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Bureau of Economic Geology, Jackson School of Geosciences
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Case Study From

NEW ERA IN OIL, GAS & POWER VALUE CREATION

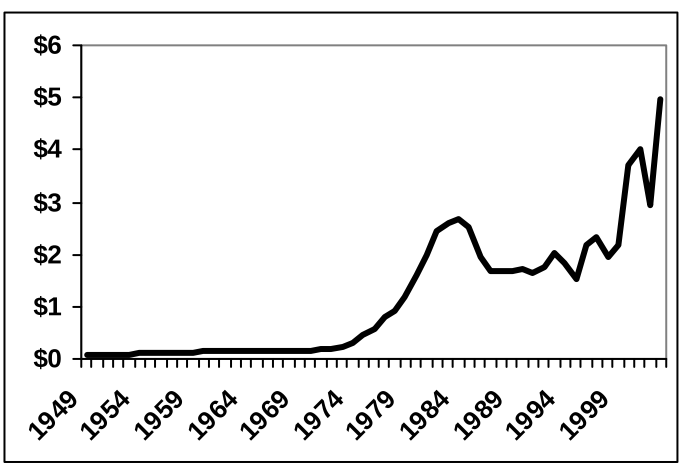
Natural Gas and Electric Power Marketization in North America[1]

North America is both the largest producing as well as consuming region for natural gas in the world. The region stands out as a region of active, relatively unfettered energy trade. The natural gas industry has a long history in the region, which contains the most expansive and complex infrastructure in the world. This infrastructure is supported by very liquid competitive markets and regulation by various entities where appropriate. These markets and their regulation went through different stages throughout their development and they continue to evolve.

- *How did the continental natural gas and electric power markets evolve?*
- *What were the key principles and steps taken to restructure the natural gas and electric power systems? How are the regulatory systems organized, and what is the importance of sub-jurisdictions for states and provinces?*
- *What are the remaining issues and how should they be solved? What are the critical market issues, and how are these testing the regulatory restructuring that has taken place thus far?*
- *What is the role of the North American Free Trade Agreement?*

INTRODUCTION

North America represents the largest and one of the most dynamic natural gas regions in the world. Overall, North America (Canada, the United States and Mexico, as defined by the North American Free Trade Agreement) is both the largest producing as well as consuming region for natural gas in the world.



Source: U.S. Energy Information Administration (U.S. EIA)

U.S. Wellhead Natural Gas Prices, Nominal, $ per thousand cubic feet ($/Mcf)

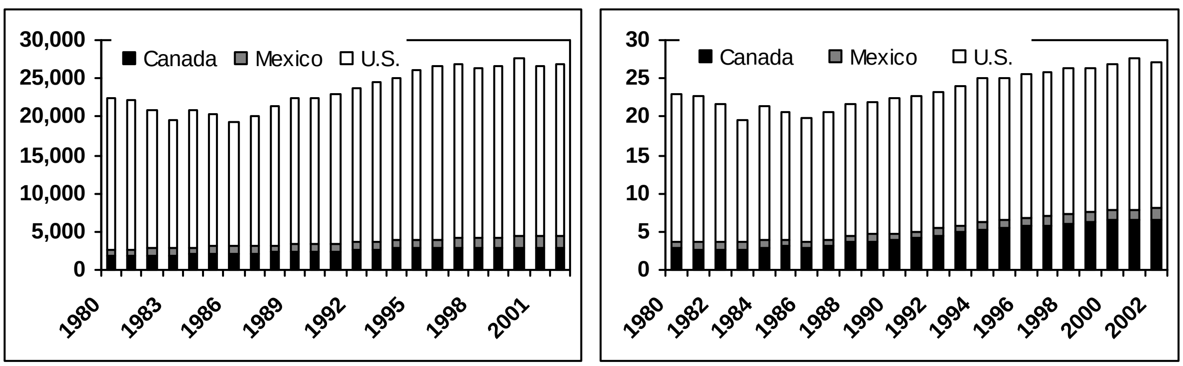
In recent years, natural prices in the U.S. have soared (see chart at left). Because of the interconnectedness within the continental marketplace, end user prices have increased at all major locations in all three countries. These price increases come after a long period in which the price of natural gas at the wellhead was first controlled, then deregulated so as to spur investment in drilling, then low enough with ample supplies to encourage broad use of this relatively clean burning fossil fuel for a

[1] This case study was prepared using publicly available information.

number of applications, most notably electric power generation. Rapidly rising natural gas prices have posed issues for producers (after years of a soft price environment, industry consolidation, capital constraints in the post-Enron era and natural maturity among key producing basins, supply-side response has been less elastic than in the past); major customers (natural gas is the primary feedstock for petrochemicals, fertilizers and incremental electric power generation); and core consumers (residential and small commercial consumers are no longer protected from price volatility by wellhead-to-burnertip regulation).

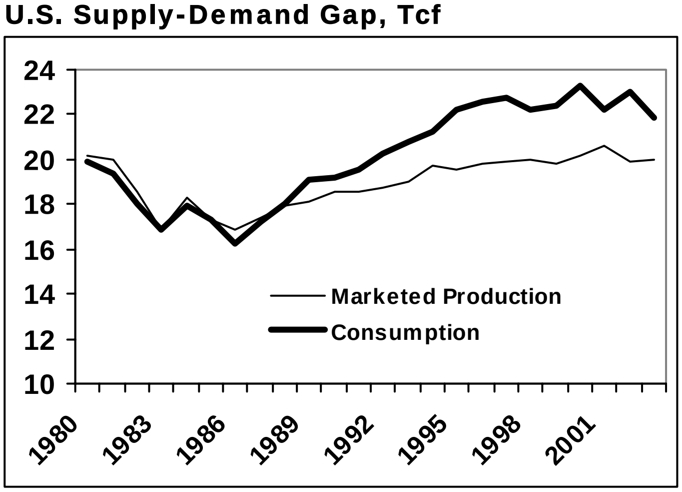
All three country members of the North American marketplace produce natural gas. Proven reserves are roughly 51 trillion cubic feet (Tcf) in Canada, 187 Tcf for the U.S. and 15 Tcf for Mexico (albeit with a large, relatively unexplored resource base). Within North America, the U.S. dominates as the major consuming nation but natural gas demand in Mexico and Canada has grown, and in Mexico's case growth in natural gas consumption is expected to be quite rapid. For all three countries, growth in demand is being driven by natural gas use for electric power generation; for industrial applications (feedstock for petrochemicals and other products and, in Canada's case, to support crude oil production from oil sands).

North American Natural Gas Demand (left, billion cubic feet, Bcf) and Production (right, trillion cubic feet, Tcf)



Source: U.S. EIA

U.S. Supply-Demand Gap, Tcf

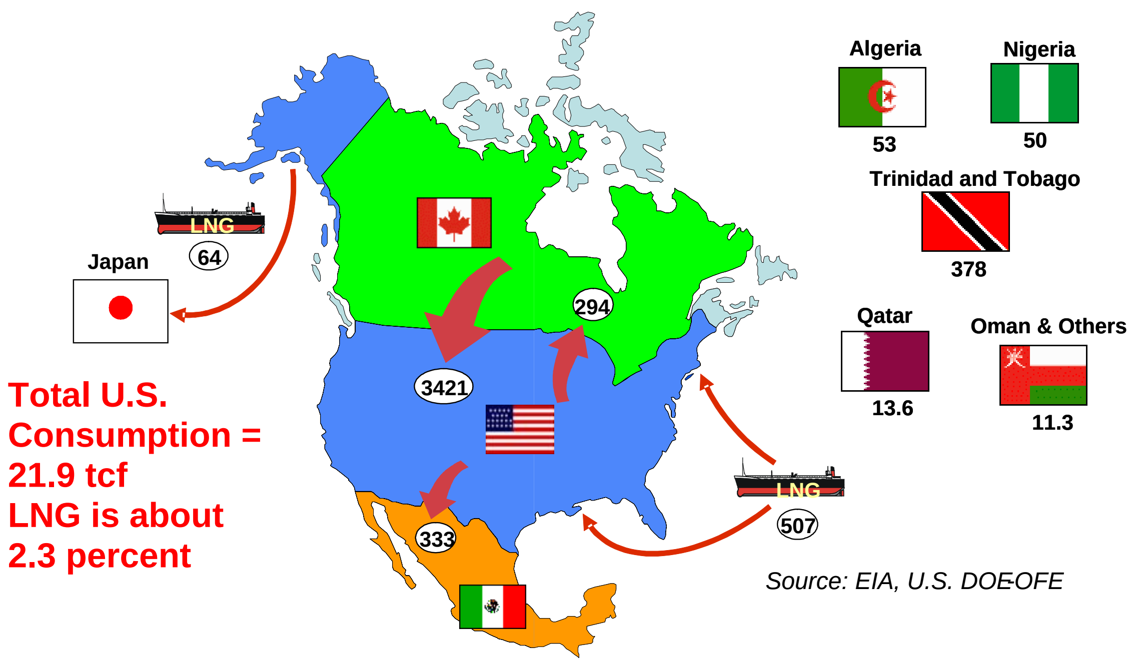


Source: U.S. EIA

Since the late 1980s, natural gas demand in the U.S. has not been fully met by domestic production. Exports from Canada became increasingly important to closing this gap. All outlooks for North American natural gas project the U.S. supply-demand gap to continue into the future, largely a function of maturity in "Lower 48" producing fields and basins. In addition, questions persist about Canada's export potential as that country's producing fields and basins mature. Resource potential in both countries remains strong but with numerous challenges. In the U.S., prospective areas include Alaska, where development issues include distance, cost and environmental concerns; non-conventional reservoirs (coal seam gas and tight sands) which pose technical and cost challenges; and deep water as well as deep drilling depths in the U.S. Gulf of Mexico, high risk plays that also present infrastructure problems to support resource exploitation. In Canada, the Mackenzie Delta in the "Far North" has long attracted interest as a frontier area for exploration. Much debate around Alaska natural gas pipeline transportation includes Canadian interests in a route through Canada's Northwest Territory that would aggregate Alaska and Mackenzie Delta production with deliveries in Alberta for oil sands development before entry into the U.S. Lower 48 market. Interest also centers on offshore British Columbia, where the provincial government is moving toward a regime to allow exploration.

Mexico stands out as country that is, by all accounts, richly endowed with natural gas resources. Yet, policies and politics have constrained investment in exploration and production by restricting these activities to Mexico's national oil company, Petroleos Mexicanos (Pemex) and thus preventing free flows of private investment into Mexico's domestic upstream businesses. The result is that Mexico has become a net importer of natural gas from the U.S., in effect through displacement of pipeline exports from Canada and liquefied natural gas (LNG) imports by the U.S., as shown in the figure below. To close its own supply-demand gap, Mexico is looking to LNG as a solution, and also as a means of diversifying supply and perhaps providing some price competition and discreet choices for major customers.

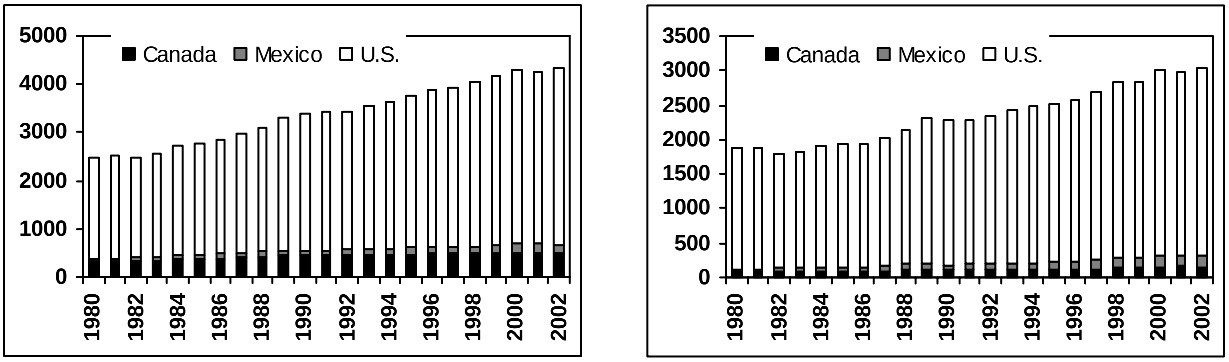
North American Natural Gas Flows, 2003, Bcf



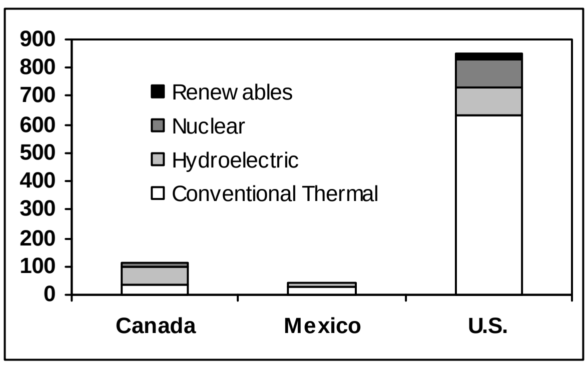
When it comes to electric power, the U.S. is the single largest consuming country in the world, using more electricity than all of Western Europe combined. The U.S. is also the single largest generator. In 2003, roughly 56 percent of Canadian electric power generation is from hydro facilities, 28 percent conventional thermal and about 13 percent nuclear. The U.S. is dominated by conventional thermal generation with coal constituting about 53 percent of generation, natural gas 15 percent and oil three percent. Nuclear made up 21 percent, hydro about 7 percent and geothermal and renewables about one percent. Notably, rising natural gas prices in 2003 – a result of the supply-demand imbalance – reduced the share of natural gas-fired power generated from 18 percent reached in 2002.

Mexico's electric power generation also is largely thermal, 81 percent of total, with oil accounting for the largest proportion. The need to reduce polluting oil-fired generators is the major factor behind increased natural gas consumption. Hydropower comprised approximately 12 percent of electricity generation, with nuclear at 4.5 percent and geothermal at roughly 2.5 percent. (All data from U.S. EIA.)

North American Electric Power Consumption (left, terawatthours, TWh) and Net Conventional Thermal Generation (right, TWh)



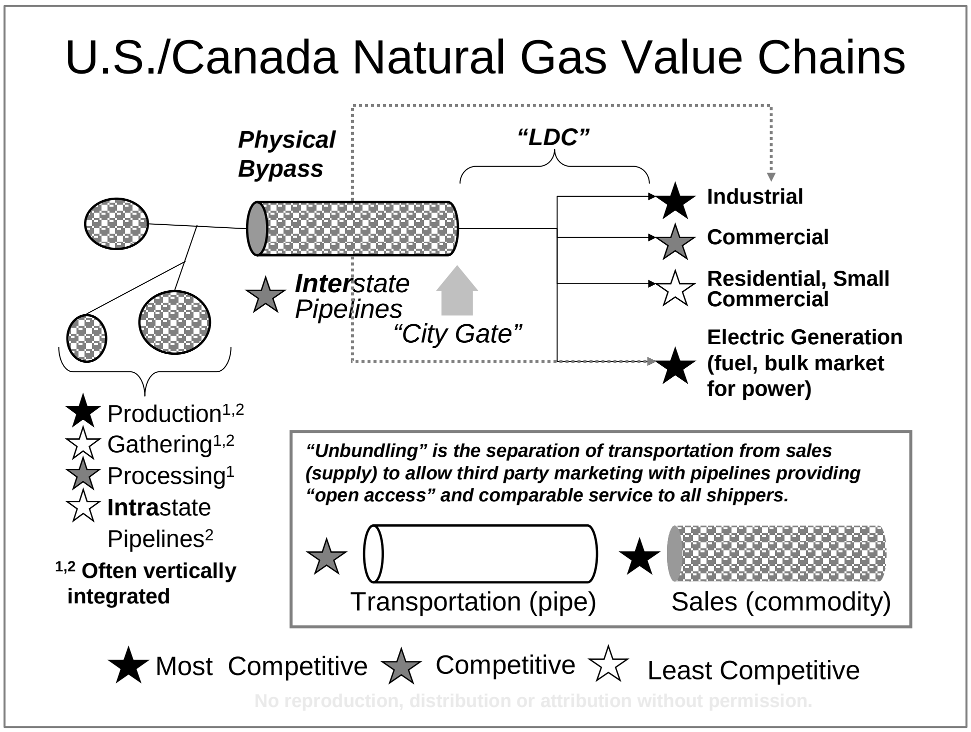
Installed Generation Capacity by Type, 2002 (gigawatts, GW)



As with natural gas, electricity trade across the North American continent is vigorous and has grown rapidly. During 2002, roughly 36 billion kWh, or terawatthours (TWh), were exported from Canada to the U.S., and about 13 TWh imported. That same year, Mexico imported about 306 million kWh, or gigawatthours (GWh), and exported about 1.5 TWh. Total North American electric power trade (the total exchanges of exports and imports) reached nearly 51 TWh, more than double the 1991 activity of just over 24 TWh.

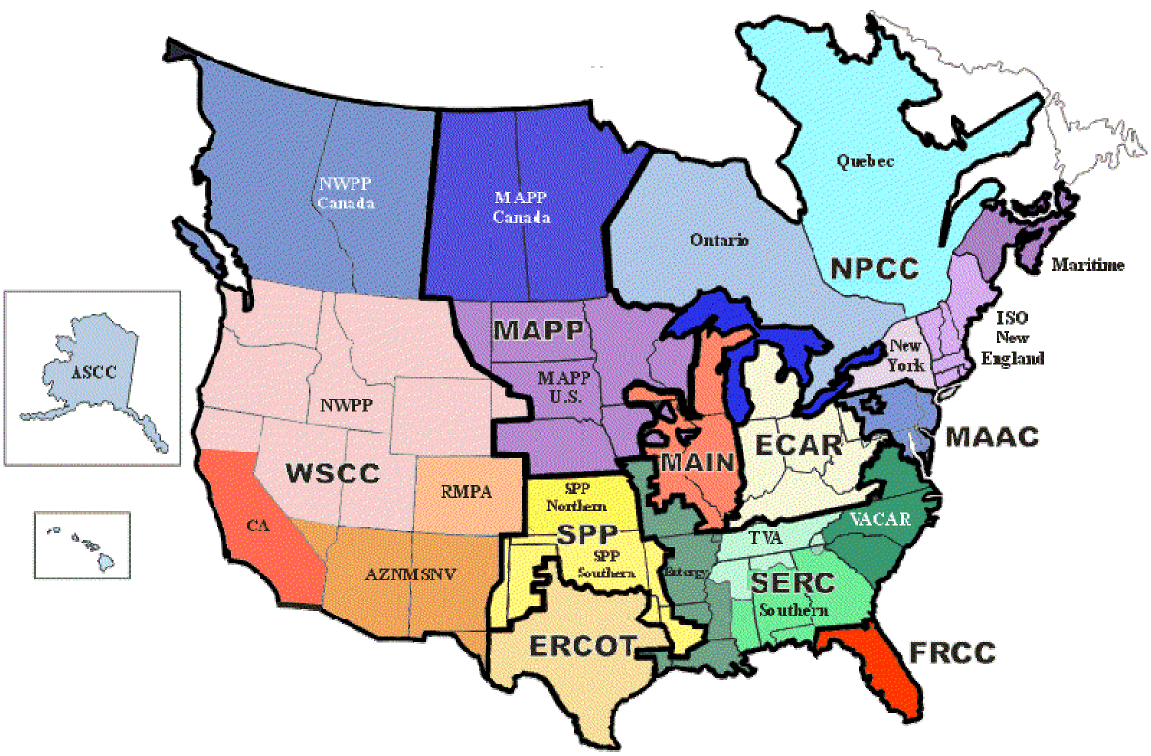
All three countries have experimented vigorously with natural gas regulatory restructuring. In the case of Canada and the U.S., experimentation included: establishing competitive wellhead pricing for natural gas; introducing third party access ("open access") on the major pipelines that cross state and provincial boundaries and that are under federal regulatory jurisdictions; creating broad, national wholesale markets for natural gas with associated trading and risk management; and, in some cases – particularly among the Canadian provinces – establishing open access and retail customer choice among natural gas utilities. While some differences existed between Canada and the U.S. with regard to style and approach, both countries faced many of the same issues and dilemmas during the restructuring process. Strong parallels can be found between Canada and the U.S. with regard to regulatory principles and processes. The National Energy Board-Canada (NEB) and the U.S. Federal Energy Regulatory Commission (FERC) both maintain transparent, administrative, case-by-case, rule making procedures that entail open, evidentiary hearings; technical conferences; public access (to both meetings and records); and oversight. The states and provinces have considerable power and influence. The provincial energy utility boards (EUBs) in Canada and the public utility commissions (PUCs) in the U.S.

have jurisdiction over natural gas pipelines and utilities that operate within their geographic boundaries. Regulatory practices are common across all agencies and jurisdictions, sometimes as a result of precedent but usually shared through active national regulatory associations (NARUC, the National Association of Regulatory Utility Commissioners in the U.S. and CAMPUT, the Canadian Association of Members of Public Utility Tribunals), which interact strongly. While conflicts often emerge between federal and state/provincial jurisdictions, usually during periods of change and disruption, the history in both countries is one of coherence. This regulatory tradition, in combination with emergence of strong cross-border trade and the seamlessness of Canadian and U.S. industry structure (U.S. ownership of Canadian natural gas business assets and U.S. investment flows into Canada are a dominant feature) has yielded an outcome that is, for the most part, a single, common market for natural gas with key features as shown below.



The modern U.S./Canada natural gas system in operation today is made up of distinct segments that all must interact. The most competitive part of the industry is upstream, a segment comprised of thousands of large and small, publicly traded or privately owned firms. Upstream activities, exploration and production, are often integrated with midstream gathering, processing and intrastate (within state boundaries) transportation. Gathering and intrastate pipelines often are indistinguishable. Interstate (or interprovincial in Canada) pipelines are long-haul lines that cross state (or provincial) boundaries. The major restructuring policy has been to separate pipeline transportation from sales of the natural gas commodity itself, so that the pipeline systems now operate national grids. Open access requires that any entity can use the pipelines without discrimination (i.e., the regulated pipeline cannot give preference to gas transported by its unregulated marketing affiliate). Before restructuring, the pipelines acted as "merchants," contracting for natural gas from producers and for sale to local distribution companies (LDCs) or gas utilities. The transition to open access was both driven by, and increased the activity of, third party marketing of natural gas. At the city gate, LDCs, which still act as merchants for the most part, take title to the natural gas for distribution to final customers. The distribution segment is the least competitive, although that is slowly changing. At the minimum, the largest industrial companies are able to receive competitive price discounts based on volume (though they often purchase "interruptible" gas supplies which can be curtailed during critical, peak demand periods). Most large LDCs offer unbundling options to industrial customers, a strategy that has been essential to preserving industrial loads. At the maximum, industrial users can "bypass" the LDC system altogether. In both Canada and the U.S., economic bypass has often been allowed by federal regulators where applicable while state and provincial regulators have preserved the LDC system, creating jurisdictional conflicts.

In both Canada and the U.S., restructuring in the electric power sector has coincided with and supplemented the competitive regimes for natural gas. A system of electricity reliability councils (see map below) established during the late 1960s as a result of blackouts in the northeastern U.S. led to strong, shared approaches for managing grid stability and reliability. At the federal level, the goal in the U.S. has been to install independent system operators (ISOs, indicated on the map) and eventually regional transmission operators (RTOs) to facilitate open access and transmission grid integrity. These organizations, some of which have assumed reliability council functions, largely facilitate bulk, wholesale transactions across state and reliability council boundaries.



The electric power produced for wholesale transactions can come from both unregulated, merchant plants (independent power projects or IPPs including cogeneration or combined heat and power facilities) or regulated plants operated by utilities (public, including cooperatives and municipal, or private, investor owned) and federal power authorities. These transactions may be conducted either by traditional utilities or third party marketers. The states have jurisdiction over retail markets. In contrast to the situation for natural gas, Canada's electric power industry is dominated by government owned entities, the provincial crown corporations. In neither country has electricity restructuring been a smooth or easy process, and huge uncertainties remain with regard to scope and direction. Many of the concepts and principles devised for natural gas restructuring have been applied to electric power, with the goal of bringing competitive, "merchant" generation into the marketplace through bulk, wholesale transactions facilitated via third party access to transmission. Because much merchant power generation is fueled by natural gas, both industry organization and market structure for natural gas and power have converged strongly – as have related problems. These include the technical difficulties of implementing open access for electricity transmission while maintaining grid stability and reliability; the challenge of pricing transmission and congestion as well as new transmission capacity; the problem of re-organizing and managing regional grids and coordinating across interconnections (both within Canada and the U.S. as well as, importantly, between the two countries); issues in deriving suitable market designs to enable price discovery for and dispatch of competitive merchant generation (pools, exchanges and so on); and the dilemma of instilling retail competition and encouraging choice and customer response to competitive prices, especially to achieve demand side efficiencies.

Meanwhile, Mexico's experimentation with natural gas restructuring has been restricted to the midstream (long distance pipelines and natural gas storage) and downstream (LDCs). Private investment in IPPs has been encouraged. The pace of change and frameworks for private investment and access have not kept pace with burgeoning demand for either gas or power.

United States

Overview

Natural gas exploration and production on private lands, including environmental and safety controls, are regulated at the individual state level by conservation commissions. Exploration and production on state lands are controlled by separated state agencies charged with management of those lands. Exploration and production on federal lands, onshore or offshore, are managed by federal agencies. Natural gas exploration and production, gathering and processing are all viewed to be "workably competitive" industries and are not regulated for prices. Tariffs for transportation within state boundaries on intrastate pipelines are regulated by state public utility commissions (PUCs). The PUCs also license new intrastate pipelines. Tariffs for transportation across state boundaries in interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC). The FERC also issues licenses (certificates of public need) for new interstate pipelines. Tariffs for natural gas distribution to final customers are regulated by PUCs. The most competitive gas service in the U.S. is for industrial customers. The least competitive service is to residential customers.

The FERC is governed by five appointed commissioners and operates as an independent authority. Enabling legislation for the FERC dates back to the 1930s (it was created as the Federal Power Commission and charged principally with development of water and hydroelectric facilities). The FERC's authority to regulated interstate natural gas commerce is embodied in the 1938 Natural Gas Act. The individual state PUCs were established at various times, generally between the late-1800s through the 1970s. Each state has a separate enabling legislation for the formation of its PUC. Notable exceptions are the state of Nebraska, which does not regulate natural gas, and Texas, where natural gas is regulated by the Texas Railroad Commission rather than the PUC. The PUCs also vary with regard to numbers of commissioners, whether commissioners are elected or appointed and sizes of staffs and budgets. The FERC and state PUCs are funded through fees charged to regulated industries.

The style of regulation in the U.S. traditionally has been "cost of service" or "rate of return," which involves a determination of revenue requirements and rate structures based upon costs provided by the regulated firms. A regulated company may be a local distribution company (LDC, or gas utility), an intrastate pipeline or an interstate pipeline. The regulated company's revenue requirements are the total funds that the company may collect from ratepayers (customers). Revenue requirements are calculated by multiplying the company's rate base by an allowed rate of return (ROR) and adding this product to the company's operating costs (OC), as shown in the formula below.

Revenue requirement = (Rate base x ROR) + OC - (Taxes + Depreciation)

The rate base is the total value of the company's capital investments, which may include construction work in progress. The allowed rate of return constitutes a profit sufficient to pay interest on accumulated debt and to provide a "fair" return to investors. A fair return is determined through a comparable earnings test (where a company's earnings are measured against those of a firm facing comparable risks), a discounted cash flow approach (where a company's capital costs are estimated by analyzing conditions in the financial market), or some other method. Operating costs include expenses for purchased gas, labor, management, maintenance and advertising. The costs of taxes and depreciation are also part of a company's revenue requirements. The regulatory process can be generally described as follows.

- A regulatory commission (a PUC or the FERC) first seeks to determine how much of an applicant's capital stock should be included in the rate base, then attempts to determine which elements of test year costs and revenues should be allowed for regulatory purposes and whether or not to allow specific changes since the test year. The final step is to determine what the fair rate of return is for the company.
- While states and the FERC have legal rules for deciding what should be included in the rate base, the same is not necessarily true for the method of calculating allowed rate of return.
- States may vary from each other and from the FERC according to the particular set of rules that are used, for example to calculate rate base, and the impact of these rules on rate case decisions. However, over the course of the long history of natural gas regulation in the U.S., the states and FERC have generally shared practices fairly quickly.
- All regulators are constrained in their abilities to calculate cost of capital. This is due in part to general disagreement within the industry of how market cost of capital should be computed, and in part because commissions are not well equipped to deal with the complexities surrounding these issues. As a result, a critical component of a rate case proceeding is a commission's reliance on historical information, or precedent, as well as the testimony of interveners, parties with specific interests in the outcome of rate cases (principally large customers and consumer advocates representing small business and residential users; competing regulated firms may also intervene).
- All U.S. regulatory commissions hear rate cases, issue blanket rulings that set broad policy parameters and act as judges and adjudicators on disputes.

With the implementation of unbundling (separation of pipeline transportation from natural gas sales, with nondiscriminatory "open access" or "third party access") in 1992, the FERC and many of the states now encouraged market-based rates for transportation service. With respect to distribution, many states are experimenting with "incentive-based" regulation designed to encourage more efficient operation and capital cost decisions than has historically been achieved with cost of service regulation.

History of Natural Gas Restructuring

When comparing the U.S. to other countries, an important difference is that the U.S. natural gas system has always been characterized by the participation of private companies, with regulation as a substitute for competition to moderate private monopoly market power. For the most part, regulation has been directed toward pipeline transportation and local distribution. However, during period of U.S. history, cost of service-style regulation was also applied to natural gas production at the wellhead with disastrous results. The following table illustrates the complex progression of regulatory policy eras in the U.S.

U.S. NATURAL GAS INDUSTRY REGULATION/DEREGULATION	
Competitive LDC industry	Emergence of natural gas industry as local distribution companies were established to provide town gas and later natural gas service.
State public utility commissions, 1885-1927	Formation of Massachusetts Gas Commission in 1885 through regulation of intrastate pipelines in all 48 states by 1927. Followed Supreme Court ruling (*Munn v. Illinois*, 1877) that established the basis for regulating monopolies (grain elevators and warehouses) as public utilities).
Development of interstate transportation, 1930s	Technological advances (mechanized trenching and arc welding) allowed construction of long-distance pipelines to transport natural gas from large producing fields in the southwestern U.S. to key market in the Northeast and upper Midwest.
Federal regulation of interstate transportation (Public Utility Holding Company Act and Federal Power Act of 1935; Natural Gas Act of 1938)	Interstate Commerce Act of 1887 provided basis for federal intervention. A U.S. Supreme Court decision in 1934, Nebbia v. New York, dealing with milk prices expanded the basis for public utility regulation. Disputes centered on pricing natural gas in cross-state sales activities and market power of interstate public utility holding companies. FPA established and authorized the Federal Power Commission. Natural gas industry now comprehensively regulated from the burner tip to intrastate transmission to interstate transmission by state and federal jurisdictions.
Federal regulation of wellhead prices (U.S. Supreme Court *Phillips* Decision, 1954)	Dispute regarding pricing of natural gas produced in Oklahoma for delivery in Michigan led to cost of service regulation at the wellhead, with FPC as agency with authority.
Beginning of wellhead price decontrol (Natural Gas Policy Act, 1978; Public Utility Regulatory Policy Act of 1978; Powerplant and Industrial Fuel Use Act of 1978)	FPC's inability to deal with the scope of wellhead regulation and provide sufficient adjustment to increase price ceilings and encourage production, as well as disparity in pricing natural gas sold in interstate markets with gas sold in unregulated intrastate markets, and resulting curtailments led to decontrol. NGPA 1978 extended wellhead price ceilings to the intrastate market, introduced the process of deregulation by loosening certification requirements to

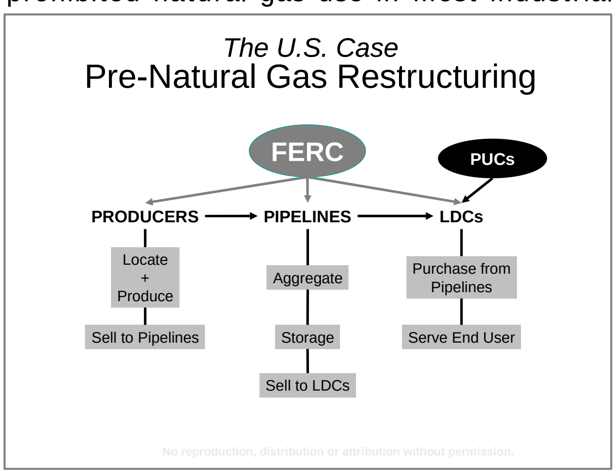
	facilitate gas flows.
First Stage of Open Access for Interstate pipelines (FERC Orders 436, 500 1985)	"Phased decontrol" with NGPA created surplus conditions. Need for flexible pricing and transportation led to “special marketing programs” that released gas from long-term contracts into price-discounted supply pools. FERC Order 436 in 1985 created the open access era, provided some resolution for take-or-pay (TOP) liabilities.
Final restructuring rule for interstate pipelines (FERC Order 636, 1992)	FERC Order 636 continues separation of merchant and transportation functions of interstate pipelines.
Order 637	To address issues in conduct by marketing affiliates of regulated interstate pipelines.

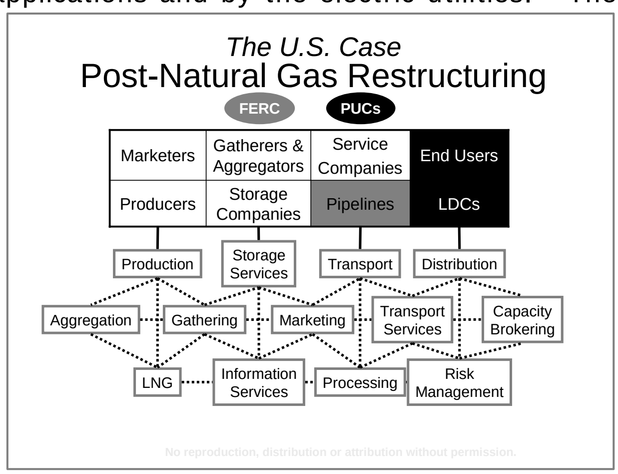
In the early days of the U.S. natural gas industry, the construction and operation of natural gas distribution systems tended to be concentrated around local deposits of natural gas. Cities and towns that were near the early discoveries of natural gas in the late 1800s were often the centers of intense competitive activity as companies struggled to build competing systems. Because all of the early natural gas companies were private and because the intense competition reduced the returns to shareholders, state level regulation of local distribution companies (LDCs) through public utility commissions evolved. The strategy was to stabilize investment returns to shareholders while attempting to mimic most of the benefits of competition to customers through regulation (competition by substitution, as it is often called). The form of regulation typically used was “cost of service” in which regulators granted a rate of return that was deemed to be reasonable to the LDCs. In exchange for a limited return, the LDCs enjoyed a monopoly franchise for service in a city or town but also had the obligation to serve all customers within that franchise.

The discovery of huge natural gas deposits in Texas and Oklahoma fundamentally changed the U.S. natural gas industries. Companies began to build long-distance pipelines to carry natural gas from the southwestern U.S. to the Northeast and Midwest where gas was needed for winter heating. Almost immediately, disputes arose among individual states with regard regulatory jurisdiction over interstate sales of natural gas. By 1938, the U.S. government was prepared to step into the conflict. Passage of the Natural Gas Act (NGA) that year gave the Federal Power Commission (FPC) regulatory authority over interstate natural gas commerce. This action was consistent with the philosophy of the times. Following the Great Depression, there was considerable mistrust of large businesses and greater faith in the ability of government to intervene and solve problems.

The NGA treated the interstate pipelines as natural monopolies. (It should be noted, however, that in debating the NGA, the U.S. Congress deliberated on contract carriage as an alternative approach.) The economics of early pipeline construction and operation and conditions in the early natural gas markets were considered to be such that it was unlikely for many companies to build competing facilities. As a result, the pipelines acted as “merchants,” contracting with natural gas producers for supply and also with local distribution companies for deliveries. Disputes related to the price of natural gas in the interstate market did not end, however, and the federal government intervened again, this time through the Supreme Court. In the landmark *Phillips* decision in 1954, the Court concluded that the FPC should also have regulatory authority over the price of natural gas at the wellhead. By this time, thousands of natural gas wells had been drilled in Texas, Oklahoma, Louisiana and other states, including the beginnings of the U.S. offshore industry. The task faced by the FPC was daunting, and the ability of federal regulators to perform efficiently was limited. Distortions began to show up immediately, most importantly in the difference between prices for natural gas in the regulated interstate market and prices in the unregulated intrastate market (meaning gas produced and sold within the boundaries of individual states). Demand for natural gas had grown and prices were rising in the intrastate market. As a consequence, producers shifted their strategies so as to sell more gas in that market. By the time of the oil embargoes and supply shocks in the early 1970s, insufficient amounts of natural gas were committed to the interstate market. During the severe winter in 1976, shortages and curtailments of natural gas supplies occurred all over the eastern U.S. To make matters worse, because the interstate pipelines controlled all transactions, there was no way for natural gas producers to engage in sales directly with customers.

Broad dissatisfaction with how the natural gas sector was managed led to an unwinding of federal regulatory control. By the 1970s, public opinion regarding government management of economic activity, including energy, had begun to erode. The preference for market-based solutions was increasing. Already the U.S. was engaged in major transformations to reduce government intervention in other sectors, such as airline transportation, telecommunications and banking. The first step was to remove regulatory control of natural gas at the wellhead, with the Natural Gas Policy Act (NGPA) of 1978, which also transformed the FPC into the Federal Energy Regulatory Commission or FERC. The strategy chosen by the U.S. government was flawed, with a tremendously complicated schedule for decontrol of natural gas from different formations, by year of discovery (vintage), and so on. The U.S. Congress created more than 200 different categories of natural gas. Overall, natural gas prices rose rapidly in response to demand. After a period of time, higher natural gas prices caused demand to fall as customers, especially large industrial users, shifted to cheaper fuels. Demand adjustments were further complicated by two additional laws that had been passed to deal with 1970s energy crises, the Public Utility Regulatory Policy Act and Powerplant and Industrial Fuel Use Act which, together with NGPA, encompassed the National Energy Act. PURPA encouraged experimentation with "co-generation" of electricity using natural gas at industrial facilities, which sold their electric power to electric utilities at a price that (presumably) reflected the costs utilities would avoid by not building new electricity generation capacity themselves. PIFUA, however, prohibited natural gas use in most industrial applications and by the electric utilities. The





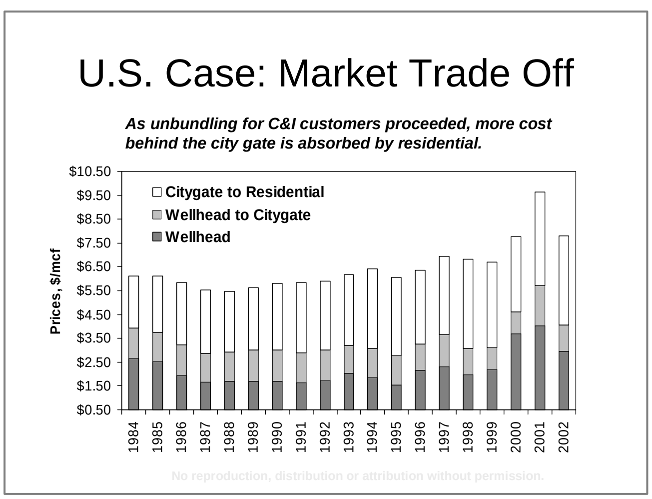
resulting confusion and the fluctuations in prices that resulted created havoc on both sides of the interstate pipeline merchant contracts. Both pipelines and producers were left holding contracts with take-or-pay obligations that led to severe financial strain for many companies. Because interstate pipelines still acted as merchants, bottlenecks existed all over the natural gas system that prevented efficient transactions from taking place.

In 1983, the FERC began to put into place the policies ultimately finalized in the 1992 "restructuring rule" (Order 636) that have led to the restructured natural gas market that we see in the U.S. today. Through a series of actions, the FERC began to dismantle the interstate pipeline merchant function. Pipelines came to be treated as common carriers, conduits through which any seller or buyer could ship gas. Natural gas became treated as a commodity where before oil companies had treated natural gas as a byproduct with no intrinsic value. Pipeline construction technology had changed dramatically over the years, and many parts of the U.S. were served by more than one interstate pipeline reducing the natural monopoly advantage. The advent of sophisticated computer information systems allowed real time trading of natural gas and financial instruments (futures contracts and other mechanisms) enabled suppliers and customers to manage commodity price risk. While conditions today are vastly different – natural gas in recent years has enjoyed a growing share of the U.S. energy mix, albeit with great price elasticity for certain kinds of demand – there is no doubt that policies in the past constrained market growth of the industry. Indeed, the position that Canada enjoys as a major exporter of natural gas to the U.S. (approximately 15 percent of U.S. consumption) is a direct outcome of the 1976 shortages.

Issues

Several issues remain following restructuring to restore and enhance competition in the U.S. gas system.

- Market disruptions. The FERC's actions to implement open access on U.S. interstate pipelines created a "wholesale market" for natural gas, with competitive pricing, trading and marketing activities, price risk management (the New York Mercantile Exchange established a natural gas futures contract in 1993), market mechanisms to facilitate trading of unused pipeline capacity and a national standards board (the Gas Industry Standards Board) to facilitate commercial activity. Beginning in 2000, surging prices for natural gas and electric generation constraints as a result of extended drought in the Pacific Northwest resulted in collapse of the electric power market in California. Disparities in natural gas prices between the California internal market and other U.S. locations and related improprieties in natural gas trading, along with the bankruptcy of Enron Corporation, led to a general collapse in the "energy merchant" segment including credit downgrades, additional bankruptcies and severe losses in market capitalization. Energy merchant businesses deal in unregulated wholesale market activities, including construction and operation of competitive, unregulated infrastructure assets. Many energy merchants were affiliated with regulated natural gas interstate pipelines and utilities. Continued conflict around issues that emerged during these events heavily impacted natural gas markets in the U.S. and Canada. A subsequent natural gas spike in 2003,



with ancillary concerns regarding natural gas field production trends, and disputes regarding how natural gas price information is compiled and communicated in the marketplace continue to retard further policy, regulatory and commercial activity.

- Lack of competitive service to small residential and commercial customers at the end of distribution systems (see chart at left). Unbundling and open access to facilitate deliveries of competitive supply for smaller customers has not materialized as expected following FERC's restructuring rule. These initiatives generally are in the domain of state jurisdictions, but federal/state coordination, always an issue, is required in some instances.
- Market power and price discovery associated with unregulated marketing affiliates of regulated pipelines. The FERC's resolve to increase transparency associated with operations by affiliates poses very real costs on the pipeline industry. Assessing costs of compliance and, for the industry, structuring operations in order to meet the FERC's mandate are priorities.
- Barriers to entry of new pipelines. The certification process, already deemed to be too onerous given competitive market conditions, has been further complicated by the market disruptions of the 2000s and lack of financial capital available from distressed energy merchant businesses and parent pipeline companies.

Electric Power Restructuring

Following early success with natural gas, some states (notably California in 1994) and the FERC (through Orders 888 and 889), and with encouragement through the Energy Policy Act of 1992, proceeded to experiment with similar unbundling and open access approaches for electricity grids. The 1992 EPAct supported creation of a bulk, wholesale market for electric power. The FERC's Order 2000 established the role of ISOs in wholesale market operations. The desire to facilitate broader, regional markets with common standards and rules of access and transmission pricing led to the introduction of the FERC's controversial standard market design (SMD) proposal. Conflicts between states jurisdictions (largely over control of transmission and transmission reliability) and the FERC, the cost of transition, technical issues in structuring the SMD and general political conflict regarding end user prices (including those for natural gas) came to a head during the August 14, 2003 blackout which affected states across the upper Midwest and northeast and customers in the interconnected Canadian provinces. Along with the collapse of California's electric power market and natural gas market disruptions associated with the tight supply-demand balance for the Lower 48, the August blackout has stymied further initiatives by the FERC for a segment of the energy sector that is considered to be crucial to growth of the natural gas industry.

Canada

The Canadian natural gas system parallels that of the U.S., with an important exception. All natural gas resources in Canada are controlled by the provincial crown governments. Exploration and production activities are carried out by private, competing firms under the rules and regulations established by provincial energy ministries. This contrasts with the U.S., where roughly two-thirds of natural gas resources and production are in the private domain (held either by companies or individuals).

Like the U.S., Canada's transportation and distribution systems are owned and operated by private (investor owned) companies regulated to control for any monopoly power. Regulation of long-distance, interprovincial pipelines is carried out by the National Energy Board (NEB) which receives its authorization from the federal National Energy Board Act. The NEB, like the FERC, licenses new pipelines, sets tariffs for transportation, adjudicates disputes and sets broad policy parameters with blanket rulings. Intraprovincial pipelines and local distribution systems are regulated by provincial energy utilities boards (EUBs). Each province has enabling legislation for its EUB. As with the state PUCs and the FERC in the U.S., the EUBs and the NEB use similar methods for regulating their client industries, and are funded by these industries. The NEB and EUBs have also, traditionally, used cost of service ratemaking like the U.S. commissions. Canada is a significant exporter of gas to the U.S., supplying about 13 percent of U.S. (Lower 48) demand. The NEB licenses and regulates all natural gas export activity from Canada.

Canada began to restructure its natural gas system ahead of the U.S. in the early 1970s with the Western Accord, which eliminated control of natural gas supply by Canada's monopoly interprovincial pipeline, TransCanada. The Agreement on Natural Gas Markets and Prices in the 1980s was a statement in principle of support for a market-based natural gas system. The Open Access Order in 1986 unbundled the Canadian system and allowed contract carriage on Canada's pipelines. Since these steps were taken, the NEB has consistently encouraged market based rates for transportation.

At the provincial level, EUBs followed the NEB with open access and market-based tariffs. Nearly every local distribution system in Canada offers some form of competitive supply to its core customers (residential and small commercial), with LDCs in Ontario moving toward full open access systems for core customer service.

With respect to electric power restructuring, the provincial governments are the critical jurisdictions because of the need to address structure of the crown corporations. Except for the province of Alberta, which has established both wholesale and retail market competition with an ISO that serves both to facilitate access and transactions and grid reliability (a similar arrangement to that of Texas), the pace of change in Canada has been slow for many of the same reasons experienced in the U.S. Some of the sharpest difficulties exist in the province of Ontario, where the stranded cost of crown corporation assets and disputes over market design have caused the provincial EUB to abandon electricity restructuring.

Mexico

Mexico has pursued a strategy of reserving upstream petroleum and gas exploration to Petroleos Mexicanos (Pemex), the national oil company. During the early days of Mexico's industry, oil and gas exploration was carried out by private foreign and Mexican companies. Disputes between the Mexican government and foreign operators, and political imperatives following Mexico's revolution, resulted in the 1938 nationalization of Mexico's oil industry. Article 27 of the regulatory law to Mexico's constitution stipulates that Pemex has sole control of the production of oil and gas and the products derived from the raw resources.

During the 1970s, hydrocarbon production did not keep pace with economic modernization, so that by 1973 Mexico found itself to be a net importer of crude oil. Critical discoveries restored Mexico's stature as an oil producer and exporter. Investment in upstream activities continued until the early 1980s when Mexico's external debt crisis, exacerbated by falling world crude prices, triggered a contraction in government spending. The collapse of crude prices in 1986 impacted upstream activity even more. Spending by Pemex on exploration and production dropped from its peak of approximately 86 percent of Pemex's total budget in 1982 to less than 60 percent in 1988. Historically, crude oil has been given priority because of its export potential and value. However, two factors contributed to an effort to increase natural gas production. One, in the late 1970s, was the desire to increase gas sales to the U.S. which led to construction of the Cactus-Reynosa pipeline as a result of negotiations between Pemex and Border Gas, a consortium of U.S. companies. The 2 bcf/day project was never realized because of disputes about pricing. The second factor was concern about inefficient utilization of energy. Energy use was, and is, highest in the energy sector itself. Expenditures were made to gather and transmit gas, especially from the huge Bay of Campeche fields, and reduce wasteful gas flaring, which has declined from 26 percent of production in 1970 to less than three percent by 1989. Domestic consumption of natural gas continued to grow in the 1980s, but with relatively little new investment in natural gas production and transmission made by Pemex. The result is Mexico's current situation of inadequate domestic production capacity to satisfy natural gas demand.

In the 1980s, in response to the critical economic situation Mexico faced after the oil market crash and currency devaluations, the Mexican government began to implement market reforms. Public opinion and political will for privatizing Pemex have historically been weak, but a series of major accidents, chronic shortages and unreliable service forced the managers at Pemex to take action. The government gradually removed the obligations on Pemex to provide everything from roads to hospitals and schools as part of its social obligations to the state. Pemex began to reduce its huge employment from more than 250,000 to just over 133,000 today. In 1992, Pemex was reorganized into four functional subsidiaries for exploration and production, refining, natural gas and basic petrochemicals and secondary petrochemicals. The government also changed Pemex's tax status by creating a corporate tax rather than controlling all of Pemex's revenues and returning some portion to the company for reinvestment. The corporate tax rate for Pemex remains high (more than 60 percent) and Pemex still does not have independence with respect to its budget planning.

In 1995, further, more dramatic steps were taken to reform Mexico's energy sector. The regulatory law to the constitution was changed to allow private investment in natural gas transportation, distribution and storage, in recognition of the importance of this fuel to Mexico's economic development. A regulatory commission has been created (the Comissión Reguladora de Energía or CRE), charged with the privatization of assets formerly controlled by Pemex. Rules have been established for pipeline tariffs and first hand sales of imported gas from the U.S. (although Pemex is expected, at some point, to resume its bid to be a net exporter of gas). The CRE handles all auctions for state-owned assets (portions of the Pemex pipeline grid and local distribution networks) that are to be turned over to private operators, and uses a price cap formula (RPI-X) with five-year reviews to regulate tariffs.

In spite of all of these reforms, deep problems exist in Mexico's oil and gas sector. Pemex has watched its market share of exported oil erode as other countries moved aggressively to lure private investment into their upstream businesses. The investment demands on Pemex for improvement and expansion projects are huge. While the company has had some success with foreign placements of debt, many questions remain about Pemex's ability to finance capital improvements. Finally, while the effort to attract private investment into Mexico's natural gas pipeline and distribution segments continues, Pemex remains the sole supplier of natural gas which will restrict growth of Mexico's natural gas market.

As noted previously, Mexico also faces shortfalls in electric power production. The 1992 electricity law created opportunities for IPPs to be established, but with constraints on sales (only five percent of generation can be sold to an entity other than Comisión Federal de Electricidad, Mexico's national electricity organization). Most of the IPPs constructed for dispatch to CFE customers use natural gas. Natural gas price trends in the U.S. have heavily impacted IPP finances and placed burdens on CFE which buys the electric power production and, increasingly, guarantees the natural gas fuel contracts. Along with Luz y Fuerza del Centro (LFC), the distribution company for Mexico City, portions of the CFE grid face high non-technical losses, upwards of 20-30 percent in urban areas and roughly 15-16 percent overall.

The CRE has five appointed commissioners. A law passed by the Mexican Congress in 1995 established the CRE as an independent entity, but Mexico's energy ministry retains a great deal of influence. The CRE handles conflicts and disputes with operators through private consultations rather than public meetings typical of the U.S. and Canada.

REFERENCES

U.S. Energy Information Administration, www.eia.doe.gov, for data and country briefs.

Much of this case study was prepared from research reports and publications produced by Dr. Michelle Michot Foss and CEE. See www.beg.utexas.edu/energyecon for details and to obtain reports.