction

Jurisdictional issues are important in the U.S. because federal and state regulatory entities may have different attitudes towards competition. This section discusses the division of authority among the FERC, the DOE and state PUCs.

(1) FERC Authority

As described in Part II, FERC has historically regulated interstate utility activities. FERC replaced the Federal Power Commission on October 1, 1977, and took on the existing FPC role as well as some newly defined responsibilities. In terms of transmission, FERC has been granted certain specific powers through various legislative acts, as described in earlier sections.

(2) Non-Jurisdictional Utilities

Non-jurisdictional utilities are public power organizations that are not directly subject to FERC authority. They include federal PMAs, rural electric cooperatives, municipal utilities and state power authorities, and the members of ERCOT.[37] These utilities are not directly affected by FERC rulings on restructuring issues such as open access transmission because most (with the unique exception of federal PMAs) are authorized by state or municipal authority and therefore not subject to federal regulation. It is likely that non-jurisdictional utilities will gradually choose to submit transmission tariffs and take the incentives offered to them to participate in the open access regimes.

(3) FERC vs. States

Until recently, there was a fairly clear line of jurisdiction between the FERC and state regulatory commissions. From the passage of the FPA until the issuance of Order 888, FERC had authority over wholesale transactions, while states retained authority over retail sales of electricity to end users. However, the unbundling taking place as utilities respond to increased competition and begin to restructure has resulted in a change in FERC's approach. In Order 888, the jurisdictional line blurred: FERC asserted authority over the transmission portion of retail unbundled transactions. Previously FERC had conceded state jurisdiction over retail transmission when bundled.

[37] Because ERCOT has only DC links to other transmission systems, its members do not engage in interstate commerce involving electricity. Its IOU members are therefore not subject to FERC jurisdiction.

Based on Order 888, states retain jurisdiction over the local sale or distribution of power. FERC developed a seven point test to determine what constitutes local distribution. If a utility's service meets these criteria, it will be subject to state regulation:

1. Close proximity to retail customers
2. Radial design of the system
3. Inflows are common, outflows are rare
4. Power is not reconsigned or transported on to other markets
5. Power is consumed in a comparatively restricted geographical area
6. Meters measure flows at the interface between transmission and local distribution
7. Distribution systems feature reduced voltage[38]

Several states, individual utilities, and industry groups objected to a FERC role in regulating unbundled retail transmission, but Order 888 refuted most objections. In addition, FERC strongly urged a cooperative relationship between federal and state regulatory bodies, and emphasized that its authority will "not affect matters otherwise left to the state by Congress." FERC has thus developed a record implying that it will work together with states on transmission access issues and will seek to defer to state regulatory commissions whenever possible. Ultimately, it is unclear what the jurisdictional lines between federal and state authorities will be, although the FERC currently appears to have control.

(4) States

As discussed above, the role of state regulation in the area of retail transmission is changing. The FPA and the EPAct both suggest that states should play a role in regulating local distribution. In addition, they authorize states to regulate generation and transmission siting. State PUCs will continue to play this role. The change is in the definition of "local distribution." FERC has stated that "it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs," and that it is also "important to develop mechanisms to avoid regulatory conflict and help provide certainty to utilities as to which regulator has jurisdiction over which facility."[39]

These mechanisms will further clarify the role of states in a restructured environment, as will initial case-by-case implementation of Order 888 and other open access requirements mandated by FERC. States will still regulate retail pricing as well as local programs designed to assist low-income or elderly customers or to encourage conservation. In addition, until some implementation occurs and some precedent is developed, it is reasonable to assume that states will continue to regulate local distribution of retail electricity. Moreover, much of the continuing restructuring debate will be carried out on a state by state basis.

(5) FERC v. DOE

As is described in detail in other sections of this study, the DOE has some limited authority over electric utilities with respect to international transmission issues. The DOE issues Presidential permits for the construction of international electric transmission lines and authorizes any exports of electric energy to foreign countries. This DOE role is particularly relevant given the current conflict between Enron Power Marketing, Inc. (EPMI) and El Paso Electric Company (El Paso) regarding El Paso's permits to export electricity to Mexico.

Enron sought a DOE order to require El Paso to provide EPMI nondiscriminatory transmission access over the U.S. portion of the lines connecting two border substations in the U.S. with two substations in Mexico so that it could provide capacity in response to a request for bids issued by CFE. EPMI also requested that the DOE amend El

[38] 61 Fed. Reg. at 21620.

[39] 61 Fed. Reg. at 21625.

Paso's Presidential Permits to the extent necessary to grant EPMI's requests. Although transmission access is governed by FERC, DOE has authority in this case due to the international nature of the request. However, on November 1, 1996, the Secretary of Energy issued Delegation Order No. 0204-163, delegating to FERC the authority to modify or condition El Paso's Presidential Permits for its border facilities and/or its authorization to export.

Thus, the issue will be heard by FERC, rather than the DOE, despite the fact that DOE generally has authority in such matters. FERC is currently allowing presentation of evidence by El Paso Electric before making a decision on the matter. The issue is therefore still pending.

2. Legal

This section reviews legal issues relevant for cross-border trade and investment. The two main topics covered are the legal framework of cross-border transactions and mechanisms for dispute resolution in the international context. The legal framework comprises the North American Free Trade Agreement (NAFTA), tax treaties and laws, and the export licensing authority of the U.S. DOE and the Mexican SE. Issues examined in the section on dispute resolution include the available forums and procedures.

a) Framework

(1) North American Free Trade Agreement (NAFTA)

The North American Free Trade Agreement between Mexico and the U.S. does not generally address the energy sector. In the NAFTA section covering basic energy and petrochemicals, the three signatory countries confirm their full respect for their constitutions. They also recognize the desirability of strengthening the important role that trade in energy and basic petrochemical goods plays in the North American region and of enhancing this role through sustained and gradual liberalization.

The NAFTA's energy provisions incorporate and build on the General Agreement on Tariffs and Trade (GATT) disciplines regarding initiative restrictions on imports and exports as they apply to energy and basic petrochemical trade. The NAFTA provides that under these disciplines a country may not impose minimum or maximum or export price requirements, subject to the same exceptions that apply to quantitative restrictions. The NAFTA also makes clear that each country may administer export and import licensing systems, provided that they are operated in a manner consistent with the provisions of the Agreement. In addition, no country may impose a tax, duty or charge on the export of energy or basic petrochemical goods unless the same tax, duty or charge is applied to such goods when consumed domestically.

This section of the NAFTA also provides that import and export restrictions on energy trade will be limited to certain specific circumstances, such as to conserve exhaustible natural resources, deal with a short supply situation or implement a price stabilization plan. Further, when a NAFTA country imposes any such restriction, it must not reduce the proportion of total supply made available to the other NAFTA countries below the level of the preceding three years or other agreed period, impose a higher price on exports to another NAFTA country than the domestic price or require the disruption of normal supply channels. Based on a reservation that Mexico has taken, these obligations do not apply between Mexico and the other NAFTA countries.

NAFTA limits the grounds on which a signatory country may restrict exports or imports of energy or basic petrochemical goods for reasons of national security. However, based on a reservation that Mexico has taken, energy trade between Mexico and the other NAFTA countries will not be subject to this discipline, but will instead be governed by the Agreement's general national security provision.

The NAFTA confirms that energy regulatory measures are subject to the Agreement's general rules regarding national treatment, import and export restrictions and export taxes. The three countries also agree that the implementation of regulatory measures should be undertaken in a manner that recognizes the importance of a stable regulatory environment.

To promote cross-border trade in natural gas and basic petrochemicals, NAFTA provides that state enterprises, end users and suppliers have the right to negotiate supply contracts. In addition, independent power producers, CFE and

electric utilities in other NAFTA countries also have the right to negotiate power purchase and sale contracts. Each country will also allow its state enterprises to negotiate performance clauses in their service contracts.

Regarding investment in the electricity sector, Annex 602.3 of the Agreement restates, in more general terms, the types of private participation allowed in Mexico by the 1992 Electricity Law and its 1993 Implementing Regulations, which were described at length above. Regarding customs duties, the NAFTA requires that duties on all industrial goods, except as indicated by reservations and exceptions claimed by each country, are to be eliminated by 2003, using one of five staging schedules specified in the Agreement. Specific duties applicable to cross-border trade and investment in electricity are discussed in the following section.

Various commentators have speculated that NAFTA energy provisions are likely to result in a minor impact on U.S. electricity trade with Canada and Mexico over both the short and long term, primarily because the Agreement only addresses federal regulations, rather than state and provincial regulations concerning the generation and distribution of electricity. The state and provincial regulations tend to be more stringent and in most cases, supersede federal regulations.

(2) Taxes

(a) Income

Although many aspects of the income tax laws of the U.S. and Mexico are applicable to the type of investments relevant to this study, the most important of these from an investor's perspective is the avoidance of double taxation, which can occur when dividends from foreign investments are repatriated to the country of origin. The discussion in this section focuses on that aspect of taxation. There are also important tax considerations connected to the decision to acquire assets in a foreign country, which is one of the investment options considered in later sections, but these considerations are in general specific to the acquisition being considered.

Taxation of cross-border investments between the U.S. and Mexico is governed by the tax laws of the two countries, and by an income tax treaty that became effective on December 28, 1993.[40] The general purpose of such treaties is to avoid both double taxation and evasion of taxes by the signatory countries. Avoidance of double taxation is generally accomplished outside of the treaty by the use of credits for foreign taxes paid, which are a standard feature of most countries' income tax laws. Treaties clarify the use of such credits by allocating certain types of income to each country. They also reduce the effective rate of overall taxation by reducing withholding taxes on dividends, interest, royalties, rental payments and capital gains. Due to the particularities of the U.S. and Mexican income tax laws, the treaty is applicable in only one important respect relevant to cross-border investment in the electricity sector, as explained below.

Both the U.S. and Mexico allow the use of foreign tax credits. The credit allowed by the U.S. is capped at approximately the lesser of foreign taxes paid or the U.S. tax attributable to the foreign income. If the foreign tax on a dollar earned in Mexico is equal to or less than the U.S. tax that would be charged, that dollar will bear a total tax of 35 percent, the U.S. corporate tax rate. If the foreign tax is higher than the U.S. tax would be, no U.S. tax is charged, and the "excess" foreign tax can, under certain circumstances, be used to offset U.S. tax due on other foreign-source income. The U.S. taxes both corporate income and shareholder dividends, and imposes a 30 percent withholding tax on dividends repatriated to foreign shareholders. This rate has been reduced by the treaty to 5 percent, if the shareholder owns at least 10 percent of the equity in the foreign corporation, or 15 percent in all other cases (the 15 percent rate will decline to 10 percent after the treaty has been in effect for 5 years).

Mexico has a foreign tax credit which is also capped at the lesser of the foreign tax paid or the Mexican income tax attributable to the foreign income. The corporate income tax rate in Mexico is 34 percent. Unlike the U.S., however, Mexico has an integrated tax system, meaning that it does not tax shareholder dividends, and as a result has no dividend withholding tax. The only exception to this rule is if the amount of the dividend exceeds "previously taxed income", which is similar to the definition of earnings and profits in the U.S. In this case, the excess dividend

[40] Convention Between the Government of the United States of America and the Government of the United Mexican States for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income.

is grossed up by a fixed factor and taxed at the Mexican corporate tax rate. Treaty provisions for a maximum dividend withholding rate therefore do not generally apply to funds repatriated from Mexico to the U.S.

(b) Customs Duties

An import duty of two percent -- declining to zero in 1998 -- is currently charged on imports of electricity into Mexico. No duties are imposed on electricity imports into the U.S., nor on imports of natural gas, diesel, fuel oil or coal into either country. Some duties remain on imports to Mexico of certain capital equipment items used in generation and transmission facilities, but those duties will be eliminated by 1998, with a few exceptions.[41]

(c) Value Added Tax

Mexico imposes a value-added tax (VAT) on all goods and services consumed in Mexico. Since April 1, 1995, the rate charged has been 15 percent, calculated on an ad valorem basis. The VAT represents a one-time tax paid by the ultimate consumer. However, each business in the process chain from raw materials to finished goods is required to bill its customers for the VAT on its sales of goods and services (the "output" tax) and to pay the VAT on its purchases of goods and services (the "input" tax). Input taxes paid are then credited against the amounts due from its own activities. The net amount payable by each business is considered to represent tax on the value added by that business. Imported goods and services are subject to the VAT, which is calculated on the sum of the purchase price and any import duties levied. Exported goods and services are exempt.

In general, the VAT does not represent an additional cost to businesses in Mexico, because although all private and governmental enterprises are required to pay the tax to their suppliers, the amounts charged will normally be deductible from their own VAT liability. In the event that the activity of an enterprise is exempt from VAT, any taxes paid to suppliers will be deductible for income tax purposes.

(3) U.S. Department of Energy Licensing Authority

(a) Overview

The section provides an outline of the federal regulations governing applications for export authorizations and Presidential Permits.

Electricity exports are the subject of comprehensive regulation by the Deputy Assistant Secretary for Fuels Programs (DAS) of the DOE under the FPA. Section 202 (e) of the FPA provides that no person shall transmit any electric energy from the United States to a foreign country without first having secured an authorizing order. Executive Order No. 10485 provides that no person may construct, connect, operate, or maintain facilities for transmission of electricity on one of the borders of the United States without having secured a Presidential Permit. Under delegated authority, the DAS implements both programs. As noted above, however, this authority has recently been partially delegated to the FERC for a particular case, with an indication by the DOE that such delegation may occur in the future on a case-by-case basis.

Though the FPA requires that only the transmitter of electric energy across the border requires export authorization, the DOE has historically interpreted this provision to require that both the transmitter of energy and the owner of the energy must apply for and secure an order authorizing exportation. Since assignment of export authority to the DAS in 1989, this requirement has been interpreted, albeit on an informal basis, to require the last entity holding title to the electricity at the border to apply for the export authorization.

In exercising its Presidential Permit authority, the DAS coordinates with the Department of Defense and the Department of State, which are guided by considerations of national security and foreign relations, whereas DAS review has centered on technical system reliability and environmental issues. The DAS does not consider the economic desirability of the long-term transaction nor the price terms. It examines the contracts only for the

[41] Of the major pieces of equipment necessary for generation and transmission facilities, the following have tariffs that remain in effect: large boilers have a duty rate of 12 percent in 1997, declining to zero in 2001; electric motors and generators have a rate of six percent in 1997, declining to zero in 2003; and transformers have a rate of nine percent in 1997, declining to zero in 2003.

purposes of reviewing the coordination and reliability arrangements. In considering reliability, the DAS may request the views of electric utility industry regional reliability councils.

The DAS exercises the federal environmental review responsibility pursuant to the National Environmental Policy Act (NEPA). These cases involve high voltage transmission lines and may involve preparation of a full-scale environmental impact statement (EIS).

The governing standard under the FPA is that the DAS "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede the coordination of facilities" subject to FPA jurisdiction. This standard is generally referred to as the "reliability" standard.

Published regulations governing applications for both export authorization and Presidential Permits do not provide for public hearings on the Presidential Permit itself, but commonly allow hearings on the draft EIS. Because of the NEPA review process, the Presidential Permit application procedure takes far longer than the FPA procedure (with applicants often initiating the latter a year or more after the former has begun).

(b) Construction of Transmission Lines (Presidential Permits)

(i) Governing Regulations

Section 205.300(b) states that in connection with an application described in the discussion above, attention is directed to Sections 205.320 through 205.327, "concerning applications for Presidential Permits for the construction, connection, operation and maintenance, at the borders of the United States, of facilities for the transmission of electric energy between the United States and a foreign country in compliance with Executive Order 10485, as amended by Executive Order 12038." Id. at § 205.300(b). Section 205.320 provides that "any entity who operates an electric power transmission or distribution facility crossing the border of the United States ... shall have a Presidential Permit." Like the application for authority described in the previous section, an application for a Presidential Permit should be submitted to the DAS.

Section 205.321 states that "pursuant to the Department of Energy (DOE) responsibility under the National Environmental Policy Act, the DOE must make an environmental determination of the proposed action." The Rules add that if, as a result of this determination, an environmental impact statement must be prepared, the permit processing time normally will be 18-24 months. If no EIS is required, then a six-month processing time normally would be sufficient. 10 C.F.R. § 205.321.

Section 205.322 outlines the information that must be submitted with each application regarding the applicant, the transmission fines, and the environmental impact to be covered by the Presidential Permit. In addition to the same basic corporate information covered under Section 205.302 described above, the applicant shall also list all existing contracts that the applicant has with any foreign government, or any foreign private concern, relating to any purchase, sale or delivery of electric energy. Id. at § 205.322 (a). The applicant is also required to submit a technical description providing the following information: (1) number of circuits, with identification as to whether the circuit is overhead or underground; (2) the operating voltage and frequency, and, (3) conductor size, type and number of conductors per phase. Depending on whether the circuit is overhead or underground, there is additional information which must be provided. Id. at § 205.322(b)(1)(i)-(iii).

Section 205.322(b)(2) asks for a map of the facilities to be used, indicating ownership of the facilities at or on each side of the border. Section 205.322(b)(3) requires additional information if the application is for a bulk power supply facility operated at 138 kV or higher. Finally, Sections 205.322(c) and (d) require applications to contain information on the environmental impact for each routing alternative (described below), including a list of each flood plain, wetland, critical wildlife habitat, navigable waterway crossing, Indian land, or historic site which may be impacted by the proposed facility, a description of the minimum right-of-way width for construction, operation, and maintenance of the transmission lines and the rationale for selecting that right-of-way, and a brief description of all practical alternatives to the proposed facility and a discussion of the general environmental impacts of each alternative. Id. at § 205.322(c)-(d).

Presidential Permits are not transferable, and no substantial change shall be made in any facility authorized by permit or in the operation thereof unless or until such change has been approved by the DAS. Id. at § 205.323. The same annual reports required under Section 205.308(c), described above, must be filed if granted a Presidential Permit. Id. at § 205.325. The application fee is $150.00. Id. at § 205.326, and all applications are subject to the same continuing obligation to submit supplemental information as the DAS may deem pertinent. Id. at § 205.327.

All applicants for Presidential Permits are responsible for the costs of preparing any necessary environmental document, including an EIS, arising from the DAS's obligation to comply with the National Environmental Policy Act. The DAS will determine whether an environmental assessment (EA) or EIS is required within 45 days of the receipt of the Presidential Permit application.

Sections 205.328 and 205.329 provide two alternatives for NEPA compliance. If an EIS is required, the first alternative permits applicants to enter into contracts with independent parties to conduct an environmental review, subject to certain conditions. 10 C.F.R. § 205.328. The second alternative involves the DOE contracting to prepare the EIS, subject to certain conditions. Id. at § 205.329. If an EA is required, the applicant may be permitted to prepare it for review and adoption by the DAS under both alternatives or the applicant may follow either of the two alternatives discussed above. Whenever the DAS determines that a project is no longer economically feasible, or that a substantial financial burden would be imposed by the applicant bearing all of the costs of the NEPA studies, the DAS may waive the NEPA compliance procedures outlined above and perform the necessary environmental review, completely, or in part, with its own resources.

Finally, the Rules state that "prior to the preparation of any Presidential Permit application and environmental report, a potential applicant is encouraged to contact ERA and each affected state public utility regulatory agency to discuss the scope of the proposed project and the potential for joint state and federal environmental review." 10 C.F.R. §§ 205.328(d) and 205.329(c).

(ii) Implementation

The entity who owns the facilities used to carry the electricity across the U.S.-Mexico border must have a Presidential Permit to lawfully use the facilities for such purpose. If an entity enters into either a wheeling arrangement or purchase and resale arrangement with another entity who owns facilities that will be used to carry the cross-border electricity, that other facility owner will have to obtain a Presidential Permit.

If the border facility owner has an existing Presidential Permit, however, it may be used by the parties to cover the new transaction. Presidential Permits are subject to the same reliability conditions discussed above for export authorizations. Therefore, a transmitting entity would have to ensure that its proposed electricity transmissions do not violate the reliability clause contained in the existing Presidential Permit of the border facility owner.

Should an entity seek to construct its own facilities at the border, it would be required to obtain a Presidential Permit (there is no exemption for "instruments of the state"). Applications for new transmission lines require a comprehensive EIS which can be very costly, and can delay authorization to transmit cross-border electricity for 18 months to two years to allow for U.S. government review of the EIS.

(c) Export Licenses

(i) Governing Regulations

The federal regulations covering applications for authorization to transmit energy to a foreign country are embodied in Title 10 of the Code of Federal Regulations, Subpart W, Sections 205.300 through 205.309, 10 C.F.R. §§ 205.300 - 205.309. Section 205.300(a) states that "an electric utility who proposes to transmit any electricity from the United States to a foreign country must submit an application .... The application shall be submitted to the Office of Utility Systems of the Economic Regulatory Administration (ERA)." This authority has since been reassigned several times, and now resides with the DAS.

C.F.R. Section 205.301 states that each application should be made at least six months in advance of the initiation of the proposed electricity export, except when otherwise permitted by the DAS to resolve an emergency situation. Section 205.302 of the Rules also outlines the contents of the applications. In addition to basic corporate information (name, state organized or incorporated), the Rules request a description of the transmission facilities to

be used and a technical discussion of the proposed electricity export's reliability, fuel use and system stability impact on the applicant's present and prospective electric power supply system. Section 205.302(g) states that the "applicant must explain why the proposed electricity export will not impair the sufficiency of electric supply on its system and why the export will not impede or tend to impede the regional coordination of electric utility planning or operation." 10 C.F.R. § 205.302(g). When the application is for authority to export less than 1,000,000 kilowatt hours annually, applicants need not furnish information called for in Section 205.302(g) and the general and detailed maps described below in Section 205.303.

Section 205.303 provides that certain exhibits are required to be filed with each application, including: (1) a copy of the agreement or proposed agreement; (2) a showing that the proposed export of electricity is within the corporate power of the applicant, and that the applicant has complied or will comply with all pertinent federal and state laws; (3) a general map showing the applicant's overall electric system and a detailed map highlighting the location of the facilities to be used, identifying the location of the proposed border crossing point(s) or power transfer point(s) by Presidential Permit number whenever possible; (4) a statement of any corporate relationship or existing contract between the applicant and any other person, corporation, or foreign government, which in any way relates to the control or fixing of rates for the purchase, sale or transmission of electric energy; and, (5) an explanation of Operating Procedures to inform neighboring electric utilities in the U.S. of the available capacity and energy which may be in excess of the applicant's requirements before delivery of such capacity to the foreign. purchaser, 10 C.F.R. §205.303(a)-(f). In all events, applicants may be required to furnish supplemental information that the DAS deems pertinent, regardless of the amount of electric energy to be exported. Id. at § 205.304.

Section 205.305 provides that an authorization to transmit electric energy from the United States to a foreign country shall not be transferable or assignable. 10 C.F.R. § 205.305 (a). It also provides that the DAS may at any time subsequent to the original order of authorization, after opportunity for hearing, issue such supplemental orders as it may find "necessary or appropriate." Id. at § 205.305(c). Section 205.306 states that "no authorization ... shall be deemed to prevent an authorization from being granted to any other person or entity to export electric energy or to prevent any other person or entity from making application for an export authorization." In other words, issuance of an export authorization is not akin to grant of a franchise.

Section 205.308 requires annual reports to be filed with the DAS, by February 15 of each year, covering each month of the preceding calendar year, detailing the gross amount of kilowatt-hours of energy, by authorized category, received or delivered, and the cost and revenue associated with each category. Id. at § 205.308(c). Finally, there is a $500.00 application fee, payable to the Treasurer of the United States, required for each application. Id. at § 205.309.

(ii) Implementation

Unless the last entity taking ownership in the electricity crossing the border is an "instrument of the state," the DAS routinely has required that such entity obtain an export authorization. DAS determinations of whether an entity is an "instrument of the state" are made on an informal, case-by case basis. Section 202(e) of the FPA provides that " ... no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so." Municipalities and political subdivisions of the states are not a "person" subject to Section 202(e). "An electric utility or other entity subject to DOE jurisdiction under part II of the FPA who proposes to transmit any electricity from the U.S. to a foreign country must submit an application or be a party to an application submitted by another entity." 10 C.F.R. § 205.300(a) The FPA defines "electric utility" as "any person or state agency (including any municipality) which sells electric energy ... " FPA, Section 3(22). Municipalities and political subdivisions of a state, will probably be exempt from obtaining an export authorization. However, this is by no means certain and a ruling on the issue would have to be obtained from the appropriate agency

With regard to identification of the last entity taking ownership in the electricity crossing the border, two hypothetical cases are instructive. First, if the utility holding title enters into a wheeling arrangement with one or more U.S. utilities in order to transmit the electricity to the border, and title does not pass to either of the wheeling party(s), then the utility holding title must obtain an export authorization (assuming a jurisdictional exemption is not given by the DAS). Second, if the utility holding title enters into a "purchase and resale" arrangement with another U.S. utility to transmit the electricity to the border, then the latter entity, having received title to the electricity, would be required to obtain the export authorization (again, assuming that the latter entity is not exempt).

(iii) Filing Process

Once the application for export authorization is filed with the DAS, public notice of the filing is placed in the Federal Register and the application is subject to a 30-day public comment period. If there are no comments, opposition, or requests for intervention by the end of the 30-day period, the DAS reviews the application under a single criterion -- "electric reliability," as discussed earlier. If the applicant's reliability showing is sufficient, or if the DAS and the applicant can easily cure any deficiencies in the initial showing, then the DAS usually issues the export authorization within 2 months from the data of the filing of the application.

The DAS considers two factors in assessing the "electric reliability" effects of the proposed arrangement: (1) whether the applicant has adequately demonstrated that it has sufficient supply resources; and, (2) in the course of moving the electricity across the border, how the regional transmission system will load up or respond to the transmission. As to the former factor, the DAS will consider it met if the arrangement between the U.S. entity and the foreign entity condition their contract on transmitting electricity only up to the point where the U.S. entity's reliability (or sufficient supply resources) is compromised. As to the latter factor, DAS looks to technical and operational issues related to power flow. Applicants submit complex, technical studies (usually elaborate computer programs) to demonstrate the latter factor.

Finally, if an export authorization is required, it need not be limited to a single sale, but may be crafted to accommodate the contractual arrangement with CFE; in that regard, a "blanket" authorization was recently issued to the WSCC and its 23 members for exports to BC Hydro, in which the DAS agreed to flexible terms regarding the effectiveness of the authorization (initial term of 2 years with opportunity to extend) and use of maximum supply limits.

(4) Secretaría de Energía Licensing Authority

There is no special permit for export required in Mexico. The authority to export is contained within the generation permit granted by the CRE, which is discussed in detail below.

b) Dispute Resolution

This section discusses the various methods of dispute resolution available to participants in cross-border trade and investment relationships in the electricity sector. Dispute resolution considerations concerning other types of international commercial arrangements, for example vendor contracts, labor contracts, consulting contracts, etc., are not addressed. There are three basic methods for the resolution of contractual disputes: mediation, arbitration and litigation. Each of these methods is considered in the sections below.

(1) Mediation.

Mediation is a method whereby the parties, either using their own representatives or employing the services of a neutral third party, attempt to come to an agreement as to how their dispute should be resolved. A good guide for describing how a typical mediation proceeding would work is Mediation, Dispute Resolution Directory 1996 ("MDRD"). The principle features of mediation can be summarized as follows:

- Mediation is generally voluntary. Id. However, some U.S. courts require mediation before a case may be litigated.
- Mediation is non-binding. MDRD 96, at 3-19.
- A mediator has no authority to impose a decision. Rather, a mediator guides the parties through the negotiation process, advising, listening to both sides, and helping the parties to arrive at a settlement. Id.
- Mediation can be required by a contract provision or can be agreed to in the absence of a contract provision on an *ad hoc* basis.
- There are professional mediation services that can be employed. Martindale-Hubbell's Dispute Resolution Directory 1996, at 5b-4, has a listing of organizations, including law firms, which may be hired as professional mediators.

- Generally, the expense of mediation is shared equally between the parties.
- The professional mediator is usually someone knowledgeable in the area of dispute so that he or she has some understanding of the issues. Id. at 3-21.
- Mediation is flexible, and often, informal. Id. at 3-19. However, the process is often governed by procedures and rules already established by professional dispute resolution organizations such as the American Arbitration Association. Id.
- Mediation is usually quick and efficient. Id.

(2) Arbitration.

Arbitration is a quasi-judicial means of dispute resolution. It is usually voluntary on the part of the parties and may be binding or non-binding, depending on the agreement of the parties. In arbitration, the arbitrators are expected to hear both parties' evidence and then arrive at a decision. The process of arbitration is similar to that followed in a court proceeding but without the accompanying formalities.

Mexico and most states in the U.S. have uniform arbitration acts which provide a general procedure for arbitration. Arbitration procedures in most states are very similar. Since Arizona's arbitration statute is typical of the majority, it is used here to provide an indication of the features of such statutes.[42] Arizona, along with a number of other states, has adopted the Uniform Arbitration Act. Uniform Laws Annotated, Master Edition, Volume 7; A.R.S. § 12-1501-1518. Arizona law requires the parties to a suit to submit to arbitration if the amount in controversy is less than fifty thousand dollars. A.R.S. § 12-133(A). However, a court may waive this compulsory arbitration requirement upon a showing of good cause. A.R.S. § 12-133(B). Also, parties by agreement may voluntarily submit themselves to arbitration regardless of whether suit has been filed. A.R.S. § 12-133(D). Under Arizona's arbitration laws:

- Arbitration awards are valid, and enforceable. A.R.S. § 12-1501.
- Arbitrator fees are paid out of the arbitration award, unless provided otherwise.
- Parties to the arbitration may appeal the decision or challenge the award. A.R.S. § 12-133(H); A.R.S. § 12-1512.
- Courts may confirm, modify or correct an arbitration award, and thereafter, the award is enforceable to the same extent as any other judgment or decree. A.R.S. § 12-1514.

In Mexico, Title Four of Mexico's Código de Comercio (Mexican Commercial Code) entitled Commercial Arbitration, sets forth the procedures and rules regarding arbitration. Mexican Commercial Code §§ 1415-1463. The following list summarizes many of the important aspects of Mexican arbitrations:

- The arbitration provisions in the code are applicable to National and International arbitration in Mexico, unless otherwise provided by other laws or treaties. Mexican Commercial Code § 1415.
- An agreement to arbitrate may be contained in a contract or may be an independent agreement. Mexican Commercial Code § 1423.
- Under the Mexican Commercial Code, parties may agree as to where the arbitration will take place (§ 1438), the procedures (§ 1435), who the arbitrator or arbitrators may be (§ 1426), the language to be used (§ 1438), the law to be applied (§ 1445), and how costs will be assessed (§ 1454).
- An important difference between the Mexican arbitration provisions and the typical U.S. arbitration provisions is that in Mexico the arbitration award must be in writing, and must set out the reasoning supporting the arbitration decision. Mexican Commercial Code § 1448.

[42] If arbitration is required in a state other than Arizona, that state's specific laws should be reviewed.

The parties to an arbitration can make reference in the contract to the uniform arbitration procedures of whatever jurisdiction they want to use. Under both Mexican and U.S. laws, the parties can by agreement design their own procedures for arbitration in an arbitration clause. These procedures might include:

- Location to hold arbitration hearing
- Makeup of the arbitration panel (does not have to include lawyers)
- Discovery of documents and testimony to be allowed
- Language in which the proceeding will be conducted
- Whether the decision of the arbitrator or arbitrators will be binding or non-binding
- Substantive law that will apply
- If binding, the court system which the parties agree will be used to seek an order enforcing the terms of the arbitration findings
- The allocation of the expenses of the arbitration

There are also public and private arbitration associations and forums that can be employed, including a number of international groups that have arbitration services, such as:

- Inter-American Convention on International Commercial Arbitration (1975)
- Swedish Arbitration Act (1929)
- Model International Commercial Arbitration Rules (UN Commission on International Trade Law)(1976)
- Model Law on International Commercial Arbitration (UN Commission on International Trade Law)(1985)
- European Convention on International Commercial Arbitration (1961)
- Rules of the Court of Arbitration of the International Chamber of Commerce
- American Arbitration Association: International Arbitration Rules

An additional consideration regarding arbitration is that it is usually not open to the public, nor a matter of public record. This is in contrast to litigation, which is usually both open to the public and a matter of public record.

(3) Litigation.

For the type of commercial arrangements evaluated in this study, the resolution of disputes using litigation would take place in Mexican federal or state courts or United States federal or state courts. The following sections outline some of the key issues regarding litigation as a dispute resolution mechanism.

(a) Jurisdiction.

The parties may not stipulate to bestow subject matter jurisdiction on Mexican courts or United States courts. Depending on the nature of the contract or the nature of the behavior that gives rise to the dispute, it would be possible for the Mexican courts to have jurisdiction over the subject matter and the person of the U.S. contracting party and possible for a U.S. court to have subject matter jurisdiction over the dispute and personal jurisdiction over the CFE.

The jurisdiction of Mexican courts over commercial transactions has the following characteristics:

- Mexican courts have the power to resolve and decide controversies that derive from commercial transactions. Mexican Commercial Code § 1049.

- If a transaction has a commercial impact on one party and is of a civil nature for the other party, the transaction is governed by commercial law. Mexican Commercial Code § 1050.
- If foreign merchants engage in commercial operations within Mexico, they submit themselves to the Mexican Commercial Code and all the laws of Mexico. Mexican Commercial Code § 14.
- Foreign entities which are established in the Mexican Republic are subject to the jurisdiction of the Mexican tribunals. Mexican Commercial Code § 15.

In the U.S., subject matter jurisdiction is determined by statute:

- Federal district courts have original jurisdiction over civil matters arising under the Constitution, laws and treaties of the U.S. 28 U.S.C. § 1331.
- Federal district courts also have jurisdiction where the amount in controversy exceeds $50,000 and the dispute is between parties of different States. 28 U.S.C. § 1332(a)(1). Likewise, there is jurisdiction if the amount exceeds $50,000 and the dispute is between a citizen of the U.S. and a subject or subjects of a foreign state. 28 U.S.C. §§ 1332(a)(2).
- Federal district courts have original jurisdiction without regard to the amount in controversy of any non-jury civil action against a foreign state. 28 U.S.C. § 1330.
- Foreign states are afforded certain jurisdictional immunities. 28 U.S.C. §§ 1604. However, there are general exceptions to the jurisdictional immunity afforded foreign states. 28 U.S.C. §§ 1605 and 1607.

(b) Language.

If a contract is to be interpreted and a dispute resolved in a Mexican court, the contract must be in Spanish, and if the dispute is resolved in a U.S. court, it must be in English. A part of a legal dispute can include a dispute as to the correct translation from English to Spanish or Spanish to English. Thus, prior to entering a contract the parties should agree on a translation in both English and Spanish to avoid future disputes over the translation.

(c) Service of Process.

To serve a complaint on the CFE for an action pending in the United States requires the assistance of the Mexican court system. To serve a complaint on a U.S. contracting party for an action pending in a Mexican court requires use of the provisions of Hague Convention:

- Under the Inter-American Specialized Conference on Private International Law of 1975, a court of competent jurisdiction of Mexico or the U.S., in conjunction with proceedings in civil or commercial matters, may issue Letters Rogatory (Letters of Request) to another court of competent jurisdiction for service of process abroad.
- In Mexico, the Mexican Consulate in the area of the issuing court will certify that the documents are legal and that the issuing court had jurisdiction over the matter.
- The Letters of Request and Service Agreement must be translated into Spanish or English by a court certified interpreter. Mexican Commercial Code § 1074.

(d) Evidence

Discovery of evidence in Mexico is far more restrictive than in United States. Accordingly an action pending in a Mexican court would involve less discovery than the same action pending in a U.S. court. Specific aspects of each country's evidence rules are summarized in the following list:

- The Mexican Rules of Evidence are found in the Mexican Commercial Code §§ 1194-1210.

- Under the rules the Mexican judge is afforded much discretion as to what evidence is admissible in the proceedings. The code lists specifically the types of evidence recognized under the law. Mexican Commercial Code § 1205.
- The Mexican evidentiary rules put limitations on time for presenting evidence, distinguishing between evidence inside and outside the state where the action is pending. Mexican Commercial Code § 1206-1210.
- Unlike the U.S., Mexico also allows for tribunal to tribunal requests for evidence. Mexican Commercial Code § 1240.
- The U.S. refused to ratify the provision of the Inter-American Specialized Conference on Private International Law of 1975 which allowed certain procedures for the taking of evidence by foreign tribunals.
- However, the U.S. would probably use the Hague Convention procedures regarding the taking of evidence. Under these procedures, the courts would transmit letters through the Central Authority of Mexico.
- Mexico, as do most other countries, views discovery as a means to prove cases, not as a search for evidence to establish or find the basis for a case. Thus, the Mexican courts, not the litigants, control discovery.
- Under the Hague Convention, parties may not discover more in evidence in Mexico than if the case was pending in Mexico.
- In the U.S., both federal and state rules of evidence are construed very broadly. The main standard for the admissibility of evidence is relevance. Fed. R.Evid., Rule 402. However, the U.S. courts must follow very complex rules regarding hearsay evidence.
- Likewise, in the U.S. the discovery rules are very liberal. The standard for discovery is whether the information sought is reasonably calculated or likely to lead to the discovery of relevant evidence. Fed.R.Civ.P., Rule 26; Ariz.R.Civ.P., Rule 26.
- Mexico allows for document requests if:
  - a court proceeding is pending;
  - the documents are identifiable as to the date, subject, and other reliable information;
  - the request, on its face, demonstrates a direct relationship between the evidence being sought and the issues in the pending proceeding.

(e) Choice of Forum and Choice of Laws.

The parties can agree to the choice of forum and can agree as to what substantive law would apply, but cannot stipulate subject matter jurisdiction if it does not otherwise exist. Mexican Commercial Code § 1093. In the absence of an agreement, the court hearing the case would decide on the substantive and procedural law to be applied.

(f) Judgments.

(i) Enforcement in the U.S.

When a party to a dispute receives a judgment, if it is a Mexican judgment to be executed in the United States, there are procedures that have to be employed to secure a U.S. judgment based on the Mexican judgment. When a U.S. judgment based on the Mexican judgment is obtained, the U.S. judgment is enforced against the U.S. entity. Enforcement of Mexican judgments in the U.S. may differ from state to state within the U.S. However, the overall process is likely much the same. As an example, the following are the procedures which must be followed to enforce a Mexican judgment in Arizona[43]:

[43] Arizona is used only as an example. If a judgment is going to be enforced in the U.S., the specific laws of the state where enforcement is to take place should be reviewed.

- First, the Mexican judgment must be authenticated or certified by evidence sufficient to support a finding that the matter in question or the judgment is what in fact it purports to be.
- Second, the judgment must be presented to a diplomatic official of the U.S. to authenticate the certification by the Mexican official.
- Third, the judgment must be translated into English. Translation creates an opportunity for dispute over the correctness of the translation.
- Fourth, the judgment creditor must offer proof that the Mexican court had jurisdiction over the judgment debtor and the subject matter of the claim. It is likely that the Mexican creditor would have to show that enforcement of the Mexican judgment in Arizona would not violate public policy or Arizona law.
- The enforcement proceeding could be administered in the state court as a Motion for Summary Judgment. The court could decide all matters by affidavits, however, an evidentiary hearing with witnesses and translators will probably be required by the court if the affidavits are contested or if the judgment is not allowed by motion.

(ii) Enforcement in Mexico

If the judgment is for a U.S. entity in a U.S. court, in order to be enforced in Mexico that judgment must be filed in a Mexican court and an order allowing the enforcement of the judgment received from a Mexican court. This would also be true if it were an action on a dispute, or an action to enforce an arbitration award. The procedures for enforcement of a U.S. judgment in Mexico are as follows:

- The first step is to obtain a conformed, certified copy of the U.S. judgment, and the documents establishing proper service of process on the Mexican defendant, and have them translated into Spanish. The judgment must be a final judgment, meaning that the time for any appeal must have run. The judgment on its face should recite the circumstances which establish the court's jurisdiction over the matter, and the facts establishing the entitlement to judgment, as well as state that appropriate service of process has been made on the defendant. It is important that the factual circumstances that gave rise to the dispute which resulted in the judgment would not violate the public policy of Mexico.
- Second, the judgment and documents should be presented to the Mexican Consulate in Arizona. The party should request a notarized statement from the Mexican Consulate based on their review, that the documents are valid, legal, and properly issued by an Arizona court. This certification must be in Spanish. The judgment and documents may also be certified by the U.S. State Department Council General's Office and then processed to the Mexican Foreign Ministry for validation and certification.
- Third, after the judgment and documents have been certified, the judgment creditor must make a request to a court of competent jurisdiction in Mexico to enforce the judgment. The request, called an Exequatur, must set out all the foregoing circumstances and include the names and addresses of both the parties seeking to enforce the judgment and the party against whom the judgment is to be enforced.
- Fourth, the exequatur and all the supporting documents, which include the certified, original English version of the judgment and supporting documents, a Spanish translation of the judgment and supporting documents, and the verification from the Mexican Consulate, must then be filed in the Mexican court which has jurisdiction over the defendant.
- Fifth, all of these documents must be served on the defendant in Mexico. If the defendant objects in a timely manner, a hearing will be conducted and the court could potentially address whether the Arizona court had appropriate jurisdiction, whether service of process was properly made on the defendant, whether defendant is liable and the judgment should be entered against him, whether the judgment has arisen under circumstance which violate Mexican public policy, and/or whether the translation from English into Spanish was accurate.
- If the court rules in favor of the defendant, a Mexican judgment allowing enforcement of the Arizona judgment will not be issued.

- If the Mexican court agrees with the plaintiff, then it issues a judgment ("Sententia") allowing for enforcement of the Arizona judgment in Mexico. The Sententia is then enforceable in Mexico as a Mexican judgment, and if the defendant has any locatable property or money, the plaintiff may collect. These rulings are subject to an appeal process much like in the U.S.

(g) Damages.

Generally speaking, the scope of damages resulting from litigation in Mexico is not nearly as great as that in the United States. For example, punitive damages and treble damages awards are generally not allowed in Mexico and under some circumstances may be allowed in the United States. However, Mexican law like U.S. law, does provide for liquidated damages in limited circumstances, mainly when the amount of actual damages is uncertain.

(h) Costs Incurred.

As a general rule, the costs incurred in pursuing the litigation, whether in the U.S or Mexico, will be borne by the non-prevailing party. Fed.R.Civ.P., Rule 54(b); Mexican Commercial Code § 1082. If there are attorneys involved in the commercial dispute, an assessment of costs includes the prevailing parties attorneys' fees. Fed.R.Civ.P., Rule 54(b); Mexican Commercial Code § 1083.

3. Technical and Economic

This section provides a brief review of technical and economic issues affecting cross-border trade and investment.

a) Systems-Related Issues[44]

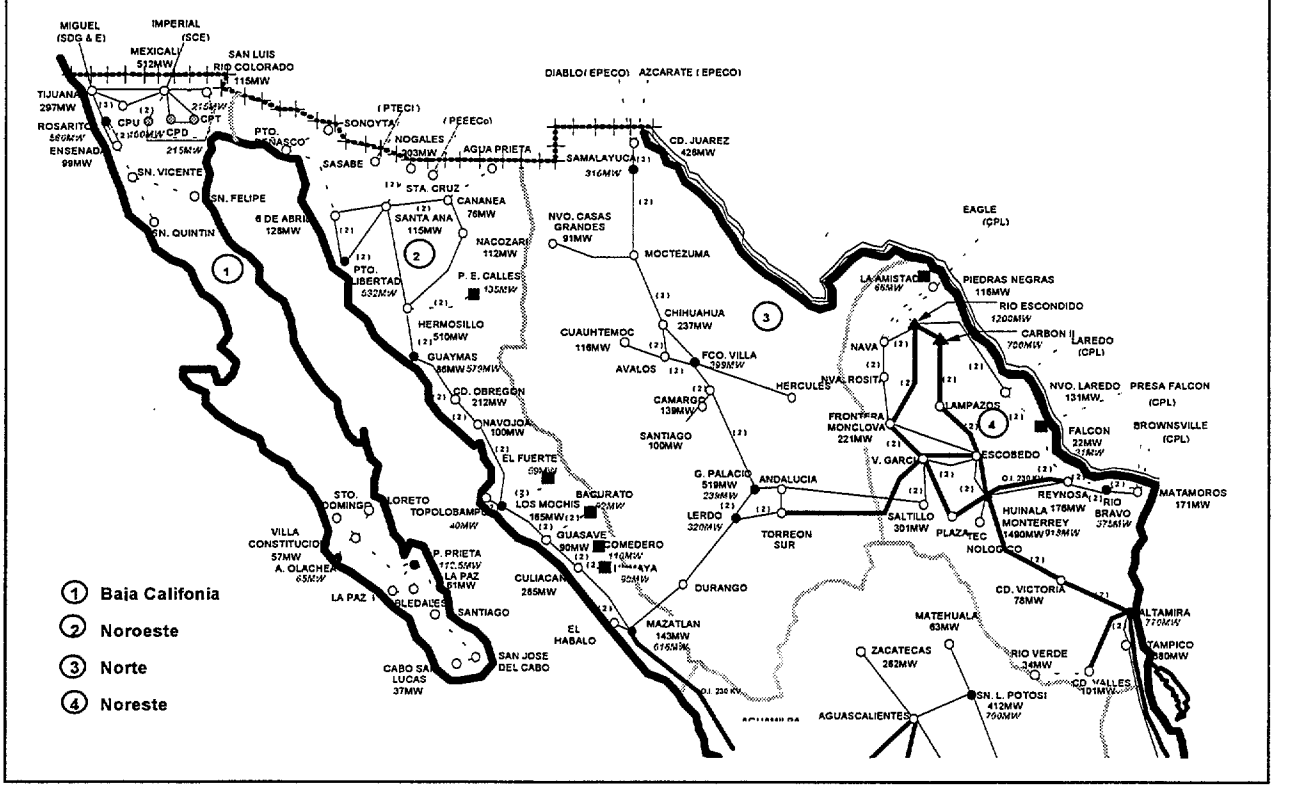
(1) Interconnection and Available Transmission Capacity (ATC)

There are 13 electrical interconnections between the U.S. and Mexico, as illustrated in Figure 9. Total transfer capability is less than 900 MW, including 150 MW which is operated in a normally open mode The two 230 kV interconnections between San Diego Gas and Electric and CFE can handle 408 MW. Two interconnections between CFE and El Paso Electric are 115 kV with a combined capacity of 200 MW. Three interconnections between Central Power & Light and CFE are 138 kV with a transfer capability of 150 MW but are operated in a "normally open" mode. There are four 69 kV interconnections with a total transfer capability of 120 MW, and two distribution connections with a combined capacity of only 14 MW. Minor improvements could be made to expand emergency services but a material increase in cross-border trade will require a significant expansion of existing transmission capacity.

[44] This section draws heavily from the DOE-SE Study.

The WSCC maintains information on maximum path transfer capabilities within its system.[45] Detailed information on available transmission capacity will be available for both the WSCC and ERCOT systems on the OASIS as soon as it achieves full operational status.

Figure 9: Mexico-U.S. Interconnections



(2) Stability and Synchronization

All generators in an electrical generating system rotate in synchronism. In the U.S. and Mexico they rotate at a nominal 60 Hertz, or cycles per second The aggregate load plus system losses must be in balance with the total power produced by the generators to maintain this frequency. The CFE, ERCOT and WSCC systems are currently not synchronized with one another. While all are 60 Hertz systems and the generating units within each are synchronized, the systems are not synchronized with each other. Expansion in cross-border trade will require addressing this issue through either direct current (DC) back-to-back facilities or isolating a portion of either the Mexico system or the U.S. system.

Stability of a generating network is the ability of all the generating units within the network to stay synchronized. Failure of multiple transmission lines can cause individual generators to speed up or slow down. When generators in the system speed up or slow down in relation to each other, the generators are out of synchronism and the system becomes unstable. Stability must be considered in the design of any new transmission lines.

(3) Reliability and Operating Standards

Reliability of an electrical system is the ability to provide electricity of the appropriate voltage and frequency and to avoid interruption of service. Quantitative standards can be used to describe the reliability of a system. Loss of load probability (LOLP), the N-1 or N-2 performance standard (ability to continue operating if the most critical

[45] Technical Studies Subcommittee of WSCC, WSCC 1996 Path Rating Catalog, WSCC, Feb. 1996.

component of the system fails, or the two most critical components fail, respectively); and the generation reserve margin [reserve margin = (generating capacity-peak load)/peak load] are three of the most common quantitative standards.

Achieving increased reliability is generally a function of cost. By spending more on generation, transmission and distribution resources, redundancy can be increased and reliability improved. The preferred levels of reliability may vary by customer. Some customers may have needs that suggest they would be willing to pay more for more reliable systems. Others may prefer to pay lower prices at the expense of some of the reliability they currently enjoy. Some U.S. systems are more reliable than prescribed by the standards. This is due in large part to surplus capacity that was planned and built to meet high load forecasts that have not occurred.

Establishing a permanent tie between the U.S. and Mexico would be accomplished through either a DC or an alternating current (AC) interconnection. A partial solution with an AC tie would cost significantly less but would require that a portion of either the U.S. or Mexican system be isolated in order to be operated in synchronism with the foreign system. System reliability with a DC interconnection would be enhanced relative to the AC option. The systems would not have to operate in synchronism and therefore there would be no isolation of a part of either system required.

In comparison, costs of a DC interconnection are significantly higher than those for an AC interconnection. A DC tie would allow for more reliability. Consumers on both sides of the border potentially benefit from the additional reliability possible by being connected to generating plants on both sides of the border. An AC tie, by its nature, means electricity trade would be limited to the region which operates in synchronism with the foreign system. The geographic area of trade would therefore be more open with DC interconnection.

b) Project Development Issues

This section outlines three important project development issues for new generation and transmission projects in either country: project economics; financing considerations; and the approval process for permits other than those described above.

(1) New Generation

(a) Economics

A new combined-cycle gas turbine (CCGT) plant will cost approximately $650 per installed KW, and can produce energy at the busbar at roughly $35 per mWh. Fuel, capital costs, capital recovery period and plant size are key determinants of the busbar price. Siting a plant in the U.S. vs. Mexico involves a number of issues which will vary by location within each country, as well as between countries. Cost of capital, access to fuel (transportation costs), access to the market (transmission costs), the environmental approval process and time involved to obtain necessary permits and right-of-way may differ depending on the location and country in which the plant is located.

(b) Financing

There are several important financing considerations regarding the construction of a new generation plant in the border region: country location (Mexico or the U.S.); ownership (government, IOU, IPP or APP); project finance[46] "mode", if applicable (Build-Own-Operate, Build-Own-Operate-Transfer, Build-Lease-Transfer, etc.); and off-take arrangement (long-term PPA, "merchant" plant, or combination). Each of these issues is discussed below.

Country Location -- All other things equal, a generation project located in Mexico will be perceived by the investment community as more risky than one in the U.S., and will therefore require a higher return on equity and interest rate on debt. The exact amount of this difference is specific to the project and to the economic conditions prevailing in each country at the time of financing. As a rough approximation, however, a privately financed project in Mexico could be expected to require an after-tax equity return five to 10 percent higher than in the U.S., and to

[46] Project finance refers to a financial arrangement in which the project's debt is secured only by the expected cash flows of the project, rather than by the greater corporate assets of the developer, which is the norm in corporate finance. Such debt is deemed to be non-recourse or limited-recourse, because the lenders have no or limited recourse to the assets of the borrower.

pay interest rates two to six percent higher. The term of debt available would also likely be shorter than for a plant in the U.S. by three to five years.

Offsetting this disadvantage to siting a project in Mexico, such projects will have access to a variety of loans, guarantees and development funds from bilateral and multilateral institutions that are not available for projects built in the U.S. Bilateral sources include the U.S. Export-Import Bank (EXIM) and other bilateral export-import banks, the U.S. Trade and Development Agency (TDA), the International Finance Corporation (IFC, the private sector arm of the World Bank), and the International Investment Corporation (IIC, the private sector arm of the Interamerican Development Bank). Additional programs are offered by the U.S. Overseas Private Investment Corporation (OPIC) and the World Bank's Multilateral Investment Guarantee Agency (MIGA), but these programs are not currently available in Mexico because Mexico is not a signatory to the MIGA conventions.

An additional consideration is currency convertibility, assuming that the capital for a generation project would come largely or partly from hard currency countries. There are currently no long-term financial instruments available to reduce exchange rate risk between the Mexican Peso and the U.S. Dollar or other hard currencies. As a result, an investor supplying dollars to a project in Mexico would require either an additional return to account for the risk of devaluation, or the indexation of the capacity portion of the tariff to the exchange rate.

Finally, location will have an impact on the tax consequences of a generation project. As noted in earlier sections, Mexico and the U.S. have signed a Tax Treaty that largely eliminates intentional double taxation. However, the tax laws in each country result in potentially large differences in taxation for a given year, which can result in a situation where taxes paid in the country where the project is located may not be fully deductible from taxes owed in the home country of the investor.

Ownership -- Ownership will have a significant impact on the financing that can be obtained for a project. CFE, for example, has access to on-lending from multilateral development institutions at preferential rates, although it must compete for those funds with other government entities. IOUs will finance projects with their own retained earnings and long-term bonds, which generally have relatively high investment ratings and correspondingly low interest rates. IPPs and APPs will rely on their own and other equity contributions, as well as debt that typically comes from a variety of sources. These independent developers will generally use a project finance structure, which results in higher debt and equity costs than those available to IOUs, but also utilizes a more leveraged capital structure, which tends to reduce the overall cost of capital for the project. The net effect of ownership on overall financing costs is therefore project specific, but should be considered carefully.

Project Finance Mode -- If a project is constructed on a project finance basis, the specific arrangement used can affect the overall cost of the project. One important distinction is between projects that are owned and/or operated by the developer -- e.g., Build-Own-Transfer (BOT) or Build-Own-Operate-Transfer (BOOT) -- and those that are built by the developer and then leased to the utility buying the power -- i.e., Build-Lease-Transfer (BLT). As a general rule, the more risk borne by the developer, the higher the resulting cost of capital; BOT and BOOT projects would therefore have higher costs of capital than BLT, since the developer assumes the risk of operating the plant.

Off-take Arrangement -- If a project is developed using a project finance structure, the arrangement for selling the capacity and energy provided by the plant will have an impact on the financing terms that can be obtained. As a general rule, more security is better, so a long-term PPA will result in a lower cost of capital. Such PPAs are increasingly difficult to obtain in the U.S., however, with the result that some facilities have been announced that will function as "merchant plants", selling all or part of their output on the competitive wholesale market. This type of arrangement is obviously much riskier than a long-term PPA, and will therefore raise the project's cost of capital.

(c) Approval Process

(i) U.S.

The most important permits required to build generation in the U.S. are those that relate to air emissions and other environmental matters. Various general business permits and licensees are also required, but these are generally perfunctory, and may be quickly obtained at little cost.

With some state-by-state and local variations, the environmental permitting process for new generation is generally the same in all four border states. Using the example of a 450 MW gas-fired CCGT plant, the level of emissions

would classify such a facility as a major emissions source, requiring local, state and federal approvals. The minimum time to obtain such approvals will be 18 to 24 months *after* the key permit applications have been "deemed complete" by the lead permitting agencies. Permit preparation time has to be added to this figure, bringing the total permitting cycle to between 24 and 40 months, depending on site-specific conditions.

Any power plant permitting process is highly site specific, and can not commence until after a site has been selected. In the site selection process, important factors that may influence the difficulty of obtaining a permit include the distance to interconnecting power lines and gas lines, and proximity to other (particularly residential) development, as well as to national parks, monuments or other environmentally sensitive areas.

The major environmental permits required include the following:

Environmental Impact Assessment -- Nearly all jurisdictions require filing of an EIA for a major air pollution source -- i.e., over 100 tons of NO_X per year, which would include most generation stations -- to evaluate the project's environmental impacts and planned mitigation measures. Subjects studied include air emissions, geological and historical impacts, additional traffic, construction, noise and visual impacts, water use and discharge requirements and regional socio-economic impacts. Information gathering and report drafting normally takes between four to six months. The approval process can take between 12 to 18 months and includes public hearings in most cases. Approval of the EIA is normally given only after all other statutory permits have been issued.

Major Air Permit—This permit will normally determine the overall preparation period required for the entire permitting process. There are two questions which determine the length of this process:

- For major emission sources, the Environmental Protection Agency (EPA) makes the final decision on the permit, which adds up to eight months to the state approval cycle of 18 months, after the application is deemed complete.
- Pre-permit air monitoring may be required, including up to 12 months of site-specific meteorological data collection and air dispersion modeling. The monitoring is usually required for remote sites where little historical information is available. The actual scope and length of monitoring time can be a matter of negotiation, but requires the submission and approval of a plan before a determination can be made. The maximum time that would be required for this process is about two months for monitoring protocol preparation plus four months for approval and negotiations.

To summarize, the air permitting cycle may consist of the following:

Meteorological site monitoring and dispersion modeling:	4 to	16 months
Air permit preparation and approval, state and federal:	21	24
Total	25 to	40 months

Local Permitting—Local jurisdictions have a major input into the EIA, particularly since local interest groups may express significant opposition to a project. While the municipality does not have the final decision on the EIA, it does have the right to approve a project within its jurisdiction. This is particularly the case if the site is located in an area that is not zoned for heavy industry, which a power plant would be considered to be. To obtain a zoning change or other local permit usually takes between nine to 12 months, and is done in parallel with other permitting activities. The actual permit may not be issued until the EIA is approved.

Water Use Permit—The difficulty in obtaining water use permits is normally related to the amount of water available at a particular site. Once water rights are obtained, a state use permit can usually be obtained within nine to 12 months.

Effluent Discharge—Water discharge permits are obtained from state authorities and require proof that certain maximum chemical and contamination levels will not be exceeded. CCGTs generally do not have high amounts of water or other liquid discharges. This permit usually requires six to nine months to obtain.

Hazardous Wastes—There are usually very limited amounts of hazardous wastes from a CCGT plant. A disposal plan for those wastes is covered by the EIA, and this plan is generally the only requirement if actual disposal is

contracted to a competent firm. Additional requirements may be imposed on storage of chemicals and oils. Permits for hazardous wastes are usually an administrative matter with relatively short lead times.

(ii) Mexico

CFE bases its legal opinion regarding permits and licenses for external power producers on the 1992 Energy Law and its 1993 Implementing Regulations, as follows.

Self-supply, cogeneration, independent power production, generation for electric power exports, and imports with the purpose of self-supply are activities that require prior permission from the CRE. Once permits are granted, they are valid indefinitely except for independent power producers, which are valid for up to 30 years.

The external power producers must request prior authorization from the CRE to generate electric power under different conditions from those in the permit. Changes in use of the electric power generated shall require issuance of a new permit.

When a generating plant belongs to various owners, the permit shall in turn be granted to all interested parties, who shall in a convincing and attesting manner designate a common representative before the CRE, with sufficient power to act on behalf of the joint owners, and they shall jointly and severally assume responsibility to comply with the 1992 Energy Law, the 1993 Implementing Regulations and the conditions established by the respective permits.

The licensed suppliers shall take the necessary steps for compliance with official Mexican standards and shall assume the risk stemming from any circumstance that might obstruct or modify the operating condition of the generating plant and the availability of power from the same.

The CFE, in all cases protecting the general interest and safety, efficiency and stability of the public utility, may grant permits for each of the activities referred to in this section, as well as for the exercise of various other activities. In addition, it may authorize the transfer of rights derived from the permits and impose appropriate conditions according to provisions of the 1992 Energy Law and the 1993 Implementing Regulations.

Applications for permits shall be presented to the CRE in accordance with formats provided by the CRE and must contain the following information:

- Name, firm name or trade name and location of the applicant
- Purpose of the permit and, when applicable, the time frame proposed by the applicant
- Location of the plant, capacity of the facility and places where power will be used
- Plan for fuel supply, including information about the source, type, substitutes and costs or, when applicable, the use of national waters
- When applicable, the availability and dependability of excess capacity and associated power, capacity and supplementary energy requirements, whether back-up energy requirements will be firm or subject to availability, and transmission services required
- Any other information according to the purpose of the permit

The following documents shall be submitted with the permit application:

- Those that certify the identification and, when applicable, the legal validity of the applicant
- A general description of the project, including characteristics of the plant and auxiliary facilities, annual generation and fuel consumption estimates, information regarding any intended use of water, as well as information concerning compliance with ecological standards and use of the soil according to provisions in applicable regulations
- Information certifying ownership, possession and authorization to use the surface area where the facilities shall be located or, when applicable, a report on anticipated legal proceedings to that effect

The CRE shall review the application within 10 business days. Once it is reviewed, the CRE shall solicit the opinion of CFE, which must be based on objective criteria about the availability and dependability of excess capacity and power of the project, capacity and reserve power requirements and transmission services foreseen in the permit application. CFE shall give an answer within the following 30 working days. The time period shall be reduced to 10 business days in cases of Low Level Production (less than 30 MW). When CFE's opinion implies modifications or restrictions on the positions stated in the permit application, these shall be made known to the applicant so that he may state his point of view within 10 working days. If observations are expressed, the CRE shall hear the petitioner and decide on the changes and adjustments that, when applicable, must be made on the application.

Once the preceding steps have been taken the CRE shall, when applicable and with the knowledge of the applicant, request clarifications and additional information it deems pertinent, requiring the applicant to present for addition to the case file a descriptive technical report justifying the project to be developed, which must include in detail: plant characteristics and auxiliary facilities, annual generation and fuel consumption estimates, any intended use of water, use of soil according to provisions in applicable regulations and information concerning compliance with ecological standards.

Once the information and documents described in the previous paragraph have been received, the CRE shall within the following 30 working days make a judgment on the legal basis of the application and, if it is approved, shall issue the permit.

Permits shall at least contain the following data:

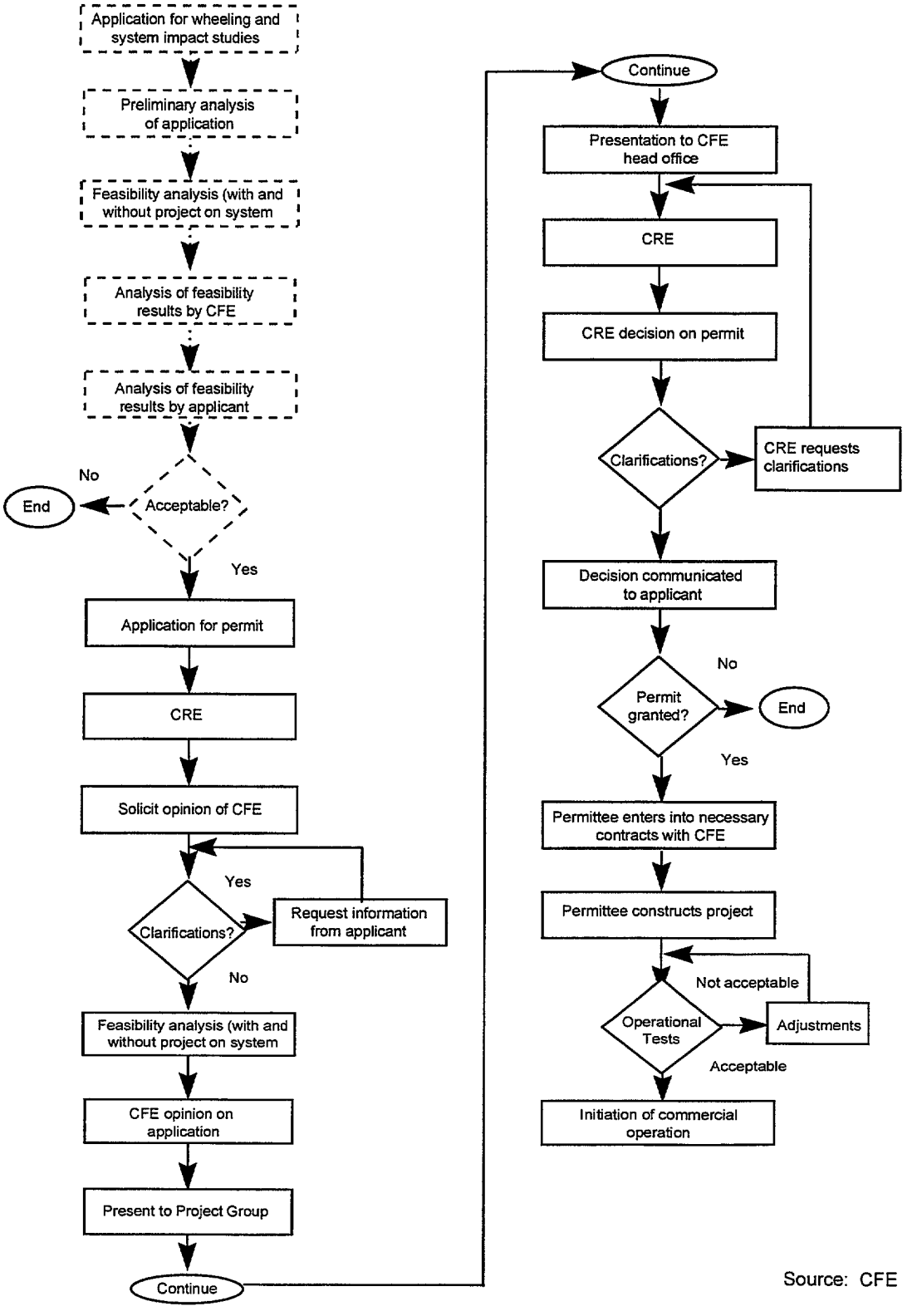
- Name, firm name or trade name of the applicant
- Location of the facilities
- Work plan, when applicable
- Date of commencement and completion of respective works, including date they will be placed in service, and considering, when applicable, the project's successive stages
- Duration of the permit
- Description of facilities
- Authorization activities
- The permit holder's obligations, causes for termination of the permit and time periods pertaining thereto

No permit shall be required for self-supplying electric power facilities that do not exceed 0.5 MW, nor for the operation of generating plants that are exclusively for personal use in emergencies resulting from interruptions in public utility electric power.

As part of the application process CFE undertakes studies of the external producer's impact on the normal operation of the electric power system. Separate evaluations are made of the project's feasibility and its wheeling effects.

As Figure 10 illustrates, the CRE participates throughout the administrative process to grant the permit. There are also feedback steps to clarify or modify some preliminary statements of the project.

Figure 10: Permitting Process for Generation Projects in Mexico



Source: CFE

Prior to applying for the SE generation permit, several other permits must be obtained from the agencies described below:

Secretaría de Comercio y Fomento Industrial (SECOFI) -- SECOFI is the Ministry of Commerce and Industrial Development, and also heads the Comisión Nacional de Inversiones Extranjeras (National Foreign Investment Commission). This Commission grants the Permiso para Establecer una Empresa con Capital Extranjero (Permit to Establish a Company with Foreign Capital) which must be obtained before incorporating a business entity in Mexico.

Secretaría de Relaciones Exteriores (SRE) -- The Ministry of Foreign Relations provides two types of permits or documents necessary for foreign companies. The first is the Permiso para Uso de Denominación o Razón Social (Permit for Use of Company Name), which applies only to companies newly established in Mexico. The second is the Aviso Notarial sobre la Inversión o No Extranjera (Notarial Announcement on Foreign Investment) that states whether a foreign company is using foreign capital or not.

Secretaría de Hacienda y Crédito Público (SHCP) -- SHCP is the Ministry of the Treasury, which provides a Cedula de Identificación Fiscal (Taxpayer Identification Card) necessary for all entities doing business in Mexico.

Departamento del Distrito Federal (DDF) -- Local permits are specific to the jurisdiction in question, but the land-use and other permits granted by the Department of the Federal District provide an illustrative example of those required by most state and local governments. The documents that may be required from this and similar agencies include the following:

- Constancia y/o Certificado de Zonificación (Proof and/or Certificate of Zoning)
- Licencia de Uso del Suelo (Land Use License)
- Constancia de Uso de Suelo (Proof of Land Use)
- Licencia de Demolición Total o Parcial (License for Total or Partial Demolition)
- Licencia de Construcción (Construction License)
- Aviso de Terminación de Obra (Notice of Work Termination)
- Autorizacion de Uso y Ocupación (Use and Occupation Authorization)
- Visto Bueno de Prevención de Incendios (Fire Prevention Approval)
- Registro de Descarga de Aguas Residuales (Wastewater Discharge Registration)

Finally, permits must be obtained for emissions and the other environmental aspects of a project. Requirements for environmental assessments have been published in the Environmental Gazette (Gaceta Ecológica, V. 1, 1989, pp. 286-358). In addition, the Secrataría del Medio Ambiente, Recursos Naturales y Pesca (SMARNP, the Ministry of the Environment, Natural Resources and Fisheries) has established ambient standards for ozone, SO_X, NO_X and Total Suspended Particulates (TSP). Source standards have been established for certain categories of point sources, such as fired boilers. No standards have yet been published for combustion turbines, but SMARNP will reportedly accept a representation that the control technology for a plant meets the latest U.S. *and* European standards. There is no current requirement that continuous emissions monitoring equipment be installed.

(2) New Transmission

(a) Economics

The economics of new transmission lines are project specific and generalizations are subject to significant error. For purposes of discussion, however, it is useful to examine rough cost estimates for representative projects. Four such projects have been identified, the costs of which are presented in Table 4:

- *Baja California:* southern California to Baja California Norte
- *Ciudad. Juarez:* southern Arizona to northern Chihuahua
- *Reynosa:* southern Texas to northern Tamaulipas
- *Santa Ana, Sonora:* southern Arizona to northern Sonora

Table 4: Illustrative Potential Cross-Border Transmission Interconnections

(all costs in 1996 U.S. Dollars)

Component	Route			
	Southern CA to Baja California Norte	Southern AZ to Northern Chihuahua	Southern TX to Northern Tamaulipas	Southern AZ to Northern Sonora
Transmission Line				
Length (km.)	230	560	480	180
Tension (kV)	500	345	345	345
Circuits (no.)	1	2	3	1
Cost (US$M)	$60.00	$195.00	$165.00	$40.00
Transformer Banks				
Relationship	500/230	345/230	345/230	345/230
Capacity (MVA)	900	600	600	450
Cost (US$M)	$5.00	$3.50	$3.50	$3.00
Back-to-Back Converters	NA	1	1	NA
Capacity (MW)	NA	450	450	NA
Cost (US$M)	NA	$90.00	$90.00	NA
Compensation	50% (series)	NA	NA	NA
Cost (US$M)	$4.00	NA	NA	NA
Phase Shifters	1 x 600 MVA	NA	NA	NA
Cost (US$M)	$9.00	NA	NA	NA
Right-of-Way				
Cost (US$M)	$3.00	$10.00	$9.50	$2.50
Total Cost (US$M)	**$81.00**	**$298.50**	**$268.00**	**$45.50**
Transfer Capacity (MW)	**600**	**450**	**450**	**250**

Sources: Routes and equipment requirements from CFE; cost estimates from SRP.

Two of the four interconnections are AC links: one from southern California in the U.S. to Baja California in Mexico, which is already synchronous with the rest of the WSCC; and one from Arizona to Sonora, which would involve the isolation of a section of the CFE grid from the rest of the SEN. The costs of each are discussed below.

Baja, California -- The cost of single 500 kV circuit with a 600 MW capacity is estimated to be approximately $81 million, or $135,000 per MW. The major driver of cost is the transmission line, which accounts for about 75 percent of the estimated total costs. Since Baja California is already part of the WSCC system there is no need for DC back-to-back conversion.

Ciudad Juarez -- Two 345 kV circuits with a 450 MW capacity would cost about $299 million, or $664,000 per MW. The transmission line represents about half of total costs while DC back-to-back conversion is about 45 percent.

Reynosa -- The costs for two 345 kV circuits with a capacity of 450 MW would be about $268 million, or $595,000 per MW. Transmission line and DC back-to-back converters represent about 60 percent and 33 percent of the total, respectively.

Santa Ana, Sonora -- A single 345 kV circuit with a capacity of 250 MW would cost approximately $46 million, or $184,000 per MW. Transmission costs represent almost 90 percent of the total. With no provision for DC back-to-back conversion this project might require the isolation of a portion of the CFE or the WSCC system.

These examples are oversimplified and are therefore very rough estimates of potential project costs. It is apparent even from this simplified example, however, that there are two important drivers of costs: length of the transmission line and the presence of a DC back-to-back converter.

(b) Financing

All of the financing considerations discussed above for generation projects also apply to transmission, but in reality a transmission project is likely to be easier to finance. This is because transmission service will continue to be regulated, with the result that it is much less risky than generation, and will command correspondingly lower returns on equity and interest rates on debt.

(c) Approval Process

(i) U.S.

Construction of transmission lines can require federal, state, and local environmental compliance activities dealing with natural (biological and cultural) resources, waste streams, and water runoff. Local and municipal permits vary widely and are not described in detail in this section, but generally cover issues such as environmental impacts on local plant species, local noise ordinances (audible noise from 60 Hz operation is an issue for high voltage lines and related equipment), and general construction permits. These processes generally span from as little as a few months to as much as a year. Federal and state processes can range from approximately six months to one year on average, but can extend as far as two years in complex cases. State processes differ somewhat among the four border states (Arizona, California, New Mexico, and Texas), but are similar in that they all involve a statutory process that results in a state-issued certification of the environmental compatibility of a proposed transmission line.

(a) Basis for Permitting

As with the permitting of a generating facility, transmission lines involve a comprehensive site selection process that generally begins with a broad-range "corridor" study, followed by regional site studies, and finally detailed site selection. In the U.S., public involvement and public information processes have been a required element of transmission siting in recent years. Public concerns over aesthetics, property value, and electromagnetic fields associated with power lines have been key issues in public involvement processes throughout the nation. Though none of these are regulatory issues, the experiences of U.S. utilities in recent transmission siting cases indicate that voluntary public involvement processes are an essential part of successful transmission line siting. Such processes can be as simple or as rigorous as necessary depending on population density, local concerns, and other case-specific issues. But they can generally be carried out in parallel with, and even integrated with the siting studies that are required for other permits. As with generating facilities, the criteria addressed in transmission siting processes involve proximity to residential development, compatible land-use, zoning, proximity to national parks and wilderness areas, and natural resource impacts.

(b) Major Permits

A brief summary of some of the primary regulations is listed below.

The National Environmental Policy Act requires federal agencies to balance environmental and non-environmental policy objectives in the context of their decision-making activities. NEPA can be triggered by any federal action (i.e. federal funding, federal land, federal permit). Proposed actions fall into one of five categories: (1) actions which are exempt from NEPA; (2) actions which are categorically excluded; (3) actions which are covered by an existing NEPA environmental document; (4) actions which require preparation of an environmental assessment to determine if an environmental impact statement is needed; or (5) actions which require preparation of an EIS. The NEPA procedural and documentation requirements are different for each category. An EIS is the most complicated and time consuming NEPA process and is required if the impacts of the proposed action are considered "significant." The EIS process can take a minimum of six months, but more typically may take a year or more. In very complex cases, EIS processes have taken as much as two years.

The Endangered Species Act (ESA) provides for conservation of threatened and endangered species of fish, wildlife, or plants. In addition, the ESA provides for conservation of "critical habitat"—i.e., habitat that is of special significance to the species and has been formally designated as such. For construction projects, it must be determined if any protected species or habitats could be negatively impacted by the construction project. If negative impact is possible, all federal projects (or projects with any federal links) require initiation of a formal Section 7 consultation process. Private agencies may initiate a Habitat Conservation Plan (HCP) under the ESA. Both processes are intended to explore impacts and agree on mitigation and if applicable provide incidental take permits. A formal consultation and an HCP can be completed in less than six months, but more typically would take a year or more.

All migratory birds are protected by federal law. In addition to the ESA, two other federal laws which specifically protect birds include The Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act. If the project negatively impacts a migratory bird or its nest, special permits and negotiation with U.S. Fish and Wildlife Service may be required.

Under Section 404 of the Clean Water Act, the Environmental Protection Agency and the Army Corps of Engineers have concurrent jurisdiction over the dredge and fill of the waters of the United States, while the U.S. Fish and Wildlife Service has an important advisory role to those agencies. For construction projects impacting river bottoms or wetlands, a 404 permit must be obtained from the COE. This process requires compliance with NEPA, ESA and special considerations for preserving wetlands.

Native plants are protected by state native plant laws. Construction projects which negatively impact cactus, specific desert trees, or other protected species require notification to the Department of Agriculture and may require some salvage activities to protect native plants.

Under the National Pollutant Discharge Elimination System (NPDES), the EPA has jurisdiction over any projects which involve sites greater than five acres. The NPDES permitting process is designed to ensure that storm water runoff or other drainage from a project site does not have adverse downstream impact. For transmission line construction, the NPDES permit is generally not a concern but is a necessary compliance procedure.

The National Historic Preservation Act (NHPA) provides for the protection of all facilities, geographical features, sacred objects or burial sites, artifacts, and other resources with historic and/or cultural value. NHPA can be triggered whenever federal funds, federal land, or other federal permits or licenses are involved. Compliance with NHPA results in the issuance of an archaeological clearance, and requires consultations with any affected Native American tribes and interested members of the public. Ethno-historic reports as well as archaeological reports may be required. The NHPA compliance process typically requires 6-18 months.

State laws within Arizona, California, New Mexico, and Texas will also apply. Each state has its own laws pertaining to public and private lands. In general, most will have regulations for state lands while regulation of private lands will be more variable. Arizona and New Mexico do not require separate tribal consultations for either state or private lands unless a burial site is anticipated or encountered. However, in the southwestern U.S., many of the tribes encourage consultation. Some American tribes (e.g., the Tohono O'odham) claim ancestral ties within Mexico, asserting extended jurisdictional interest.

(ii) Mexico

The permitting process described above for generation also applies to transmission, with the important exception that no CRE permit for generation is required for the construction of transmission capacity only. As noted above, such capacity may be jointly constructed by CFE and a private developer, or by the private developer alone for self use. Facilities built by a private developer alone, however, may not be interconnected with the SEN.

c) Market Competitiveness

This section reviews some of the factors that will effect the competitiveness of various participants in the regional wholesale electricity market, and also the viability of different trade and investment opportunities.

(1) Loads and Resources

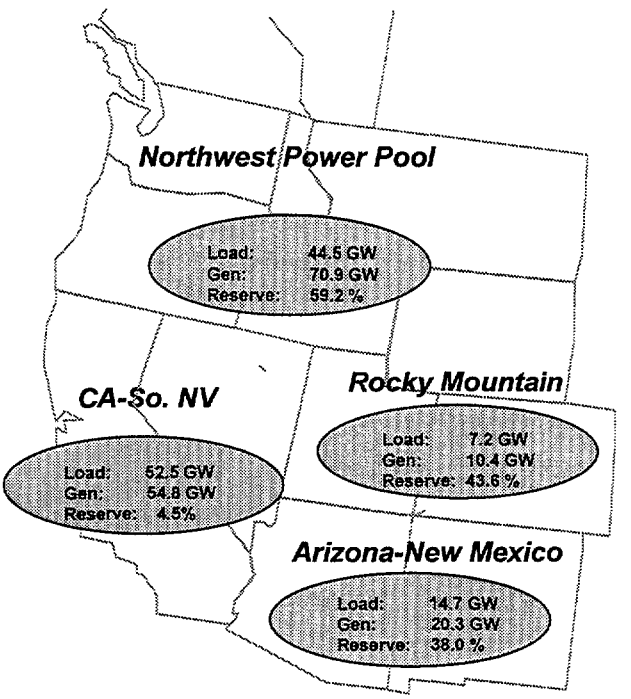
As noted above, there is currently excess capacity in all three regional systems, with reserve margins ranging from 24 percent in CFE and ERCOT to 33 percent in WSCC, as illustrated in Table 5. Reserve margins in the four WSCC sub-regions vary considerably, however, as illustrated in Figure 11.

Table 5: Regional Electricity Markets -- 1995

	WSCC	ERCOT	CFE*	Total
Total Peak Demand (Non-coincident GW)	102	44	25	171
Total Retail Energy Sales (gWh)	531,000	262,000	141,000	934,000
Residential	32%	35%	25%	
Commercial	31%	26%	8%	
Industrial	33%	34%	55%	
Other	4%	5%	12%	
Total Installed Capacity (GW)	152	58	32	242
Hydro	39%	1%	28%	
Coal	24%	28%	7%	
Gas/Oil	29%	62%	52%	
Nuclear	7%	9%	4%	
Other	1%	0%	9%	
Installed Reserve Margin	33%	24%	24%	30%

Source: World Energy Service U.S. Outlook, Fall-Winter 1995-96
Electric Power Annual, 1995, Vol. I
DOE/EIA-0348(95)/1, July 1996
CFE, Desarrollo del Sector Eléctrico de México: 1996-2006, Documento de Trabajo, August 20, 1996
*Energy sales percentages not directly comparable to WSCC/ERCOT due to classification differences with regard to end-users

Figure 11: WSCC Summer Loads and Resources



WSCC

Load (1996)	118.9 GW
Generation (1996)	156.4 GW
Reserve	37.5 GW
Reserve %	31.5%

Source: WSCC Report

In the U.S., deregulation of the wholesale -- and potentially the retail -- power markets will lead generators to extract greater operating efficiencies from their existing generation assets, continuing a trend toward higher utilization factors. Competitive pressures will also result in "capacity creep" -- i.e., the uprating, reactivating and repowering of existing capacity, which has occurred in other capital intensive industries such as oil refining and pulp and paper manufacturing. The outlook for the next 10 years, therefore, is for minimal new generation to be built and a gradual absorption of the available excess capacity due to increased loads. Generation may be built, however, in areas where there are transmission constraints, or by companies that believe that prices will be higher than generally expected.

In Mexico, although reserve margins are currently adequate, a significant amount of new capacity will be required during the next 10 years, as illustrated in Table 6 and Figure 12.

Table 6: Planned Additions to Generating Capacity in Mexico -- 1996 to 2005

Project	Location	Type	Service Date (First Stage)	Capacity Requirement (MW) 1998	1999	2000	2001	2002	2003	2004	2005
1 Cerro Prieto II and III	Baja California	GEO	1996		100						
2 Rosarito 7 (Note 1)	Baja California	GT	1996		150						
2 Rosarito 8 and 9	Baja California	CC	1996			450					
3 Chihuahua	Chihuahua	CC	1996				450				
4 Monterrey (Note 2)	Nuevo Leon	CC	1996			450		225			
5 La Venta 1 and 2	Oaxaca	WIND	1996		54						
6 Tres Virgenes	Baja California S.	GEO	1996	10							
7 San Rafael	Nayarit	HYD	1997		24						
8 Pto. San Carlos 4 and 5	Baja California S.	DIES	1997				37.5		37.5		
9 Campeche II	Tabasco/Campeche	CC	1997			225					
10 Guerrero Negro 6 U'S	Baja California S.	DIES	1997		18						
11 El Chino 1 and 2	Michoacan	GEO	1997		50						
12 El Sauz	Queretaro	CC	1997				450				
13 Hermosillo 1 and 2	Sonora	CC/GT	1997				150	225			
14 Altamira (Note 3)	Tamaulipas	CC/C	1997						450	450	
15 Rio Bravo 4 and 5	Tamaulipas	CC	1997				450			450	
16 Saltillo	Coahuila	CC	1998					225			450
17 Tula-San Juan	Hgo.-Qro.	CC	1998					450	450		
18 F. Villa Rep.	Chihuahua	CC	1998						249		
19 El Cajon 1 and 2	Nayarit	HYD	1998								636
20 Leon-AGS 1 and 2	AGS-Leon-SLP	CC	1998					450		450	
2 Rosarito 10 and 11	Baja California	CC	1999						450		
21 Laguna 1	Durango	CC	1999							225	
4 Monterrey	Nuevo Leon	GT	1999							150	
22 Oriental	P. Rica - Tuxpan	CC	1999								450
23 Valladolid	Valladolid	CC	1999								225
	TOTAL			10	396	1125	1538	1575	1637	1725	1761
							System Total:				9766

Notes:

1: If this unit does not enter service on the date planned, it is possible to utilize temporary imports from the U.S.

2: If projects at Nuevo Leon and the Electric Industrial Group are completed, the 450 MW for the year 2000 will not be required.

3: A gas-fired combined-cycle unit will be installed if there is sufficient gas; if not, a dual-fired steam facility of 2 ,350 MW units will be installed.

CC: Combined cycle; GT: Gas turbine; C: Coal; GEO: Geothermal; DIES: diesel internal combustion; WIND: Wind power

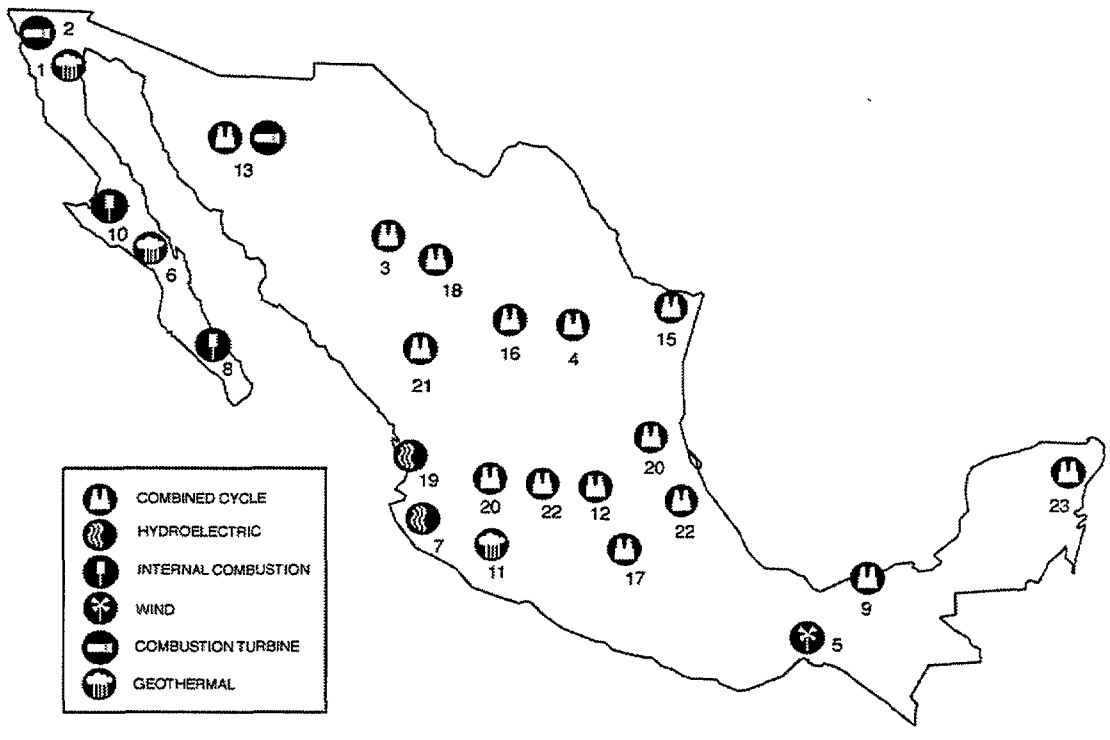


Figure 12: Planned Generation Additions in Mexico -- 1996 to 2005

(2) Prices

Consumption in the WSCC is expected to increase at an average annual rate of approximately two percent over the next five years. Hydro and coal account for about 70 percent of electricity production, and capacity utilization for coal and nuclear are about 76 and 70 percent, respectively. Although utilization has been increasing over time the effect of deregulation and an increasingly competitive market will result in even higher utilization factors. Thus, although demand is growing steadily, the factors described above -- increased utilization, reduced reserve margins and capacity creep -- may tend to offset much of the potential for higher wholesale prices Retail prices are not yet deregulated but there is significant pressure for price reductions, as described above. Retail competition, if it is enacted, will serve to put pressure on the industry to reduce retail prices. A competitive market will result in increased efficiencies in operations from meter reading to billing to general administrative functions. Cross subsidies that occur in a regulated environment will be reduced or eliminated by market pricing, although subsidies for low-income residential consumers are likely to continue, funded by charges paid by all customers. Prices will still differ by customer class, but those differences will be due to market forces rather than an accounting allocation of costs. Retail customers will pay lower prices on average for generation, but their total bill may change little if full stranded costs are recovered by the local utility.

Like WSCC, consumption in ERCOT is expected to increase at an average rate of approximately two percent over the next five years. Coal and natural gas account for about 85 percent of total generation. Based on current pricing information it appears that natural gas is on the margin during on-peak periods. Both coal and natural gas are on the margin during off-peak periods. Capacity utilization is 67 percent for coal and 53 percent for nuclear.

At the wholesale level ERCOT will face the same price pressures as in the WSCC. Increasing demand will put upward pressure on prices, but increased utilization, reduced reserve margins and capacity creep exert downward pressure. With lower current utilization factors than the WSCC, ERCOT may have potential for more rapid downward movement of prices. The proposed ISO in ERCOT will serve to improve efficiency in the utilization of transmission. The fact that two utilities account for 64 percent of generation in ERCOT may mitigate the otherwise greater downward pressure on prices. In the long run, prices will tend to converge with those in the WSCC, since any significant difference will result in new transmission between the two systems or new generation in the area with transmission constraint. Texas does not have an active retail competition proposal, but pressure from retail customers is likely to result in consideration of the issue in 1997. In any event, retail prices in ERCOT will likely stay near the current regulated rates and cross-subsidies will continue until retail competition is introduced.

(3) Market Shares by Producer

As illustrated in Table 7, the WSCC is dominated by several large IOUs that account for just over half of all net generation and purchases, the Bonneville and Western Area Power Administrations, and two non-federal public utilities, SRP and the LADWP. By far the most important of these in terms of the wholesale power market is the BPA, since it sells all of the federal energy it is responsible for on the market, rather than using some for native load, as is the case with the large IOUs.

Market share in ERCOT is much more concentrated with two large IOUs -- Houston Lighting and Power Company and Texas Utilities Electric Company -- accounting for two thirds of the entire market. There are no PMAs in Texas, and only one significant federal generation project, the Lower Colorado River Authority, which accounts for just four percent of net generation and purchases.

Table 7: Market Shares in WSCC (U.S.) and ERCOT

Region & Entity	Share of Net Generation & Purchases	Region & Entity	Share of Net Generation & Purchases
WSCC (1993)		ERCOT (1995)	
IOUs		IOUs	
Arizona Public service	4%	Central Power & Light Company	7%
Pacific Gas & Electric	15%	City Public Service	8%
Pacificorp	11%	Houston Lighting & Power Company	27%
Puget Sound Power & Light	4%	Texas Utilities Electric Company	40%
Public Service of Colorado	4%		
Southern California Edison	14%		
Total IOUs	**52%**	**Total IOUs**	**82%**
Federal		Federal	
Bonneville Power Administration	15%	Lower Colorado River Authority	4%
Western Area Power Administration	4%		
Total Federal	**19%**	**Total Federal**	**4%**
Other Government		Other Government	
Salt River Project	4%	City of Austin	5%
Los Angeles Dept. of Water & Power	4%	Texas Municipal Power Pool	4%
Total Other Government	**8%**	**Total Other Government**	**9%**
Other	**19%**	**Other**	**5%**

Sources: HISTCDR.XLS Spreadsheet from ERCOT Bulletin Board System 07/29/96
Energy Information Association, IOU's 1993, January 1995
Publicly Owned Electric Utilities 1993, February 1995

(4) Implications of Border-State Restructuring

This section discusses some of the implications for cross-border trade and investment of the state-level restructuring activities underway in the region.

As described in an earlier section, California is likely to offer retail competition first among the border states, with a power exchange in operation in 1998 and retail direct access starting then and being fully available a few years later. Major utilities in Arizona have also expressed support for retail competition. As currently planned, 20 percent of retail customers will likely have choice in Arizona in 1999, expanding to full access in 2003. Prospects for retail competition in Texas and New Mexico are unclear.

On the wholesale level, with the agreement to turn ERCOT into an ISO, it appears that competition will come to most of Texas rather quickly. Wholesale sales in California will be available through the WEPEX in 1998 and will be facilitated by the formation of the California ISO. Direct wholesale sales to California resellers other than regulated utilities will also be available.

The implications of these developments for cross-border trade and investment in electricity can be categorized into five areas: (1) transmission and distribution operations; (2) transmission and distribution expansion; (3) fuel-type arbitrage opportunities; (4) pricing and dispatching of existing generation; and (5) generation expansion and ownership change.

Transmission and Distribution Operations -- The move toward ISOs which operate transmission systems as one grid over a wide area probably has the greatest potential for causing change in the business relationships in the border area. While the competitive implications for various participants will depend on the design of transmission price structures (now being vigorously debated in California) there is no doubt that there will be profound shifts in the ability of various participants to do business over a wide geographical area.

The general flow of power in the region today is from Arizona and New Mexico into southern California and from the Pacific Northwest into northern California. Although some transactions bring power from the Pacific Northwest to the Southwest and from the Southwest into northern California, transmission constraints between northern and

southern California ("path 15") generally limit the size of these transactions, resulting in a locational difference in the price of electricity. Creation of an ISO will highlight this bottleneck and increase pressure to eliminate it.

Presently, energy transactions between California and Mexico across the international border are largely confined to the interconnections in the Baja California/San Diego area. Under the California proposal, facilities under control of the California ISO will extend to the Palo Verde switchyard in the Phoenix area. Thus, access to the system across the Sonora/Arizona border will give parties on both sides of the border improved access to the entire California market.

Although the restructuring of ERCOT into an ISO for the state of Texas should improve access to the entire state, physical limitations in transmission links between ERCOT and WSCC suggest that integration of Texas into the western U.S. power market will take longer to materialize. However, a significant difference in the energy price between the two areas suggests that there will be pressure to construct additional links between the two systems.

Transmission and Distribution Expansion -- Although it is too early to predict what specific changes to the transmission system will be prompted by the move toward open access and retail competition, it is possible to make some general observations.

As institutional barriers to long-distance transmission are addressed through regional ISOs, physical limitations will become more visible. Already mentioned are the ERCOT/WSCC barrier and the "path 15" barrier between northern and southern California. Over the longer term, transmission expansion will generally be favored to areas with lower primary fuel costs, where transmission of electricity will compete with transportation of primary fuels.

Institutional issues related to who plans, decides and finances transmission expansion in the new environment have yet to be worked out, but as regional price differences highlight physical bottlenecks it is likely that solutions to the institutional issues will be found.

Fuel Arbitrage Opportunities -- There is generally a geographical element to the type of fuel used for generation. The Pacific Northwest generates significant energy using hydroelectric resources, generation within California largely depends on imported natural gas and generation in the Southwestern U.S. generally relies on coal. In Texas, much generation uses well-head natural gas as a fuel source. As the electricity markets become more efficient and transparent and as barriers to transmission between regions historically served by different utilities come down, arbitrage opportunities between fuel types should increase.

Pricing and Dispatching of Existing Resources -- The most visible and significant short-term changes to be seen as a result of the current restructuring efforts will be in the pricing and dispatching of existing resources. As currently proposed, the rules under which the California exchange will operate encourage non-California utilities to bid generation into the exchange and to meet energy requirements from the power exchange.

Although the economy energy market at the wholesale level is currently quite active in the western U.S., the volumes of transactions in the WEPEX should be significantly larger, providing increased opportunity for least-cost management of non-California systems.

Generation Expansion /Change of Ownership -- In the long run, implications of the competitive marketplace on generation expansion and ownership will probably be the most profound, and also the most uncertain, of the changes brought about by the move to a competitive market. One of the key near-term events in this regard will be the divestiture activities of Southern California Edison and Pacific Gas and Electric. It will also be interesting to observe the transition of non-utility generators from operations supported by contractual purchase of their output to operations which compete for the sale of energy with other generators regardless of ownership.

(5) Power Marketers and Aggregators

As noted earlier, the volume of sales by power marketers has been increasing at an exponential rate. During the third quarter of 1996, sales by the top marketer in the WSCC, Enron Power Marketing, actually exceed those of the BPA. Total sales by marketers during that quarter, if annualized, would represent more than 20 percent of all wholesale transactions in 1995.

The increasing role of power marketers has had several important impacts on the wholesale market. First, it has dramatically increased liquidity, which leads to more efficient "discovery" of prices -- i.e., a more accurate reflection of true market value -- and less price volatility. When the BPA temporarily stopped its wholesale sales July 1996, for example, spot prices immediately rose from their normal range of $20-25 per mWh to more than $40. When the BPA withdrew from the market in November 1996, however, there was no increase in prices, which was cited by energy traders as an indication of a maturing market.

Power marketers have also put intense pressure on wholesale prices, reducing the margins available for generators and other wholesale market participants. This has encouraged strategies for more effective generation asset management and utilization, as described above, and has discouraged the construction of all but the most efficient new plants.

Finally, power marketers' focus on the needs of customers has led to the introduction of a variety of new products, as described above. Perhaps more importantly, they have forced other market participants -- i.e., IOUs and other integrated utilities -- to shift their attention from the traditional concerns of reliability, planning and regulatory affairs toward their customers as well. This shift would of course happen without marketers as the industry is gradually deregulated, but marketers have arguably increased the pace of this movement by their aggressive pricing and sales strategies.

(6) Mergers and Acquisitions

This section discusses recent merger and acquisition (M&A) activity in the western U.S., summarizes the leading forces behind those efforts and looks forward at still-developing trends that could affect electric utilities.

U.S. electric utilities are merging at a record pace. More than $50 billion of domestic M&A involving electric utilities have been announced since January 1994, and most industry analysts expect the pace to accelerate. This M&A activity is leading to larger energy companies that are able to offer their customers a wider range of products and services. The mergers, most of which have not yet been completed, fall into three broad categories, and are summarized in Table 8:

- Electric utilities ("E + E" in the table)
- Electric and gas utilities ("E + LDC" in the table)[47]
- Electric or combination utility and petroleum-based business

Alliances are also being created to obtain many of the same objectives as M&A without the substantial transaction costs.

[47] LDC stands for Local Distribution Company, the gas equivalent of an electricity distribution company.

Table 8: Select Utility Mergers and Acquisitions (1992-1996)

Acquiring Utility	Acquired Utility	New Name	Date Announced	Value	Status	Type
Enova (SDG&E)	Pacific Enterprises (SoCal Gas)		10/96	$2.8B	Pending/ Friendly	E/LDC + Pipe
Ohio Edison	Centerior Energy	FirstEnergy	9/96	$1.5B	Pending/ Friendly	E + E
Northwestern PS	Empire Energy		9/96	$120M	Pending/ Friendly	E + Propane
Houston Industries	NorAm Energy		8/96	$3.5B	Pending/ Friendly	E + LDC/Pipe
Delmarva P&L	Atlantic Energy		8/96	$961M	Pending/ Friendly	E/LDC + E
MidAmerican Energy	IES Industries		8/96	$1.2B	Failed/ Hostile	E/LDC + E/LDC
Enron	Portland General	Enron	7/96	$2.1B	Pending/ Friendly	Pipe/Trader + E
Texas Utilities	ENSERCH		4/96	$1.7B	Pending/ Friendly	E + Pipe/LDC
Western Resources	Kansas City P&L	Maxim Energies	4/96	$1.9B	Won /Proxy/ Hostile	E/LDC + E
UtiliCorp United	KCP&L		1/96	$1.7B	Failed/ Friendly	E/LDC + E
WPL Holdings	IES Industries and Interstate Power	Interstate Energy	11/95	$4.5B	Pending/ Friendly	E/LDC + E/LDC
Puget Sound P&L	Washington Energy	Puget Sound Energy	11/95	$488M	Pending/ Friendly	E + LDC
Baltimore G&E	Pepco	Constellation Energy	9/95	$3B	Pending	E/LDC + E
Union Electric	CIPSCO	Ameren	8/95	$1.2B	Pending	E/LDC + E/LDC
PECO	Penn P&L		8/95	$3.8B	Term./ Hostile	E/LDC + E
PS Colorado	Southwestern PS	New Century Energies	8/95	$3.1B	Pending/ Friendly	E/LDC + E
Northern States Power	Wisconsin Energy	Primergy	5/95		Pending/ Friendly	E/LDC + E/LDC
Sierra Pacific Resources	Washington Water Power	Altus	6/94	$3.4B	Term./ 6/96	E/G/W + E/G
Midwest Resources	Iowa-Illinois G&E	MidAmerican Energy	7/94		Complete/ 6/95	E/LDC + E/LDC
PSI Resources	Cincinnati G&E	CINergy	12/92	$3.4B	Complete/ 10/94	E + E/LDC

E = Electric utility **LDC** = Local gas distribution utility **E/LDC** = Combination electric and gas utility **Pipe** = Interstate or intrastate gas pipeline

Source: SRP

(a) Merger of Electric Utilities

In announcing mergers between electric utilities, executives have generally emphasized two key factors:

- Increased efficiencies, resulting from greater economies of scale and reduced duplication. Mergers of contiguous utilities generally fit this pattern. To achieve these efficiencies, duplicative work processes and departments are reduced in size or scope. This allows the merged entity to increase dividends and either cut or freeze rates for several years.
- Generating resources and fuel mix. Some utilities want to expand their exposure to the fuel used in the other company's generating stations, while others want to broaden their fuel mix. In several instances, merging companies are participants in one or more large generating stations.

(b) Merger of Complementary Businesses

In the last year or so, the composition of utility M&A activity has shifted. Although stand-alone electric utilities continue to announce mergers, a more significant trend is mergers between complementary energy providers, principally between electric utilities and gas utilities/gas pipelines. The merger between PSI Resources and Cincinnati Gas & Electric was the first such combination. That was followed by mergers between Puget Sound Power & Light and Washington Energy, Texas Utilities and ENSERCH, Enron and Portland General, and Houston Industries and NorAm Energy. The November 1996 announcement of a merger between Enova and Pacific Enterprises is further evidence of this trend. Mergers of complementary utilities account for more than half of the value of all mergers involving electric utilities over the last 12 months.

When complementary utilities announce a merger, they provide a slightly different set of reasons. These justifications, which build on the above list of M&A drivers, include:

- The ability to provide total energy solutions to customers.
- Obtaining access to a partner's successful non-utility business (part of the reason for the Houston Industries/NorAm Energy merger).
- Achieving a certain minimum number of customers, assets or market capitalization that would render the merged company safe from future unsolicited M&A attempts.
- The merger of separate electricity and gas utilities pose fewer "market power" problems for state and federal regulators than would the merger of two electric utilities. Regulators have generally assumed that the merger of contiguous electric utilities would diminish competition and damage other market participants, particularly customers. Therefore, regulators have required the merged entity to make significant concessions to mitigate this potential market power.
- Developing a broader business portfolio to cushion the effect of potentially negative stranded-cost regulatory decisions.
- Securing a fuel source for generating stations, or an end use for gas being transported through pipelines or LDCs.

Most of the mergers of electric utilities or complementary businesses are undertaken for essentially defensive reasons. Their value lies in achieving cost reductions in order to become more competitive in a deregulated environment.

(c) Combination of Converging Businesses

The combination of converging energy businesses will produce large entities capable of providing a broad range of energy products and services to their customers across the nation or even the world. This trend is demonstrated by the evolution of Enron, which in the mid-1980s Enron was an interstate natural gas pipeline with a small LDC network and scattered gas-producing properties. Starting in the late 1980s Enron extended its reach in both

directions on the chain of energy production. It invested in oil and gas exploration and production, as well as in independent power production, chiefly gas-fired. In the early 1990s, Enron began investing in energy trading. The July 1996 merger between Enron and Portland General represents the convergence of discrete yet related energy markets (oil and gas production, oil and gas transportation, independent power production, electricity and petroleum trading, and retail electricity generation/distribution). In addition, Enron's financing and trading subsidiary, Enron Capital & Trading, adds another dimension to this full-service energy company.

Another example is Amoco, a large integrated oil company, which formed an electricity subsidiary in mid-1994 for two reasons: to reduce operating costs at its energy-intensive facilities around the world; and to participate in the business opportunities created through deregulation in the U.S. Amoco received wholesale power marketer status from the FERC in late 1995. It will use this to market excess power from its cogeneration sites in the U.S. Amoco's electricity group also plans to develop, build and operate generating stations near its gas fields, oil refineries, plastics plants and other facilities around the world. To date, this subsidiary has acquired 10 percent of the Trinidad & Tobago Power Generation Company (1,178 MW total generating capacity) as well as ownership stakes in cogenerators in Argentina and Columbia. Other integrated oil companies, including Texaco, Arco and Chevron, have either launched electricity groups or expressed interest in entering the electricity business as a seller.

There are a number of factors that support this convergence of the petroleum and electricity markets. Integrated oil companies have substantially greater revenues, earnings and assets than even the largest electric or combination utilities. Leaders of integrated oil companies have developed elaborate risk-management mechanisms. Since these businesses consume large amounts of electricity, many oil companies built on-site cogeneration facilities in the 1970s and 1980s. Thus, many oil companies have some experience generating and distributing electricity.

In addition to the ability to provide business customers with an unparalleled choice of energy products, these companies can also offer customers the ability to pay all energy bills at one time. This would dramatically simplify the process of tracking, managing and paying for energy among commercial customers, government agencies, municipal entities, quick-service restaurants, schools and other multi-site customers. The nation's largest retail stores receive over 500 bills for electric and gas service each month. Energy managers for these chain stores have demanded simplified billing from the utilities that serve them. The company that could offer these commercial customers a single monthly bill for all their energy usage would have an immediate and compelling competitive advantage over other energy providers.

(d) Alliances or Virtual Mergers

While outright mergers or acquisitions have received much attention, a related trend -- the formation of marketing alliances between competing or complementary providers -- also is making an impact. These alliances are easier to conclude than an actual merger: they are not subject to regulatory approval; they are generally undertaken for specific reasons, such as the ability to offer a defined set of products or services; and they tend to be less disruptive to the employees of the aligning companies than a merger. Finally, compared to a merger, a marketing alliance is easier to undo if it doesn't work out as anticipated. Several such alliances have been announced in recent months:

- AllEnergy, an alliance between New England Electric System and Eastern Enterprises, a subsidiary of Boston Gas Company, will provide retail energy commodities and energy services to customers throughout the Northeastern U.S.
- Westcoast Energy and Coastal launched an alliance that has significant experience in gas exploration, production, transmission, and delivery together with a new wholesale electricity trading business. The alliance, as yet unnamed, plans to provide retail electric and gas commodities as well as services.
- Mobil Oil and PanEnergy announced an alliance in August 1996. This alliance brings together Mobil, one of the world's largest producers and refiners of oil and natural gas, with PanEnergy, one of the U.S.'s largest interstate natural gas pipelines. Both companies have long-standing risk-management groups as well as experience in cash and futures energy trading and arbitrage. PanEnergy received FERC approval to market wholesale electricity in early 1996, and opened its trading operations in April 1996.

(e) Regulatory Considerations

State and federal regulators may not approve outright ownership of a retail gas or electric utility by a multinational oil company. The life-sustaining services that gas and electric utilities provide to their customers may convince regulators that ownership by a distant corporate parent is not "in the public interest," which is the legal standard used by most regulatory commissions when they consider mergers.

In addition, PUHCA has generally prohibited substantial investments in utilities by non-utilities. However, reform or repeal of PUHCA is being addressed in Congress, as described in earlier sections, which could further encourage electric utility M&A by utilities and non-utilities.

(7) Gas and Electric Market Convergence

As described in the previous section, electricity and gas utilities are forming mergers and alliances at a rapid pace. Such mergers allow the resulting entity to provide a set of integrated energy products and services to customers, and also take advantage of expanded customer bases, the competitive strategies developed in the respective industries and economies of scope between the two businesses.

From the customer viewpoint, the ability to offer integrated services is only important because energy management has begun to be viewed on an integrated basis by more sophisticated large consumers, a trend that is likely to continue. Such management was not necessary when gas and electricity were provided under regulated prices. As deregulation moves forward, however, market-based price differentials between electricity and gas will increase the savings to be gained by having the ability to arbitrage between them. Commercial customers with large air conditioning needs, for example, can switch between electric and gas chillers depending on the relative prices of each. Increasing differentials between peak and off-peak prices within the electricity market will also provide opportunities for energy arbitrage, allowing large customers to use gas-fired reserve generators during short periods of very high electricity prices.

As a result of integrated energy management, it is expected that the gas and electricity markets will gradually converge. This will tend to reduce locational differences in the price of both types of energy, since a transmission constraint in one could be overcome by transporting the other, assuming sufficient capacity exists. It will also lead to a general convergence in the prices of both at a given location. Differences will still remain, however, due to the unique nature of each commodity. One of the most important of these is the fact that electricity cannot be stored, which results in large differences between peak and off-peak prices in a totally competitive market. Gas does not share this characteristic, and will therefore provide an attractive opportunity for fuel switching during periods of high electricity prices, as explained in the example above.

(8) Financial Trading

As financial trading in electricity -- as distinct from trading in the physical commodity itself -- increases, it will have several effects on the market. First, it will add liquidity to the wholesale market and enhance price transparency, as transactions by power marketers are already doing. Second, it will also increase the range of products that are available, by providing a reference price that can be used for bilateral contracts, as discussed above. Finally, it will facilitate the operation of power exchanges and pools by providing a mechanism for arranging bilateral transactions outside the pool. As noted in an earlier section, this type of arrangement is used in the England and Wales pool, where most transactions are also covered by contracts for difference between two parties. CfDs -- which are usually structured as an option, but can also be a future or a forward (a series of sequential future contracts) -- define a sale or "strike" price. If the contract is exercised, the buyer owes the seller the quantity purchased times the strike price, and the seller owes the buyer the quantity purchased times the pool price. Rather than exchanging money twice, they two parties settle by exchanging the difference between the two prices. CfDs are an effective method of reducing overall transaction costs in a pool, since the ISO need not be concerned with bilateral contractual arrangements; generators are dispatched based on their bids only, and bilateral arrangements are settled with CfDs.

(9) Stranded Investment Costs

This section provides a summary of potential impacts resulting from stranded cost recovery provisions in FERC Order 888, discusses FERC's suggested approach for recovery, and summarizes the specific approach being taken in California.

FERC Order 888 reaffirmed its commitment to allow recovery of prudently incurred stranded investment costs. The Commission decided that the most appropriate means for recovering these stranded costs is through direct assignment to the departing wholesale customer, either through an exit fee or a surcharge on transmission. Thus, a departing customer will be required to pay costs incurred to serve it when it was a bundled requirements customer. The potential result of this requirement -- and equivalent treatment of retail customers, if it occurs -- is that retail electricity prices may not fall significantly in the near term, since customers will have to pay a surcharge when leaving their current provider, or may stay with that provider at higher cost to avoid such a charge. This limited impact on prices may in turn reduce any increased demand that would result from price reductions.

(a) FERC's Suggested Recovery Approach

As discussed above, in the case of stranded investment resulting from changes in wholesale contracts, FERC requires an approach involving direct assignment of stranded costs to the departing wholesale generation customer through either an exit free or surcharge on transmission. The payment can be made as a lump sum, amortized over a period of time, or assigned as a surcharge on the departing customer's transmission rate. Regardless of the method chosen, the total amount paid must be independent of the amount of transmission services purchased, and therefore will not influence that decision.

The Commission adopts a "revenues lost" formula to determine a departing customer's stranded cost obligation (SCO):

$$SCO = (RSE - CMVE) \times LO$$

where:

RSE = *Revenue Stream Estimate* -- average annual revenues from the departing customer over the three years prior to the customer's departure, less the average transmission-related revenues the utility would have recovered from the customer over the time period under the utility's new transmission tariff. For a retail customer who has become a wholesale customer, distribution revenues will be subtracted from this amount.

CMVE = *Competitive Market Value Estimate* -- determined in one of two ways, at the customer's option: Option (1) is the utility's estimate of the average annual revenues (over the reasonable expectation period (LO) that it can receive by selling the released capacity and energy; or Option (2), the average annual cost to the customer of replacement capacity and energy, based on the customer's contractual commitment with its new supplier(s).

LO= *Length of Obligation* (reasonable expectation period) --the period of time the utility could reasonably have expected the customer to continue to take service.

The formula is subject to several conditions. First, the SCO, quantified as (RSE -CMVE), can be no greater than the average annual contribution to fixed power supply costs, defined as RSE less variable costs. Second, the formula is designed for wholesale and retail-turned-wholesale stranded costs; it is not applicable for stranded costs from retail competition, which will be determined by the states, unless they decline to do so, in which case FERC will decide them on a case-by-case basis. Third, the utility must notify customers in advance of how much their stranded cost obligation would be, and the method by which it is calculated, by filing an estimate of those costs no later than 120 days prior to the end of each wholesale customer's contract term.

Finally, Order 888 allows a customer the choice to market the released capacity and energy, to broker the capacity and energy or contract with either a marketer or broker. If the customer chooses to broker the released capacity and energy, any resulting revenue will offset the utility's estimate of the competitive market value of the brokered capacity and energy. If the customer's brokering efforts fail to produce a buyer within 60 days, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined under the formula.

The FERC believes that giving the customer the option to resell the capacity and energy protects against a utility understating the market value. The Commission also argues that this protects against a utility selling the freed

capacity at subsidized prices to gain a competitive advantage because if the customer avails itself of the option, the utility will no longer control the released capacity.

An up-front estimate of market value for capacity and energy is required for the calculation of this formula. The utility must estimate the CMVE, using its own choice of estimation methods, and make all work papers available to the departing customer. The utility may also sell all or part of its generating assets in order to determine the competitive market value of the assets. The FERC will presume that the competitive market value established under an open asset sale would fully satisfy the utility's responsibility to minimize stranded costs. A stranded cost claim associated with such a divestiture of assets would be measured by the book value less the sale price.

(b) State Authority/California Approach

In cases of stranded costs caused by retail-turned-wholesale customers, FERC will be the primary forum for resolution. However, in the case of stranded costs caused by retail competition, states have jurisdiction over distribution and therefore can require payment of stranded costs in authorizing retail competition programs. Thus, FERC will not play a role unless the state regulatory agency fails to act. However, FERC requires that states not use the transmission grid to recover stranded costs from retail competition, but instead use distribution facilities or other services. A number of states are therefore developing methodologies for stranded cost recovery. These will vary by state, but it is useful to consider the approach being taken in California, where retail competition has developed the most, as a reasonable example of how state programs might work.

As part of the California restructuring plan, stranded costs will be recovered through a Competition Transition Charge (CTC). This CTC is designed to allow utilities to completely recover costs associated with contracts for power and prior regulatory commitments, termed "regulatory assets" by the California Public Utility Commission. In California, a stranded cost is considered to be the net book value of uneconomic generation resources. In addition, the state is also using the CTC to pay for other costs that will be incurred in the transition to a competitive market. These include union labor transition costs, the buyout of QF power contracts, and support of renewable resources and energy efficiency programs. The total cost of stranded cost recovery in California could run up to $30 billion.

The exact amount of the CTC is dependent on the level of prices in the competitive market, and is therefore not known. It will be equal to the difference between current retail tariffs -- which are sufficiently high to pay for the stranded costs listed above -- and the sum of the pool energy price, unbundled transmission and distribution costs and the costs of ancillary services. By one estimate the cost of the CTC could range from $0.023 to $0.033 per kWh. The bulk of the CTC must be recovered by the end of 2001, after which it will be eliminated.

The CTC will be added to the bills of all customers in proportion to their consumption of electricity. It will be reported separately in an "unbundled" bill. The CTC is designed to be "non-bypassable," with a few exceptions. Customers who leave a utility's system entirely will be charged a severance fee rather than the CTC. However, rates are capped so that no customer's rate will be higher than it was on June 10, 1996. In addition, to protect residential and small commercial customers and ensure that they do not shoulder an unjust portion of the CTC burden, residential rates will be reduced by at least 10 percent during the period from January 1, 1998 until March 31, 2002. These rate reductions will be funded by monetizing a portion of the CTC through the issue of revenue bonds secured by expected CTC revenues.

However, critics have pointed out that the law has a number of loopholes through which CTC exemptions can be exploited, making the charge essentially bypassable. For instance, items excluded from CTC liability include: reductions in energy use due to "normal course of business" such as strikes, moving out of state, changes in weather, and lost utility load due to improved efficiency. In addition, irrigation districts, cogenerators, and customers who had already obtained the right to replace utility power with service from federal PMAs have some exemptions. The impact of these potential bypasses is not yet clear.

In general, however, the California experience demonstrates that each state will have to develop a politically acceptable package through which stranded costs can be recovered. The impact on customers will vary depending on the provisions negotiated by state lawmakers, but regardless of the type of transition charge a state adopts, it is clear that its existence in any form will initially reduce the benefits from competition realized by retail customers.

4. Lessons Learned from International Experience

This section highlights some of the lessons learned from international experience with cross-border trading. These lessons are divided into those that are negative -- i.e., unforeseen difficulties that were discovered during implementation -- and positive -- i.e., the benefits realized from cross-border trading.

a) Unforeseen Difficulties

- *Reciprocity of access*: When one system is competitive and the other is not, there is an issue over reciprocity. This manifests itself in a number of ways. In particular, generators in the non-competitive market have access to the competitive system on an anonymous basis while generators from the competitive market are unable to compete in the interconnected system. The interconnected generator(s) gain the benefits of the prices in the competitive market -- which can be assumed to be above the marginal cost of generating in the non-competitive market -- which in a system-to-system trade would have been split between the two systems. Reciprocity of access becomes a major issue once competition in supply becomes established and generators have to start looking to alternative markets to protect their market share.

- *Price paid to interconnectors*: It is logical to assume (as stated above) that interconnected generators only offer to trade through an interconnection when they believe that the prevailing price in the competitive market is higher than the price they would expect to receive in their own market. The issue for the competitive system is the price that these generators should be paid. Should they receive the system marginal price in the competitive system? Should they receive a capacity element designed to signal the need for new capacity within the competitive system? This is one of the most frequent complaints made against interconnected generators from within competitive systems. The concern is that interconnected generators are there when the prices are high but cannot be counted upon when the system needs them. An extreme example of this concern is provided by events in the England and Wales pool in December 1995. The pool purchase price at one point rose above £1000 ($1500) per mWh due to capacity problems in France which resulted in the usual two GW of generation supplied by that country being unavailable.

- *Assumptions regarding provision of ancillary services*: There is a question as to whether interconnected generators should be assumed capable of providing ancillary services such as spinning reserve. This may depend on technicalities such as the type of interconnection, but also depends on where the dispatch priority lays -- with the home system operator or the interconnected system operator. This was one of the concerns addressed in the consideration of the adoption of a pool in Northern Ireland.

b) Positive Features

- *Minimizing impact of constraints*: One of the benefits of interconnected generation is that it can delay (or reduce) the need for strengthening of the transmission network. This can be seen in England and Wales where the French interconnection is joined to the transmission network at the opposite end of the country from the majority of the UK generation.

- *Maximizing the flexibility of different generation types*: Scandinavia best illustrates this benefit of interconnection through its use of hydro powered generation in times of high rainfall and nuclear or fossil fuelled generation during the winter and in times of low rainfall. This flexibility means that each country reduces its own need for additional generation.

- *Minimizing operational difficulties*: Northern Ireland is a good illustration of a country which benefits operationally from interconnection. As noted above, due to the small number of generating stations the system needs to operate with a high level of spinning reserve, to ensure it can cope with a generating set failure. The benefit offered by a stable interconnection with the Republic of Ireland is that it reduces the level of spinning reserve each generating set is required to carry, thereby offering the grid operator additional flexibility on a day-to-day basis via the ability to provide system support.

- *Avoiding the need for new capacity*: Interconnection can mean that a system can operate with its existing level of generation for a longer period than would other wise be the case. Clearly the duration of this benefit will depend on the prevailing price differential between the two systems, the overall plant mix and the

relative costs of new technology over time. This could be seen as a transitional benefit although the long term contracts prevailing in the Scandinavian markets suggest that the benefit may be relatively long lived.

- *Minimizing the usage of high-cost, inefficient plant*: A grid operator operating a system of merit order dispatch will dispatch an interconnected generator rather than an inefficient internal generator. Although this may lead to concerns over stranded costs, from a system and consumer perspective this has been a benefit of interconnection. In the U.K., for example, large amounts of older, less efficient generation capacity have been retired while heavy use has been made of the interconnectors from France and Scotland.

B. Specific Opportunities for Cross-Border Trade & Investment

1. Overview

As explained in Part I, the purpose of this study is to examine the legal and regulatory framework in order to identify the potential for, and impediments to, increased cross-border trade and investment between the electricity sectors of Mexico and the U.S. Preceding sections have focused on the structure of each country's electricity sector, and on the implications for increased electricity trade of the somewhat dramatic changes now occurring in the U.S. This final section applies those findings to four specific options for increasing cross-border activity:

- Option 1: Build generation in Mexico
- Option 2: Build generation in the U.S.
- Option 3: Build Cross-Border Transmission Capacity
- Option 4: Acquire Generation in the U.S.

The major drivers affecting the viability of these options are discussed within the context of three scenarios that reflect different potential electricity sector structures that might emerge from the restructuring process currently underway in the U.S.:

- Scenario A: Move Away from the Market
- Scenario B: Wholesale Competition Only
- Scenario C: Full Retail Competition

This focus on activities in the U.S. reflects the very rapid pace of change in that market, which will have an impact on the viability of the trade and investment options examined. Significant changes have also been undertaken in the Mexican electricity sector, as described above, but it is generally expected that further changes will occur at a different pace than in the U.S. Over the near-to-medium term, therefore, the restructuring events in the U.S. will likely have more impact on cross-border trade and investment opportunities than will the continuing evolution of the Mexican electricity sector.

The next section presents the options selected for analysis, together with the framework within which they were selected, and some broad indicators of the potential magnitude of opportunities represented by each option. This is followed by an explanation of the scenario methodology used, and details of its various components.

2. Identification of Options

The four options described in this section represent broad categories of investment and trade opportunity:

Option 1: Build generation in Mexico

- for export to the U.S.
- for consumption in Mexico

Option 2: Build generation in the U.S.

- for export to Mexico
- for sale in the U.S.

Option 3: Build Cross-Border Transmission Capacity

- for export from North to South
- for export from South to North

Option 4: Acquire Generation in the U.S.

- for export to Mexico
- for sale in the U.S.

With the exception of Option 3, no specific construction sites or existing assets have been examined.[48] Even in the aforementioned exception, the cost estimates provided are rough approximations. This lack of specificity is in keeping with the overall tone and structure of the study, in which the emphasis has been squarely on the impact of the changes now underway in the North American electricity market, rather than on a static analysis of the current situation.

The four options selected for analysis all include incremental investment expenditures for the construction of transmission, which will allow a resulting increase in trade, and three of the options involve the construction or purchase of generation capacity. Opportunities for increasing trade without investment in new transmission are very limited, primarily due to technical constraints, and were described in detail in the DOE-SE Study. Although the existing load and resource situation in each country suggest the most likely direction of trade over the near term, planned capacity additions and retirements will make trade in both directions viable within the medium-to-long term. Both directions are therefore considered in the case of transmission construction by itself (Option 3 below). Similarly, each of the options involving the construction or purchase of generation capacity also raises the possibility of selling the output of that capacity in the country in which it is located. Although this would not result in an increase in the cross-border *trade* of electricity, it does represent an opportunity for cross-border *investment* -- i.e., by investors from the other side of the border -- and is therefore considered as well.

As noted above, all three of the options involving the construction or purchase of generation capacity will also likely require the construction of new transmission capacity, possibly using one of the four specific routes discussed in the description of Option 3 below.

a) Option 1: Build Generation Capacity in Mexico

This option represents the construction of generation capacity in Mexico -- by CFE, Mexican or U.S. investors for export to the U.S., by U.S. investors for sale in Mexico, or for some combination of both. Current and forecast excess generation capacity in the ERCOT and WSCC regions of the U.S., combined with strong demand growth and the current need for additional capacity Mexico, suggest that most new capacity over the near term will be used to supply energy in Mexico. As CFE's investment plan makes clear, however, Mexico may well be in a position to supply energy to the U.S. wholesale market early in the next century.

The best indicator of the magnitude of the opportunity represented by Option 1 is CFE's most recent 10-year planning document which, as described in earlier sections, calls for the addition of 9,766 MW of new (i.e., in addition to that currently under construction) generation capacity by 2005. That information is repeated in Table 9. All of this capacity is open to participation by the private sector. Moreover, 5,428 MW of this capacity is located in the northern one-third of the country, where it could be used for export to the U.S. as well as for sales within Mexico.[49]

[48] Four representative transmission options were presented in Table 4 earlier in the study, and are repeated in Table 11 later in this section.

[49] This figure is the sum of the capacity planned for facilities at the following locations: Cerro Prieto, Rosarito, Chihuahua, Monterrey, Tres Virgenes, Guerrero Negro, Hermosillo, Altamira, Rio Bravo, Saltillo, F. Villa Rep. and Laguna.

Table 9: Planned Additions to Generating Capacity in Mexico -- 1996 to 2005

Project	Location	Type	Service Date (First Stage)	Capacity Requirement (MW) 1998	1999	2000	2001	2002	2003	2004	2005
1 Cerro Prieto II and III	Baja California	GEO	1996		100						
2 Rosarito 7 (Note 1)	Baja California	GT	1996		150						
2 Rosarito 8 and 9	Baja California	CC	1996			450					
3 Chihuahua	Chihuahua	CC	1996				450				
4 Monterrey (Note 2)	Nuevo Leon	CC	1996			450		225			
5 La Venta 1 and 2	Oaxaca	WIND	1996		54						
6 Tres Virgenes	Baja California S.	GEO	1996	10							
7 San Rafael	Nayarit	HYD	1997		24						
8 Pto. San Carlos 4 and 5	Baja California S.	DIES	1997				37.5		37.5		
9 Campeche II	Tabasco/Campeche	CC	1997			225					
10 Guerrero Negro 6 U'S	Baja California S.	DIES	1997		18						
11 El Chino 1 and 2	Michoacan	GEO	1997		50						
12 El Sauz	Queretaro	CC	1997				450				
13 Hermosillo 1 and 2	Sonora	CC/GT	1997				150	225			
14 Altamira (Note 3)	Tamaulipas	CC/C	1997						450	450	
15 Rio Bravo 4 and 5	Tamaulipas	CC	1997				450			450	
16 Saltillo	Coahuila	CC	1998					225			450
17 Tula-San Juan	Hgo.-Qro.	CC	1998					450	450		
18 F. Villa Rep.	Chihuahua	CC	1998						249		
19 El Cajon 1 and 2	Nayarit	HYD	1998								636
20 Leon-AGS 1 and 2	AGS-Leon-SLP	CC	1998					450		450	
2 Rosarito 10 and 11	Baja California	CC	1999						450		
21 Laguna 1	Durango	CC	1999							225	
4 Monterrey	Nuevo Leon	GT	1999							150	
22 Oriental	P. Rica - Tuxpan	CC	1999								450
23 Valladolid	Valladolid	CC	1999								225
	TOTAL			10	396	1125	1538	1575	1637	1725	1761
							System Total:				9766

Notes:

1: If this unit does not enter service on the date planned, it is possible to utilize temporary imports from the U.S.

2: If projects at Nuevo Leon and the Electric Industrial Group are completed, the 450 MW for the year 2000 will not be required.

3: A gas-fired combined-cycle unit will be installed if there is sufficient gas; if not, a dual-fired steam facility of two 350 MW units will be installed.

Technology Key: CC: Combined cycle; GT: Gas turbine; C: Coal; GEO: Geothermal; DIES: diesel internal combustion; WIND: Wind

Source: CFE

b) Option 2: Build Generation Capacity in U.S.

A second option would be to build generation capacity in the U.S. As with Option 1, this investment could be made by U.S. or Mexican investors for export to Mexico, or by Mexican investors for sale in the U.S.[50] As noted above, the current excess capacity situation in the border regions of the U.S. suggests that the former is more likely, but it is possible that new capacity could be profitably built to sell into the U.S. wholesale market as current reserve margins begin to shrink over the next few years. A handful of "merchant" plants -- i.e., non-utility generators that lack long-term power purchase agreements for all or a significant share of their capacity -- have already been announced in the WSCC, although it remains to be seen how many will be built. More importantly, a significant amount of existing generation capacity is scheduled to be retired over the next ten years in the border regions of the U.S., as illustrated in Table 10. In order to compensate for this reduction in supply and forecast increases in demand, border-region utilities are planning to add 18,197 MW of new capacity by 2005, as is also illustrated in Table 10. It should be noted that much of this capacity is scheduled to be commissioned after the turn of the century, which is well into the range of substantial uncertainty in terms of demand forecasting. Moreover, given the current rapid pace of structural change in the U.S. and the relatively stable -- and quite low -- range of wholesale prices, many observers believe that little if any new generation capacity will be added in the U.S. for several years. Despite these caveats, the figures in Table 10 represent the best available information regarding future capacity additions, and are therefore useful as an indicator of potential opportunities under Option 2.

[50] Generation in the U.S. could also be built by U.S. investors for sale in that country, but this would not constitute cross-border trade or investment, as would the other listed ownership possibilities.

Table 10: Generation Retirements and Additions: 1996 to 2005

ERCOT and WSCC (CNV, AZN and RMP Subregions)

		New Capacity				
Region	Retirements	Steam	Combined Cycle	Combustion Turbine/Diesel	Other	Total
ERCOT	1,406	1,893	4,902	724	332	7,851
WSCC (AZN, CNV & RMP)	5,175	3,513	1,392	4,346	1,095	10,346
Total	6,580	5,406	6,294	5,070	1,427	18,197

Source: Energy Information Administration (EIA), Annual Energy Review 1994, DOE/EIA-0384(94).

c) Option 3: Build cross-border transmission capacity

A third option would be to build additional cross-border transmission capacity only, and take advantage of any future differences in wholesale capacity and energy costs between the U.S. and Mexico. As noted above, large amounts of excess capacity and the resulting low wholesale prices in the U.S., combined with strong demand growth and relatively lower reserve margins in Mexico, suggest that the most likely direction of trade over the near term will be from north to south. Such transactions could take the form of the recent CFE solicitation to several U.S. companies for firm power to be supplied over an existing interconnection with El Paso Electric on a year-to-year basis. Alternatively, CFE could purchase energy from the WEPEX, after its inauguration in 1998, from other wholesale power pools that might be created in the region, from the NYMEX exchange for delivery at Palo Verde, or from other bilateral sources using some of the new "products" discussed in earlier sections. The potential for such transactions is limited, however, due to significant north-to-south transmission constraints.

For illustrative purposes, four specific potential interconnections have been identified, which were described in earlier sections, along with a rough estimate of their costs. That information is presented again in Table 11. As might be expected, the key cost drivers are length of the line, number of circuits, and whether DC back-to-back converters are required. Two of the four interconnections are AC links: one from southern California in the U.S. to Baja California in Mexico, which is already synchronous with the rest of the WSCC; and one from Arizona to Sonora, which would involve the isolation of a section of the CFE grid from the rest of the SEN, as discussed in previous sections.

Table 11: Illustrative Potential Cross-Border Transmission Interconnections

(all costs in 1996 U.S. Dollars)

Component	Route			
	Southern CA to Baja California Norte	Southern AZ to Northern Chihuahua	Southern TX to Northern Tamaulipas	Southern AZ to Northern Sonora
Transmission Line				
Length (km.)	230	560	480	180
Tension (kV)	500	345	345	345
Circuits (no.)	1	2	3	1
Cost (US$M)	$60.00	$195.00	$165.00	$40.00
Transformer Banks				
Relationship	500/230	345/230	345/230	345/230
Capacity (MVA)	900	600	600	450
Cost (US$M)	$5.00	$3.50	$3.50	$3.00
Back-to-Back Converters	NA	1	1	NA
Capacity (MW)	NA	450	450	NA
Cost (US$M)	NA	$90.00	$90.00	NA
Compensation	50% (series)	NA	NA	NA
Cost (US$M)	$4.00	NA	NA	NA
Phase Shifters	1 x 600 MVA	NA	NA	NA
Cost (US$M)	$9.00	NA	NA	NA
Right-of-Way				
Cost (US$M)	$3.00	$10.00	$9.50	$2.50
Total Cost (US$M)	**$81.00**	**$298.50**	**$268.00**	**$45.50**
Transfer Capacity (MW)	**600**	**450**	**450**	**250**

Sources: Routes and equipment requirements from CFE; cost estimates from SRP.

d) Option 4: Acquire Generation Capacity in U.S.

The final option examined is the purchase of existing generation capacity in the U.S. -- either by Mexican or U.S. investors for export to Mexico, or by Mexican investors for sale into the U.S. market. Consideration of this option was motivated by the restructuring process in California, which requires that two of the three IOUs in that state sell off 50 percent of their fossil-fuel generation capacity. Given California's history of bold regulatory actions that other states then follow, and the concerns of Congress, the Department of Justice, and energy users over the potential for increased market power as a result of restructuring, this divestiture could potentially be repeated on a mandatory basis in other states. It has already happened on a voluntary basis in the northeast, where New England Electric System recently announced that it would sell all 4,000 MW of its generation capacity.

The quality of the assets to be sold will of course vary, as will their value, depending on factors such as age, current and potential production costs, and proximity to available transmission capacity and load centers. To provide an indication of the assets that might be sold, Table 12 lists the major generating stations owned by the three IOUs in California (Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE)), along with their installed capacity, production cost per mWh in 1995, and generation in the same year. Figure 13 plots the location of those plants within the transmission grid in California. Although one of the utilities affected, PG&E, has proposed four specific plants for sale (Hunters Point, Morro Bay, Moss Landing and Oakland), this selection has not yet been accepted by the CPUC. The other affected utility, SCE, has proposed to sell all 12 of its oil- and gas-fired plants within its service territory.[51] Which capacity will actually be sold, and at what price, is therefore an open question.

[51] SCE also owns shares of plants outside of its service territory.

Table 12: Generation Capacity Owned by California IOUs

Utility	PLANT	Installed Capacity (MW)	Installed Capacity Cost ($)	($/KW)	Net 1995 Generation (mWh)	Production Costs (c/KW)
SCE	ALAMITOS	138	16,723,065	121.07	3,903	14.76
SCE	ALAMITOS	1,982	343,409,398	173.23	5,231,110	2.58
SCE	COOL WATER	580	184,822,993	318.66	813,704	2.3
SCE	COOL WATER	147	30,345,550	206.6	460,286	2.75
SCE	EASTWOOD	200	259,513,841	1298.87	540,359	0.2
SCE	EL SEGUNDO	997	181,108,867	181.74	1,960,517	3.09
SCE	ETIWANDA	911	149,985,507	164.64	1,458,653	3.16
SCE	ETIWANDA	138	14,976,075	108.42	3,263	18.91
SCE	FOUR CORNERS (Note 1)	2,270	1,146,496,445	505.11	14,686,702	1.56
SCE	HUNTINGTON BEACH	138	16,494,045	119.44	2,531	28.97
SCE	HUNTINGTON BEACH	870	151,413,204	173.96	996,523	2.95
SCE	LONG BEACH	587	171,416,457	292.27	125,583	12.4
SCE	MANDALAY	138	16,052,011	116.21	1,320	26.55
SCE	MANDALAY	435	92,695,291	212.99	1,041,291	2.8
SCE	MOHAVE	1,636	489,712,938	299.3	10,128,244	1.81
SCE	ORMOND BEACH	1,613	304,331,159	188.7	1,971,207	2.95
SCE	PALO VERDE	4,210	7,322,568,593	1739.51	26,614,880	2.43
SCE	REDONDO BEACH	1,580	277,552,484	175.72	2,347,771	3.47
SCE	SAN JUAN (Note 2)	1,779	1,772,308,955	996.24	9,926,557	2.52
SCE	SAN ONOFRE	2,254	5,418,199,461	2403.82	13,973,528	2.51
PGE	BELDEN	118	49,472,153	419.61	705924	0.18
PGE	CONTRA COSTA	718	233,034,597	324.56	1141890	2.87
PGE	DIABLO CANYON	2,301	6,515,563,650	2832.14	16269002	1.81
PGE	HELMS	1,053	882,326,512	837.92	774100	1.19
PGE	HUNTERS POINT	56	9,497,735	168.85	1683	14.94
PGE	HUNTERS POINT	371	107,135,607	288.5	965834	3.58
PGE	KERCKHOFF	34	7,900,207	231.81	115930	0.46
PGE	KERCKHOFF 2	140	154,093,011	1104.61	803490	0.23
PGE	MORRO BAY	1,056	306,685,170	290.37	1116011	4.01
PGE	MOSS LANDING	1,624	440,124,761	271.08	6177123	2.53
PGE	PITTSBURG	2,029	516,194,452	254.42	3360706	3.14
PGE	POTRERO	218	62,498,601	286.82	787789	2.13
PGE	POTRERO	201	23,799,289	118.32	10327	56.41
PGE	STANISLAUS	82	18,744,756	228.87	459106	0.32
PGE	THE GEYSERS	1,354	839,454,573	620.07	4000930	2.21
SDGE	ENCINA	982	334,511,281	340.52	1,906,857	3.41
SDGE	SAN ONOFRE (Note 3)	2,254	5,418,199,461	2403.82	13,973,528	2.51
SDGE	SILVERGATE (Note 4)					
SDGE	SOUTH BAY	714	143,948,617	201.64	1,788,282	2.44

Notes:
1. Four Corners capacity values are for the entire Four Corners plant, but SCE only owns part of Units 4 and 5
2. San Juan capacity values are for the entire San Juan plant, but SCE only owns part of Unit 3
3. San Onofre unit 1 was taken out of service in 1992. Values shown are just for San Onofre units 2&3
3. Silvergate units 1&2 were placed in storage 10/1/83, and units 3&4 were placed in storage 1/1/84

Production costs include fuel and operations & maintenance (O&M)

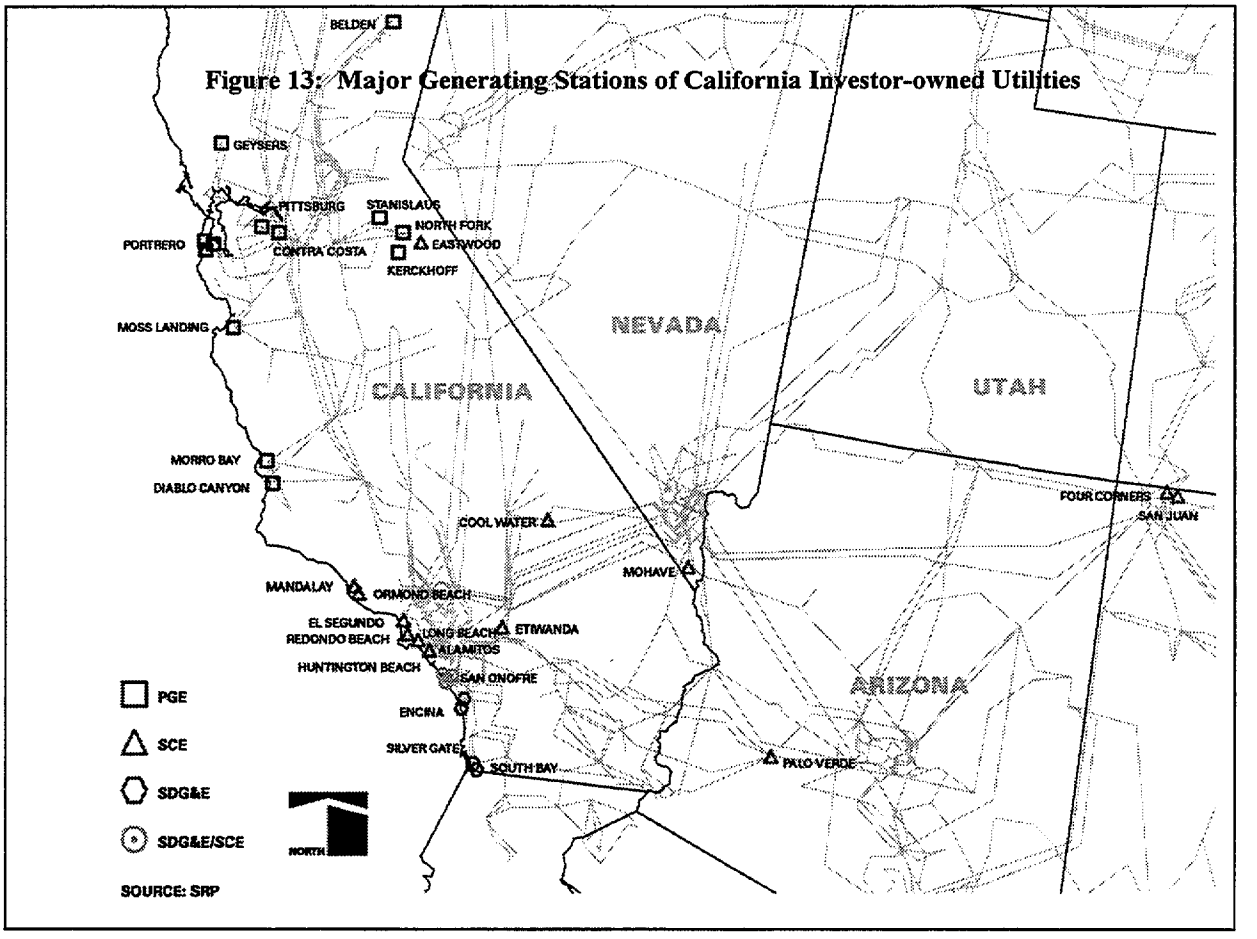
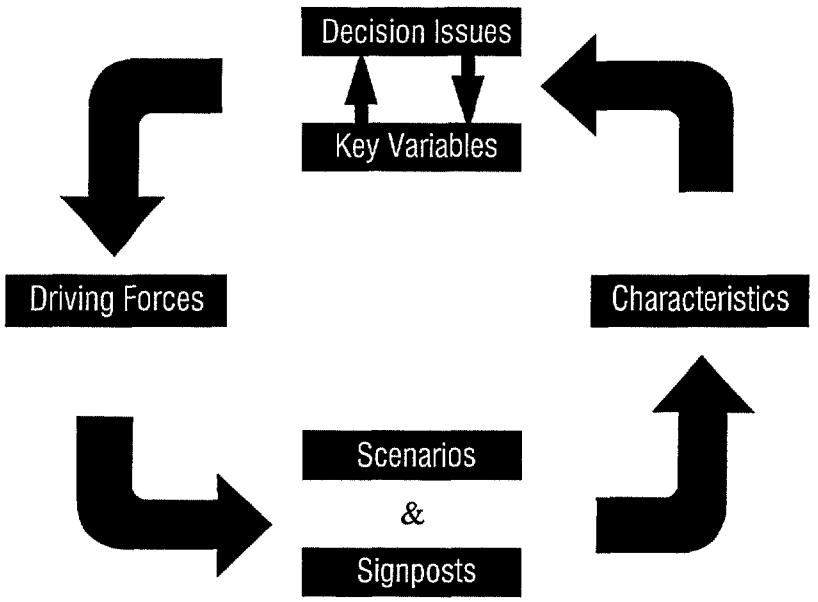


Figure 13: Major Generating Stations of California Investor-owned Utilities

3. Scenario Specification and Methodology

Now that the options under consideration are defined, this section describes the scenario analysis methodology used to examine the impact on the options of various outcomes from the current restructuring process in the U.S. The methodology relies on the step-by-step development and examination of several analytical "tools" or concepts, a process which is represented schematically in Figure 14. Each of the concepts and their role in the scenario analysis are described briefly below, and in more detail in the following sections.

Figure 14: Scenario Development Methodology



Decision issues	Those decisions that must be taken in the future. These are the decisions to undertake the investments described by each option above.
Key variables	The basis on which the decisions will be made. These are the factors that determine whether a particular option is viable -- e.g., wholesale power prices, regulatory and legal constraints, etc.
Driving forces	The forces that shape the scenarios. These are the underlying elements of the scenarios, which correspond roughly to the driving forces that have shaped the U.S. electricity industry to date, as discussed in previous sections.
Scenarios and Signposts	The different possible objective conditions, or "states of the world", that might result from the current restructuring of the U.S. electricity market. Each scenario will have certain "signposts", or early indicators, such as price trends and key events, which may be monitored in order to determine which scenario is emerging as the actual outcome.
Characteristics	The values of the key variables under each scenario. These are the observable results of the scenario, expressed in terms of the key variables of interest for this study. For example, the wholesale power price variable would have a high value in a scenario that involved a reduction in current levels of wholesale competition and a return to more intensive regulation. Predicting the likely characteristics of each scenario brings the process full circle, allowing an evaluation of the impact of the scenario on each of the identified investment opportunities.

It should be stressed that while this type of scenario development process is quite useful for quantitative analysis, the focus of this study is on legal and regulatory issues, which are more qualitative in nature. Although laws and regulations affecting the power sector have very real financial and economic consequences, they are generally specific to a particular situation. Such consequences are discussed in the analysis that follows, but only in terms of the relative impact of the different scenarios. Thus, while the price of wholesale power will likely be one of the primary variables determining the relative attractiveness of the different options, no attempt is made to quantify that impact, nor to estimate the price levels that might be realized under the different scenarios.

a) Key Variables

This section describes the four categories of key variables that have been identified as critical for the viability of the options discussed above:

- Economic -- e.g., prices for fuel, wholesale electricity, transmission services, etc.
- Technical -- e.g., reliability, stability, capacity constraints, etc.
- Legal -- e.g., taxation, export licensing, etc.
- Regulatory -- e.g., transmission access, jurisdictional issues, permitting requirements, etc.

It should be noted that not all variables will have equal importance for each investment option, nor under each scenario. In fact, some variables and their related characteristics may not change at all under different scenarios, and others may not change in ways that are predictable. Those variables are included in the sections below in the interest of completeness, and have been examined at length in previous sections of this study. The focus in the remainder of the study, however, will be on those variables and their related characteristics that are most important for the investment option and/or scenario under discussion, and can be discussed with some degree of confidence within the context of the scenarios examined.

(1) Economic

There are four key economic variables relevant to this study: fuel prices, wholesale electricity prices in the border regions of the U.S., transmission tariffs in the U.S. and Mexico, and interest rates. Fuel prices associated with different technologies and their relationship to wholesale electricity will be a key determinant in the decision whether to invest in transmission capacity only, or to build or purchase generation capacity as well. All other things equal, an increase in the price of fuel relative to that of wholesale electricity will make the generation options less attractive, since any generation unit must compete directly or indirectly with the wholesale electricity market in the U.S. under current circumstances. Wholesale electricity prices will be one of the most important economic variables for all options, for the same reason. Transmission tariffs, under the assumption of generation surpluses, will determine the distance over which differences in relative generation costs, or between generation costs and wholesale electricity prices, will justify investment in transmission and/or generation capacity. Finally, interest rates will help determine the attractiveness of investing more capital -- i.e., for transmission and generation capacity -- versus less capital -- i.e., investing in transmission and purchasing wholesale electricity.

While the prices of fuel, electricity and transmission will almost certainly be different under each of the scenarios described below, fuel prices are also dependent on a variety of economic, political and other factors outside the scope of this study. Fuel prices therefore will not be discussed as a characteristic of the scenarios. Interest rates, while important for determining the viability of the options, have no obvious relationship to the scenarios evaluated, and therefore will also be omitted in the discussion of scenario characteristics.

(2) Technical

The technical variables relevant for the four options fall into two categories. The first category includes the reliability and stability considerations associated with synchronous operation of the two countries' electricity grids, which were discussed in earlier sections. These considerations are important for any option involving the construction of additional interconnection capacity, since they mandate the use of either an expensive back-to-back converter station, or of load isolation. The second category encompasses the physical constraints on parallel path

flows that limit the flow of electricity to the border region in both countries. The option of strengthening the AC interconnections was considered and eliminated in the DOE-SE Study.

These technical constraints have already been explicitly incorporated into the development of the four transmission interconnection possibilities described above. Parallel path flows might change under different scenarios, but such changes are impossible to predict, and reliability and stability considerations are unlikely to change at all.[52] Technical variables are therefore not included in the discussion of scenario characteristics.

(3) Legal

Several legal issues affect the viability and attractiveness of the different investment options, the most important of which are taxation, export licensing authority and dispute resolution mechanisms. While these issues are of crucial importance, they were discussed at length in earlier sections. Moreover, they also do not impact the investment options in different ways, and are unlikely to change under different scenarios.[53] Legal variables are therefore omitted from the discussion of scenario characteristics.

(4) Regulatory

A variety of regulatory variables will influence the attractiveness of different investment options, and are also likely to change somewhat under different scenarios. The most important of these are transmission access and pricing, jurisdictional questions, the process for and pricing of generation divestiture, and permitting requirements for generation and transmission projects. Transmission pricing is appropriately considered above as an economic variable, but the method used to determine that pricing is a regulatory issue. Transmission access within the U.S. will be a key determinant of the degree of competition in the wholesale and retail markets in that country, which will in turn impact wholesale electricity price levels and the viability of various import and export opportunities. Jurisdictional issues between federal and state regulatory bodies in the U.S. could have an impact on the eventual level of competition that is achieved, the timeframe over which it occurs, and the regulatory treatment of specific cross-border issues. Finally, permitting requirements will have a major impact on whether some projects are viable at all, and if so at what cost.

Some of these variables and their related characteristics will likely change under different scenarios, and will therefore be discussed as appropriate to the specific investment option and scenario.

b) Driving forces

As noted above, the driving forces behind the scenarios are derived from those that have shaped the U.S. electricity sector for some time. While earlier sections described these forces in terms of their impact on developments to date, the focus of this section is the future, and specifically how these forces are shaping the current restructuring process. The driving forces identified for purposes of this scenario analysis are as follows, and are described in more detail in the paragraphs below:

- High retail electricity prices
- Technology
- Environmental concerns
- Legal and regulatory developments

[52] This does not mean, however, that reliability and stability considerations have nothing to do with the scenarios. They are in fact explicitly incorporated into Scenario C, as described below. The different scenarios do not suggest, however, that reliability and stability standards and procedures will be relaxed or enhanced in ways that materially affect the attractiveness of the various investment options.

[53] Legislative mandates regarding market structure have a clear impact on many of the variables in several categories. Such mandates are a driving force behind the scenarios, however, rather than determinants of the viability of a particular option. They are therefore considered in the following section.

(1) High Retail Electricity Prices

Of these driving forces, retail electricity prices are clearly among the most important. Residential, commercial, and industrial customers in the U.S. have seen a decline in real prices of 15, 24 and 33 percent, respectively, since 1982. The perception is still strongly held, however, that retail electricity rates are too high. This perception is driven largely by the significant price disparities that exist among customer classes and regions, and by the fact that the cost of electricity from new generation capacity is currently below the average cost of existing generation. The decline in generation costs realized over the last several years is a result of both advances in technical efficiency and a steady decline in the real cost of fossil fuels. Regardless of whether electricity prices are high or not in historical terms, the pressure to reduce them is strong and increasing, and will be a factor in any future scenario. What will differ among the scenarios is the importance of prices relative to other considerations.

(2) Technology

Technology will likely continue the key role it has played in the evolution of the North American electricity sector. As described earlier, this role has in the past been related primarily to economies of scale in generation, which increased continuously until the introduction of high-efficiency combined-cycle units in the 1970s. Economies of scale are now assumed to reach their peak at about 250 MW. The much smaller capital requirements of such units have been one of the key factors leading to the introduction of a competitive wholesale market in the U.S. While there is some scope for this trend to continue in the form of distributed generation, a potentially more important development is the increasing computerization and automation of electricity supply and consumption.

On the supply side, more sophisticated metering now allows detailed load profiles to be constructed, which will allow suppliers -- including power marketers, load aggregators and other non-utility market participants -- to tailor products that lower the overall cost of energy for particular customers or classes of customers. This sophistication is mirrored on the demand side, where energy services companies are now able to computerize and integrate an entire building and/or company's energy system in order to lower total energy costs by responding to time-of-use prices and other incentives for demand-side management. While technology will continue to advance under any potential scenario, it will be developed and introduced at a much more rapid pace in those scenarios that allow electricity prices to be driven primarily by market forces.

(3) Environmental Concerns

Environmental concerns have been responsible for several significant trends in the electricity sector, as described earlier. These concerns are now firmly entrenched in the planning process and operation of generation capacity, in particular. Regardless of which scenario is imagined for the future, it is unlikely that concern with the environmental impact of electricity generation will relax to the point where regulation of plant construction, emissions, etc., is significantly loosened. Environmental concerns are more likely to shape future events through their potential impact on the overall structure of the market.

State-level regulation has provided an effective mechanism for the incorporation of environmental concerns into the utility planning process. Regulators have required that utilities use Integrated Resource Planning (IRP) to examine both demand- and supply-side options to meet forecast increases in demand. They have also used the monopoly status of many utilities to cross-subsidize Demand-Side Management (DSM) programs that might be economically, but not financially viable. The combination of reduced regulation and market-based prices that appears to be evolving raises questions regarding whether this type of activity can be sustained in the sector structure that emerges from the current process. Some observers concerned with the environmental consequences of the electricity sector have therefore voiced opposition to certain aspects of the structure that appears to be developing. Either an increase in this type of concern, or perhaps a single major event with environmental consequences, could therefore slow the momentum toward market-based restructuring. It is this type of impact that is taken into account in the scenarios described below.

(4) Legal and Regulatory Developments

Legal and regulatory developments have in many ways been responses to the other driving forces described above. The series of laws and regulatory orders described earlier in this study largely addressed specific perceived problems in the electricity sector -- such as the rise of large holding companies able to exercise monopoly power -- or

attempted to impose order on a sector that was perceived to be in disequilibrium. Laws and regulations also reflect the political and ideological context of the period. The FPA was enacted at a time when the abuses of large companies in many areas of the U.S. economy were being addressed, and both the EPAct and FERC Order 888 were developed during a world-wide movement toward more open intra- and international markets.

There is no reason to expect that this pattern will change in the future. Legal and regulatory activities could therefore shape future scenarios either by institutionalizing and accelerating trends already underway -- as FERC Order 888 and California's restructuring legislation appear to do -- or by reflecting a change in public and and/or sector sentiment regarding the benefits and costs of a market-based electricity sector. Such a change could occur in response to a signal event -- such as large-scale blackouts and/or a high-profile environmental situation -- or as a result of gradually rising concern about the effects of a competitive marketplace on the environment, residential customers or system stability and reliability.

c) Scenarios and Signposts

This section describes the three scenarios developed to take account of these driving forces. The feature that differentiates one scenario from another is competition. The three scenarios therefore correspond to models 2 (single buyer), 3 (wholesale competition) and 4 (retail competition) of the alternative market structures described in previous sections.

- Scenario A: Move Away from the Market (single buyer)
- Scenario B: Wholesale Competition Only
- Scenario C: Full Retail Competition

While another metric, such as the level of regulation, could also have been used to differentiate the three scenarios, the existence and level of competition are the most fundamental attributes of a given market, and will therefore largely determine opportunities within that market. It should be stressed that none of the three scenarios should be considered to be the "base case", in the sense that it represents an expected outcome. No attempt to predict which of the scenarios is most likely is made in this analysis, although Scenario B corresponds most closely to the existing situation in the U.S.

Each of the scenarios is described briefly in the remainder of this section, along with the characteristics of that scenario -- i.e., the observed values of the key variables -- and any "signposts", or leading indicators, that might be observed if the Scenario comes to pass.

(1) Scenario A: Move Away from the Market

Under Scenario A, environmental and/or legal and regulatory events would be the key driving forces. A "watershed" environmental or system reliability event -- such as a third blackout in the WSCC caused by problems at the California/Oregon border -- would raise public awareness of the restructuring process, and provide a focal point for opponents of market-based changes. Alternatively, as noted above, a general rising level of concern over these or other issues could lead to legislative or regulatory efforts to halt the move toward market-based reforms. Under either situation, the market-based structure would be replaced by a return to increased regulatory control. The other driving forces -- high retail prices and technology -- would still remain, however. The wholesale market would therefore be replaced by returning to a PURPA-style solicitations for new generation capacity. Solicitations would be implemented by an IRP process, with renewed emphasis given to DSM and marginal cost pricing. If the concern or event that results in this scenario were environmental, the merit-order dispatch and ultimate cost of generating capacity could also be affected by an emissions "adder" attached to each unit's variable operating cost, providing gas and renewable technologies with a strong competitive advantage vis-a-vis coal and oil. If the concern or event were related to reliability, reserve margins could be increased, either voluntarily by the NERC, or by legislative or regulatory action. High retail prices would also result in agreements to replace cost-based regulation with performance-based regulation, to provide increased incentives for cutting non-generation operating costs.

The characteristics of Scenario A would be as follows:

- Wholesale electricity prices will rise as the wholesale market dwindles, especially if reserve margins are increased due to reliability concerns. This impact may be mitigated somewhat by a more effective solicitation process for new capacity and cost-reduction measures induced by performance-based regulation. These impacts will likely be small, however, compared with the large price reductions that have resulted from wholesale competition.
- Transmission tariffs will probably stay at their current levels, since the Order 888 tariffs already filed with the FERC both provide uniformity among utilities and are cost-based, and therefore compatible with a return to increased regulation.
- Transmission access will likely be significantly curtailed, however, especially if reliability concerns are important. If that access is reduced, it could also be accompanied by increased control of cross-border trade between border utilities.
- State regulatory bodies would likely regain jurisdictional control over some activities recently claimed by the FERC, although this might not be the case if federal legislation is enacted that defines the structure and operation of the sector.
- Permitting requirements for generation and potentially transmission could become more restrictive. This is especially true if environmental considerations result in the enlargement of emissions control areas to include contiguous areas in Mexico, or if generation built in Mexico for export to the U.S. would have to count those emissions as occurring in the U.S.

The signposts associated with this scenario could include the following:

- A watershed event of the type described above
- A notable increase in press coverage of the perceived negative impacts of market-based restructuring
- Announcement of a serious legislative initiative to change or reverse the course of restructuring
- A change of course by the CPUC or other national leader in regulatory reform

(2) Scenario B: Wholesale Competition Only

Under Scenario B, legal and regulatory events would again take precedence, but with less significant consequences. Due to poor results from retail competition pilot programs or full implementation in selected states, or successful court challenges to the California plan and/or its followers, restructuring efforts would essentially come to a halt. Wholesale competition would remain intact, with the markets maturing as trading volume and intermediary activity increases, but retail competition would not be realized. Wholesale competition could be implemented through a power pool mechanism and an ISO, such as in California, or through bilateral contracts and an ISO, such as is occurring in Texas. The specifics of the mechanism used may have some impact on the characteristics important for this analysis, but whether or not wholesale competition occurs is far more important than the specific arrangements used.

The characteristics of Scenario B would resemble those of today's market, with some modifications:

- Wholesale electricity prices would probably maintain their current level until reserve margins tighten to the point where excess capacity is required, at which time they would begin a gradual increase.
- Transmission tariffs would remain at the levels and in the format specified by Order 888, and the CRT would be indefinitely postponed.
- OASIS would come on line in an effective sense sometime in 1997.
- Jurisdictional divisions would continue in their present form, with the FERC and DOE continuing their role as strong advocates of competition and its requirements for open access and transparent pricing.

- Because the restructuring process would be slowed somewhat from its current pace under this scenario, it is likely that adequate provisions would be made to ensure that any generation capacity divested by existing utilities would sell for something close to its fair market value.
- Permitting requirements would also remain as they are, although some evolution might occur as new generation starts to be built in the U.S. on a significant scale, which has not occurred for several years.

The signposts for Scenario B could include the following:

- News of poor results from retail competition pilot programs -- e.g., no significant price decrease for residential customers, lack of interest, successful retention of customers by the distribution utility
- Successful court challenges to retail competition in California or other states with planned implementation set for 1998
- Announcement of a serious legislative initiative to prohibit or limit retail competition

(3) Scenario C: Full Retail Competition

Under Scenario C, the driving forces of high retail prices and technology would be allowed to shape the market, with legal regulatory developments encouraging that process, rather than hindering it, and no significant role for environmental concerns. The California model or a variation of it would essentially be replicated throughout the country, either region by region or through a national plan mandated by Congress, probably through the delegation of authority for such a plan to FERC. State-level arrangements would probably give way to regional ones, with boundaries determined by the transmission grid and the location of major generation and load centers, rather than state boundaries. ISOs would almost certainly be used, in order to implement regional coordination of transmission, and formal power pools might be used as well. As with Scenario B, however, the exact mechanism used for the wholesale market is less important than the fact that competition would be extended to retail customers. One exception to this rule, for the purposes of this study, is the mechanism used for transmission pricing.

Many of the characteristics of Scenario C depend largely on specific regulatory decisions taken during the restructuring process, but the solutions used by California provide a guide to how those decisions might look:

- Full retail competition will mean lower retail prices, as pressure is placed on retail margins (i.e., the spread between retail and wholesale prices). Since the wholesale market is already competitive, little if any new pressure will be added to wholesale prices. The retail margin would likely be squeezed significantly as aggressive retail marketing takes hold. As in Scenario B, wholesale prices will likely maintain similar levels as today, fluctuating around a nominal value based on seasonal and other short-term factors.
- The stranded cost recovery mechanism will have a significant impact on the amount of price reduction seen by retail customers. While the quoted retail price may be lower, any transition charge to pay for stranded costs will tend to equate the old and new retail prices. Full stranded recovery, by definition, means that in the aggregate there will be no savings to customers until the stranded costs are fully recovered and the retail market is fully competitive with no "adders" to account for lost revenues.
- Transmission tariffs in this Scenario would probably change from the single charge per KW per time period required by Order 888 to some form of congestion-based tariff, or the CRT proposed by FERC.
- If retail competition on a regional or national level is implemented, it seems inevitable that FERC will play a larger role, despite the clear deference to state regulatory authorities exhibited in most aspects of recent decisions. This is especially true if federal legislation is passed that mandates retail competition, since FERC would likely be the vehicle by which that mandate is implemented.
- If divestiture of generation capacity is required as part of the move to full retail competition, the rapid pace of the restructuring process under this scenario raises the possibility that those assets could be sold for less than their fair market value, possibly at a price determined by regulators. Proposals are being considered in

California to prevent this occurrence, by putting the assets into a trust until the pool prices become transparent, but it is unclear at this stage whether those proposals will be enacted.

- Permitting requirements would likely not change under this scenario.

Signposts associated with Scenario C could include:

- A positive reception to the promised introduction of federal legislation mandating retail competition early in the new Congress
- Acceptance of retail competition by groups representing residential customers
- Positive results from current and planned retail competition pilots creating pressure for full implementation in the utility's service area and for similar steps in neighboring regions

d) Summary

The key characteristics of the three scenarios are summarized in Table 13:

Table 13: Characteristics of Restructuring Scenarios

Characteristic	Scenario A: Move Away from the Market	B: Wholesale Competition Only	C: Full Retail Competition
Economic	• Wholesale electricity prices rise as competition reduced • Transmission tariffs remain as filed for Order 888	• Wholesale electricity prices steady over near term, rise as reserve margins tighten, but at slower rate than Scenario A • Transmission tariffs remain as filed for Order 888	• Wholesale electricity prices steady over near term, rise as reserve margins tighten, but at slower rate than Scenario A • Stranded cost recovery delays retail price cuts • Transmission tariffs based on congestion pricing
Technical	• No change	• No change	• No change
Legal	• No change	• No change	• No change
Regulatory	• Reduced transmission access • Increased state regulatory jurisdiction • More restrictive permitting	• OASIS comes on-line in 1997 • Generation capacity sold at fair market value • No change in permitting	• OASIS comes on-line in 1997 • Increased FERC jurisdiction • Generation capacity could be sold at less than fair market value • No change in permitting

As the discussion in this section makes clear, opportunities for cross-border trade and investment depend on a variety of variables – economic, technical, legal and regulatory. This complexity is increased by the uncertainty surrounding many of these variables due to the evolution of the U.S. power sector. Moreover, while changes in the U.S. power sector have been the main focus of this study, significant changes are also underway in the Mexican power sector. These must also be assessed to adequately identify cross-border trade and investment opportunities.

Scenario analysis is a necessary tool for integrating the consideration of particular options with possible outcomes of power sector evolution. This study examines four broad investment options and three scenarios for the development of the U.S. power sector in order to illustrate the variety of issues that must be addressed. The analysis of any specific investment option, however, must be undertaken on a case-by-case basis, precisely because of the multitude of influences that affect its viability. While such analysis is beyond the scope of this study, the issues raised, as well as the scenario methodology used, will hopefully provide a useful starting point for its undertaking.

C. Conclusions

This section presents some of the conclusions that can be drawn from the analysis presented in this study, which can be organized into four broad categories.

1. Gains from Increased Trade and Integration

One of the most important and robust conclusions to emerge from this study is that there are significant potential gains available from increasing the coordination and integration of the Mexican and U.S. power systems. This conclusion is borne out by previous experience on the border, as well as by international experience with increased system integration and cross-border trading.

- The long history of cross-border coordination and trading between Mexico and the U.S. has already yielded substantial benefits for each country:
  - Excess geothermal capacity in Baja California Norte has served the large demand in southern California at a relatively low cost, while at the same time providing revenue to service the capital costs of those facilities until demand in Baja increases sufficiently to utilize their full capacity.
  - Similarly, regions of Mexico remote from the SEN have been served by interconnection with neighboring U.S. utilities at a fraction of the cost required to extend service from the SEN.
  - Existing agreements between CFE and neighboring utilities in the U.S. have provided valuable backup and emergency capacity.
  - CFE purchases of power from U.S. utilities have allowed it to meet WSCC stability criteria in the Baja California Norte power grid without the need for substantial new investments.
- While benefits to date have been substantial, the recent changes in both countries discussed in this study have made their electricity markets more diverse and competitive, creating additional opportunities for cross-border coordination, trade and investment. It must be emphasized, however, that these opportunities are made available not as a result of the regulatory and legal changes themselves, but rather as a result of the increased integration and coordination between systems that such changes make possible. Moreover, as noted in the study and in other conclusions below, regulatory and legal changes are responses to other developments, and in particular to the dramatic increases in generating efficiency made possible by continuing technological advances.
- The potential magnitude of these additional opportunities is suggested by previous international experience. Benefits from increased system coordination and trading have been primarily of three types, as is illustrated by the experience of various Western European countries:
  - Reduced need for new capacity, as has been the case in England and Wales, through its interconnection with France, and in Scandinavia, where the integration of three national systems has reduced the need for new generation capacity in each.
  - Operational benefits, as in the case of Northern Ireland, where a strong interconnection with the Republic of Ireland has reduced the amount of spinning reserve required to be carried by each of its small number of generating stations.
  - Reduced need for additional transmission investment, as in England and Wales, where interconnection with France has relieved the capacity constraints caused by a predominantly one-way flow of energy toward London from the rest of the country.
- Additional benefits are available from increasing the integration of the larger energy markets in Mexico and the U.S. These opportunities are made possible by the integration of electricity and other energy markets that is already occurring on each side of the border. This trend is the most visible in the case of electricity and gas, where mergers between electric and gas utilities have speeded the convergence of those markets.

Such convergence is likely with other fuels as well, however, such as coal and fuel oil, although the extent of convergence will depend ultimately on how substitutable one fuel is for another, as well as the alternative uses of each.

2. Investment Opportunities

In order to realize the benefits of increased integration and trade, investments in transmission, generation and system coordination will likely be necessary. While such investments are in general desirable, the analysis of specific opportunities in the context of different competitive scenarios undertaken in this study illustrates that no general conclusions can be reached regarding the attractiveness of particular types of investment without considering the broader environment in which those investments will be made. Similarly, the specifics of each project are unique, and will ultimately determine its viability; they must therefore by carefully analyzed on a project-specific basis.

- In the case of transmission, the viability of a specific project will depend very much on factors such as the loads and resources in each region and the resulting market price of power, the terrain over which the line is routed, and the need for DC converters, as well as a variety of other variables that will depend on which competitive scenario is realized. Due to the changing nature of the power systems on both sides of the border, additional routes should be continuously investigated and evaluated.

- In the case of generation, the factors determining the viability of a specific project will include loads and resources in the region, fuel prices, and technological developments, as well as the scenario-specific variables described above. Generation projects will often be linked to new transmission capacity, as well, as was emphasized in the description of investment opportunities in this study.

- In order to achieve true integration, however, generation and transmission projects should not be analyzed in isolation, but rather as part of a larger analysis that includes all potential resources in both countries. Such coordination offers the best opportunity to maximize the benefits of cross-border trade and investment.

- As private and/or non-utility investment plays a greater role in the financing of generation, the type of financial arrangement used will have different impacts on the cost of energy. The financial impact of different arrangements should be evaluated, and used to formulate policies that lead to an equitable sharing of risks between utilities and independent generators while ensuring the lowest possible cost of electricity.

3. Legal and Regulatory

Although this study described a variety of important legal and regulatory changes in both countries that have taken place in the last several years, many important cross-border issues have not been resolved by the regulatory bodies and/or courts of Mexico and the U.S.

- The status of a non-U.S. entity under the Federal Power Act and FERC Order 888 is not yet defined. A resolution of that issue would facilitate the integration of the two countries' power grids.

- Regulatory and legislative changes continue to occur in both countries, which will impact the attractiveness of various cross-border trade and investment opportunities, and the possibility of greater integration and coordination. Developments in both countries should therefore be closely monitored by market participants and official agencies. As a way to increase communication between these entities, informal discussions regarding general developments and specific issues in each country could be held on a regular basis.

4. Technical, Financial and Economic

As noted above, the legal and regulatory changes described in this study are in general responses to more fundamental underlying technical, financial and economic forces, which will continue to play a key role in the evolution of the Mexican and U.S. power systems.

- Advances in technology will be particularly important. Further increases in generation efficiency will bring down the price of energy, while advances in metering, communications and information technologies will

increase the potential benefits from cross-border trade and integration and speed the process of fuel convergence.

- High retail electricity prices and the pressure to reduce costs will remain strong forces for change in the U.S. power industry. Whatever course restructuring efforts take, therefore, will likely include measures that respond to these concerns. This is especially true in the case of retail electricity prices, which must fall along with commercial and industrial rates to avoid strong resistance to change on equity grounds.

D. Suggested Next Steps

In order to build on the bi-national effort undertaken for this study, the following list summarizes suggestions for additional steps that could be taken to facilitate the process of cross-border trade and investment.

- Identify forums to improve communications and cooperation among CFE, other relevant Mexican government entities (such as CRE), and FERC. This dialog should include discussion of the "safe harbor" provisions of FERC Order 888.
- Explore additional transmission interconnection opportunities. This should include a re-examination of the technical feasibility of additional AC interconnections between CFE, WSCC and ERCOT.
- Undertake a joint study of gas/electricity links for cross-border activities.
- Analysis of optimal project finance "modes" to facilitate cross-border activity.
- Continued monitoring of legislative and regulatory developments in both countries.
- Investigation of ways to standardize contractual arrangements.

Appendix A: Glossary of Electricity Industry Restructuring Terms

This glossary contains terms that are relevant to the restructuring process now underway in the United States. Italicized words indicate a related entry in the glossary.

Affiliated Power Producer (APP) Unregulated affiliates of *Public Utilities* that engage in the generation of electricity. APPs are one of two types of *Exempt Wholesale Generator*, which are in turn a class of *Non-Utility Generator*. The other type of EWG are *Independent Power Producers*, which are not affiliated with *Public Utilities*.

Ancillary Services Services typically provided as part of B*undled* transmission service, but which must be offered separately under the *Pro Forma Tariff* required by FERC *Order 888*. These services include at a minimum: scheduling; system control and dispatch; reactive supply and voltage control; regulation and frequency response; energy imbalance service; spinning reserve; and supplemental reserve.

Available Transmission Capacity (ATC) FERC *Order 889* requires that all *Transmission Providers* post the transmission capacity expected to be available on their system (Available Transmission Capacity), as well as the *Total Transmission Capability (TTC)* of that system for each *Posted Path*, which includes any transmission path that a customer might want to use.

Bundled The various services and products that comprise delivered power -- energy, transmission service and distribution service – have traditionally been bundled together as a single product. These services and products can also be offered on an *Unbundled* basis, as can their component parts. Generation and transmission can be offered separately, for example, and transmission service can be further unbundled into the transmission of power and its associated *Ancillary Services*.

Capacity Reservation Tariff (CRT) FERC's *CRT-NOPR* proposed to replace the *Network and Point-to-Point Transmission Services* required in the *Pro Forma Tariff* contained in FERC's *Order 888* with a CRT. Under the proposed CRT, utilities and all other power market participants would reserve firm rights to transfer power between designated receipt and delivery points.

Comparability The principle established by FERC to ensure that *Transmission Providers* offer service on their transmission system that does not put the purchaser of that service at a disadvantage relative to the provider. The comparability standard requires that a transmission provider offer transmission access to other parties "on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."

Competition Transition Charge (CTC) A non-bypassable charge to be assessed on all current California retail customers as a way to compensate utilities for the value of S*tranded Investments* in generation assets.

Congestion-Based Transmission Pricing A method of *Transport Transmission Pricing* that takes account of the relative congestion of different transmission paths, providing an incentive for users of transmission services to take into account the economic cost of those services, and for new generation capacity to be sited in locations that will not exacerbate transmission constraints.

Contract for Differences (CfD) A bilateral financial arrangement used in England and Wales. These contracts are struck between two parties in order to maintain a stable income stream, and are generally related to the expected pool price. Differences between the actual pool price and a contractual strike price are paid by the two parties, so that the total price paid for energy procured from the pool is equal to the sum of the pool price and payments made or received via CfDs

CRT-NOPR FERC's Notice of Proposed Rulemaking that introduces its proposed *Capacity Reservation Tariff.* This NOPR was issues at the same time as *Orders 888 and 889.*

Energy Policy Act of 1992 (EPAct) Title VII of the EPAct encouraged development of the wholesale power market in the U.S. by: 1) creating a new class of generating company, *Exempt Wholesale Generators*, that are exempt from *Public Utilities Holding Company Act of 1935 (PUHCA)*; and 2) expanding the FERC's authority to approve applications for transmission services.

Exempt Wholesale Generator (EWG) A class of generators, created by the *Energy Policy Act of 1992 (EPAct)*, that are exempt from the ownership restrictions of *Public Utilities Holding Company Act of 1935 (PUHCA).* The two categories of EWG are *Independent Power Producers (IPPs)* and *Affiliated Power Producers (APPs).*

Federal Power Act (FPA) The FPA was originally passed in 1920 but modified when it became part of the *Public Utilities Holding Company Act of 1935 (PUHCA).* It brought interstate transactions under federal authority by prohibiting states from regulating interstate pricing and trade of electricity and assigning that responsibility to the Federal Power Commission (FPC, which later became FERC). The FPA has been the key legislative vehicle for federal regulation of electricity ever since.

Independent Power Producer (IPP) *See Affiliated Power Producer (APP).*

Independent System Operator (ISO) An independent entity that exerts technical control over a utility control area. ISOs are responsible for generation dispatch as well as for frequency and voltage control, and therefore must be independent from the financial arrangements entered into by market participants. ISOs can be implemented in conjunction with a *Power Pool*, as in California or England and Wales, or without a pool, as in Texas.

Jurisdictional Utilities *Public Utilities* whose interstate activities fall under the jurisdiction of FERC, and are therefore directly affected by FERC *Orders 888 and 889. See also Non-Jurisdictional Utilities.*

Load Aggregator Companies that consolidate the electricity requirements of multiple customers, or multiple sites owned by the same customer, in order to increase bargaining leverage and reduce the cost of purchasing electricity.

Mega-NOPR Two concurrent *Notices of Proposed Rulemaking (NOPR)* issued in March 1995, which proposed to require utilities to provide *Open Access* to the interstate transmission network in the U.S. in order to facilitate a more competitive wholesale electric power market. After receiving comments, FERC issued *Orders 888 and 889*, the final rules on *Open Access, Stranded Costs*, and real-time information system requirements.

Network Transmission Service One of two types of transmission service required by the *Pro Forma Tariff* in FERC's *Order 888.* Network service allows the user to vary the schedule, points of delivery and receipt without incurring an extra charge for each change. *Point-to-Point Transmission Service* is also required.

Nodal Transmission Pricing A method of transmission pricing under which the seller or buyer simply pays the spot price prevailing at his "node" of the transmission grid, and does not pay an explicit transmission charge. The cost of transmission is assumed to be incorporated into the price differentials between nodes, eliminating the need to schedule and pay for transmission service. This system has the advantage of incorporating transmission constraints into the implicit price of transmission on a continual basis.

Non-Jurisdictional Utilities Public power organizations that are not directly subject to FERC authority. They include federal Power Marketing Authorities, rural electric cooperatives, municipal utilities and state power authorities, and the members of the Electric Reliability Council of Texas (ERCOT). These utilities are not directly affected by FERC rulings on restructuring issues such as *Open Access* transmission because most (with the unique exception of federal PMAs) are authorized by state or municipal authority and therefore not subject to federal regulation. Certain activities they may engage in, however, such as requesting transmission services from a *Jurisdictional Utility*, may give FERC jurisdiction over those specific activities.

Non-Utility Generator (NUG) Private companies that own and operate generating capacity, but are not *Public Utilities.* NUGs can be either *Qualifying Facilities* or *Exempt Wholesale Generators*, which include *Independent Power Producers* and *Affiliated Power Producers.*

Notice of Proposed Rulemaking (NOPR) When it is considering new rules and regulations, the FERC issues NOPRs on specific issues. In a NOPR, the FERC states its proposed rules and invites commentary . Following an evaluation of the responses received, the Commission issues its final orders, which are binding.

Open Access One of the principal goals of FERC *Orders 888 and 889*: to provide open access to the transmission grid so that wholesale market participants can buy from and sell to whomever they please. The *Pro Forma Tariff* contained in *Order 888* is referred to as an "open access" tariff because it is designed to achieve this goal.

Open Access Same-Time Information System (OASIS) An electronic bulletin board required by FERC in *Order 889*. All *Transmission Providers* that are *Jurisdictional Utilities* are required to participate in an OASIS that will provide *Open-Access* transmission customers with electronic information about *Available Transmission Capacity* and prices.

Orders 888 and 889 FERC's final rules on *Open Access, Stranded Costs*, and real-time information system requirements. These orders have significantly speeded up the power sector restructuring process in the U.S. *See also Mega-NOPR.*

Performance-Based Regulation A regulatory framework within which utilities' earnings and/or tariffs are tied to the achievement of specified performance measures, rather than to the level of their fixed assets, as in *Rate-of-Return (ROR) Regulation.*

Point-to-Point Transmission Service One of two types of transmission service required by the *Pro Forma Tariff* in FERC's *Order 888*. Point-to-Point service is defined as the receipt of capacity and energy at designated point(s) of receipt and transmission of such capacity to designated point(s) of delivery. *Network Transmission Service* is also required.

Postage Stamp Transmission Tariffs A specific type of *Transport Transmission Pricing* in which a single price is charged for delivery from and to any point on the system.

Posted Path *See Available Transmission Capacity (ATC).*

Power Broker A company that arranges transactions between buyers and sellers in the wholesale power market, but does not take ownership of the power itself.

Power Marketer A company licensed by FERC to buy and sell electricity at market (i.e., unregulated) prices.

Power Pool A trading arrangement by which participants in the pool purchase capacity and/or energy at a spot (i.e., very short-term) price. Power pools can either be "partial cost", such as the New England Power Pool (NEPOOL) in the U.S., in which member utilities trade short-term energy only and split the savings from the resulting more efficient dispatch of generation; or "full cost", such as the England and Wales Pool, in which the pool price paid by purchasers is allowed to rise to the level necessary to induce new generation capacity to be built. *See also Independent System Operator (ISO).*

Pro Forma Tariff The sample *Open-Access* transmission tariff provided by FERC in *Order 888*. It contains the terms and conditions under which transmission service will be provided, including procedures for establishing reservation priority, for reserving capacity, for curtailment of service and for *Reassignment* of transmission rights. *Order 888* does not specify prices, but requires that they conform to a previous FERC policy statement on transmission pricing. All *Jurisdictional Utilities* were required to file a pro forma tariff in July 1996.

Public Utilities Holding Company Act of 1935 (PUHCA) A Federal law that regulates the corporate structure of, and issue of securities by electric utilities. The Act also places a variety of restrictions on utilities that are structured as holding companies.

Public Utility A regulated investor-owned utility that falls under the jurisdiction of the FERC. The term "public" has several meanings within the U.S. electricity sector, which can be the source of some confusion. In addition to Public Utilities, there are "publicly owned" utilities, which are owned and operated by a federal, state or local government body. Any private company can be also be "publicly held", meaning that it is a joint-stock company whose shares are publicly traded on a stock exchange. *See also Jurisdictional Utilities.*

Public Utility Commission (PUC) Generic term for a state regulatory body with jurisdiction over the retail tariffs and most intra-state activity of public utilities. PUCs are known by other names in some states – such as corporation commission, department of public utilities, railroad commission, etc. – but all of these entities perform the same general type of activity.

Public Utility Regulatory Policies Act of 1978 (PURPA) One five laws that comprised the National Energy Act. PURPA led to a significant change in the structure of the U.S. electricity industry, and laid the foundation for some of the structural changes now underway. Most importantly, it defined several classes of non-utility *Qualifying Facilities* – small producers or those that use renewable or other alternative technologies -- which were independent generators from which investor-owned utilities were required to purchase electricity at the IOU's own marginal or "avoided" cost of generation.

Qualifying Facility (QF) *See Public Utility Regulatory Policies Act of 1978 (PURPA).*

Rate-of-Return Regulation (ROR) A regulatory framework within which the total amount of revenue collected is set to equal the sum of operating expenses and an allowed return on the utility's rate base. This is the traditional method of regulating *Public Utilities* in the U.S. *See also Performance-Based Regulation.*

Reassignment The reassigning of transmission service rights to another party other than the *Transmission Provider*. Under *Order 888, Point-to-Point Transmission Service* is reassignable, but *Network Transmission Service* is not.

Reciprocity A principle established by the FERC and included in the *Pro Forma Tariff* in *Order 888*. The reciprocity clause specifies that utilities that own, control or operate transmission assets and receive *Open-Access* transmission service must in turn provide *Open-Access* service to the transmitting utility. The purpose of this provision is to ensure that *Non-Jurisdictional Utilities* are not able to take advantage of *Open Access* transmission service offered by *Jurisdictional Utilities* without opening their own transmission grids to others.

Regional Transmission Group (RTG) A voluntary regional organization, open to all segments of the wholesale electricity industry, that sets mandatory procedures for its members for requesting and providing transmission access, coordinating transmission planning, and resolving transmission disputes.

Responsible Party *See Transmission Provider.*

Retail Wheeling An *Unbundled* transmission or distribution service that allows a retail customer to purchase electricity from a party other than the utility that owns the transmission or distribution lines over which the electricity is delivered. Retail Wheeling differs from *Wholesale Wheeling* in that the beneficiary of the service is a retail, rather than wholesale, customer. *See also Wheeling.*

Safe Harbor Under *Order 888, Non-Jurisdictional Utilities* have the option of filing a tariff with the FERC along with a request for a declaratory order that the tariff meets the FERC's *Comparability* standards. This option is called the Safe Harbor provision, because it allows a *Non-Jurisdictional Utility* to take pro-active measures to ensure that it is not denied *Open-Access* transmission services based on a claim that it does not offer reciprocal services.

Stranded Costs Investments in generation assets, usually made in a regulated environment with *Rate-of-Return Regulation*, which are uneconomic in an unregulated, more competitive environment. The FERC ruled in favor of reimbursing the owners of such stranded costs, on the grounds that a utility should not be penalized in a newly competitive environment for decisions it made before such an environment was viable. *Order 888* declares that the appropriate means for recovering these stranded costs is through direct assignment of such costs to the departing wholesale customer, either through an exit fee or a surcharge on transmission. Stranded Costs are also known as *Stranded Investments* and *Uneconomic Assets*.

Stranded Investments *See Stranded Costs.*

Total Transmission Capacity (TTC) The maximum capacity of a transmission *Posted Path*, subject to technical constraints. FERC *Order 889* requires that all *Transmission Providers* post the transmission capacity expected to be available on their system (*Available Transmission Capacity*), as well as the Total Transmission Capability of

that system for each *Posted Path*, which includes any transmission path that a customer might want to use.

Transmission Provider As defined in FERC's *Order 889*, a Transmission Provider is "any *public utility* that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce." A *Responsible Party* is the Transmission Provider or any agent delegated to meet the provider's responsibilities.

Transport Transmission Pricing A method of transmission pricing under which a user of transmission services pays a fee for a specified transmission service. This service is often referred to in the U.S. as being *Unbundled* from the energy with which it is associated. Transmission prices of this type can be *Postage Stamp* or dependent on distance. In either case, the tariff to be paid is generally known in advance, and is considered as a separate cost.

Unbundled *See Bundled.*

Uneconomic Assets *See Stranded Costs.*

Wheeling The movement of electricity over the transmission and/or distribution system of a utility, for the benefit of the purchaser of the Wheeling service, in exchange for a fee.

Wholesale Wheeling *See Retail Wheeling and Wheeling.*