GAS MARKET INTEGRATION IN THE SOUTHERN CONE

Editors
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INTER-AMERICAN DEVELOPMENT BANK

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Inter-American Development Bank

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Contents

Foreword

Gas Market Integration in the Southern Cone is part of a larger effort by the Inter-American Development Bank (IDB) to promote integration of energy markets in South America's Southern Cone region. Although the rich analyses and results make it difficult to select a focal point for this foreword, the main goal of the IDB agenda for regional integration is capturing the larger gains from trade and fairly distributing them.

The benefits associated with integrated, competitive gas markets are large. Consumers benefit from a more stable and secure supply carried by interconnected networks and access to many market participants. They also gain from increased competition and lower monopoly rents and prices. Producers also benefit since they can sell to a broader range of customers and spread downturn risks across countries. Because an integrated, competitive market improves pricing transparency, potential consumers and investors can more easily evaluate business opportunities, thereby promoting new investments.

Southern Cone countries have undergone a lengthy process to integrate their gas sectors. Despite results achieved through the creation of bilateral transactions, there is still a long way to go. Industry structure and political barriers persist in preventing market integration and regional trade. Consumption remains low, and enormous investments are required to expand transmission and distribution infrastructure to increase consumption. Industry incumbents ignore the incentives required to invest in regional market integration, which would involve new market entrants playing a more prominent role. Although integration is on the agenda of most political summits in the Southern Cone region, gas-trade liberalization and the harmonization of regulatory frameworks associated with market integration require many difficult political decisions and serious commitments, as recent events have shown.

Advancing toward regional gas-market integration demands the simultaneous removal of political and economic constraints. To this end, a dialogue is needed between national authorities, the gas industry, and consumers. It should start by recognizing the political and economic

obstacles to integration and agreeing on the search for solutions aimed at a socially equitable distribution of integration's benefits. Doing so will require that the participating parties accept two guiding principles. First, the parties should accept at least some of the targets for advancing toward gas-market integration. Agreeing on such milestones will allow for evaluation of the process and, if necessary, its redirection. Second, the parties should recognize that the process of integration will inevitably bring losers and winners; this reality calls for credible, stable, and acceptable mechanisms for compensating losers.

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Editors' Introduction

Paulina Beato and Juan Benavides

In South America's Southern Cone, natural gas is the most promising energy industry for regional market integration. Natural-gas reserves are abundant and unevenly distributed. In addition, the infrastructure for regional transport is fairly well developed. Moreover, the region has significant potential for market growth, especially in light of Brazil's enormous energy market. Gas-power plants in particular are expected to grow and play a key supply role in both Brazil and Chile. Furthermore, market integration—such as increased convergence of gas and electricity markets—could reduce energy-supply costs within the region. Finally, business strategies of the region's natural-gas companies focus on exploiting cross-border synergies.

The integration-conducive environment that prevailed during 1996–2001 was instrumental in promoting gas trade across Southern Cone countries. The gas industry undertook enormous infrastructure investments. Over this period, seven pipelines were built connecting Argentina's production areas with Chilean markets. In 1999, the 3,150-kilometer Bolivia-Brazil pipeline was completed, and a project linking northern Argentina with Brazil's southern border was finalized.

The Southern Cone gas industry's advance toward regional integration stalled with Argentina's 2001 macroeconomic crisis. Four key obstacles to integration emerged. First, gas prices in Argentina—already low compared to international standards—fell to about one-third of their historical levels in dollars. Similarly, gas transmission and distribution tariffs fell to one-third of historical levels. Thus, while producers lacked incentives to invest and sell gas in domestic markets and to increase gas exports, domestic demand boomed. Second, in March 2004, an Argentine resolution allowed rationing contracts with interruptible clauses and contracts to export gas volumes greater than in 2003. This resulted in a reduction in exports to Chile. Third, a deep political crisis emerged in Bolivia, owing to political opposition to exporting liquefied

natural gas (LNG) to the United States using Chilean ports. Fourth, in 2004, Argentina's government signed a temporary agreement with Bolivia for importing Bolivian gas. However, this agreement restricted Argentina from exporting the Bolivian gas to third countries.

Despite the recent backlash, the benefits of regional integration remain. Moreover, economic growth and investor confidence began to strengthen in mid-2003 and are now consolidating. Thus, a new push toward integration appears appropriate. To this end, this book aims to open a dialogue that will stimulate gas integration by providing a systematic analysis of obstacles and opportunities and offering a road map toward a regionally integrated, competitive gas market.

The reader should note that most of the work on this book occurred during the first half of 2003, when perspectives on regional integration were favorable. After the 2004 crisis, a chapter analyzing the effects of the Argentina-Bolivia-Chile crisis was prepared, and the country analyses were modified to include relevant implications of the crisis. Despite the book's optimistic outlook on gas-market integration in the Southern Cone, Argentina's 2004 gas-supply crisis and its repercussions on gas exports to Chile were a critical turning point. Indeed, the atmosphere at the Fourth Latin American Gas and Electricity Congress, held in Rio de Janeiro in April 2004, reflected the seriousness of the crisis, with most presenters speaking of disintegration, rather than integration.

Chapters 1-4 analyze specific features of the natural-gas sector in four Southern Cone countries with significant gas consumption or reserves: Argentina, Bolivia, Brazil, and Chile. Each of the chapter authors brings a wealth of experience and knowledge to bear on the respective country sectors. However, such author diversity implies that the country chapters are not fully homogenous. In this regard, the editors have sought to strike a balance between analytical homogeneity and country diversity.

Chapter 5 analyzes Peru's natural-gas sector to identify forces pushing for integration. Although this country's gas market is far from being part of the Southern Cone market—the editors' initial decision in 2003 was to exclude the analysis—the 2004 crisis, associated export restrictions, and

results of the 2004 Bolivian referendum have pushed integration of the Peruvian gas sector to the forefront of discussions.

Chapter 6 presents a proposal for advancing and managing the integration process. The proposal structures a set of recommendations for promoting gas-market integration in Latin America. It relies on European experience, while also recognizing the Southern Cone's distinguishing features. The proposal recommends starting the process with broad agreement on certain principles, perhaps embodied in a multilateral agreement. Relevant players and institutions would then work on details of implementation, as in Europe. The chapter also elaborates on the minimal principles on which countries should agree.

Chapter 7 discusses the relevant forces pushing for and against regional integration. Specifically, it discusses how the proposal set forth for advancing and managing the integration process deals with these issues. An analysis of the forces for integration is structured around three topics: regional market features, industry structure, and regulatory frameworks. The chapter also discusses the necessary conditions that a proposal promoting gas integration should meet to enhance favorable forces and minimize unfavorable ones.

Chapter 8 then analyzes the effects of the Argentina-Bolivia-Chile crisis on prospects for integration. As the chapter shows, natural-gas integration in the Southern Cone remains a question mark, at least for now. The region's main gas exporters are experiencing significant political and economic crises that have significant implications for the natural-gas industry, affecting the outlook for cross-border gas trade. The chapter considers the implications of solutions Argentina and Bolivia are seeking as the gas sector represents an important setback to the integration process led by private investors. The reasons are threefold. First, price controls in Argentina is changing this country's Southern Cone market role from gas exporter to importer. Second, Chile's ability to import gas from Bolivia is offset by political motivations. Third, gas imports from Brazil are much lower than earlier expected because recent changes in the country's energy policy will likely reduce prospective demand.

Chapter 9 presents industry views on regional gas-market integration. Although the concerns of sector companies differ with regard to the process of integration, three main areas are of common concern. First, companies agree that larger market integration would benefit both the industry and consumers. Producers would benefit from selling to a broader group of customers and spreading downturn risk across countries. Consumers would benefit from a stable and secure supply carried by interconnected networks and access to many market participants. Moreover, an integrated gas market would permit greater efficiency in infrastructure operation and larger economies of scale shared by consumers and industry. Second, integration of gas industries across distinct countries poses key challenges concerning the setup of a competitive regulatory framework and harmonization among national legislations. Third, the current situation demands political negotiation between relevant countries to avoid anti-integration solutions to the region's economic and political crises. Lacking political negotiation, the Southern Cone gas market could be driven toward further disintegration as each country seeks domestic solutions to current instability.

In summary, this book's contributions aim to provide a framework for discussing and negotiating a set of basic principles to underpin the regulatory framework and energy policy to permit market integration and price convergence. To advance gas-market integration, Southern Cone countries should also work toward increasing economic and political integration. Indeed, political and macroeconomic convergence is essential to reduce political and regulatory risks associated with gas trade and infrastructure and to promote long-term investment.

PART I

Country Analyses

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Chapter 1

Argentina: From Growth to Crisis

Diego Bondorevsky and Diego Petrecolla

The past decade witnessed dramatic changes in Argentina's natural-gas market. Before the 1990s, the state had a monopoly over the production, transport, and distribution of natural gas.[1] This changed in 1992, when under the framework of state reform legislation (Law 23.696), *Gas del Estado* (GdE) was privatized (Law 24.076). A new regulatory framework was established to promote competition in such segments as production and commercialization, and regulate segments considered natural monopolies, such as transport and distribution.

The liberalization of the upstream sector, which resulted in the privatization of YPF,[2] started in mid-1989. Divestiture was completed in several steps. In September 1992, Law 21.145 enabled the allocation of YPF shares among various parties.[3] In mid-1993, the public offering of YPF shares resulted in an equity allocation of 20 percent to the federal government, 11 percent to various provinces, and 10 percent to employees. The remaining 59 percent was floated in the market. In 1999, the government sold all of its YPF shares (with the exception of 1,000 class "A" shares) to Repsol, the leading Spanish oil producer.

These changes led to the reconfiguration of Argentina's natural-gas industry into four segments: production, transport, distribution, and commercialization. The production segment has some 30 active operators. From 1994 until the 2002 macroeconomic crisis, the price of

1. Through YPF (Yacimientos Petrolíferos Fiscales), the former state-owned oil company, and through GdE (Gas del Estado), the former state-owned gas transport and distribution company.
2. See Decree 1055/1989 (October 10, 1989), Decree 1212/1989 (November 8, 1989), and Decree 1589/1989 (December 27, 1989).
3. Up to a 51 percent stake was transferred to the federal government, up to 39 percent to the provinces, and up to 10 percent to YPF employees.

natural gas at the point of access to the transport system in each basin was deregulated. Since 1993, production has increased by more than 70 percent; not until 2002 did this trend change.

During the privatization process, the main pipelines of the gas transport system were split into two private companies. At the same time, the natural-gas distribution system was divided into eight regional companies. ENARGAS (*Ente Nacional Regulador del Gas*), the government agency created in 1993 through the Natural Gas Act, regulates transport and distribution tariffs. It monitors regulatory compliance with the law and the contractual conditions applicable to each transport and distribution company.

Regional interconnection of Argentina's gas market began in the 1970s, when an agreement was signed to construct a gas pipeline between Bolivia and Argentina. Through this agreement, GdE purchased natural gas produced by YPFB (*Yacimientos Petrolíferos Fiscales Bolivianos*), Bolivia's state-owned oil company. The agreement assured Bolivia of a certain volume of gas export to Argentina; in return, Argentina was secured a steady flow of lower-priced, nonrenewable fuel.

More recently, the interconnection process between Bolivia and Argentina has undergone significant changes. GdE and YPF (the national oil and gas producer) have been privatized, and pipeline construction between Bolivia and Brazil has led Bolivia to redirect its gas output to the Brazilian market; however, in 2004, the link between Bolivia and Argentina was re-opened.

During 1995–2000, significant progress was made toward integrating Argentina's energy with that of neighboring countries. However, contrary to its original interconnection experience with Bolivia, Argentina has become a net exporter of energy products since 1998. Furthermore, the private sector has replaced state-owned enterprises in the move toward integration. Indeed, in 1995, private companies laid the first oil and gas pipelines and established the first electrical transmission cross-border lines between Argentina and Chile. Jadresic (1999) states the factors that contributed to development of these cross-border interconnections:

- Deregulation of the energy sector in both Argentina and Chile, which made it possible for the private sector to invest in markets traditionally controlled by the public sector; and

- Adoption of new technologies in electricity power generation, such as the combined-cycle power generation, which provided critical mass for the construction of transport infrastructure.

However, after the government froze domestic prices of natural gas in 2002, increased domestic consumption, combined with lack of upstream and downstream investment, led to Argentina's natural-gas crisis, which has reduced exports and affected markets in neighboring countries (particularly Chile, which is dependent on Argentina's natural gas).

Evolution of Supply: Production and Imports

Domestic Production and Reserves

The Hydrocarbons Law (No. 17.319) governs Argentina's gas extraction and production. Increased production in recent years has been driven by exports to Chile, initiated in 1997. Between 1993 and 2003, production reached 98.1 percent (table 1-1). Natural gas is extracted from four main basins: Austral, San Jorge, Neuquina, and Noroeste, all of which are located far from centers of consumption.[4] A point-to-point network connects production and consumption centers (figure 1-1, p. 8).

In 2003, Argentina had proven natural-gas reserves of 613,084 million m^3; Neuquina Basin accounted for 51 percent of proven reserves, while Austral Basin had 23 percent, Noroeste Basin 20 percent and San Jorge Basin 6 percent. Over the 1993–2003 period, Austral and San Jorge basins showed the largest increases (table 1-2). Until 2000, Argentina was South America's second largest holder of proven gas reserves, after

4. Argentina's basins are located in the provinces of Chubut, Jujuy, Mendoza, Negro, Neuquen, Río Negro, Salta, Santa Cruz, and Tierra del Fuego. Major consumption centers are in Buenos Aires, Córdoba, and Santa Fe.

Venezuela.[5] However, Bolivian proven reserves surpassed Argentina's in 2001 due to new discoveries in Bolivia and lack of exploration in Argentina.

TABLE 1-1. ARGENTINA PRODUCTION AND PROVEN RESERVES, 1988–2003 (millions of m^3)

Year	Production	Proven reserves	Proven reserves/ production
1988	22,734	773,016	34
1989	26,713	773,016	29
1990	23,018	579,056	25
1991	24,643	592,869	24
1992	25,043	540,899	22
1993	25,568	516,662	20
1994	26,576	535,328	20
1995	29,190	619,295	21
1996	33,373	685,586	21
1997	37,074	683,796	18
1998	38,630	686,584	18
1999	42,426	748,133	18
2000	44,872	777,609	17
2001	45,994	763,526	17
2002	45,819	663,523	14
2003	50,644	612,496	12

Source: Energy Secretariat.

Even as Argentina's proven reserves have fallen and exploration was brought to a standstill after the 2002 crisis, domestic and foreign demand have increased. As table 1-1 shows, the ratio of proven reserves to production fell from 17 in 2001 to 12 in 2003; thus, at current production levels, reserves are estimated to last 12 years.

Because gas is a non-renewable resource, the issue of available reserves takes on added importance. On the basis of recent exploratory discoveries in Argentina's five productive basins, the Energy Secretariat concludes that only three—Austral, Neuquina, and Noroeste—show potential for future incorporation of reserves.[6]

5. See British Petrol Statistical Review of World Energy (2003).
6. See *Prospectiva* (2002).

TABLE 1-2. ARGENTINA'S PROVEN RESERVES BY BASIN, 1993–2003
(millions of m^3)

Basin	1993	1995	1997	1999	2001	2003
Austral	64,019	136,347	160,301	171,437	175,988	138,248
Cuyana	1,121	854	806	879	503	515
Neuquina	313,781	343,801	329,157	377,117	377,891	311,762
Noroeste	123,897	122,145	172,063	165,363	161,644	124,511
San Jorge	13,844	16,148	21,469	33,337	47,395	38,048
Total	**516,662**	**619,295**	**683,796**	**748,133**	**763,421**	**613,084**

Source: Energy Secretariat.

Production Sector Structure

Although Law 17.319 removes all restrictions on market entry, the sector structure limits effective competition. Several factors help to explain poor competition in the extraction sector:[7]

– One company, YPF, controlled 60 percent of all sales at the time that legal competition was established.

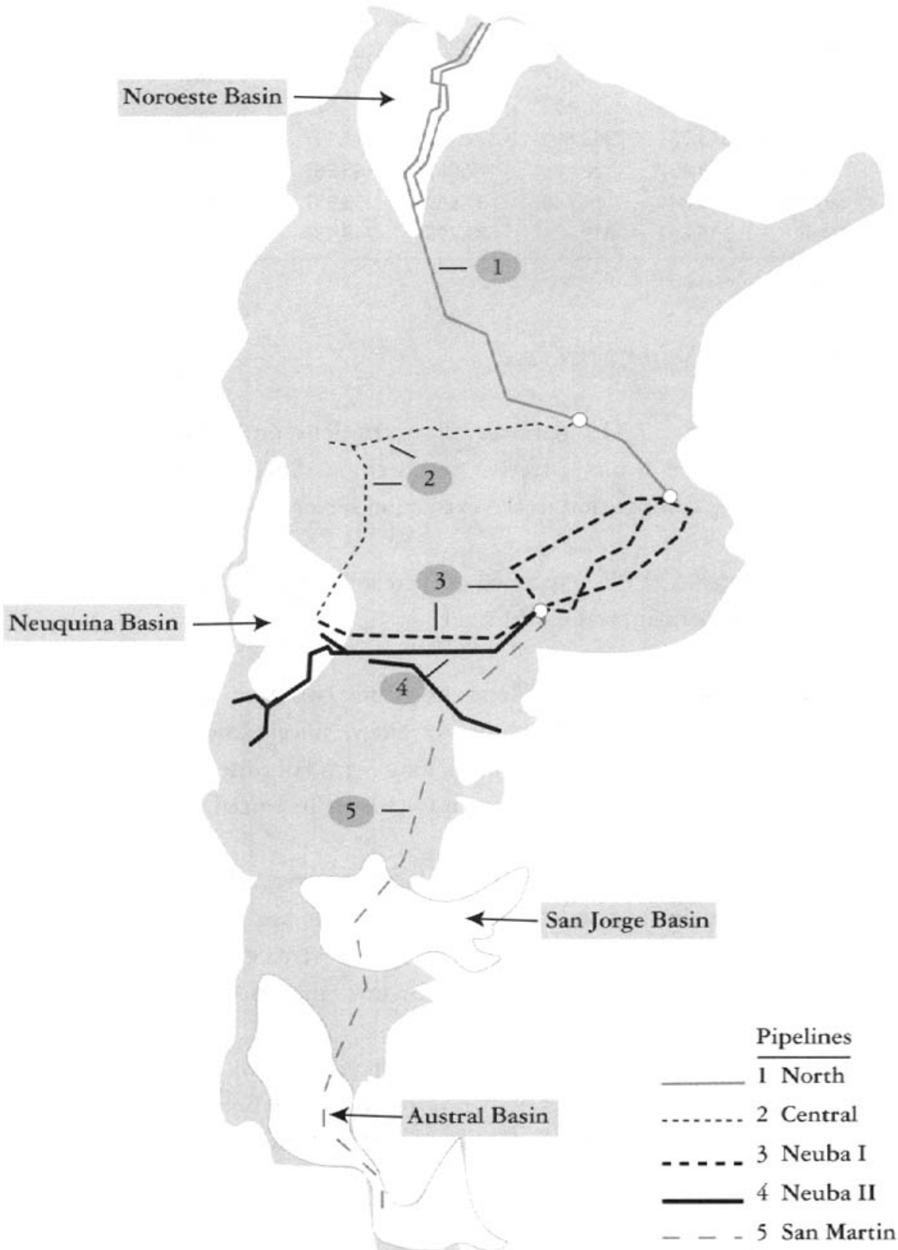
– Heavy investment in exploration of reserves was required, which barred new suppliers from market entry, since exploration involves high-sunk production costs (i.e., a long period of time will be required for a company to produce enough to recover its initial investment).

– Concessions for selling gas are attached to reserves; thus, high levels of reserves are in the hands of one company or an associated group either bars potential competitors from entry or prevents current competitors from increasing their share of sales by lowering prices.

In 1992, GdE bought 90 percent of its gas from YPF, while the remaining 10 percent was either imported from Bolivia (7 percent), carried through North Pipeline, or purchased from private domestic producers (3 percent). After liberalization of Argentina's upstream sector,

7. For an extensive analysis of the competition problem, see Bondorevsky and Petrecolla (2002).

FIGURE 1-1. ARGENTINA BASINS AND MAIN PIPELINES



Source: ENARGAS.

more than 30 firms began extracting natural gas from the country's main basins. The Herfindahal-Hirschman Index by basin shows a decrease between 1997 and 2000 (table 1-3). As of 2001, YPF supplied more than half of Argentina's natural-gas market (table 1-4); moreover, its market position and potential to set prices are expanded through its Astra subsidiary. In short, YPF is a key player in regional market integration since the company controls, either directly or indirectly, more than 70 percent of Argentine exports.

TABLE 1-3. HERFINDAHAL-HIRSCHMAN INDEX AND CONCENTRATION INDEX, 1997 AND 2000

		Basin			
Year	**Index**	**Neuquina**	**Austral**	**Noroeste**	**Total**
1997	HHI	4,451	2,771	5,898	3,973
	C4	n.a.	n.a.	n.a.	n.a.
2000	HHI	3,854	2,479	4,452	3,409
	C4	88.3	87.5	94.3	76.7

HHI = Herfindahal-Hirschman Index, C4 = Concentration Index.
n.a. = not available.
Sources: Novara (1997) and ENARGAS, Resolution 1483 (2000).

In October 1999, YPF signed a letter of commitment, pledging to gradually phase out trading in natural gas produced by third parties. According to this commitment, YPF agreed not to trade third-party gas after May 2003.[8] To date, ENARGAS has no record of this commitment having been met.

Wholesale Prices

Unlike Argentina's electricity market, where wholesale prices declined, the wholesale price of natural gas increased from the 1994 deregulation to the 2001 price freeze.[9] As figure 1-2 shows, the country average increased 35 percent between 1993 and 2001 (14 percent, if measured from 1994, when the price was effectively deregulated).

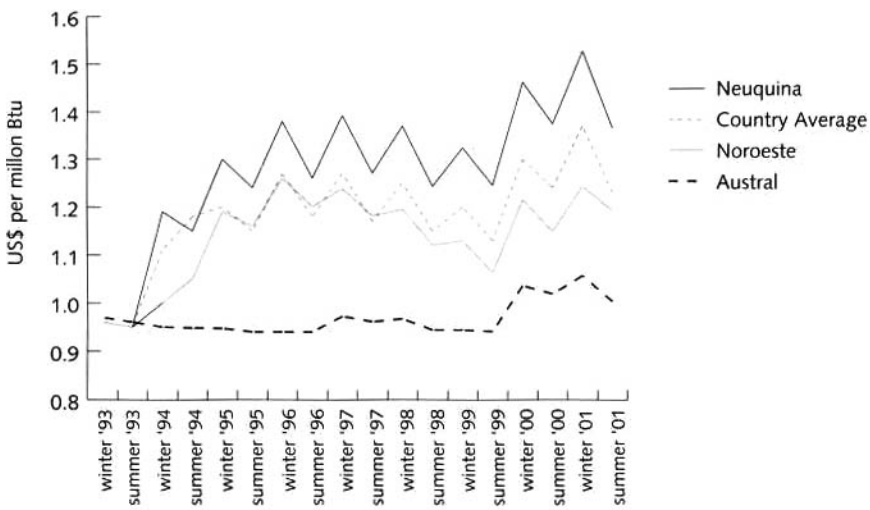
8. ENARGAS, file 4943 (1999, 467–69).
9. For a comparison of the electricity and natural-gas markets, see Gerchunoff, Greco, and Bondorevsky (2003) and Petrecolla and Ruzzier (2003).

TABLE 1-4.PRODUCER PARTICIPATION BY BASIN AND EXPORTS, 2001
(percentage)

	Own and third-party gas				
Producer	**Austral**	**Neuquina**	**Noroeste**	**Total**	**Exports**
YPF	38.65	5.75	50.85	51.12	57.75
YPF-Total-Pan American-Wintershall	-	-	2.95	1.66	7.71
Pluspetrol-Astra	-	-	7.54	1.75	5.65
Total-Pan American-Wintershall	1.83	16.12	-	9.45	10.30
Pecom (now Petrobrás)	15.05	6.40	-	6.68	-
Tecpetrol-Movil-CGC	-	-	17.33	4.03	5.17
Propietarios de Sierra Chata	-	6.82	-	3.84	12.71
Petrouruguay	-	0.27	-	0.15	0.71
Other	44.47	14.64	21.33	21.32	-
Total	**100**	**100**	**100**	**100**	**100**

Note: Official updated data is unavailable.
Source: ENARGAS.

FIGURE 1-2. PRICE TREND IN THE CONTRACT MARKET BY BASIN, 1993–2001



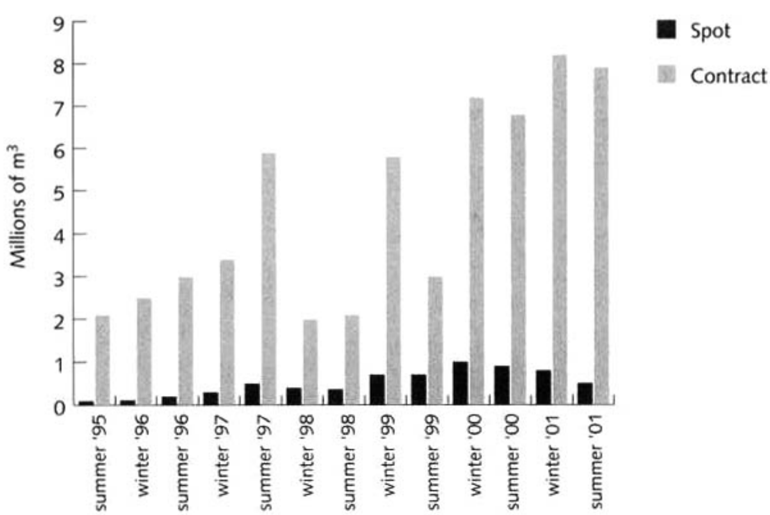
Source: ENARGAS.

Spot Market Development

Development of a mature spot market is an important step toward creating a competitive environment among natural-gas producers and traders. However, as figure 1-3 shows, Argentina's spot market has not grown significantly, despite regulatory incentives established by Decree 1020/95 (which set an upper limit to the acquisition prices that the pass-through regime could pass on to final consumers). Thus, if the distributor acquires natural gas at a price lower than the reference price, it is allowed to pass through 50 percent of the difference between the purchase and reference prices. However, if the purchase price comes in higher than the average basin price, the distributor is punished by being allowed to pass on only 50 percent of the difference between the purchase and average basin price to consumers.

Distributors are neither rewarded nor punished for prices that come in between the floor and ceiling; rather, they are permitted to pass on the purchase price to customers (i.e., a classic pass-through). Despite incentives, spot-market transactions in 2001 represented 9.5 percent of total distribution purchases, and participation of large consumers and trader companies increased substantially.

FIGURE 1-3. COMPARISON OF SPOT AND CONTRACT MARKETS, 1995–2001



Source: ENARGAS.

Imports

The third article of Law No. 24.076 (and its amendments) establishes natural-gas export and import guidelines for firms and allows imports without prior authorization. Before 1997, Argentina was a net importer from Bolivia through the North pipeline. In 1993, Bolivian imports represented 7 percent of natural-gas supply, compared to only 1 percent in 1999 (table 1-5).

Sector structure has limited Argentina's ability to import gas from Bolivia. The pipeline connecting Bolivia and northern Argentina, whose capacity is 6,000 cubic meters (m^3) per day, has not been used to import Bolivian gas since September 1999, when Bolivia began exporting to Brazil through the Santa Cruz-São Paulo pipeline. Repsol-YPF interests help to explain why this pipeline went unused, despite Argentine distributors' intent to buy gas directly from Bolivia. In 1993, a distributor group, Litoral Gas,[10] sought an alternative Bolivian supplier, Refinor, but the company's offer was too expensive.[11]

Repsol-YPF market control relies on its control of Refinor, a strategic company that transports, processes, and commercializes natural gas from the Noroeste Basin and Bolivia. It is where Bolivian gas is refined before being injected into the TGN pipeline. Refinor also owns the pipeline that connects the Bolivian pipeline with the refinery. It is ruled by Law No. 17.319, which established that transport lines in the upstream segment would remain in the hands of producers without restrictions. Currently, YPF owns 50 percent of Refinor; Petrobrás and Pluspetrol own 28.5 and 21.5 percent, respectively.

Although gas imports were insignificant during 2002–03, the 2004 energy crisis led to an agreement between Argentina and Bolivia to increase Bolivian flows through the North pipeline (with certain restrictions) to help curb Argentina's natural-gas deficit.[12]

10. Litoral Gas included *Gasnor S.A.*, *Distribuidora de Gas del Centro S.A.*, and *Gas Natural Ban S.A.*

11. These attempts culminated in a note from Litoral Gas to Argentina's regulatory body, ENARGAS, stating that it had no other choice than to accept YPF's price for domestically produced or traded gas (ENARGAS, file 4943).

12. ENARGAS reported that, between June 15, 2004 and July 11, 2004 nearly 100 million m^3 of natural gas were imported from Bolivia, in addition to the 85 million m^3 imported in 2003.

TABLE 1-5. ARGENTINA'S NATURAL-GAS IMPORTS, 1993–2003

Year	Millons of m^3	% Total output
1993	1,883	7
1994	2,423	8
1995	2,288	7
1996	2,198	6
1997	1,804	5
1998	1,805	4
1999	468	1
2000	17	0
2001	0	0
2002	99	0
2003	85	0

Source: ENARGAS.

Current Supply Problems

Under Argentina's 1991 Convertibility Law, utility companies operating in the country made sales on the domestic market in U.S. dollars, to which the Argentine peso was pegged. With abandonment of this law in January 2002, Argentine utility companies suffered sizeable losses as the value of the peso fell dramatically. Concurrent with devaluation, the government imposed a freeze on utility tariffs, holding them at their peso-denominated rate. The shock was particularly severe in the gas sector. Since January 2002, producers have received three times less in domestic demand (measured in U.S. dollars) than in December 2001. Since nearly 90 percent of natural-gas demand comes from domestic consumers, the freeze on natural-gas tariffs has resulted in lower investment in production, as well as producer development, exploration, transport, and distribution activities. Moreover, it has changed the relative prices of energy types. While natural gas prices have remained unchanged,[13] prices of other energy sources—that is, tradeable products, such as petrol—have increased by more than 80 percent since devaluation of the peso. This caused demand for compressed natural gas (CNG) to increase 43 percent during 2001–03, while overall domestic demand grew 7 percent over the same period.

13. By virtue of Economic Emergency Law No. 25.561, which forbids adjustment of public-services tariffs.

Lack of sector investment and increased demand caused, in part, by the government's 2002 price freeze, led to a crisis in the first half of 2004. In March 2004, ENARGAS confirmed this crisis situation, when it published a report warning of system risk; the report concluded that scarcity of natural gas would arise during winter 2004 if Argentina's government authorities failed to take appropriate actions.[14]

In response, the following actions were taken in April 2004:

- The Argentine and Bolivian governments signed an agreement to increase Bolivian natural-gas imports over a six-month period.[15]

- Through Decree 181/2004, the Energy Secretariat established a program to normalize natural-gas wellhead prices; price adjustments will occur during 2004–06, and prices will be freed up beginning in 2007.[16,17]

- The Secretary of Energy approved a program to reduce natural-gas exports.[18]

- Argentina's government approved a program to reduce natural-gas consumption of residential users and small customers.[19]

- Argentina's government purchased Venezuelan fuel oil to substitute for natural gas in electricity production.

14. See *Informe de Abastecimiento 2004 ENARGAS*, available at www.enargas.gov.ar

15. See *Declaración Presidencial de Buenos Aires*, Executive Power and Resolution 710/2004, Energy Secretariat.

16. Through Decree 181/2004, the government authorized a wholesale price adjustment, starting in 2004. The process includes real price increases for May and October 2004 and May and July 2005, restricted to sales to power generators and certain large industrial users. Natural-gas sales whose end-consumption involves residential and small commercial customers are excluded from these price increases. The measure establishes that, by no later than January 1, 2007, the wholesale natural-gas market must again be fully liberalized.

17. Resolution 208/2004 of the Ministry of Planning, which implements Decree 181/2004, breaks up the market into three prices, according to customer category: 1) residential customers will be protected from any price increase until the end of 2006; 2) industrial users and power plants currently buying from natural-gas distributors will face gradual increases every six months until mid 2006, and price controls will be eliminated at the end of that year; and 3) industrial users that typically buy directly from gas producers (usually the largest consumers) will receive no protection from price controls.

18. See Resolution 265/2004, Disposition 27/2004, and Resolution 659/2004; Energy Secretariat.

19. See Resolution 415/2004, Energy Secretariat. This program established incentives, through tariff reduction, to consumers whose recorded consumption levels were lower than those recorded in the same month of 2003.

These measures tempered potential adverse effects over the domestic market. However, reduction in exports to Chile created a problem in bilateral energy relations between Argentina and Chile, which remains unresolved.

Natural Gas Demand

Domestic Consumption

The incremental increase in natural-gas consumption over the last decade was interrupted by the 2002 macroeconomic crisis. The 2001–02 drop in domestic consumption occurred mainly in power generation (–10 percent in 2002). Residential customers, on the other hand, maintained their consumption levels, thanks to the low price of natural gas relative to that of substitute fuels (table 1-6).

TABLE 1-6. TOTAL DOMESTIC CONSUMPTION, 1993–2003
(millions of m^3)

Year	Residential	Commercial	Industry	Power generation	CNG*	Other	Total
1993	5,637	867	7,747	5,931	760	885	21,828
1994	5,651	866	8,794	5,728	940	687	22,666
1995	5,756	948	9,200	7,142	1,007	486	24,538
1996	5,843	924	9,351	8,713	1,092	497	26,420
1997	5,803	995	9,743	8,617	1,268	505	26,930
1998	5,877	949	9,910	8,548	1,412	564	27,260
1999	6,557	1,016	9,777	10,680	1,509	636	30,175
2000	6,967	1,053	9,965	10,899	1,677	677	31,238
2001	6,717	1,008	9,627	8,898	1,851	686	28,787
2002	6,656	987	9,797	7,784	2,040	725	27,990
2003	6,910	1,031	10,690	8,751	2,640	808	30,830

* Used in NGVs.
Source: ENARGAS.

In 2003, increased domestic consumption of natural gas resumed as domestic-market prices of alternative energies grew. That year, nearly 63 percent of natural-gas domestic sales were concentrated in industry and gas-powered generation, while residential users accounted for 22

percent, followed by natural gas vehicles (NGVs), at 9 percent (table 1-7).[20] According to ENARGAS (2002), large industrial users accounted for 90 percent of industrial consumption, 50 percent of which consisted of chemical, petrochemical, distillery, and iron and steel industries.

NGV consumption had the largest share of increased demand, reaching 147 percent between 1993 and 2003, making Argentina the world's largest CNG market. This resulted from government policies that encouraged CNG use and raised prices of alternative fuels, such as gasoline. Currently, Argentina has 1,249,029 NGV and 1,218 CNG service stations.

In 2002, residential consumers represented about 96 percent of all natural-gas users, about the same percentage found a decade earlier (table 1-8). New residential and industrial users in Argentina's gas network numbered only 40,000 in 2002, fewer than during the 1993-01 period, when 1.5 million new users were recorded as a result of privatization.

TABLE 1-7. TOTAL DOMESTIC CONSUMPTION, 1993–2003
(Percent)

Year	Residential	Commercial	Industry	Power generation	NGV	Other
1993	26	4	35	27	3	4
1994	25	4	39	25	4	3
1995	23	4	37	29	4	2
1996	22	3	35	33	4	2
1997	22	4	36	32	5	2
1998	22	3	36	31	5	2
1999	22	3	32	35	5	2
2000	22	3	32	35	5	2
2001	23	4	33	31	6	2
2002	24	4	35	28	7	3
2003	22	3	35	28	9	3

Source: ENARGAS.

20. ENARGAS (2002) points out that, while the freeze on the natural-gas tariff continued in 2002, the price of liquefied petroleum gas (LPG) increased more than 100 percent.

TABLE 1-8. NATURAL-GAS USERS, SHOWING NUMBER OF RESIDENTIAL USERS, 1992–2002

Year	Residential	Total	% Residential
1992	4,351,300	4,552,900	95.6
1993	4,522,400	4,739,900	95.4
1994	4,716,500	4,947,300	95.3
1995	4,998,300	5,076,200	98.5
1996	4,998,300	5,238,800	95.4
1997	5,150,700	5,398,800	95.4
1998	5,340,400	5,596,700	95.4
1999	5,504,900	5,765,300	95.5
2000	5,647,400	5,910,400	95.6
2001	5,754,000	6,018,800	95.6
2002	5,796,400	6,060,800	95.6

Source: ENARGAS.

Demand Forecast

Given the current situation of Argentina's natural-gas sector, no reliable demand forecasts are available. Table 1-9 shows the most recent forecast, provided by the Energy Secretariat in 2002.

TABLE 1-9. DEMAND FORECAST, 2004–2012
(millions of m^3)

Sector	2004	2006	2008	2010	2012
Residential	6,975	7,201	7,418	7,634	7,848
Commercial	1,602	1,652	1,699	1,746	1,792
Industry	9,826	10,144	10,450	10,766	11,094
Power plants	12,004	13,714	15,661	15,327	15,123
Transport	2,267	2,449	2,642	2,839	3,043
Total	**32,675**	**35,159**	**37,870**	**38,312**	**38,900**

Note: Based on average scenario.
Source: Energy Secretariat, *Prospectiva* (2002).

Exports

Encouraged by market liberalization and the 1995 Gas Protocol signed with Chile, Argentina began exporting natural gas in the late 1990s.[21] During 1997–2003, natural-gas exports rose more than 1,000 percent, making Argentina the region's major natural-gas exporter. In 2003, Chile represented 91 percent of the country's exported natural gas (followed by Brazil and Uruguay, which account for only 8 percent and 1 percent, respectively). Natural gas destined for Chile is extracted from the Austral, Neuquina, and Noroeste basins and transported by seven pipelines connecting the two countries. The Uruguaiana interconnection pipeline transports exports to Brazil, while three cross-border pipelines—Cruz del Sur, Colón-Paysandú, and Casablanca—transport exports to Uruguay.

Unlike the importation process, exportation of natural gas must be approved by the Energy Secretariat within a 90-day period. The main condition established by the legal framework for approval is for these exports to have no effect on domestic provision, which is unclear in certain cases, as the 2002 crisis situation illustrates. In cases of no response to authorization within the 90-day period, the export is automatically approved.

Decree 951 of 1995 established that export agreements, which imply construction of pipelines or provision of new equipment, require ENARGAS intervention before the Energy Secretariat grants final authorization. Resolution 298 of 1998, which regulates the exporting of natural gas, highlights the following principles:

- *Transparency.* All gas-export information must be provided national authorities (domestic consumers, government, and investors in the transport and distribution segment).

21. The process of exporting natural gas had its geopolitical root in a 1995 agreement signed by the Argentine and Chilean governments (known as the Complementary Economic Agreement), whereby standards regulating interconnection and supply between the two countries were set forth. Article 2 of this agreement states that "the parties shall not place restrictions on producers of natural gas from Argentina and Chile to export gas to the neighboring country on the basis of their properly certified reserves and availability, for which exporters and importers make a commitment." Article 6 further specifies that operation of the gas pipelines will be governed by a system of open access. In August 1999, another agreement between the two countries established norms for energy commercialization.

– *No discrimination.* No producer can offer sales whose foreign- and national-market conditions differ.[22]

– *Authorization.* Export authorizations can be granted if the exports do not affect domestic consumption. Authorizations are either long term (more than two years, involving average volumes greater than 100,000 m^3 per day) or short term (less than two years, involving average daily volumes of 100,000 m^3 or fewer).

The Resolution also established that the Energy Secretariat would assess export procedures every five years. Such evaluations would account for level of investment in exploration and exploitation, evolution of reserve, domestic and foreign sales, potential depletion of national and regional resources, price evolution of natural gas and substitute fuels, and general conditions of world energy markets.

In 2001, through Decree 131/2001, the Energy Secretariat established that export authorizations request a reserves reposition rate higher than zero and a ratio of reserves to production equal to 12 or more years.

Sector problems resulted in the modification of these regulations in 2004.[23] Executive Power authorized the Energy Secretariat to design a temporary export-rationing program to satisfy domestic gas demand. As of June 2004, this program effectively reduced natural-gas exports to Chile by 7,300 m^3 per day.[24, 25]

22. Since 2002, this principle has not been followed because sales to Chile are still in dollars at the pre-pesification level, while domestic sales remain in pesos.

23. See Resolution 265/2004, Energy Secretariat and Disposition 27/2004, Undersecretariat of Fuels.

24. On March 24, 2004, the Energy Secretariat passed Resolution 265/04, suspending export of gas quantities in excess of approved volumes under existing export permits. On March 29, 2004, the Undersecretariat of Fuels issued Decision 27/04, which approved a provisional program to restrict gas exports, thereby affecting firm deliveries of natural gas under existing export permits. Moreover, on June 17, 2004, the Energy Secretariat passed Resolution 659/04, approving a Complementary Domestic Gas Market Supply Program, which replaced the program approved on March 29. These quantitative restrictions affected natural-gas producers. During May and June 2004, some producers were required to cancel certain exports to Chile, and had those quantities delivered to the Argentine market.

25. To resolve the conflict generated by these recent resolutions, Argentina and Chile created a bilateral commission (*Grupo de Trabajo Bilateral Ad Hoc*) responsible for coordinating actions to minimize the effects of export restrictions on the Chilean natural-gas market.

Transport and Distribution

Privatization

From the outset of its activities in 1952, GdE had a monopoly on the transport, distribution, and commercialization of natural gas. Before privatization, the Ministry of the Economy set a fixed tariff, which was generally below costs. The tariff structure differentiated between types of consumers but not between peak and non-peak demand. The state company had serious problems meeting winter demand. Customers were also affected by frequent outages and low pressure. In 1992, GdE was an inefficient transporter and distributor, unable to expand its capacity to meet increased demand, with declining quality of service. At the same time, its deficits created a heavy burden for the state.

Law 24.076 (1992), provided for the privatization of GdE as part of the state reform framework (law no. 23.696). The government expected to introduce competition, strengthen productivity and efficiency, and increase the quality of services, while eliminating GdE's budget deficit. With the explicit aim of promoting competition, the restructuring process distinguished between industry stages in which market forces were in play and those characterized by monopoly elements.

The company was divided, horizontally and vertically, into 10 companies: two transport companies (*Transportadora de Gas del Norte* [TGN] and *Transportadora de Gas del Sur* [TGS]) and eight distribution companies (*Distribuidora de Gas Buenos Aires Norte, Distribuidora de Gas Metropolitana, Distribuidora de Gas del Litoral, Distribuidora de Gas Pampeana, Distribuidora de Gas del Noroeste, Distribuidora de Gas del Centro, Distribuidora de Gas del Sur,* and *Distribuidora de Gas Cuyana*),[26] which have been granted a geographical exclusivity to build and operate gas distribution systems in their respective areas.[27]

26. In 1997, a ninth distribution company (*Distribuidora de Gas Nea Mesopotámica S.A.* [Gas Nea]) was added.
27. The granted concession period was 35 years, with an optional extension period of 10 or more years.

Transport Infrastructure

The 2002 crisis[28] caused both transport firms to suspend investment projects; thus, for the past two years, the system's available transport capacity has remained flat at the 2001 level (121 million m^3 per day). Between 1993 and 2002, total transport capacity grew by 49.1 million m^3 per day (a 65 percent increase in available capacity at the outset of privatization) (table 1-10). Yet, no new main pipelines (excluding export pipelines) were built between 1993 and 2003. Network capacity was increased through additions of loops and compression.

TABLE 1-10. TRANSPORT CAPACITY OF MAIN PIPELINES, 1993–2002
(millions of m^3 per day)

Pipeline	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
North	13.4	13.4	14.6	16.9	17.1	17.1	19.9	20.4	22.5	22.5
Central	11.2	14.8	15.7	16.3	20.2	25.4	27.8	31.9	31.9	31.9
Neuba I	11.0	11.2	11.2	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Neuba II	18.5	26.0	26.6	26.6	27.6	27.6	27.6	27.6	28.4	28.4
San Martin	15.4	15.8	16.9	16.9	16.9	17.3	18.0	20.9	22.3	22.3
Total	**69.5**	**81.2**	**85.0**	**90.2**	**95.3**	**100.9**	**106.8**	**114.3**	**118.6**	**118.6**

Source: ENARGAS.

During 2003–04, use of transport capacity increased. January 2004 figures are higher, on average, than levels recorded in previous years during the same month. The reasons are increased injection of natural gas into the system and paralysis in nominal transport capacity (table 1-11). As table 1-12 (p. 23) shows transport capacity to Chile (41.1 million m^3 per day), Brazil (2.8 million m^3 per day), and Uruguay (5.1 million m^3 per day). All the pipelines were built between 1996 and 2002.

The only official project to build a new main pipeline was confirmed in early November 2003. The Technit Corporation will construct a pipeline in

28. See ENARGAS (2002) and IAPG (2003).

northeastern Argentina that will connect Bolivia with the Argentine province of Santa Fe (passing through the provinces of Chaco, Formosa, Misiones, and Corrientes). Pipeline construction will extend some 1,500 km and will require a total investment of US$1 billion, of which Argentina's government will contribute US$250 million. During the first phase of the project, total pipeline capacity will be 10 million m³ per day, increasing to 22 million m³ per day in the second phase. The project expands Argentina's potential capacity as a natural-gas exporter and transit country to Brazil or Chile. It also aims to supply gas to currently unserved regions of northeastern Argentina.

TABLE 1-11. USE OF TRANSPORT CAPACITY FOR SELECTED YEARS
(Injected gas/transport capacity)

	1993		1996		1999		2002		2003		2004	
Pipeline	**Jan.**	**July**	**Jan.**	**July**	**Jan.**	**July**	**Jan.**	**July**	**Jan.**	**July**	**Jan.**	**July***
North	0.56	0.92	0.812	1.005	0.796	0.966	0.862	1.041	0.798	0.976	0.842	n.a.
Central	0.898	0.923	0.579	0.97	0.574	0.874	0.534	0.826	0.497	0.854	0.771	n.a.
Neuba I	0.712	0.797	0.872	0.96	0.663	0.962	0.565	0.888	0.696	1.063	0.938	n.a.
Neuba II	0.758	1.038	0.445	1.069	0.515	0.99	0.44	0.921	0.429	0.917	0.58	n.a.
San Martin	0.889	1.026	0.788	0.936	0.818	0.989	0.842	0.999	0.79	1.025	0.921	n.a.
Average	**0.763**	**0.940**	**0.699**	**0.988**	**0.673**	**0.956**	**0.648**	**0.935**	**0.642**	**0.967**	**0.810**	**n.a.**

* n.a. = not available.
Source: ENARGAS.

Figure 1-4 (p. 24) shows the evolution of transport capacity since 1993 and projected capacity through 2009, when the Northeast pipeline will become operative.

Distribution Infrastructure

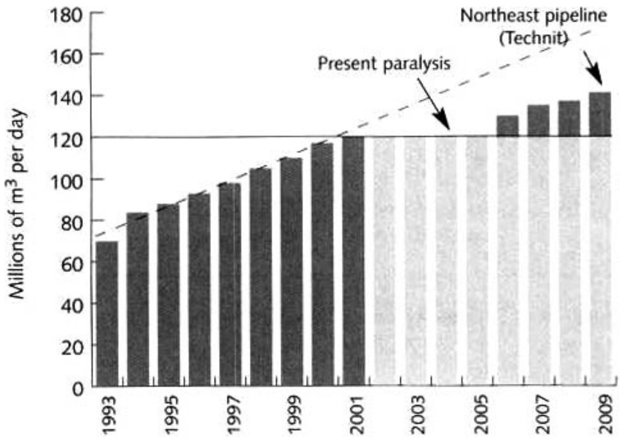
Distributors Metrogas and Ban, which have operated in Buenos Aires and the surrounding area since GdE was privatized in 1993, have the largest number of residential users. In 1997, the state granted a new distributor, Gas Nea, license to exploit service in northeastern Argentina; the next year, Gas Nea started to operate in Entre Rios Province. Today, Argentina has nine operative, natural-gas distribution firms, all of which are in private hands.

TABLE 1-12. CROSS-BORDER EXPORT PIPELINES

Zone/project	Shareholder	Regulatory framework	Date begun	Capacity (millions of m^3 per day)	Length (km)
CHILE-NORTH ZONE					
Gas Atacama	Endesa Chile, CMS Energy	Concession, Law 17.319	July 1999	8.5	941
NorAndino	Enerpac	Transport license, Law 24.076, Article 16	October 1999 (construction)	7.1	1,180
CHILE-CENTRAL ZONE					
Gas Andes	Nova Gas Intl. Canada, Gener. and Metrogas Chile, CGC and Energy Comp. Arg.	Transport license, Law 24.076, Article 16	August 1997	9.0	467
Gas Pacífico	Nova Gas Intl. Canada, El Paso Energy USA, ENAP and Gasco Chile, YPF	Concession, Law 17.319	November 1999 (construction)	9.7	638
CHILE-SOUTH ZONE					
Condor-Posesión	ENAP, Repsol-YPF	Concession, Law 17.319	1999	2.0	9
Bandurria/Cullén	ENAP, UTE San Sebastián	Concession, Law 17.319	1996	2.0	83
Magallanes-Posesión	ENAP, UTE Area Magallanes	Concession, Law 17.319	1999	2.8	33
BRAZIL					
Aldea Brasilera-Uruguaiana	TGM, Nova Gas Intl. S.A., Tecgas N.V., CMS Gas Argentina	Transport license, Law 24.076, Article 16	2000	2.8	450
URUGUAY					
Cruce Río de la Plata (Cruz del Sur)	Pan American Energy (40%), BG (40%), ANCAP (20%)	Transport license, Law 24.076, Article 16	2002	2.4	65
Colón-Paysandú	ANCAP	Transport license, Law 24.076	1999	0.7	15
Casablanca	ANCAP	Transport license, Law 24.076	2000	2.0	10.4

Source: Energy Secretariat.

FIGURE 1-4. EVOLUTION OF ARGENTINE TRANSPORT CAPACITY, 1993-2009



Source: Greco (2004).

The total distribution network has a length 111,766 km. Between 1993 and 2002, nearly 45,000 km were constructed (including pipeline replacements); this extension represented a 65-percent network increase, similar to that of the transport system (table 1-13).

TABLE 1-13. NATURAL-GAS DISTRIBUTION NETWORK, 1993–2002
(kilometers)

Distributor	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Ban	13,943	16,566	17,341	17,767	18,192	18,821	19,354	19,885	20,255	20,412
Camuzzi Pampeana	13,386	17,144	18,056	18,372	18,932	19,470	18,338	19,340	21,551	22,786
Camuzzi Sur	8,316	9,577	10,607	10,941	11,607	11,920	10,939	11,189	12,052	12,945
Centro	6,055	8,538	9,137	9,346	9,718	10,161	11,047	11,768	12,088	12,402
Cuyana	5,330	6,525	6,815	7,276	7,674	7,978	8,165	8,462	8,697	8,890
Gas Nea	n.a	n.a	n.a	n.a	n.a	591	1,806	1,977	1,977	2,020
Gasnor	4,445	4,999	5,127	5,299	5,549	6,025	6,238	6,658	7,029	7,250
Litoral	4,747	6,330	6,751	7,076	7,438	7,862	8,329	8,706	9,170	9,287
Metrogas	11,191	12,294	12,820	13,160	13,311	13,951	14,557	15,022	15,678	15,774
Total	**67,412**	**81,973**	**86,654**	**89,237**	**92,421**	**96,779**	**98,818**	**103,007**	**108,498**	**111,766**

n.a.: = not applicable.
Source: ENARGAS.

Regulatory Framework

Law 24.076 and associated Decrees and Executive Orders regulate the gas transport and distribution segments. The four main principles of the natural-gas regulatory framework are:

– consumer protection (ie, the right to obtain a continuous and secure flow of services at fair prices, compatible with long-term service sustainability);[29]

– competition in the wholesale market;

– fair and reasonable tariff structures (ie, allowing efficient operators to be reimbursed for reasonable capital costs); and

– nondiscriminatory treatment of domestic and international consumers (however, the authorization of exports is dependent on satisfaction of domestic demand).

Gas producers, distributors, and independent traders are allowed to undertake commercialization activities, while transport companies are explicitly forbidden to do so. Two priority objectives that the regulation outlined were a competitive setting of the natural gas price and nondiscriminatory access to the transport and distribution systems.

Authorization for operating distribution and transport services is conferred through respective licenses for geographic areas. Such licenses do not obligate holders to pay a cannon or compensation and are granted for 35 years (with the right to a 10-year extension under specific circumstances).

Setting Tariffs

ENARGAS, the natural-gas sector's regulatory agency, sets transport and distribution tariffs and determines maximum prices.[30] The rate end-users are

29. Distributors must satisfy every reasonable demand for natural-gas services.

30. It should be noted that the five-year revised tariff of 2002, established by law, was never implemented because of the macroeconomic crisis.

charged consists of three price components: transport, distribution, and gas at the point of entry into the transport system.[31] Transport and distribution charges are set via a price-cap formula that includes an X factor to pass through efficiency gains to consumers and a K factor to encourage investment.

This arrangement means that users who purchase gas through a distributor pay the price negotiated by the distributor, while those who negotiate directly with a trader or producer pay their agreed on price. The cost that the distribution company pays is adjusted seasonally—in May and October—using a pass-through mechanism.

In short, tariffs that final users pay have three types of adjustment: 1) six-month, seasonal adjustments according to the reference price at the wellhead, 2) six-month adjustments determined by variations in the U.S. producer price index, and 3) five-year adjustments made according to productivity (X factor) and investment (K factor).

Open Access

Third party access (TPA) is an important instrument for creating a competitive natural-gas market. TPA gives suppliers and customers the right to have their gas transported through pipelines that they do not own or control. The challenge is to define and enforce the capacity that pipeline companies must make accessible (Bøe Moen 2003). Thus, a prerequisite for increased competition through TPA is available pipeline capacity.

Argentina has two types of cross-border regimes for pipeline companies: transport concessions and transport licenses. Agents that participate in the upstream sector that also have business activities at the final destination own pipelines under concession.

31. These prices differ from the wellhead price since they are added to the cost of gas treatment, processing, and transport. The processing stages determine gas quality and the appropriate price based on caloric efficiency, degree of purity, and content of pollutants and other harmful substances. As mentioned above, wellhead prices between 1994 and 2001 were set freely in the market.

Hydrocarbon Law No. 17.319 of 1967 regulates concession pipelines. Although the Law establishes the obligation of TPA, the open-access obligation refers to non-used capacity. Since producers control these pipelines, it is difficult for other producers to find room for their gas. However, if open access is feasible, ENARGAS regulates tariffs. For pipelines under license, Gas Law No. 24.076 guarantees vertical separation of transport and commercialization activities. These international pipelines, directly ruled by Law No. 24.076, are extensions of the national license transporters, TGN and TGS.

Unbundling

The separation between competitive and non-competitive segments required by Argentine regulation differs between concession and license transporters. Unbundling of transport from production and commercialization is mandatory for pipelines under licenses regulated by Law 24.076. However, it requires only legal unbundling; that is, a single company may not undertake both transport and commercialization activities; however, a holding company may have firms in both segments (e.g., Petrobrás). Under Law 17.319, unbundling is not mandatory for pipelines under concessions. In such cases, the producer is allowed to transport and sell its own gas in the importing country's market.

Capacity Release

Release programs do not increase competition in gas markets with diverse supply routes and multiple producers. However, if supply routes are few and deliveries are under the control of an incumbent through long-term contracts (with no secondary trading), then development of competitive markets requires some form of release program to provide new entrants initial access to energy and/or delivery capacity (EFET 2002). For short-term supplies, release programs can have the added advantage of facilitating the development of gas-trading hubs, which leads to greater price transparency and further stimulates competition and efficient use of resources. Full separation of transport and trading activities can reduce the need for gas release because commercial pressures will tend to encourage the trading company to market all available energy or secondary capacity.

Nonetheless, persistence of effective monopoly control—for example, control of a particular gas quality or import route, combined with lack of a liquid traded market—may call for a release program to create sufficient supply availability. An appropriately conceived, gas-release program can be used to kick-start competition in countries and regions where a well-established monopoly or oligopoly dominates (EFET 2002).

Argentina developed capacity release as a regulatory instrument in 1997.[32] Under this program, incumbents agree to, or are forced to, open up a percentage of existing long-term supply and capacity contracts to third parties, without affecting upstream contracts that underpin investments and supply security.

Opening Up the Market

Distributors are the only companies that offer an aggregate service at the point of consumption (fluid, transport, and distribution). In addition, they are uniquely qualified to provide such a service to residential, commercial, and industrial users with consumption levels below 5,000 m^3 per day. Those who consume higher levels per day can choose to unbundle the service; that is, they can buy gas and transport it to primary suppliers (producers and transport companies) or to an independent trader that can provide gas at the wellhead or city-gate (gas plus transport).

After privatization, the threshold for accessing the wholesale market was reduced from 10,000 to 5,000 m^3 per day, thereby increasing the number of consumers for potential bypass. Within the context of the second tariff revision, ENARGAS planned a progressive reduction of this threshold from 5,000 to 0 in October 2002; however, after currency devaluation, this process was suspended.

Sector reform also gave large consumers the option of choosing between contracting gas on a firm or interruptible basis. Selecting interruptible

32. ENARGAS, Resolution No. 419/97.

service included a substantial discount—as much as 26 percent in certain regions.

In practice, Argentina preserves the link between the user and service access (bypass) and the distribution company because each client—not the trader, who competes with the distributor—directly requests the bypass. This arrangement has allowed for development of the bypass, which, since privatization, has grown in number of clients and volume of gas (table 1-14).

TABLE 1-14. VOLUME OF GAS COMMERCIALIZATION, BY TYPE, 1993–2001
(millions of m³ per day)

		Users with commercial bypass, according to service received from distribution company					
Year	Users without physical bypass	Transport and distribution	Distribution	Subtotal	Users with physical bypass	Traders	Total domestic market
1993	54.8	0.9	-	0.9	0.5	-	56.2
1994	52.1	2.8	1.0	3.8	0.8	-	56.7
1995	50.2	6.4	2.0	8.3	0.9	-	59.5
1996	46.3	12.2	2.8	15.0	1.5	-	62.7
1997	42.5	15.6	4.8	20.3	3.0	-	65.9
1998	43.4	12.7	6.9	19.5	3.6	4.6	71.2
1999	46.5	13.2	7.8	21.0	6.3	7.7	81.5
2000	43.5	16.4	9.9	26.3	6.7	9.5	86.0
2001	38.9	16.8	9.3	26.1	7.5	7.5	80.1

Source: Greco (2003).

Vertical Integration Provisions

The tender process for selling companies resulting from the privatization of GdE set measures for preventing collusion among investors. For example, no investment group could buy the majority of assets of more than one transport company. In addition, they could not purchase more than two distribution companies or more than one transport and a distribution company combined.

However, the regulatory framework placed no restrictions on groups that participated in the electricity market. Although the electricity and gas

industries were privatized the same year and are closely related, they are regulated by separate laws. Neither the Gas Law (No. 24.076) nor the Electricity Law (No. 24.065) is restricted with regard to the simultaneous participation of investment groups in both markets.

Bilateral Agreements

Argentina's government has entered into agreements with neighboring countries to import and export natural gas. The country's bilateral agreements with Bolivia, Brazil, and Uruguay are analyzed below.

Bolivia-Argentina

Bolivia's large stock of natural gas is directed mainly to the Brazilian market through an interconnecting pipeline. In 1993, Petrobrás and YPFB signed a 20-year contract for Brazilian purchase of natural gas from Bolivia. Brazil wants to modify the take-or-pay contract (under which buyers pay for a given contracted volume of gas) because the projected rise in consumption did not occur, and it now pays for 24 million m^3 of gas per day, despite daily consumption of only 14 million m^3. Argentina could purchase gas from Bolivia for domestic consumption and to export to Chile; however, there is strong Bolivian opposition to the latter.

Bolivian gas would be a logical substitution when Argentina's Noroeste Basin reserves are depleted. In 2001, Pluspetrol inaugurated two collection pipelines between Madrejones-Bermejo (Bolivia) and Campo Durán (Argentina). The gas imported from Bolivia is liquefied at the Refinor plant in Campo Durán and is also used to generate electric power in its combined-cycle plant in northwestern Argentina.[33]

In May 2004, Argentina's government signed a temporary, six-month agreement with Bolivia to import Bolivian gas through North pipeline.[34]

33. These collection pipelines transport unprocessed natural gas to Refinor's processing plant.
34. See "Declaracion Presidencial de Buenos Aires," signed in Buenos Aires April 21, 2004.

The agreement established that the maximum volume of Bolivian imports would be 4 million m^3 per day. It also limited Argentina's use of Bolivian gas to its domestic market (i.e., it was restricted from re-exporting Bolivian gas to third countries).

Brazil-Argentina

In 1996, Argentina and Brazil developed a Protocol of Understanding on energy integration. The two governments agreed to set the necessary conditions to promote bilateral energy trade. Gas trade between Argentina and Brazil became viable in 2000, when the TGN network (the transmission company in northern Argentina) was extended to the Brazilian border.

The TGM (*Transportadora de Gas del Mercosur*) pipeline runs from Aldea Brasilera (Enter Rios, Argentina) through Paso de los Libres, arriving at the Brazilian border town of Uruguaiana. The pipeline supplies gas to a 600-MW AES power plant in Uruguaiana. An extension of the pipeline, which will connect Uruguaiana to Porto Alegre, is under construction. TSB (*Transportadora Sul Brasileira de Gas*) will operate the 615-km extension, which is expected to begin transporting 15 million m^3 per day in 2005.

Potential Argentina-Brazil pipelines include the Trans-Iguaçu and Mercosul. The Trans-Iguaçu would cross from Argentina's Noroeste Basin into southern Brazil, while the Mercosul pipeline would tap northwestern Argentina's Neuquina Basin, extending to Curitiba, Brazil, and possibly on to São Paulo.[35] However, recent natural-gas discoveries in Bolivia and potential Brazilian discoveries could discourage development of these pipeline projects.

Uruguay-Argentina

Colón-Paysandú is the first pipeline to link Argentina and Uruguay. Constructed in 1999 and operated by ANCAP, the Colón-Paysandú pipeline crosses the Uruguay River from Argentina and provides gas to industrial plants and the Paysandú distributor in western Uruguay.

35. See www.iie.org/programs/energy/downloads/Proceedings/EnergySectorProfiles/Brazil.doc

The Santa Cruz pipeline, which links Punta Lara, (Buenos Aires Province, Argentina) with the cities of Colonia and Montevideo (Uruguay) was inaugurated in November 2002. This pipeline can carry more than 2 million m^3 per day across the Río de la Plata, from Argentina's gas reserves to Uruguay's major urban and industrial areas. TGS completed the Argentine territory extension to Punta Lara.

In January 2000, the governments of Argentina and Uruguay signed institutional agreements with regard to the harmonization of regulation between the two countries. Participating institutions were Argentina's respective gas and electricity regulators; ENARGAS and ENRE (*Ente Nacional Regulador de la Electricidad*); Argentina's Energy Secretariat; and Uruguay's Ministry of Industry, Energy, and Mines.

Challenges to Regional Integration

The regulatory framework that governs Argentina's natural-gas market is developed. Compared to U.S. and EU norms, Argentina's standards are highly competitive. In recent years, the country has developed an impressive pipeline infrastructure linking neighboring countries, and has become a net exporter of energy products. Thus, Argentina's legal and regulatory framework has made an enormous increase in regional trade feasible. However, key issues must be addressed to continue fostering integration of natural-gas markets.

First, countries in the Southern Cone region must guarantee competition between natural-gas producers by setting clear regulations regarding open access to networks. The cases of Repsol-YPF in Argentina and Petrobrás in Brazil, with their privileged position in the Bolivian market, illustrate the danger of dominant producers abusing their position and the regulatory roadblocks their potential competitors face as a result of the dominant producers' privileged arrangements with national governments.

Effective market integration requires increased enforceability of competition law. YPF has been accused of blocking the opportunity for Bolivia and Brazil to strengthen their gas-sector relations. A 1999 ENARGAS investigation shed light on the perverse effects of YPF behavior on the interconnection

process with Bolivia (Bondorevsky and Petrecolla).[36] Although national laws are well designed to create a competitive gas market, the issue of how firms achieve compliance with Argentine laws must be carefully addressed.[37]

Second, unbundling should be required of all pipelines. Argentine transport concessions, regulated under National Gas Law No. 17.319, should clearly separate gas-system operations. Like Europe's international pipelines, they should require an internal "Chinese Wall" and include a code of conduct to guarantee non-discrimination regarding commercial information and non-preferential treatment.

Third, rules ensuring transparency of international pipeline operation are a fundamental step toward market integration. Creating an independent system administrator would be an important measure to ensure the transparent operation of national and international pipelines. Similar to Argentina's electricity market administration,[38] an independent natural-gas administrator would oversee the effective implementation of long-term contracts.

In addition to capacity release, other conditions are required to develop competition. Authorities should encourage the creation of an independent authority to register and supervise effective use of the pipeline and development of a spot market for spare capacity, which is declared with the independent administrator. Establishing an independent administrator to allocate spare capacity through a spot market would lend transparency to the system since transporters could not hide the effective use of the pipeline, and prices would be market based. Such measures would transform the pipeline transport capacity into a commercially tradable commodity.[39]

36. ENARGAS, file 4.943 (August 1999).

37. Bondorevsky and Petrecolla (2002) analyze the abuse of market power that has characterized YPF in recent years. YPF acknowledged use of anti-competitive clauses and unfair practice with regard to its customers and pledged to discontinue its anti-competitive behavior. To date, however, YPF has not implemented any of these modifications.

38. Cammesa is an independent operator of electricity markets; its members include participants in the industry's three segments and one national-government representative.

39. Decree 180/2004, "Trust Fund and Electronic Market Place for Natural Gas," is in line with this purpose; however, it applies only domestically. It creates an electronic marketplace for natural gas and establishes a trust fund to direct investments in gas transport and distribution systems.

Finally, regulations should provide investors sufficient incentive to ensure that the enormous pipeline investments needed are undertaken. The infrastructure development that occurred during the 1990s should not be paralyzed by the recent macroeconomic crisis following currency devaluation or interventionist measures in the energy markets.

The effects of currency devaluation on Argentina's energy sector are far from being resolved. The government has not allowed natural-gas distributors to pass through to retail tariffs wholesale prices that exceeded winter 2001 levels in Argentine pesos, despite large-scale devaluation of the peso, growing domestic inflation, and significant economic recovery. It is hoped that recent government measures—including Decree 181/2004, which re-establishes future liberalization of the wholesale natural-gas market—will solve Argentina's natural-gas pricing problem, despite delayed implementation and incompleteness in guaranteeing a sustainable supply to Argentine and other Southern Cone customers.

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Chapter 2

Bolivia: Enormous Reserves, Political Restrictions

Manuel Dussan

Gas production centers in Bolivia are located far from ports and high-consumption areas, limiting the country's export potential. Although natural gas is competitively priced and abundant, Bolivia's domestic market lacks a critical mass to develop gas reserves of approximately 1,560 billion cubic meters (m^3). Bolivia exports natural gas to neighboring Argentina and Brazil and liquefied natural gas (LNG); both types of exports enjoy a sufficiently large market to justify investment in export infrastructure. During the 1990s, Bolivia passed several critical laws aimed at promoting private investment in the natural-gas sector and providing an incentive for exploring and developing natural-gas reserves:

- Capitalization Act of 1994. Authorized the restructuring of state-owned companies and their capitalization by private strategic partners that took administrative control of them.

- Economic Sectors Regulatory System (SIRESE) Act of 1994. Created an independent, professional regulatory system for the sector.

- Hydrocarbons Law of 1996. Established risk-sharing contracts with YPFB (*Yacimientos Petrolíferos Fiscales Bolivianos*), the state hydrocarbon monopoly, as the basic plan for hydrocarbon exploration and production by private companies, along with free entry into the gas transport and distribution business and reduction in royalties and participation in new fields from 50 percent to 18 percent.[1]

1. A 25 percent surtax on windfall profits from new gas fields was to compensate partially for the large reduction in royalties and participation; to date, however, no company has paid the surtax.

In 1996, YPFB was restructured into two exploration and exploitation companies, a transport company, a refinery, and several other service companies. The next year, multinational companies capitalized exploration and transport companies, investing US$850 million in their development. Concessions provide for free entry to the transport sector for a maximum of 40 years. Transredes, the gas transport company created by YPFB capitalization, handles virtually the entire pipeline network for the domestic market, while three companies handle export pipelines.

Despite Bolivia's substantial headway in adopting principles that promote gas-market development—state-monopoly elimination, participation of competitive private companies, free entry, free access to gas pipelines, independent regulatory body, separation of activities, and freedom to export—significant barriers remain. Among the most critical are a high degree of government intervention in export-related decisions—despite regulations granting freedom to export—and Petrobrás' dominant position in exports; the company has a significant stake in reserves and gas production in Bolivia, in transport contracting, and gas marketing in Brazil. Its position means that measures Bolivia takes to promote greater competition and use market mechanisms to increase the export market will be useless without greater opening of the Brazilian market, which Petrobrás dominates.

This chapter identifies and analyzes the obstacles that Bolivia's natural-gas sector presents to creating an integrated, regional gas market. Despite the country's partial energy-integration agreements with Argentina and Brazil and the general agreements on gas-sector integration within the Southern Cone Common Market (Mercosur) framework, in practice, these agreements have been limited in scope and slow in application.

Sector Overview: Regulation, Industry, and Supply

Landmark decisions in development of Bolivia's natural-gas industry have resulted in changes in the sector's structure and legal framework. In 1936, concessions to Standard Oil Company were terminated, and YPFB

became the state oil company, exercising control over oil and oil-derivative activities. In 1955, the Petroleum Code was passed, establishing a concessions system. Then, in 1969, the Code was repealed, and concessions to the Bolivian Gulf Oil Company were nationalized. Passage of the General Hydrocarbons Law in 1972 established a system for exploration and exploitation contracts, whereby YPFB owned production, retained royalties and taxes, and provided contractors their production share; this Law was amended in 1990. Finally, in 1996, a new Hydrocarbons Law (No. 1689) was passed, which is still in force.

Hydrocarbons Law of 1996

The Hydrocarbons Law of 1996 established the general framework applicable to the natural-gas sector. It is characterized by providing free entry to sector activities and open access to transport facilities, freeing trade and establishing a separation between competitive and non-competitive industry segments. Thus, the sector's regulatory principles are consistent with regional-market integration. However, their application—along with the industrial structure of neighboring countries—creates obstacles to integration.

Regarding exploration and exploitation of new hydrocarbon fields, the 1996 Law establishes risk-sharing contracts between YPFB and private companies. These are granted, through public tender, for a maximum of 40 years (with 7 years for exploration and 7 additional years if commercial discoveries are made). Although these contracts are characterized as risk-sharing, neither the state nor the YPFB assumes financial responsibility involving third parties. The contractor owns the hydrocarbons produced; makes direct payment of royalties, shares, and taxes; and can freely market its production (subject to its obligation to supply the domestic market). Once a new field is declared commercially viable, the contractor must, within the first five years, drill at least one producing well on each 25 square-kilometer (km^2) block retained; however, it may retain the area for 10 years if hydrocarbons cannot be transported to market centers or access is limited. The Law differentiates between existing and new hydrocarbons with regard to tax and royalty payment, and, in the case of new discoveries, charges royalties at a substantially lower rate than the former system did.

The Law established that the Office of the Superintendent of Hydrocarbons of Bolivia (SuperHid), the regulatory authority, will grant hydrocarbons transport and natural-gas pipeline distribution through administrative concession for a maximum of 40 years. The open-access principle applies to natural-gas transport through pipelines, and transporters cannot distribute or market natural gas or generate electricity. Thus, the Law demands that transport activities be legally separate from other activities, although it allows for cross-holding of companies. Therefore, a single business group may control companies in all sectors and have, in fact, an entirely integrated structure.

Natural gas can be freely exported, imported, and marketed. However, the state establishes maximum wellhead prices during the first five years in which the Law is in force.

YPFB Restructuring

The Capitalization Law (No. 1544) of 1994 was the basis for reforming the hydrocarbons sector two years later. Law No. 1544 authorized:

- creation of companies with private participation, using assets of state companies in the electricity, telecommunications, mining, and transport sectors;

- capitalization of these companies, by capital increase of up to 100 percent by selected private investors through public tender; and

- free transfer of the state's stake in these companies to Bolivian citizens of legal age (by December 31, 1995), which pension funds would administer.

In 1996, YPFB was split into two exploration and production companies, a hydrocarbon transport company, a refinery, and several service companies. Each of the recently created state companies became corporations through sale of shares to interested workers for an amount not greater than their retirement benefits. In 1996, both upstream companies were capitalized through public tender. International companies were invited to participate as strategic partners; they could

acquire 50 percent of shares, giving them administrative control of the business. Foreign partners agreed to invest at least their capitalization contributions in the companies over an eight-year period. Management of the investment portfolio for state-held shares in capitalized companies (50 percent, minus the percentage sold to workers[2]) was contracted to pension fund administrators (PFAs).

In 1997, both upstream companies were capitalized as follows: Chaco S.A. by Amoco (now part of British Petroleum [BP]), at a cost of US$306.6 million, and Andina S.A. by a consortium of Argentinean companies: YPF (now Repsol), Pérez Companc (acquired by Petrobrás), and Pluspetrol (acquired by Repsol) for US$264.7 million.[3] Transredes S.A., the transport company formed by restructuring YPFB, was capitalized in 1997 by a consortium of Enron (25 percent) and Shell (25 percent) for US$263.5 million. In this case, employees of the transport company acquired a significant percentage of shares (16 percent), while the PFAs handled the remaining 34 percent. In 2000, capitalization of the other downstream units was completed.

YPFB remained responsible for tendering, awarding, signing, supervising and administering the risk-sharing contracts for hydrocarbons exploration, exploitation, and marketing. It was also responsible for administering the signing of natural-gas export contracts between Argentina and Brazil, transferring contracted volumes to producer companies, aggregating these volumes, and acting as export-pipeline shipper.

Regulatory Authorities

The Capitalization Law of 1994, Hydrocarbons Law of 1996, and Law No. 1600 of 1994 to establish SIRESE profoundly reformed the hydrocarbons sector. Before reform, the state had been responsible for sector policymaking, regulations, and monitoring, as well as acting as owner and operator of sector companies. After reform, the state limited itself to policymaking and

2. Workers purchased 2.7 percent of Chaco and 2.1 percent of Andina.
3. Repsol later bought the stake held by Pérez Companc and Pluspetrol, representing 29.75 percent of Andina S.A.

regulatory functions, while the private sector became responsible for business activities. In addition, an independent regulatory body was created.

The Ministry of Mining and Hydrocarbons (formerly the Secretariat of Energy) is responsible for defining sector policy, regulating upstream exploration and production, and establishing a range of general regulations (e.g., preparing and proposing regulations for implementing the Hydrocarbons Law, preparing and proposing standards and regulations for sector environmental protection, preparing and administering the official map of available sites for exploration, approving the flaming or venting of natural gas, monitoring compliance with technical safety standards for exploration and production, and fixing hydrocarbon prices at the wellhead).

SIRESE directly regulates electricity, hydrocarbons, basic sanitation, telecommunications, and the transport sectors. A General Regulatory Office regulates the regulators.

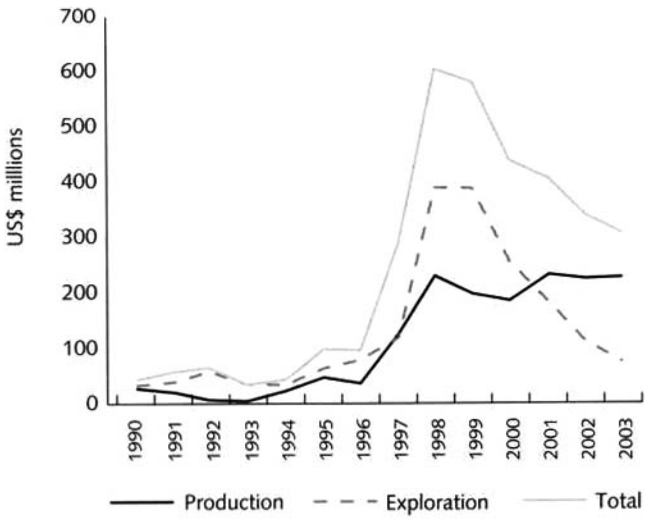
SuperHid regulates and monitors downstream activities—transport, distribution, and marketing—in the natural-gas sector. Its main functions are approving prices and rates, granting concessions and licenses, promoting competition and preventing abuse of dominant position, monitoring compliance with legal standards and regulations, guaranteeing quality of service, and serving as authority of first appeal. The General Regulatory Office of the SIRESE serves as the authority of second appeal, monitors other regulatory offices, and provides administrative coordination of the SIRESE.

Reserves

Investment of resources from upstream capitalization, together with the more favorable conditions for exploration and production established by the Hydrocarbons Law of 1996, resulted in a substantial increase in upstream investment, starting in 1997 (figure 2-1). Increased investment, in turn, led to the discovery of substantial natural-gas reserves. In 2003, investment in exploration fell to pre-1996 levels.[4]

4. The reasons are that the current reserves-to-production ratio (proven and non-proven reserves) is more than 100 years, and it is difficult to find new markets in which to monetize existing reserves.

FIGURE 2-1. UPSTREAM INVESTMENT, 1990–2003



Source: YPFB.

During the 1980s and 1990s, proven reserves of Bolivian natural gas remained relatively low and tended to decline. Only after 2000 did they rise substantially, as a result of increased incentives and resources for exploration and operations established in 1996 and initiating natural-gas exports to Brazil in 1999. During 1980–99, Bolivia's proven reserves fluctuated between 107 and 161 billion m^3; a fivefold increase to 812 billion m^3 ensued in 1999–2003, making Bolivia the Southern Cone country with the largest natural-gas reserves.

Bolivia's non-proven, natural-gas reserves kept pace with proven reserves. By early 2003, proven and probable reserves totaled nearly 1.6 trillion m^3, more than six times the 1999 amount (table 2-1); 87 percent were located in Tarija, a southern department near the Argentine border. Certified reserves were distributed among large oil companies, including Repsol, Total, Petrobrás, British Gas (BG), Exxon Mobil, and the two producer companies created from YPFB (Andina and Chaco) (table 2-2).

TABLE 2-1. CERTIFIED NATURAL-GAS RESERVES, 1997–2003
(billions of m^3)

Reserve type*	1997	1998	1999	2000	2001	2002	2003
P1	106	118	150	518	675	775	812
P2	55	70	93	394	651	706	741
P1 + P2	161	188	243	912	1,326	1,481	1,553
P3	117	90	155	499	656	705	685
P1 + P2 + P3	278	278	398	1,411	1,982	2,186	2,238

* P1 = proven, P2 = probable, P3 = possible.
Source: YPFB.

TABLE 2-2. CERTIFIED PROVEN AND PROBABLE NATURAL-GAS RESERVES TO JANUARY 2003

Company	Billions of m^3	%
TotalFinaElf	217	14.0
Petrobrás	225	14.5
Andina S.A.	398	25.7
Chaco S.A.	62	4.0
Repsol YPF	147	9.4
BG	232	14.9
Exxon Mobil	100	6.4
Panamerican	100	6.4
Energy	72	4.6
Other firms		
Total	**1,553**	**100.0**

Source: Ministry of Mining and Hydrocarbons of Bolivia.

Production

In 2001, certified production of natural gas increased significantly, and exports to Brazil reached 10 million m^3 per day, surpassing exports to Argentina. In 2002, average production stood at 24.4 million m^3 per day, but 30 percent of it was reinjected, vented, and consumed by producers or converted into liquid. The largest producers were Andina and Chaco, which received producing fields from YPFB, and Petrobrás, which operates the San Alberto megafield (table 2-3).

TABLE 2-3. AVERAGE CERTIFIED NATURAL-GAS PRODUCTION, 1998–2002
(millions of m^3 per day)

Producer amount	1998	1999	2000	2001	2002
Total production	14.7	13.7	15.6	19.6	24.4
Andina					7.9
Chaco					5.8
Repsol YPF					1.6
Pecom					1.2
BG					2.3
Petrobrás					4.5
Other firms					1.1
Producer use	6.6	6.6	6.8	6.1	7.6
Pipeline delivery	8.2	7.1	8.8	13.5	16.8

Source: Ministry of Mining and Hydrocarbons of Bolivia.

Transport

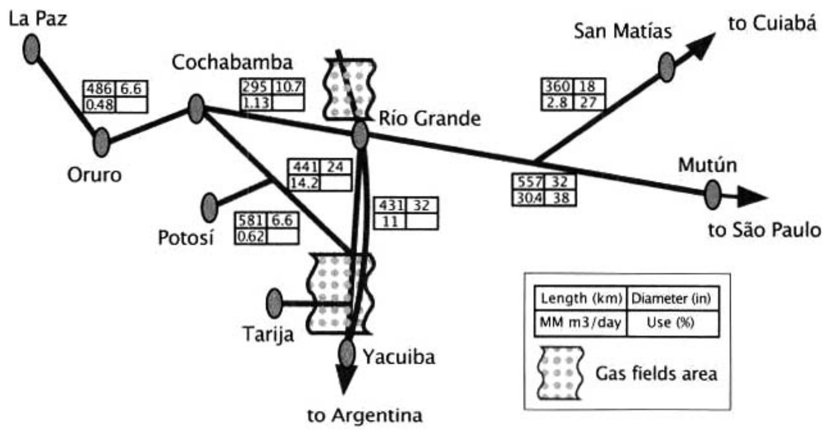
Bolivia's gas pipeline network consists of YPFB-owned pipelines that serve the domestic market and other pipelines that serve the export market. Major suppliers are GTB (*Gas Transboliviano*, serves southeastern Brazil, from Río Grande to Mutún on the Brazil-Bolivia border), GOB (*GasBol*, serves Cuiabá, Brazil, from Río San Miguel to San Matías), and Transierra (from Yacuiba to Río Grande).

Figure 2-2 shows the network of gas pipelines, including the length, diameter, transport capacity, and use factor for each main line. The total length of the trunk network exceeds 4,000 km. Although it is designed to export 30 million m^3 per day to Brazil, it currently exports only 12 million m^3 per day.

Transredes owns and operates nearly the entire domestic transport network and is the main shareholder and operator of export pipelines GTB and GOB. Petrobrás has a direct and indirect stake in the export pipelines. It is a founding partner of Transierra S.A., which, in 2003, put the Yacuiba-Río Grande pipeline into operation to increase transport capacity from giant fields in the south to the export pipeline

to Brazil. Petrobrás has a minority stake in the GTB-owned pipeline and indirectly controls it through a long-term transport contract. The company also directly controls pipelines on the Brazilian side that connect the export pipeline with this market.

FIGURE 2-2. GAS PIPELINE NETWORK*



*Empty cells indicate negligible use.
Source: YPFB.

Bolivia-Brazil Pipeline

Financing the 3,000-km gas pipeline project from Río Grande to markets in southeastern Brazil was a complex undertaking since neither Bolivia nor Brazil could finance a project costing more than US$2 billion. On the Brazilian side, the company TBG (*Transportadora Brasileira Gasoduto Bolivia-Brasil*) was created, with Petrobrás as the main shareholder.[5] On the Bolivian side, YPFB and Enron reached an agreement in 1996 to develop the country's section of the pipeline. After YPFB was capitalized, GTB was created, with Transredes, Enron, and Shell holding majority interest.[6] Capital stock equaled 20 percent of project cost. Petrobrás

5. TBG shares are distributed as follows: Petrobrás (51 percent) and BBPP consortium (49 percent) (broken down as BG, El Paso, and Total [29 percent]; Transredes [12 percent]; Enron [4 percent]; and Shell [4 percent]).
6. GTB shares are distributed as follows: Transredes (51 percent), Enron (17 percent), Shell (17 percent), Gaspetro (11 percent), BG (2 percent), and El Paso (2 percent).

financed the remainder through a turnkey contract for constructing the Bolivian section of the pipeline (financed with future transport charges and pre-payment in the form of an option for additional transport capacity).

Regulations

Natural-gas transport is regulated by Supreme Decree (D.S.) 26116 of 2001 (Regulation of Hydrocarbon Transport through Pipelines), which detailed basic regulations on transport activities established in the Hydrocarbons Law of 1996. The regulations apply to gas, petroleum-product, and crude-oil pipelines; they replace regulations in force during the 1997–2001 transition period. Although Bolivia's transport regulations meet all requirements to promote gas-market integration, certain ones do not apply to the oil-export pipelines, a major problem with regard to integration.

BASIC REGULATIONS

Basic regulations that apply to gas pipelines established under the 1996 Law are free entry to build and operate gas pipelines, subject to SuperHid-granted administrative concessions, for a maximum of 40 years. Although transport concessions are granted for specific pipelines at the interested party's request, SuperHid may tender development of pipelines of public interest. Transport tariffs are subject to regulated maximum prices (i.e., SuperHid fixes maximum tariffs but the parties can agree on discounts). The Law establishes open access to gas pipelines to the extent of available capacity and limits vertical integration, meaning that natural-gas distributors and marketers and electricity generators cannot function as transport concessionaires.

The transport code develops the above regulations in detail. It clearly defines requirements, procedures, and the time frame for processing transport concessions. It also defines transport terms and conditions, including contract models, and authorizes resale of transport capacity rights to third parties. Moreover, it establishes detailed procedures for establishing maximum transport tariffs. These regulations do not apply to tariffs for the gas export pipeline to Brazil or to other strategic projects, which are approved by government decree.

The code designates Transredes as domestic market shipper (CAMI), responsible for contracting transport services in gas pipelines of other companies serving the domestic market to ensure viability of a postage-stamp transport tariff for the domestic market.

OPEN ACCESS TO PIPELINES

Although Bolivian legislation adopted the principle of open access to gas pipelines in 1996, it was in late 2001 that SuperHid established standards for open access to pipelines that transport hydrocarbons, which apply to both existing and new capacity. These regulations established that concessionaires must provide open, nondiscriminatory access and apply currently valid tariffs to applicants that meet general terms and conditions of the service. Concessionaires must offer firm or interruptible transport service on a first-come, first-served basis. Firm service must have priority over interruptible service in the operating program of the pipelines. The regulations also establish firm contracts, which are contingent on construction and commissioning of capacity expansion.

To guarantee open access, procedures have been established to receive and register applications for firm and interruptible transport services to determine their chronological order of entry, as well as fixed deadlines for responding to such requests. When capacity expansion is required, the concessionaire must initiate an open invitation to other interested parties to submit their applications. Using the news media and its website, the concessionaire must periodically provide information on contracted transport, and available capacity. The negotiating terms with applicants or shippers must remain confidential.

In addition, the regulations establish procedures for settling open-access disputes. SuperHid has created an Open Access Commission, which is responsible for controlling, monitoring, investigating, and supervising the open-access process.

ACCESS TO EXPORT PIPELINES

Three contracts have been signed to transport gas to Brazil through the GTB-owned pipeline. Each contract involves three parties: GTB (transporter), YPFB

(shipper), and Petrobrás (purchaser). The basic contract or transport contract quantity, known as the TCQ, establishes an initial volume of 9 million m^3 per day, rising to 18.08 million m^3 per day after six years. The second contract or transport capacity option, known as the TCO, establishes added volume of 6 million m^3 per day; Petrobrás prepaid the TCO as part of the pipeline-financing plan. The third contract or transport capacity extra, known as the TCX, establishes the commitment to transport an additional 6 million m^3 per day, which is to reach 30.08 million m^3 per day.

The transport contracts have five main features. First, they are ship or pay contracts whose capacity charge has an initial value of US$0.3176 per million British thermal units (Btu), increasing 0.5 percent annually, and a commodity charge starting at US$0.002 per million Btu, increasing 3.5 percent annually. The TCO contract does not include the capacity charge since Petrobrás prepaid it. Second, these are 20-year contracts, except for the TCO (a 40-year contract). Third, the contracts have a most-favored-nation clause, according to which the transporter may not, during a transition period, offer firm transport service to third parties at a rate that results in a gas price lower than the combined transport and supply tariff. Fourth, through the three contracts, Petrobrás contracts all basic capacity of the gas pipeline, and the transporter may not make a firm offer of this capacity to third parties without Petrobrás' authorization. Fifth, TCQ and TCO contracts are complemented by a payment contract through which Petrobrás agrees to pay the transporter for contracted capacity on the shipper's behalf.

Through these contracts, Petrobrás can obstruct Bolivian gas exports by other companies, even if it is not using full capacity of the export pipeline. In addition, there are limitations on exporting gas through other pipelines for which Petrobrás has not contracted the entire capacity, since it controls pipelines on the Brazilian side. The BG project for exporting gas to Comgás, the São Paulo distributor, illustrates the problem of Petrobrás' market power. BG signed transport contracts with Transredes and GTB; the latter raised its compression capacity to increase transport capacity to 37 million m^3 per day, but had difficulty obtaining access to the Brazilian pipeline. Interruptible service was obtained initially, requiring intervention of the National Petroleum

Agency (NPA) so that Petrobrás could authorize BG use of 2.5 million m^3 per day of unused, contracted capacity.

Resolution of open access recognizes the importance of coordinating and harmonizing standards and procedures applicable to open access with neighboring countries. Clearly, open access to pipelines that Bolivia grants within its borders could be frustrated by restrictions a neighboring country imposes once gas crosses the border. With this in mind, the resolution instructs the Open Access Commission to establish good coordination with Brazil's NPA.

Although bi-national partial agreements promote natural-gas supply to Brazil and energy integration with Argentina, the effects of these agreements are limited. The supply agreement with Brazil protects gas exports to Brazil, with commitments not to apply restrictions to the export and import of Bolivian gas, exemption from import taxes, payment in freely available dollars, and a guarantee that gas from other countries destined for Brazil will be given free right-of-way through Bolivian territory. The agreement with Argentina is broader, including commitments to respect the principles of open access and non-discrimination, maintain competitive conditions, avoid application of subsidies or taxes, and adopt common regulations to permit development of competition in energy trade.

Rates

The transport code established a transitional period (May 16, 1997–May 16, 2001) for applying transport tariffs; during this time, a postage-stamp tariff of US$14.5 per thousand m^3 was established for the domestic market. Since this tariff was not high enough to cover transport costs under efficient conditions, a deferred account was established to compensate the transporter for the shortfall.

Beginning May 17, 2001, a postage-stamp tariff was applied to each transport concession, sufficient to recover the financial costs of providing the service; it was calculated on the basis of two optional methods: 1) cash flow and 2) required income. The cash-flow method makes the

discounted value of projected income during 20 years equal to the sum of investments made during the same period, AOM and financial costs, taxes and levies, and the residual value of installations. The required-income method calculates average annual transport costs based on the sum of AOM and financial costs, depreciation, taxes, and a reasonable return on assets. All companies chose the cash-flow method.

The tariff method establishes a cross subsidy between foreign and domestic markets. Natural gas transported to foreign markets through the domestic network is subject to a surcharge, covering the difference between domestic-market transport costs and the US$14.48 per thousand m^3 total base rate currently charged. The surcharge shippers pay may not exceed US$1.06 per thousand m^3; with the exception of GTB, transport concessionaires must pay the foreign market any amount above this ceiling. In addition, both markets must pay (in 20 years) a tariff surcharge for the deferred account accumulated as of May 17, 2001.

According to this method, transport tariffs are revised every four years, using updated data, whenever important changes occur in the investment program or when there is a positive or negative difference greater than 8 percent between effectively transported, accumulated volume and the volume estimated for rate-setting. In this way, the concessionaire limits the risk of lower-than-expected revenue resulting from fluctuations in transported volume. SuperHid-approved tariffs are considered maximum values, and a binomial tariff structure may be applied, depending on the type of service (firm or interruptible) (table 2-4).

Domestic Market

Bolivia's domestic natural-gas market has been stagnant for the past five years and is marginal compared to the production capacity of current proven reserves and volume exported. As table 2-5 shows, domestic consumption has fluctuated between 2.9 and 3.4 million m^3 per day since 2000. Domestic consumption in 2002 represented just 20 percent of the gas delivered to the transport network. That year, electricity generation represented 43 percent of domestic gas consumption, while the gas delivered to distribution companies accounted for 38 percent.

TABLE 2-4. EVOLUTION OF TRANSPORT TARIFF RATES, MAY 1997–OCTOBER 2002 (US$ per thousand m^3)

Transport rate	May 16, 1997	May 17, 2001	January 1, 2002	February 1, 2002	April 10, 2002	October 1, 2002
Foreign market						
Base rate	6.36	5.77	5.93	6.22	6.23	6.24
Deferred account surcharge		1.11	1.27	1.42	1.43	1.43
Domestic market subsidy		0.91	0.97	1.09	1.10	1.10
Total base rate	6.36	7.79	8.17	8.73	8.76	8.77
Domestic market						
Base rate	14.48	13.37	13.21	13.06	13.05	13.05
Deferred account surcharge		1.11	1.27	1.42	1.43	1.43
Total base rate		14.48	14.48	14.48	14.48	14.48
Domestic market cost	14.48	19.95	20.22	20.98	20.98	20.98
Transierra	n.a.	n.a.	n.a.	n.a.	n.a.	7.35
GTB (Río Grande-Mutún)	n.a.	n.a.	n.a.	n.a.	n.a.	10.06
Rio Grande Compression	n.a.	n.a.	n.a.	n.a.	n.a.	1.90
GTB (Río Grande-San Miguel)	n.a.	n.a.	n.a.	n.a.	n.a.	5.29
GOB (San Miguel-San Matías)	n.a.	n.a.	n.a.	n.a.	n.a.	19.03

n.a. = not available.
Source: SuperHid.

TABLE 2-5. SUPPLY VERSUS DEMAND, 1998–2002 (millions of m^3 per day)

Factor	1998	1999	2000	2001	2002
Production	14.7	13.7	15.6	19.6	24.4
Producer use*	6.6	6.6	6.8	6.1	7.6
Pipeline delivery	8.2	7.1	8.8	13.5	16.8
Export	4.9	3.9	5.8	10.6	13.4
Argentina	4.9	1.7	0.1	0.1	0.3
Brazil	n.a.	2.2	5.8	10.5	13.1
Domestic	3.2	3.2	2.9	2.9	3.4
Electricity generation	1.9	1.8	1.6	1.3	1.4
Distribution	1.2	1.2	1.2	1.1	1.3
Refinery	0.0	0.1	0.2	0.2	0.2
Other	0.2	0.2	0.1	0.3	0.4

* Own consumption, converted to liquid, reinjected, and vented.
n.a. = not available.
Source: Ministry of Mining and Hydrocarbons of Bolivia.

Composition of Domestic Demand

Industry uses about 85 percent of gas bought by distribution companies, while 12 percent goes to gas-powered vehicles. Residential consumption represents less than 2 percent of the gas sold in distribution networks. At the end of 2002, residential users totaled only 15,065, representing less than 1 percent of all households (table 2-6).[7] Several factors account for incipient development of the residential market: subsidized LPG prices, high cost of connecting new residential customers, and lack of a clear policy for providing residential consumers gas service.

TABLE 2-6. NATURAL-GAS CONSUMERS, 1998–2002

Consumer	1998	1999	2000	2001	2002
Residential	4,701	6,469	9,276	12,524	15,065
Commercial	547	597	733	984	1,179
Industrial	833	874	920	934	926
CNG	15	15	20	23	32
Total	**6,096**	**7,955**	**10,949**	**14,465**	**17,202**

Source: Ministry of Mining and Hydrocarbons of Bolivia.

Small private companies are responsible for natural-gas distribution in the cities of Santa Cruz, Cochabamba, Sucre, and Tarija, operating under licenses that expire in 2009; while YPFB is responsible for La Paz and other cities. YPFB owns the supply and feeder mains in all cities and is a minority shareholder in the distribution companies for Santa Cruz and Cochabamba. Emcogas, the company with the most users, operates in Cochabamba; at the end of 2002, it had only 7,500 users.

Regulation

The Hydrocarbons Law of 1996 authorizes free entry to provide natural-gas distribution services, subject to a maximum 40-year concession tendered by SuperHid in coordination with respective municipal governments. The Law states that distributors have the exclusive right to supply their concession

7. According to the 2001 national census, some 2 million Bolivian households used firewood (34 percent) and LPG (58 percent) as their major cooking fuels.

areas (except thermoelectric generators). The government has not yet developed these regulations. In fact, regulation of this activity has been based on ministerial resolutions that predated reform.

The Law establishes, as a general principle, that natural gas can be freely marketed domestically; however, over a five-year transition period (started when the Law entered into force), SIRESE fixes maximum market prices.[8] Marketing regulations established that, during the transition period, the maximum gas price for sale to fuel-fired generation plants, industries, and distribution companies without valid supply contracts would be determined using a formula based on average export price to Argentina and Brazil, plus the transport tariff on domestic consumption.

The formula was applied until mid-2001, when the government issued a decree fixing the maximum price for thermoelectric plants at US$45.9 per thousand m^3, equal to the maximum city-gate price SuperHid set for other consumers in 1997. This price is equivalent to the wellhead price of US$31.4 per thousand m^3, considerably less than the average price for gas exportation to Brazil during the first half of 2003 (US$60 per thousand m^3 at the wellhead).

International Trade

Bolivia's natural-gas exports evolved in the late 1960s, when the Salta fields in northern Argentina failed to meet production goals and the opportunity arose to monetize about 57 billion m^3 of proven reserves in Santa Cruz by constructing a gas pipeline to the Argentine border and using idle capacity of the Salta-Buenos Aires pipeline.

Exports to Argentina and Brazil

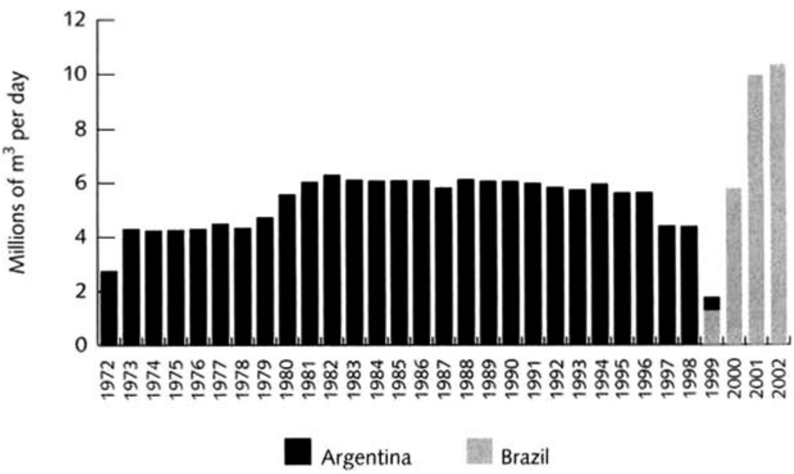
In 1968, YPFB/Bolivian Gulf Oil and Argentina's GdE (*Gas del Estado)* signed a 20-year contract to supply 4 million m^3 per day over the first seven years and 4.5 million m^3 per day over the remaining years. Gas exports through the Santa Cruz-Yacuiba pipeline began in 1972.

8. This period can be extended, depending on domestic-market developments.

Exported volume was later increased to 6.5 million m³ per day, and the contract was extended to 1999. Fifty-three billion cubic meters (US$ 4.56 billion) were exported under this contract (figures 2-3 and 2-4).

In 1974, Brazil and Bolivia signed an agreement to explore the potential for developing bi-national projects. The viability of exporting natural gas from Bolivia to Brazil was explored during the 1980s. A decision was made to study project feasibility in the early 1990s. Because economic conditions had improved, Brazil expected vigorous growth in energy demand and gas was becoming an attractive substitute for more costly fuels. For its part, Bolivia needed a new export market to replace dwindling demand from Argentina, where natural-gas discoveries had been made.

FIGURE 2-3. VOLUME OF NATURAL-GAS EXPORTS TO ARGENTINA AND BRAZIL, 1972–2002
(millions of m^3 per day)



Source: YPFB.

In 1991, YPFB and Petrobrás, signed a letter of intention to export 8 to 16 million m³ of natural gas per day and for Braspetro to participate in gas exploration in Bolivia. Preliminary project-feasibility studies were prepared. YPFB and Petrobrás signed a gas-supply contract in 1993 (which was revised in 1994 and 1995). Its main terms were:

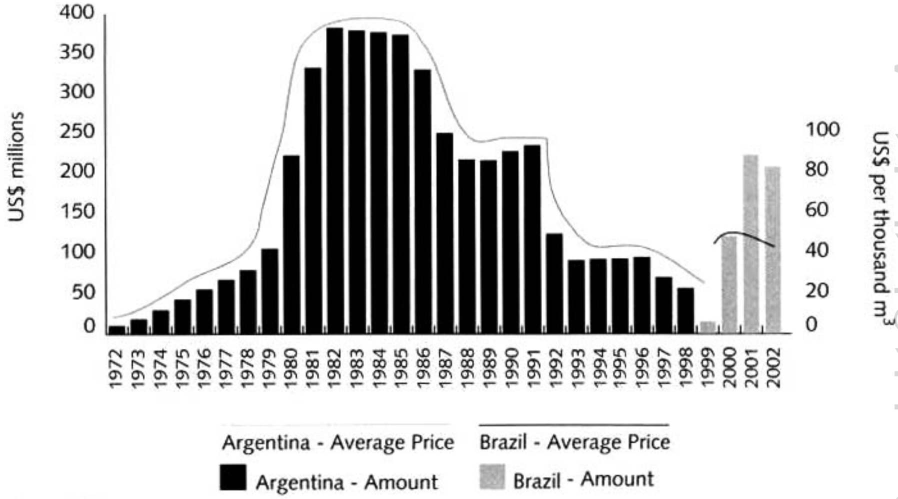
– A 20-year supply contract for an initial maximum volume of 8 million m^3 per day, gradually increasing to 16 million m^3 per day in the eighth year, with an option to purchase up to 30 million m^3 per day.

– YPFB guaranteed delivery of a maximum contracted volume and Petrobrás committed to take-or-pay for 80 percent of maximum contracted volume (with lower percentages in the first two years). Petrobrás had the right to replace, for a 10-year period, annual volumes that were paid for but not taken.

– While the point of delivery was the border, Petrobrás covered the cost of gas delivered to Río Grande and transport costs within Bolivia.

– The base price of gas delivered to Río Grande increased gradually from US$0.95 to US$1.06 per million Btu. It was adjusted quarterly according to an indexing formula that weights increases in the price of fuel oil No. 6 in Europe and the United States.

FIGURE 2-4. VALUE AND AVERAGE ANNUAL PRICE OF NATURAL-GAS EXPORTS TO ARGENTINA AND BRAZIL, 1972–2002

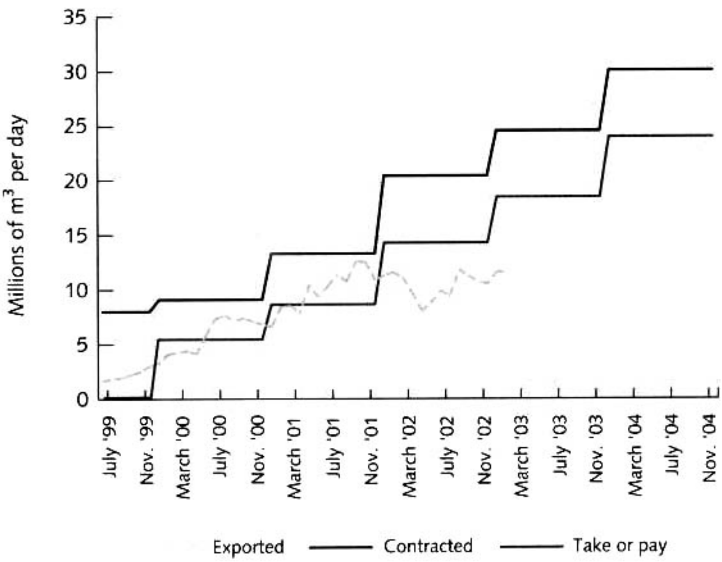


Source: YPFB.

Since 1996, the supply contract has been significantly revised twice: 1) in 1998, to increase the contracted volume by 2.08 million m³ per day starting in 2007 and 2) in 2001, to exercise the option to purchase additional volumes and increase contracted volume to 30.08 million m³ per day starting in 2004, with take-or-pay obligations for up to 80 percent of contracted volume.

Figure 2-5 shows the maximum contracted volumes and the take-or-pay volumes (which reflect revisions to the 1996 contract); the volumes delivered are also shown. It can be seen that, in 1999–2001, Petrobrás met the take-or-pay obligations but in 2002 did not take 35 percent of contracted volume. Lower than expected growth in Brazilian demand and high prices of imported gas, resulting from high international fuel-oil prices, led Brazil to request renegotiation of volumes and prices in the supply contract (figure 2-6).

FIGURE 2-5. CONTRACTED, TAKE-OR-PAY, AND EXPORTED VOLUMES TO BRAZIL, JULY 1999–NOVEMBER 2004

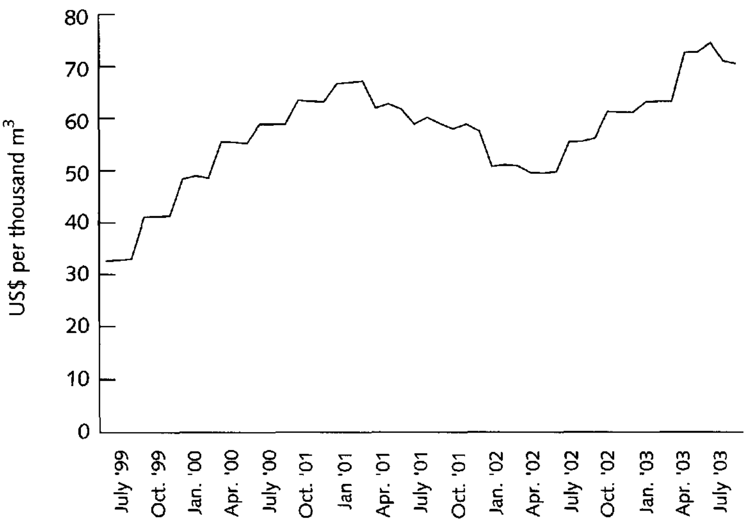


Source: YPFB.

Current problems with the gas-supply contract to Brazil are complex and diverse. The four described here have a major effect on market integration

in the Southern Cone. First, since 2002, Brazilian demand for natural gas has been far below projected volumes, resulting from the successful energy-savings program put into practice during the electricity rationing period; recovery of reservoir levels in large hydroelectric plants; and excess installed thermal-generation capacity, which has postponed the ambitious expansion plan for thermoelectric generation. Second, the Brazilian government considers that gas import prices are not sufficiently competitive to promote development of the Brazilian gas market. Third, Petrobrás recently discovered significant gas fields in the Santos Basin, near metropolitan São Paulo, which will compete with Bolivian gas when production begins at the end of this decade. Fourth, any reduction in supply price affects royalties received by the Bolivian national government, departments, and YPFB.

FIGURE 2-6. AVERAGE NATUAL-GAS EXPORT PRICE TO BRAZIL, JULY 1999–JULY 2003



Source: YPFB.

Export Regulation

The Hydrocarbons Law of 1996 establishes that natural gas can be freely imported, exported, and marketed, except for the volumes required to

satisfy domestic demand and meet the conditions of export contracts signed by YPFB before the Law went into effect.

Regulations with regard to institutional organization of the hydrocarbons sector were passed in 1997, making YPFB the administrator of natural-gas export contracts to Argentina and Brazil. The Gas Marketing Regulations (D.S. 25144) of 1996, which explain this function in detail, established key export conditions. YPFB was assigned the responsibility of collecting and administering gas-export contracts signed with Brazil and Argentina. Moreover, YPFB was to act as the main contractor for export contracts and was responsible for transfer of supply obligations to producers under back-to-back contracts. In addition, an Aggregation Committee, composed of YPFB and producers, was assigned the task of allocating gas volumes established in the contract to producers.

Allocations were to be made first to producers that supplied gas under the contract for export to Argentina. Any additional volumes required were to be allocated, by open invitation, to producers who would supply them at the average export price Petrobrás paid. If the volumes producers offered exceeded the required volume, this was to be prorated and allocated, based on the uncontracted, proven exportable reserves of each producer. It was understood that Petrobrás had a preferential right over third parties to supply Brazil with gas from its own Bolivian fields. Producers were to maintain uncontracted, proven exportable reserves to meet export commitments to Brazil until the contract ended.

To export Bolivian gas, the producer must obtain a natural-gas export license from SIRESE. This license is granted if the volume to be exported does not exceed the producer's uncontracted, proven exportable reserves (accounting for the reserves needed to supply the domestic market). If the volume to be exported exceeds 10 percent of these reserves, the aggregator must certify that these volumes are not required to meet the export commitments already made by YPFB.

In 1999, SuperHid defined the requirements for granting natural-gas export licenses. The resolutions issued at the beginning of that year limited

the duration of export licenses to one year. After that period, when information on the substantial increase in certified reserves was known, SuperHid issued a new resolution that increased the duration of licenses to 20 years and established simple requirements for granting them.[9]

In 1999 and 2000, the contracted volumes for export to Brazil were allocated according to the procedures described above. Results show that 20.5 percent of total contracted volume was allocated to companies that exported gas to Argentina, 10 percent through tenders, and 69.5 percent through the preferential right held by Petrobrás. Companies such as Andina and Total also participate through their Petrobrás partnerships in the megafields of San Antonio and San Alberto (the main supply source). Table 2-7 shows the participation of suppliers in exports.

TABLE 2-7. ALLOCATION OF CONTRACTED VOLUME FOR EXPORT TO BRAZIL, BY SUPPLIER 1999–2000

Supplier	%
Petrobrás	69.5
Andina	11.2
Chaco	6.7
Pérez Companc	3.7
Repsol YPF	3.6
Tesoro (BG)	3.6
Vintage	1.6
Dong Won	0.1

Source: YPFB.

Starting in 1999, certain producers managed to contract directly smaller volumes of gas for export to Brazil and Argentina. BG signed a sales contract with Comgás, a BG subsidiary and São Paulo distributor, which became effective in 2001. Andina exports gas to Cuiabá. In 1999, Pluspetro began independent exports to Argentina, first via Bermejo and then through Yacuiba. In 2002, these companies' export volumes represented 25 percent of total exports.

9. SuperHid Administrative Resolution No. 0376/99.

New Export Projects

Export contract commitments and projected domestic demand over the next 20 years can be met with less than 20 percent of proven and probable reserves. Therefore, gas producers, with government support, are developing projects aimed at monetizing uncommitted reserves.

The most promising project, in terms of progress made and market size, involves LNG export by the Pacific LNG consortium (composed of Repsol, BG, and Panamerican Energy). The project includes construction of an 800-km gas pipeline to a Pacific port; a treatment plant; and two liquefaction trains, with a total capacity of 28.3 million m^3 per day; LNG export to the western U.S. (southern California) and Mexico (Baja California); and export of condensate, natural gas, and LPG resulting from treatment at port. Partners Sempra Energy and CMS Energy Corporation, who purchase the liquefied gas, invest an estimated US$5 billion.

Project feasibility and negotiations are well under way. Two main ports have been studied for gas processing and export: Patillos (Chile) and Ilo (Peru). The Chilean port has lower costs, a key factor in economic viability; however, this option has met with political resistance in Bolivia. Production and marketing of liquefied gas are key project components. The project will use wet gas from the Margarita megafield, which contains a higher proportion of liquids than the average Bolivian field (about 2,825 barrels per million m^3 versus 882 barrels per million m^3). To sell gas in California at a price of US$3.50 per million Btu, the netback price at the wellhead is estimated at US$0.70-0.90 per million Btu.

Negotiations with the Bolivian government have reached a critical stage. The government requests a guarantee of steady income of royalties and taxes, but the netback price at the wellhead varies with fluctuations in the wholesale market price for gas in the U.S., where the regassified gas will be sold. In addition, project promoters request tax incentives to make the project attractive. These would include a tax exemption on equipment import and tax holidays. The popular revolt that recently cost the Bolivian president his job and led to postponing the project (on condition of popular consultation) shows the important role politics plays in such a project.

A second export project at an advanced stage of preparation is the San Marcos thermoelectric plant, which aims to sell electricity to Brazil. Located on the Bolivia-Brazil border, the plant has a 100-megawatt (MW) capacity. A consortium including Duke Energy and Petrobrás initially promoted the project; however, an unfavorable climate for thermoelectric plants in the Brazilian electricity market and the withdrawal of Duke Energy in 2002 have stalled the project.

Other export projects under consideration include a fertilizer project; a gas-to-liquid project, with an initial capacity to produce 10,000 barrels per day of clean products; and a petrochemical complex to process the ethane content of gas exported to Brazil. According to Bolivian authorities, if all projects identified for exporting and using gas as a feedstock were developed, current estimated demand over the next 20 years would double and only 40 percent of certified reserves—proven and probable—would be monetized.

Challenges to Regional Integration

The key principles for developing a competitive regional gas market—free entry, open access, customer choice, separation of activities, and effective regulation—are all present in Bolivia's gas-sector regulations and structure (table 2-8). Even so, market development is tenuous, given the problems that persist: segmented markets, single-company dominant power, market intervention by government, and administration by fiat of the most critical export contract.

Reserve Monetization

Bolivia has an ample supply of competitively priced natural gas;[10] however, its small domestic market lacks the critical mass needed to develop gas reserves. The country's export potential—whether by pipeline shipping or conversion into other value added products—is limited by the country's geography, as mentioned above. Because of the country's unique conditions, the market for Bolivian gas has been neighboring Argentina and Brazil, whose demands have reached a

10. Production costs for the Bolivian gas fields are estimated at US$14-18 per thousand m^3.

critical mass that justifies investment in interconnections and where natural gas can compete with substitutes. Bolivian exports were first marketed to Argentina, when this country lacked sufficient gas reserves, and then to Brazil, a potentially large market.

TABLE 2-8. COMPARISON OF COMPETITIVE MARKET CONDITIONS

Condition	European Union	Bolivia
Free entry	Objective and nondiscriminatory criteria to authorize entry of new service providers	System of licenses and concessions with objective conditions
Open access	Regulated access	Regulated access
Customer choice	Progressive goals for opening market	Free wholesale market, but with price caps
Separation of activities	Independent transport system operator	Independent transport companies
Regulatory capacity	Independent body responsible for regulation	Independent regulation by SuperHid

Source: Author's elaboration.

Argentina recently experienced a serious energy crisis because regulated wellhead prices failed to provide incentives to invest in expanding production capacity and gas demand has increased substantially in response to recent economic recovery and artificially low gas prices. As a result, Argentina's government had to curtail gas exports to Chile and Uruguay, ration supply to industrial consumers, and negotiate imports from Bolivia. In April 2004, the presidents of Argentina and Bolivia signed an agreement (*Declaración Presidencial de Buenos Aires*) to strengthen economic and energy integration. The agreement authorizes, as an initial emergency measure, export of 4 million m^3 of natural gas per day over six months. It also calls for specific actions to promote development of an interconnecting gas pipeline with a capacity of 20 million m^3 per day and a possible five-year extension of the export contract (subject to positive results of the referendum on energy policies convoked by the Bolivian government). These developments have increased the potential for resuming substantial gas exports to Argentina.

Future development of the natural-gas pipeline export market will necessarily give priority to Argentina and Brazil, whose markets and transport infrastructure are solid. Projects to export value added products converted from natural gas are unlikely to succeed over the medium term because of the high cost of transporting products to consumption centers. Exporting LNG is an attractive alternative for monetizing gas reserves and overcoming regional market limitations.

Government Intervention in the Market

Given Bolivia's abundant natural-gas reserves and low production costs, one would expect that liberalizing wholesale prices and promoting a competitive market would lead to lower natural-gas prices at the wellhead. Producers have great interest in monetizing the reserves that lack a market, especially those producers without a large share of gas exports to Brazil.

Lower prices could lead to reduced revenues from royalties, depending on the price elasticity of demand, since royalties are paid as a fixed percentage of the average export price. Clearly, in a country like Bolivia, where fiscal revenues from gas exports represent about half of all other (non-hydrocarbon) national tax revenues,[11] the royalties issue is of great political and economic importance to the government. Unlike crude oil and its derivatives, for which benchmark prices for royalty payments can be found in the international market, the only benchmark for natural gas is the regional-market price.[12] Concern over the fiscal effect of the export price partly explains why government intervention in export negotiations and market segmentation, based on long-term contracts, continues.

11. It is estimated that natural-gas exports to Brazil, at an average price of US$1.50 per million Btu, would generate US$370 million annually in state income, in the form of royalties and taxes. In 1996–99, tax income from non-hydrocarbon sources was estimated at US$700 million per year. See Lykke E. Anderson and Robert Faris, "Reducing Volatility Due to Natural Gas Exports: Is the Answer a Stabilization Fund?" (prepared for the Andean Competitiveness Project in February 2002).

12. The Regulations on the Payment of Hydrocarbon Royalties (1997) establishes that, for the payment of natural-gas royalties, the wellhead price will be the weighted average of the export prices at the borders and domestic sales at the points of sale, adjusted by transport rates, if applicable.

Current legislation states that Bolivian producers may freely market their gas, giving priority to the domestic market, subject to SuperHid's simple authorization to export. In practice, however, the freedom to market gas is limited. Renegotiation of the export contract with Brazil illustrates this point: It could not be handled directly by those responsible for the contract on the Bolivian side (YPFB and the Aggregation Committee) and had to be negotiated by the two governments. Likewise, the Bolivian government has intervened in the LNG export project, not only on matters under its authority, such as selecting the port of export or establishing tax incentives, but also on establishing export prices. When the export contract was being renegotiated, the government discussed options for guaranteeing that tax revenues would not be reduced; with regard to LNG exports, it has discussed a guaranteed minimum amount for revenues from gas royalties.

Government intervention in the export business is neither desirable nor sustainable over the long term, since it could create a disincentive to invest in exploration and production. It could be interpreted as an attempt to modify current rules to calculate gas royalties and capture additional economic rent of natural gas, creating uncertainty about the stability of the regulatory regime. Within the framework of agreements adopted as part of Mercosur's broader market development, this situation is unsustainable. Nonetheless, the Bolivian government and producers cannot be expected to abandon their share of gas economic rent to transporters and marketers in neighboring countries. Regional market development is a gradual process, whereby the countries involved progressively adopt common practices that enhance competition.

However, Bolivia's 2003 popular revolt, which led the republic's president to resign, makes it necessary to recognize the importance of the political factor and government intervention in developing natural-gas export projects. The controversy over the LNG export project gave some special interests a loophole for mobilizing a population concerned about an ongoing economic crisis. In light of recent events, it is unrealistic to think that, in the medium term, producers and marketers will be freer to negotiate and develop gas export projects, subject only to the condition

that they must give priority to supplying the domestic market. In the short term, the priorities are to 1) gain political support for LNG exports and take advantage of the window of opportunity to execute this project and 2) control the process of revising hydrocarbon legislation to avoid radical changes that would negatively affect future foreign investment.

Recent political events confirm that export of natural gas and use of gas reserves are national issues that affect local politics significantly. To guarantee a peaceful resolution of the popular revolt, the new government promised to implement a referendum on energy policy. On July 18, 2004, a referendum was voted to define the natural-gas industry's future. The referendum included questions on five substantive issues: 1) repealing the Hydrocarbons Law of 1996; 2) reclaiming state ownership of all hydrocarbons at the wellhead; 3) transferring the state's stake in hydrocarbon companies to YPFB and restoring its participation in the hydrocarbon production chain; 4) supporting President Mesa's policy of using natural gas as a strategic resource to regain access to the Pacific coast; and 5) authorizing gas exports, conditioned by supplying national demand, fostering local demand, and increasing royalties and taxes on gas production to 50 percent.

Responses to all five questions were predominantly "yes," and both the government and opposition groups claimed victory. A large majority approved questions 1-3, while 4 and 5 received lukewarm approval. Although Chile was not mentioned in the questionnaire, the political opposition tried to block the possibility that the government reopen talks on exporting Bolivian gas using a Chilean port.

The mild support with regard to question 5 was a positive signal for the development of gas exports, including the LNG project and exports to Argentina; however, it remains uncertain whether the proposed increase in royalties and taxes will have a major negative effect on foreign investment in gas production. President Mesa has already stated that it would seek to change the current upstream contracts for a variety of risk-sharing contracts between the public and private sectors, which might become the only feasible exit for the Bolivian gas.

Strong support of using natural gas as a means of gaining access to the Pacific Ocean could become a barrier to developing a regional gas market. The recent agreement for emergency gas exports to Argentina prohibits the diversion or marketing of Bolivian gas to other countries in the region, which Chile protested as an obstacle to regional integration.

The government is preparing a hydrocarbons bill that would include a complementary tax on hydrocarbons, which might increase royalties and taxes for large gas fields to 50 percent; declare sovereignty on hydrocarbon resources; and strengthen YPFB's role in the hydrocarbon industry.

Looking ahead—and assuming that results of the referendum support gas exports and a new hydrocarbons law—it remains uncertain whether the government will commit to reducing its ad-hoc intervention in the export market and instead concentrate on defining an energy policy that promotes exports and value added projects and supporting regional agreements to facilitate regional market development.

Competitiveness in Brazil and Petrobrás' Dominant Position

Greater competition in the regional natural-gas market is restricted by prior commitments and rights acquired in take-or-pay and ship-or-pay contracts, which are important in the case of gas exports to Brazil through Petrobrás.

YPFB acts as aggregator in a scheme whereby administrative rules are applied to allocate export quotas to existing producers; this limits the role of the export contract as an instrument to develop a more competitive market. For example, incremental volumes are allocated without using price bids; Petrobrás enjoys preferential treatment in allocating incremental volumes and has a firm transport contract for virtually the entire capacity of the export gas pipeline.

Petrobrás holds a large stake in Bolivian natural-gas reserves and production, the contracting of gas transport capacity to Brazil, and importing and marketing natural gas in Brazil. Introducing a competitive market and reducing Petrobrás' market power would significantly affect

Bolivia's fiscal revenues and the interests of Petrobrás, which took on contractual take-or-pay obligations needed to ensure the financial feasibility of the export project.

Over the medium term, development of gas exports to Brazil will be conditioned mainly by the competitiveness of Bolivian natural gas in Brazil, growing demand in Brazil, and the extent of open access in this market. Clearly, the market will not develop if Bolivian gas cannot compete successfully with gas produced in Brazil and alternative fuels, or if energy demand fails to grow vigorously. Table 2-9 shows the structure of export prices to Brazil, according to the current supply contract with Petrobrás. During 2002–03, the average price of gas delivered at the border was approximately US$70 per thousand m^3, and the transport price to the border accounted for 30 percent of this price. If transport tariffs in Brazil are added, transport likely would represent more than 60 percent of city-gate prices in southeastern Brazil.

Renegotiation of the Brazil Contract

Petrobrás has requested renegotiation of contracted prices and volumes in order to adjust the supply contract to Brazilian market conditions. However, the competitiveness issue will not likely be resolved by adjusting the price of gas at the wellhead. Rather, it will also require adjustment of transport prices. That both Bolivian gas producers—BG and Andina—have not managed to develop new export markets in Brazil, despite their ability to reduce wellhead prices below the price at which gas is now sold to Petrobrás, illustrates this point.

Table 2-9 also shows that distortions in the export transport tariff, caused by the deferred account and the domestic market subsidy, marginally affect the price of exports to the border (less than 3 percent). Thus, although such distortions are undesirable in a competitive market, in practice, they have not hindered export-market development.

Traditionally, contract renegotiation with Petrobrás has been carried out by the parties involved, based on contractual conditions and procedures. However, due to its political and macroeconomic importance, renegotiation

is increasingly a bi-national agreement process, through which Bolivian producers negotiate price and volume changes as a group represented by the Bolivian government, with little room for competition. Participation of both countries' governments, however, presents an opportunity to use renegotiation as an instrument to provide flexibility with regard to the restrictions the export contract imposes on development of a more competitive market. This is important, given the Bolivian government's concern that the benefits of a potential price reduction may not be passed on to Brazilian consumers, which would limit growth of the export market to Brazil.

TABLE 2-9. GAS EXPORT PRICE TO BRAZIL

	2002		2003 (first quarter)	
Price	**US$ per thousand m³**	**%**	**US$ per thousand m³**	**%**
Wellhead (equiv.)	46.3	69	54.5	72
Transport to Río Grande	8.8	13	8.8	12
Base	6.3	9	6.3	8
Deferred account	1.4	2	1.4	2
Domestic market subsidy	1.1	2	1.1	1
Export in Río Grande	55.1	82	63.2	84
Compression in Río Grande	1.9	3	1.9	3
GTB	10.1	15	10.1	13
Export in Mutún	67.1	100	75.2	100

Source: YPFB.

Actions to mitigate current restrictions include releasing contracted but unused transport capacity, developing a secondary market for transport capacity, limiting YPFB's role as aggregator (allowing price competition for supplying additional quantities of gas to Brazil beyond already contracted volumes), and opening the gas market in Brazil.

Domestic Market Competition

Although the Hydrocarbons Law of 1996 liberalized wholesale prices starting in 2001, the government regulates city-gate prices in the domestic market at levels significantly lower than the export price, effectively segmenting the two markets.

If reserves are ample, production costs are low, and several producers are operative, then liberalization of wholesale prices, announced in the Law, should lead to lower prices at the wellhead; greater penetration in the domestic market; and substitution of more expensive fuels, such as LPG, thereby benefiting consumers. Although Bolivia's domestic market is marginal compared to certified reserves, it is important to adopt a policy that promotes competition in domestic and export markets; eliminates price caps; and promotes development of a secondary market for transport capacity and use of market mechanisms to manage the contract with Petrobrás, instead of the current volumetric approach. As other member countries of the enlarged Mercosur—especially Brazil—take similar measures, the regional gas market will grow, which is essential for monetizing Bolivian gas reserves.

Retail competition is a key factor in developing a competitive market in developed countries with high household energy consumption sufficient to justify the measurement and administration costs of extending free choice to the small-consumer level. In a country like Bolivia, where natural-gas penetration, family income, and residential and commercial energy consumption are low, greater retail competition does not make economic sense in the short or medium term.

Chapter 3

Brazil: A Key Push for Integration

Edmar Luiz Fagundes de Almeida

Brazil's natural gas industry (NGI) faces insufficient demand in relation to supply commitments. Major players in the gas chain are bound to long-term contracts that stipulate larger supplies than are currently demanded, particularly from power generators. In a regionally integrated market, Bolivia and Argentina would serve as the primary exporting countries to Brazil. However, if Brazil's electricity demand remains less than originally anticipated and recently discovered gas fields become productive, then the potential for cross-border trade would diminish.

In the late 1990s, gas-based power generation was the main anchor for gas-supply projects. Four major factors drove energy policymakers and players to favor gas-based power generation as the country's main gas market: large regional potential for gas supply, development of gas-thermal generation (Islas Samperio 1995), entry of private capital into the electricity industry,[1] and lack of a space-heating market.

To guarantee Brazil's power supplies, especially after the 2001 energy crisis, and to stimulate investment, the federal government launched the Priority Plan for Thermal Power Generation (PPT). As a result, the country has built about 4,000 megawatts (MW) of gas-based thermal generation capacity since 2001. The energy rationing of 2001 reduced expected electricity demand in 2003 by 10 percent, leaving Brazil's electricity industry with significant overcapacity. Today, most gas-based, power-generation capacity is not dispatched. Potential demand is about 20 million cubic meters (m^3) per day; by March 2004, however, actual demand was only about half that amount.

1. Lower capital intensity makes this technological option more suitable for private-company investment.

Evolution of Supply and Demand

Gas Production

During 1993–2002, gas production doubled (table 3-1). Although total natural-gas sales to end-users increased 226 percent over the period, domestic sales increased only 70 percent. Thus, gas imports account for most of the sales increase over the past four years. Because domestic production has increased more than domestic sales, Petrobrás has had to accelerate projects to increase its own gas consumption to avoid massive flaring.[2]

TABLE 3-1. BRAZIL'S NATURAL-GAS BALANCE FOR SELECTED YEARS (millions of m^3)

Factor	1993	1996	1999	2002
Imports	0	0	400	5,269
Production	7,355	9,167	11,855	15,525
Reinjection	1,487	1,650	1,600	3,383
Flaring and losses	1,281	1,501	2,276	2,136
Total own consumption	856	1,325	2,333	3,219
In platforms	n.a.	n.a	1,514	1,876
In refineries and NGPU*	n.a	n.a	819	1,343
Natural gas liquids	349	379	431	622
Sales	3,424	4,360	5,349	11,100
Adjustments	–43	–46	267	333

* NGPU = Natural Gas Processing Unit.
n.a. = not available.
Source: National Petroleum Agency (ANP).

Because Brazil's system of natural gas transmission is limited to the country's southern and southeastern regions, with a smaller network interconnecting northeastern states, many regions—primarily in the north—have nearby availability but no pipeline network for consumption. A notable example is Amazonas; nearly bereft of pipelines, that state is forced to reinject significant amounts of gas produced in the region.[3]

2. Petrobrás' goal is to reduce flaring in the Campos Basin, its most productive oil and gas basin, to less than 10 percent of total gas production.
3. Currently, only the heavy proportion of gas produced in the Amazon is commercialized; the remainder is reinjected for lack of transport capacity.

Reserves

Although proven gas reserves in Brazil reached 316 billion m^3 by late 2003 (roughly 3 percent of Latin American reserves), it was considered insufficient to cover anticipated demand. However, in 2003, Petrobrás discovered giant offshore gas fields in the Santos Basin,[4] with an estimated volume of about 420 billion m^3. Of this total, 78 billion m^3 were added to the Brazilian gas reserves at the end of 2003. The remaining 342 billion m^3 are under evaluation and prospects are positive. If this volume is certified, Brazil's gas reserves will more than double, reducing the need for imports in the medium and long term.

According to Petrobrás, over a 20-year period, the Santos Basin gas reserves can produce about 50 million m^3 per day, more than all gas produced today (about 45 million m^3 per day as of June 2004). However, specialists argue that full development of these gas fields would take 6 to 10 years. Petrobrás estimates the total investment necessary for development of the field at about US$2.5 billion.[5] Thus, one can conclude that, at least over the medium term, imports from neighboring countries will still be needed to complement domestic supply.

Ten Brazilian states have significant natural-gas reserves. São Paulo leads in terms of total reserve holdings since the July 2003 discovery; reserves jumped from 3.8 billion m^3 in 2002 to 420 billion m^3—if all announced volume is certified—after the Santos Basin find. In 2002, Rio de Janeiro had nearly 115 billion m^3 of proven reserves; followed by Amazonas, which held roughly 48 billion m^3; and Bahía, with 23 billion m^3.

Bahía, once Brazil's largest holder of natural gas reserves, has steadily declined in reserve levels (although they picked up in 2002). Falling reserves have been a trend throughout northeastern Brazil since the mid-1990s. Rio Grande do Norte, the second largest northeastern producer

4. It should be noted that the Santos Basin is located near the states of São Paulo and Rio de Janeiro, the country's major gas markets.
5. *Jornal do Brasil*, "Petrobrás Exportará Gás para os EUA" (September 26, 2003).

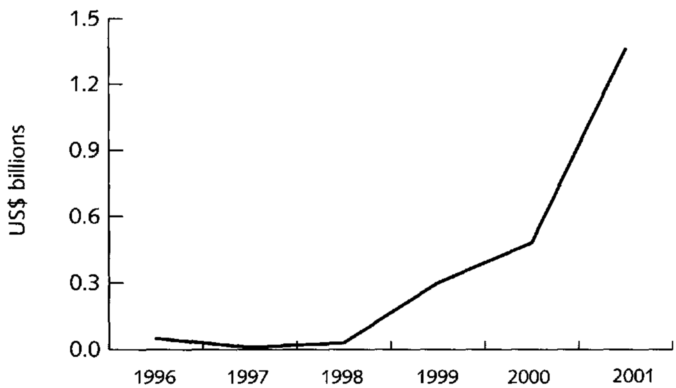
after Bahía, had reserves of 24 billion m³ in 1999. This level fell to less than 19 billion m³ in 2002. Although not a substantial decrease, projected growth for northeastern gas demand, especially for power generation, makes the region's production potential a key issue.

Exploratory Efforts

According to the U.S. Geological Survey, Brazil's undiscovered natural-gas resources total 5.5 trillion m³, or 40 percent of South America's total estimated, undiscovered gas resources. If Brazilian gas producers, principally Petrobrás, can extract a small portion of these resources, little room will remain for large-scale imports.

Liberalization of Brazil's upstream sector has attracted numerous international oil and gas companies; currently, about 40 oil companies have concessions of exploratory blocks. Foreign direct investment (FDI) has increased substantially since 1999, from about zero to almost US$1.5 billion in 2001 (figure 3-1).

FIGURE 3-1. FOREIGN DIRECT INVESTMENT IN BRAZIL'S OIL INDUSTRY, 1996–2001

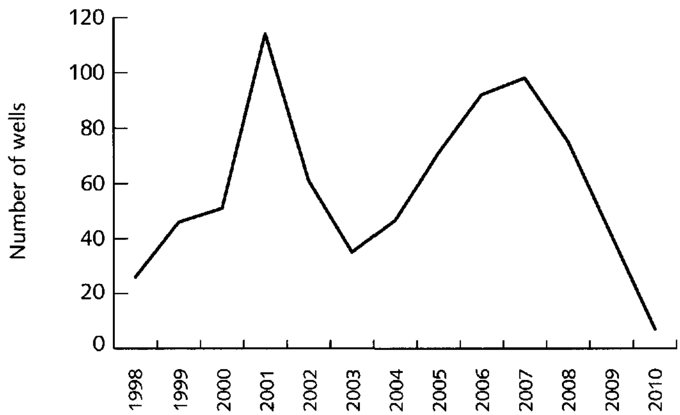


Source: Central Bank.

In 1998, Brazil's National Petroleum Agency (ANP) leased 115 blocks (known as Round Zero) exclusively to Petrobrás. These blocks were part of Petrobrás's exploratory portfolio before opening of the Brazilian

upstream.[6] Although exploration was not open to private companies, Petrobrás formed partnerships with private operators to explore and develop the Round Zero blocks. Since 1999, ANP has held five bidding rounds, conceding 70 additional blocks. Thus, significant oil exploration is under way in the Brazilian upstream (figure 3-2) and since 70 percent of Brazil's gas reserves is associated with oil, the more companies drill for oil, the more gas will likely be discovered.

FIGURE 3-2. NUMBER (ACTUAL AND PROJECTED) OF EXPLORATORY WELLS DRILLED, 1998–2010



Source: Author's own calculations.

Since 1998, exploration led to 67 gas discoveries in Brazil.[7] Twenty-five were associated with oil, while 42 were gas only. During 1999–2002, about 60 billion m^3 were added to Brazil's proven reserves, increasing total proven reserves to 236 billion m^3. Significant gas discoveries were concentrated in the states of Rio de Janeiro, Bahía, and Espírito Santo. The gas field (430 billion m^3) discovered in the Santos Basin has the potential to triple Brazil's proven gas reserves.[8]

6. Federal Law 9478 of 1997 required Petrobrás to devolve all blocks it was exploring to the ANP. Round Zero, which conceded many blocks to Petrobrás under special conditions, resulted from a political agreement to facilitate transition to a more market-oriented concessionary system.
7. Only a portion of these has been found to have commercial potential.
8. The reserve is crucial for the Brazilian gas industry because it is located near metropolitan São Paulo, the country's largest gas market, and the field contains non-associated gas.

During 1993–2002, Brazil's reserves-to-production ratio fell consistently. This decline would normally indicate a growing need for supplies, especially imports, to meet demand growth. However, if the volume of the Santos Basin discovery is certified, Brazil's reserves-to-production ratio will rise from 15 years to nearly 40.

Natural Gas Demand

Although Brazil's natural-gas demand has expanded rapidly over the last five years, its share in the country's total energy mix is still only 7.5 percent, indicating that the market is still in its infancy, with tremendous growth potential. Gas demand remains heavily concentrated in industry and power generation; as table 3-2 shows, in March 2004, 54.5 percent of total gas sales went to industry; while power generation accounted for 31.5 percent of total gas sales. The automotive sector is the fastest growing consumer segment, accounting for 11.5 percent of all gas sales. Residential and commercial sectors play a minor role, together accounting for only 2.6 percent of the country's gas consumption.

TABLE 3-2. NATURAL GAS SALES BY SEGMENT, MARCH 2004
(thousands of m^3 per day)

Segment	Number of sales	Percent
Industry	19,611	54.5
Automotive	4,129	11.5
Residential	541	1.5
Commercial	401	1.1
Electricity generation	11,323	31.5
Total	**36,005**	**100**

Source: Brasil Energia.

Geographically, Brazil has three natural gas markets:

– *Espírito Santo, Mato Grosso, Mato Grosso do Sul, Minas Gerais, Paraná, Rio de Janeiro, Rio Grande do Sul, Santa Catarina, and São Paulo.* The largest market, these southern, southeastern, and west-central states account for 82 percent of the country's industrial output, 75 percent of domestic energy supply, and 66 percent of GDP.

Espírito Santo, Minas Gerais, and Rio de Janeiro consume gas piped from the offshore Campos, Espírito Santo, and Santos basins along the Atlantic coast; while Mato Grosso, Mato Grosso do Sul, Paraná, Rio Grande do Sul, and Santa Catarina consume gas imported from Bolivia. São Paulo consumes gas piped from the offshore basins and imported from Bolivia.

– *Northeastern coastal cities.* The second largest market, these cities are linked by the Nordestão pipeline, which pipes gas from the offshore basins of Alagoas, Bahía, Rio Grande do Norte, and Sergipe. Of the northeastern states, Bahía is the largest gas consumer (about 1.6 billion m^3 in 2002). Declining basin reserves over the past few years has led officials and industry leaders to consider two projects for liquefied natural gas (LNG) regasification plants, with gas shipped from Trinidad and Tobago or perhaps Nigeria. (With recent approval of the pipeline linking the southern gas network to the Northeast, LNG plans have been put on hold.)

– *Amazon.* This region has abundant reserves but virtually no market. All gas from the productive Juruá and Urucú basins is used to extract valuable liquids, which are reinjected. Plans are under way to transport gas to such major cities as Manaus and Porto Velho. If infrastructure is put in place, gas could substitute for fuel oil in industries and mainly diesel oil in power plants in the states of Amazonas and Rondônia.[9]

Table 3-3 shows the evolution of natural gas sales by region and state between 1995 and 2002. Sales in the west-central region clearly grew the fastest (270 percent in 2002), resulting from construction of the Bolivia-Cuiabá gas pipeline, which fuels a thermal power station in the state of Mato Grosso. In 2002, the Southeast had 58 percent share of demand, up 2 percent from 2001. The increase resulted primarily from weaker growth in the South and, to a lesser extent, the Northeast.

9. The Amazon region has hundreds of isolated, diesel-based electricity systems and accounts for 90 percent of total diesel-based, generation capacity (2,000 MW).

TABLE 3-3. EVOLUTION OF NATURAL GAS SALES IN BRAZIL, 1995–2002
(millions of m^3)

Region or state	1995	1996	1997	1998	1999	2000	2001	2002	Growth rate*
Northeast	**1,732**	**1,801**	**1,898**	**2,015**	**2,211**	**2,526**	**2,645**	**2,812**	**6.3**
Alagoas	108	131	126	147	168	143	145	151	4.1
Bahía	983	1,008	1,042	1,141	1,250	1,453	1,559	1,616	3.7
Ceará	30	35	36	46	61	74	102	141	38.2
Paraíba	16	20	31	34	44	59	69	81	17.4
Pernambuco	187	182	195	202	212	239	264	283	7.2
Rio Grande do Norte	19	26	31	34	38	48	56	77	37.5
Sergipe	389	399	436	411	439	512	450	463	2.9
Southeast	**2,277**	**2,559**	**2,833**	**2,774**	**3,138**	**3,794**	**5,049**	**6,470**	**28.1**
Espírito Santo	163	199	206	221	219	263	337	353	4.8
Minas Gerais	2	70	154	190	253	305	365	403	10.4
Rio de Janeiro	1,191	1,194	1,242	1,161	1,307	1,559	2,054	2,702	31.6
São Paulo	921	1,096	1,231	1,202	1,359	1,668	2,293	3,012	31.4
South						**262**	**1,239**	**1,247**	**0.6**
Paraná						53	127	206	62.2
Rio Grande do Sul						134	895	753	–15.9
Santa Catarina						76	218	287	31.6
West-central							**154**	**572**	**271.4**
Mato Grosso							54	455	742.6
Mato Grosso do Sul							100	117	17.0
Total	**4,009**	**4,360**	**4,731**	**4,789**	**5,349**	**6,582**	**9,087**	**11,101**	**22.2**

* Year 2002 over 2001.
Source: National Petroleum Agency (ANP).

Gas Consumption: Power Generation

By March 2004, gas consumption by power generators had reached 11 million m^3 per day. Of this total, co-generation projects consumed 2.3 million m^3 per day. As mentioned above, the government and gas players expected consumption by electricity generators to boom, as a result of new gas-based generation projects. In 2000, Petrobrás' annual strategic report predicted such consumption would reach 30 million m^3 per day by late 2003. Though construction costs are lower, thermal power plants are more costly to operate than are hydropower plants, many of which are already amortized. Fearing competition with cheaper, existing hydropower plants, investors have tended to avoid gas-based projects.

Given the difficulties in attracting private investment for gas-base electricity generation projects, the government launched the PPT. Consistin of a set of incentives, the PPT envisioned construction of more than 40 gas based power plants nationwide to augment the country's electricity suppl and improve power-system reliability. Upon announcing the governmen project's objectives, analyst forecasts for gas demand growth boomed, with "pessimistic" outlook of 300 percent growth by 2015 (de Oliveira 2001). Th electricity rationing of 2001 had a major effect on the PPT, with powe demand falling sharply during and after rationing. Thus, the governmen reduced its target from more than 40 thermal power plants to about 20.

Despite lower than expected investment in gas-based generation, the PPT ha resulted in a significant increase in Brazil's gas-based generation capacity Today, total capacity is about 5,400 MW, of which large thermal powe plants account for about 4,100 MW and small-scale and co-generatio projects 1,300 MW. Thus, if all currently available, gas-based generatio capacity—about 5.4 gigawatts (GW)—were dispatched, gas demand coul reach about 20 million m^3 per day.

Energy officials now face the challenge of how to incorporate the new gas based generation projects into a hydropower-based generation system Modification of the current regulatory framework governing Brazil' electricity industry and increased electricity demand are necessary condition to boost power-sector demand for gas. Energy policy should determine th desired portion of the nation's electricity sector devoted to gas-based, therma generation plants. To increase thermal power-plant competitiveness, rules fo electricity dispatching should be changed. Current rules are based on a meri order, built according to plants' short-term marginal costs. In addition operational rules accept a relatively high risk of electricity shortage (about 5 percent). These rules result in overexploitation of dam-water reservoirs an do not guarantee minimal, gas-based generation dispatching. Moreover, the create enormous market risk for gas-based generation, given that the short term marginal cost of hydropower supply can be near zero for lengthy period because of the reservoirs' high water-storage capacity.

Risk of idle, gas-based capacity is a problem for power projects. Withou guaranteed effective demand, it is economically and technically difficult fo

the gas chain to guarantee supplies for such a large market. Furthermore, it is difficult for gas suppliers to obtain take-or-pay contracts from power plants at this level of market risk.

One possible way to reduce such risk would be to establish minimal dispatching for gas-based generation capacity to enable gas shippers and thermal plants to sign long-term contracts necessary for gas-supply investments. This minimal rate of dispatching would depend on the type of power plant (base-load or peak-shaving) and the electricity market. Recent experience in the Brazilian electricity market shows that coexistence of gas- and hydro-based power stations requires specific market rules. A minimal level for thermal power-plant dispatching would allow for improved management of water reservoirs, thereby reducing the risk of power shortages during dry periods.

Gas Consumption: Industrial Sector

Industrial-sector demand—composed mainly of petrochemical and steel plants and glass, ceramics, cement, pulp and paper factories—represents a large, stable source of demand, capable of promoting expansion projects in infrastructure, transmission, and distribution. When making investment decisions, distribution companies look to industrial demand in their concession area to judge whether, and at what scale, to invest. Contracts with industrial clients promote construction of pipelines and city-gates, which promote development of other market segments, such as residential and commercial sectors, as well as the automotive fuel market.

In the 1990s, the industrial sector led growth in Brazil's natural gas market. Demand for natural gas to meet energy needs (gas as a raw material) grew sharply; however, demand for meeting non-energy purposes stagnated as investment declined in the steel, fertilizer, and petrochemical industries.

Recent expansion of the natural gas industry has been concentrated in energy-intensive industries, dominated by large industrial firms. Industrial demand is concentrated in the chemical, iron and steel, and (to a lesser extent) pulp and paper industries. In industrial sectors, where production

is less concentrated (e.g., small food production and beverage companies and glass and textile manufacturers), natural gas plays a lesser role. Nevertheless, such industries could, as a whole, become large natural-gas consumers.

In 2002, industry accounted for 61 percent of Brazil's natural gas demand. Most of this consumption was in the chemical (32 percent), iron and steel (19 percent), ceramics (8.5 percent), and pulp and paper (7.3 percent) sectors. Fuel oil and biomass were the strongest competitors of natural gas. Biomass, consisting of organic matter (firewood, sugar cane bagasse, and other agricultural waste) accounted for 33 percent of industrial fuel demand (table 3-4).

Over the past three years, Rio de Janeiro's gas distributor, CEG-Rio, lost 19 out of 20 contracts signed with ceramics companies[10] (in northern Rio de Janeiro in 1999 and 2000, demanding 2 million m^3 per month) because of the availability of cheap, wood-based fuels. One CEG-Rio executive claims that, on the black market, firewood can run 60 percent cheaper than natural gas.

Currently, the steel industry accounts for virtually all consumption of coal coke and steam coal, while electricity is the dominant energy resource in the aluminum industry. The aluminum sector accounts for close to 20 percent of industrial electricity consumption. Traditional industries with low levels of energy efficiency, such as ceramics manufacturers and food-processing units, consume mainly firewood. Natural gas could become a serious competitor of firewood in the ceramics industry, especially since use of natural gas results in higher-quality ceramics products. The cost differential, however, forces most companies to opt for firewood.

In the near future, gas could substitute for heavy fuel oil, naphtha, and gas oil. For example, in northern Rio de Janeiro, CEG-Rio is successfully displacing industrial use of fuel oil. In 2002, CEG began supplying more than 2 million m^3 per month of natural gas to companies that, in 2001, used fuel oil to drive their factories.

10. These ceramic companies consist mainly of brick and tile factories.

TABLE 3-4. RECENT TRENDS IN THE ENERGY MATRIX FOR BRAZILIAN INDUSTRY (percent total energy)

Energy type	1992	1997	2001
Charcoal	9.6	7.0	6.0
Coal coke	13.9	12.1	10.6
Electricity	21.2	20.0	18.6
Firewood	10.5	8.9	8.8
Fuel oil	16.2	16.4	10.6
Natural gas	3.5	5.1	7.5
Steam coal	2.1	3.8	4.8
Sugar cane bagasse	12.6	14.6	15.2

Source: Ministry of Mines and Energy (MME).

Environmental factors should continue to favor natural gas, despite its being more expensive than many heavier fuel oils; however, the greatest obstacle to increased industrial consumption is price. Roughly 50 percent of industrial production occurs in São Paulo, which currently depends on Bolivian natural-gas imports. As a result of high transport costs, Bolivian gas is roughly 40 percent more expensive than domestic gas. According to industry specialists, to compete effectively with substitute fuels in the ceramics, cement, pulp and paper, and steel industries, the price of imported gas should be 20 to 25 percent less. Brazilian energy officials have used this argument to renegotiate the gas purchase contract with the Bolivian government.

Gas Demand: Transport Sector

Over the past five years, Brazil's compressed natural gas (CNG) market has experienced tremendous growth, becoming the second largest CNG market in the world after Argentina. Gas consumption in the transport sector increased from 49 million m^3 in 1997 to about 1.3 billion m^3 in 2003.

At the end of 2002, CNG sales accounted for 13.1 percent of total natural gas sales by Brazilian distributors. Like much of Brazil's natural gas market, CNG use is concentrated in Rio de Janeiro and São Paulo (60 percent), with significant growth in the northeastern states of

Pernambuco and Bahía. Currently, the country has more than 600 CNG service stations, over half of which are in Rio de Janeiro and São Paulo.

Until several years ago, Brazil's CNG market was limited to a few pilot programs. Although state governments had promoted CNG for public bus transport in the early 1980s, the CNG market emerged only in 1992 (disregarding minimal consumption levels between 1988 and 1991), with creation of CNG service stations and passage of a federal law authorizing CNG consumption by taxis and bus fleets. After impressive growth in 1992, consumption stagnated in 1993 and declined in 1994 because of macroeconomic worries and doubts concerning guarantees for automobile conversion. In 1997, this situation reversed as the government allowed private vehicle owners to convert to CNG. The first year of CNG industry growth was 1998, when demand soared to 132 million m^3, an 85 million m^3 increase over the previous year.

Other positive factors were expansion of CNG service stations and marketing campaigns. During April 2002—May 2003, CNG distribution sales grew by more than 40 percent (from 2.5 million m^3 to 3.6 million m^3 per day). In 2002 the fleet of CNG vehicles reached 400,000, with 825 companies licensed to convert vehicles from gasoline or ethanol to dual-fuel, natural-gas engines. São Paulo has 286 such companies, while Rio de Janeiro has 181.

Rio de Janeiro, the traditional leader of Brazil's CNG market, today accounts for roughly 40 percent of the national market. São Paulo, however, is quickly gaining ground through Comgás, its largest distributor. In May 2002, of the 2.6 million m^3 per day of CNG sold nationwide, CEG and CEG-Rio were responsible for 46 percent of the total (1.2 million m^3), while Comgás and Gas Natural sold 19 percent (493,000 m^3 per day). By May 2003, CEG and CEG-Rio's percentage of Brazilian CNG sales dropped to 38 percent, while sales in São Paulo rose to more than 25 percent (900,000 m^3 per day).

Petrobrás estimates that investment in CNG supply and infrastructure could total US$1.2 billion between 2002 and 2005. Roughly US$900 million will be invested in services and equipment, while the remaining

US$300 million will be used to expand the network of fuel stations. Industry sources project that, by 2005, the number of CNG pumps could triple to more than 1,000 across the country, increasing total natural-gas demand by CNG vehicles to more than 3 billion m^3.

The CNG market continues to grow rapidly. Extrapolating from current growth rates, the fleet of vehicles should reach 1 million by 2005. At this pace, the CNG share of total natural-gas sales should rise from 12 percent in May 2003 to 15 to 20 percent within the next few years (table 3-5).

TABLE 3-5. CNG STATISTICS IN BRAZIL, 2003

Statistic	**Amount**
Vehicles converted (number)	543,744
CNG service stations (number)	578
States using CNG (number)	15
Cities using CNG (number)	78
Consumption per vehicle (daily)	12.5 m^3
Consumption per vehicle (monthly)	390 m^3
Average domestic price of CNG (US$ per m^3)	0.35
Average gasoline price (US$ per liter)	0.72
Average ethanol price (US$ per liter)	0.45

Source: Folha do GNV (Natural Gas Vehicles monthly bulletin).

Demand: Residential and Commercial Sectors

The incipient stage of the Brazilian natural-gas industry complicates the development of smaller demand segments, like residential and commercial sectors. Unlike CEG and Comgás, which have built relatively developed infrastructure and distribution networks,[11] newly-incorporated distribution companies face significant costs to construct and expand their distribution networks. Companies that rely on smaller demand segments alone cannot justify such large investments. Given the overall lack of access to financing, distributors must search for large, stable sources of demand, such as power plants and industrial consumers.

11. This infrastructure is the result of decades of investment in the coal gas distribution network. In the late 19th century, Rio de Janeiro and São Paulo created public lighting companies based on coal gas. CEG and Comgás used imported coal as raw material for producing manufactured gas.

In May 2003, residential consumption (e.g., household cooking and water heating) was 556,700 m^3 per day, while commercial demand (e.g., shopping malls, offices, and public buildings) was 372,200 m^3 per day. These numbers demonstrate little growth since May 2002, when the residential sector consumed 491,300 m^3 per day and the commercial sector demanded 350,900 m^3 per day.

In addition to the lack of need for space heating, the limited presence of natural gas in the residential sector is caused by the high costs of installing gas infrastructure in existing houses and apartments. Like the smaller industrial segments, small household demand provides distribution companies little motivation to invest. The potential for residential consumption is limited to markets located near commercial centers.

Although commercial consumption is less than residential consumption nationwide, the former offers enormous potential for the Brazilian natural-gas market. Natural gas could be used for air cooling and as a substitute for liquefied petroleum gas (LPG) used for boilers and water heating. The key to capturing the largest potential clients (e.g., shopping centers, hotels, and office buildings) is cogeneration with simultaneous production of cold. If cogeneration through electricity—the main competitor—does not prove viable, large consumers could install gas-based refrigeration centers and air conditioners.[12]

Brazil's main distribution companies have attempted developing a marketing policy for the commercial sector, but confront four major disadvantages. First, obtaining financing to invest in network expansion is difficult. Second, progress in the commercial sector lags for lack of public policies directed at natural-gas industry technology, infrastructure, and human resource development. Third, weak state and municipal environmental policies fail to promote use of cleaner fuels, including natural gas. Finally, current residential and commercial consumption are confined primarily to cooking and water heating.

12. The energy efficiency of these systems is significantly lower than that co-generation systems.

Natural Gas Imports

Brazil's first shipments of imported gas arrived from Bolivia on July 1, 1999, following completion of the Bolivia-Brazil pipeline. When operating at full capacity, the pipeline can carry 30 million m^3 per day (Almeida and Machado 2001, IEA 2003b). Owing to weak demand, only about 16 million m^3 per day flowed through the pipeline at the end of 2003.

In July 2000, Brazil also began importing gas from Argentina through the Paraná-Uruguaiana pipeline, supplying a 600-MW power plant in Rio Grande do Sul. The Paraná-Uruguaiana is the first portion of the Paraná-Uruguaiana-Porto Alegre pipeline, operated by TSB.[13] If completed, the Paraná-Porto Alegre pipeline will have a capacity of 12 million m^3 per day (ANP 2003).

A third major cross-border trade project is the Lateral Cuiabá pipeline, which links the Bolivia-Brazil pipeline in the Bolivian territory to Cuiabá, the capital of Mato Grosso. Since September 2001, Bolivian gas flowing through the Lateral Cuiabá pipeline has supplied a thermal power plant in Cuiaba.

In 2003, Brazil imported 5.9 billion m^3 of natural gas, at a cost of US$582 million. The vast majority (91 percent) came from Bolivia, with only 519,000 million m^3 from Argentina (down from 753,000 million m^3 in 2001) (table 3-6).

TABLE 3-6. EVOLUTION OF NATURAL GAS IMPORTS, 1998–2003
(millions of m^3)

Country of origin	**1999**	**2000**	**2001**	**2002**	**2003**
Argentina	0	106	753	492	519
Bolivia	400	2,105	3,855	4,777	5,427
Total	**400**	**2,211**	**4,608**	**5,269**	**5,946**
Import Cost (US$ millions)	19.46	184.00	364.79	424.89	582.74

Source: National Petroleum Agency (ANP).

13. TSB (*Transportadora Sul Brasileira de Gás*) is a consortium of Petrobrás and four other companies: Ipiranga (private Brazilian), Respol YPF (Spanish-Argentine), Tecgás NV-Technit (Argentine), and Nova Gas Internacional (Canadian).

Because of the lack of demand for gas from thermal plants and the relatively high price of Bolivian gas, Bolivian imports remain below levels established in the take-or-pay contract with YPFB (*Yacimientos Petrolíferos Fiscales de Bolivia*). In July 2003, Petrobrás imported about 13 million m^3 per day from Bolivia, while it paid for 18.45 million m^3 per day.[14] Currently, Petrobrás is accumulating losses in the contract. Even though distribution companies have signed take-or-pay contracts with Petrobrás, several companies located in southern Brazil—Sulgás (*Companhia de Gás do Rio Grande do Sul*), Compagás (*Companhia Paranense de Gás*), and SCGás (*Companhia de Gás de Santa Catarina*)—are not fulfilling these obligations. However, because Petrobrás has an equity position in these companies, it has no interest in imposing losses on them.

Other companies importing gas from Bolivia are BG, owner of Comgás (São Paulo); EPE (*Empresa Produtora de Energia*), a consortium of Enron, Shell and Transredes; and Sulgás, which is owned by Petrobrás and the state government of Rio Grande do Sul. BG supplies gas to its subsidiary, Comgás, the gas distributor for metropolitan São Paulo. EPE supplies gas through the Lateral-Cuiabá pipeline to a 480-MW power plant in Mato Grosso, and Sulgás fuels the 600-MW power station in Uruguaiana, Rio Grande do Sul. These companies' volume of imported gas has decreased significantly over the past year. Given the hydropower surplus of 2002 and 2003, thermal power plants supplied by Sulgás and EPE are dispatching little energy. BG had to choose between cutting imports or incurring losses in the contract with Petrobrás. Although only three companies currently import gas, the ANP has authorized several others to import a total of about 70 million m^3 per day.

Argentina's recent gas shortage has reduced Brazilian imports from this country (from an average volume of 2.4 million m^3 per day in January 2004 to only about 1 million m^3 per day in April 2004). The gas shortage, in turn, reduces prospects for increasing exports to Brazil, augmenting the investment risk of completing the Paraná-Porto Alegre pipeline. This pipeline would, in effect, complete the pipeline ring in the Southern Cone, linking all markets and reserves.

14. The take-or-pay provisions of the contract between Petrobrás correspond to 75 percent of contracted volume. Currently this volume is 24.6 million m^3 per day.

Import Transportation Prices

In explaining relatively limited Bolivian imports, distributors in southern Brazil argue that imports will not increase in significant quantities until either the YFPB cuts the price of Bolivian gas or Petrobrás reduces the transport fee. In the first half of 2003, the cost of Bolivian gas was US$3.37 per million British thermal units (Btu). Since Bolivian gas is about US$1.7 per million Btu, the difference results from transportation costs associated with the pipeline.

Currently, Bolivian gas supply is 20 percent more expensive than domestic gas. However, the transport service prices largely account for this difference. In fact, the commodity price for domestic gas is higher than the price of the Bolivian commodity. The transport price is, at most, US$0.35 in Brazil, compared to the transport service cost of about US$1.65.

The Brazilian government has held ongoing negotiations with representatives of the YFPB, the Bolivian gas producer, to ask for a reduction in the price of Bolivian gas. Industry leaders, however, emphasize that the price of Bolivian gas is lower than that of Brazilian gas, claiming instead that what is needed is a reduction in transport charges by the Petrobrás subsidiary that operates the Brazil-Bolivia pipeline.[15] Nonetheless, YFPB appears willing to reduce the price of Bolivian gas by 20 to 30 percent if Petrobrás finds ways to import greater quantities than the current 11 million m^3 per day.

Argentine gas, distributors claim, can be as much as 40 percent cheaper than the Bolivian commodity (US$1.2 per million Btu). In addition, because of its proximity to Brazil's southern states, the transport costs of Argentine gas will be cheaper than Bolivian imports. A major demand of southern distribution companies—Compagás, Sulgás, and SCGás—is continued construction of the TSB-operated Uruguaiana-Porto Alegre

15. TBG (*Transportadora Brasileira Gasoduto Bolívia-Brasil*) is a consortium of the Petrobrás subsidiary, Gaspetro (51 percent), and international investors, including British Gas (10 percent), El Paso (10 percent), TotalFinaElf (10 percent), Enron (7 percent), and Shell (7 percent).

pipeline, which was put on hold in late 2002 because of uncertain demand conditions.

Natural Gas versus Fuel Prices

Bolivian gas prices to end-users (commodity plus transport price) have been, on average, more expensive than domestic fuel prices.[16] In response, many industries in São Paulo (ceramics, glass, and paper) have little incentive to switch from natural gas, to fuel oil. Table 3-7 compares prices for natural gas and fuel oil (type 1A).

TABLE 3-7. NATURAL GAS VERSUS SUBSTITUTE FUEL PRICES IN THE CITY OF SÃO PAULO
(US$ per million Btu)

Fuel	Price
Fuel oil (type 1A)	5.49
Industrial natural gas (m^3 per month)	
300,000-500,000	6.30
500,000-1,000,000	5.95
above 1,000,000	5.57
Kitchen gas (LPG)[1]	15.89
Residential gas[2]	22.11

[1] Bottled butane, commonly used for household cooking.
[2] 0-17.53 m^3 per month.
Sources: National Petroleum Agency (ANP) and Regulatory Agency of the State of São Paulo (CSPE).

For small consumers, fuel oil is nearly 15 percent cheaper than natural gas. Heavier fuel oils consumed by São Paulo industry are also much cheaper than the average natural gas price. While the average price for industrial consumers (US$5.94 per million Btu) is 8 percent more expensive than fuel oil (type 1A), it is roughly 17 percent more expensive than type 3A, 33 percent more expensive than type 6A, 40 percent more expensive than type 7A, and 55 percent more expensive than type 8A.

16. Since early 2003, the Brazilian currency has appreciated significantly. Nevertheless, Petrobrás has kept domestic gas prices constant and, as a result, the gap between domestic and imported gas prices has decreased.

By comparing the gas price to end-users with prices at the city-gate, one realizes that a major factor contributing to lack of competitiveness is the margin that distribution companies take. In the case of São Paulo, the margin to the industrial sector varies from 100 to 115 percent. For the residential sector, gas prices at the city-gate are multiplied by a factor of 6. Therefore, the current debate over high prices at the city-gate is misleading, considering the other problems that result in high end-user prices.

Expected Evolution of Demand and Imports

Petrobrás has positioned itself in the Southern Cone gas industry in accordance with the Brazilian government's natural gas policy, whose main aim (developed in the mid-to-late 1990s) was to increase the gas share in Brazil's energy mix from 3 to 12 percent of primary energy demand by 2010. To reach this goal, gas demand would have to reach about 70 million m^3 per day in 2005 and 120 million m^3 per day in 2010. This ambitious forecast failed to materialize because of a lack of demand in the power-generation sector and the higher price of imported gas. Petrobrás' new Strategic Plan for 2003–07 predicts increased demand from 25 million m^3 per day in 2003 to 48.8 million m^3 per day in 2007. Industrial and power sectors are expected to represent about 49 percent and 35 percent, respectively, of final demand.

Petrobrás' revised assumptions leave little room for increasing gas imports, as domestic production is projected to increase about 40 percent over the period. If one assumes a 40 percent increase in domestic production and a significant reduction in gas flaring, as planned by Petrobrás, domestic gas sales should reach 25 million m^3 per day in 2007. Therefore, imported gas should reach about 23 million m^3 per day in 2007. This scenario implies significant idle capacity in the Bolivia-Brazil pipeline in 2007.

Petrobrás' projection for future demand may prove pessimistic if certain obstacles to gas-market development are removed. Key obstacles are 1) low level of investment in the gas chain, particularly the distribution segment; 2) current levels of Bolivian gas prices at the city-gate; and 3) regulatory barriers to the coexistence of hydro- and thermal-generation power plants.

Industry Structure

Transmission Networks

Compared to more developed natural gas markets, Brazil's transmission network is small. Currently, the country has nearly 7,800 kilometers (km) of gas pipelines, half of which were added since 1999. Argentina, a much smaller country, has 12,500 km of transmission infrastructure, while the United States has 450,000 km.

Brazil has four domestic pipeline systems: Coari-Urucú (in northern Brazil), Salvador-Pecém (in northeastern Brazil), Southeast-South network (from the Campos Basin to the states of Minas Gerais, Rio de Janeiro, and São Paulo), and Espírito Santo network (from the Santos Basin, off the coast of São Paulo, to the cities of Campinas and São Paulo). Transpetro, a wholly-owned subsidiary of Petrobrás, operates and controls Brazil's domestic pipelines.[17]

Brazil also has three international gas pipelines. The TBG-operated Bolivia-Brazil pipeline transports gas from the Bolivian municipality of Rio Grande to the Brazilian states of Mato Grosso do Sul, Paraná, Rio Grande do Sul, Santa Catarina, and São Paulo. This pipeline, by far Brazil's largest, extends 2,593 km within Brazilian territory alone, with a capacity of 30 million m^3 per day. The Bolivia-Cuiabá pipeline (Lateral-Cuiabá) transports gas from Rio San Miguel in Bolivia to Cuiabá in Mato Grosso. Owned and operated by Enron and Shell (a Bolivian pension fund also has a stake), the pipeline has a capacity of 2.8 million m^3 per day and feeds a power plant in Cuiabá. The third cross-border pipeline, owned by TSB, carries imported gas from Argentina to a 600-MW power plant in the municipality of Uruguaiana in Rio Grande do Sul. The TSB project, however, envisions a second leg of the pipeline from Uruguaiana to Porto Alegre, the capital of Rio Grande do Sul. If completed, the TSB pipeline will have total capacity of 12 million m^3 per day.

17. Transpetro assets remain Petrobrás holdings.

Currently, Petrobrás' most important gas infrastructure plan is the Malhas Project (*Projeto Malhas*), which aims to double the size of Brazilian natural-gas marketing by expanding the transmission system in the Northeast and Southeast, the country's two major consumption centers.

In early June 2003, Petrobrás signed contracts amounting to US$1.2 billion in loans for the pipeline expansion project. Brazil's Bank for Economic and Social Development (BNDES) and the Japan Bank for International Cooperation (JBIC) have approved major financing programs for the project, offering US$275 million and $394 million, respectively. Petrobrás will also receive $250 million in loans from a pool of international investors. Although the Japanese banks will hold part of the assets, all extra project capacity will be transferred to Transpetro, which will operate the pipeline.

According to Petrobrás, the project will expand pipeline capacity in the Northeast by 9 million m^3 per day within the next two years, bringing total regional capacity to 14 million m^3 per day by 2012. Capacity in the Southeast will increase by 13 million m^3 per day within the next two years. Petrobrás will contract all additional capacity, reinforcing its market power in the gas supply segment.[18]

In addition to expanding existing pipelines, the Malhas Project includes the construction of eight new ones, including loops and compressor stations (table 3-8).

Petrobrás and its partners are considering several other pipeline projects, whose completion depends on financing, market development (especially in the power sector), and related factors. The most critical pipeline project will link the southeastern and northeastern networks. The pipeline will extend some 1,200 km, making it possible to supply the growing northeastern market. Petrobrás estimates that the project will cost US$800 million. The main objective is to create southeastern markets for Bolivian gas, piping part of domestic production from

18. The ANP has strongly opposed elements of the Malhas Project, arguing that they hurt the potential for competition in the gas industry. However, the Agency was forced to accept the project format, given that the government officially supports it. The oil and gas law, furthermore, does not give the ANP power to introduce changes in the industry structure.

the Santos and Campos basins to Brazil's northeastern region. Given the contracts already signed for importing Bolivian gas and current demand difficulties, southern Brazil lacks sufficient demand for all domestic gas.[19] (The recent discovery in the Santos Basin increased Petrobrás' interest in this project.) Petrobrás is also considering extending the northeastern transmission network to the state of Piauí, a project that would require 600 km of new pipeline at a cost of about US$500 million.

TABLE 3-8. NEW PIPELINE PROJECTS OF PETROBRÁS

Region	Pipeline	Length (km)
Northeast	Termoaçu (ramal)*	58
	Guamaré-Pecém (doubling of size)*	362
	Candeias-Camaçari (loop)*	49
	Atalaia Pilar (loop)*	260
	Atalaia-Catu (re-compression)*	230
	Ceara-Piaui	600
Southeast	Campinas-Japeri*	503
	Rio-Belo Horizonte (re-compression)*	357
	Cacimbas-Vitoria*	93
	Campinas-Betim	600
North	Urucu-Porto Velho	522
	Coari Manaus	417
Inter-regional	Rio-Bahía	1,200
Total		**5,251**

* Included in the Malhas Project.
Source: Petrobrás.

Petrobrás has already decided to build two pipelines to monetize gas reserves from the Urucu fields in the Amazon. One pipeline will link the city of Coari to Manaus, the largest city in the state of Amazonas. This pipeline will supply gas for a new thermal power plant that will replace current diesel-generation capacity, at a cost of US$400 million. In addition to power generation, Manaus has a significant industrial market. Another pipeline will link the Urucu reserves to the city of Porto Velho, the capital of Rondônia state. This 14-inch diameter pipeline will be 550

19. This project was recently included in Petrobrás' strategic planning for the gas sector; the gas discovery in the Santos Basin was the main incentive for this decision.

km in length, with a capacity of 2.4 million m^3 per day. Total project cost is US$250 million, and construction will take 24 months. This pipeline will also supply gas to thermal power plants, replacing expensive diesel power generation. The US company, El Paso, will have a 25 percent stake in the project and will invest in a gas-based power plant.

With regard to cross-border gas trade, the most vital transmission project is completion of the Uruguaiana Porto-Alegre pipeline. Today, only 50 of the 615 km planned have been built. The second phase, 565 km in extension, was to have begun during the first half of 2004, with a projected completion date of mid-to-late 2005. However, completion dates may be postponed because of a regional lack of gas demand. This segment of the pipeline will link the municipality of Canoas to the petrochemical complex in Triunfo. The Uruguaiana-Porto Alegre pipeline will be connected to the portion of the Bolivia-Brazil pipeline in Porto Alegre, supplying Argentine gas to the states of Paraná, Santa Catarina, and São Paulo, as well as Rio Grande do Sul. Once completed, the TSB pipeline will be well-received by Brazil's southern states, which have demanded access to Argentine gas since the late 1990s. Argentine gas is roughly 40 percent cheaper than Bolivian gas, mainly because of Argentina's geographical proximity to consumers in southern Brazil. Given insufficient demand, Argentine gas would displace Bolivian gas, jeopardizing the economics of the southern portion of the Bolivia-Brazil pipeline. Nevertheless, the Brazilian government and Petrobrás have already announced this project as a priority.

In short, enormous investments in the Brazilian gas transmission network will be needed to develop market potential. Currently, Petrobrás is the lead company for these projects, given its market power upstream and in distribution. The transmission projects being evaluated and implemented together total about US$4 billion in investment. If these projects go forward, a large volume of resources will need to be leveraged, especially from international financing institutions.

Distribution Network

Brazil currently has 18 distribution companies operating in 15 of the country's 27 states. Although the country has 24 distribution companies, 6 are not yet operative. Distribution infrastructure is heavily concentrated in Rio de Janeiro and São Paulo, the two states with largest consumption and where more than 70 percent of the country's distribution pipeline infrastructure is located. The five distribution companies in these two states are privately owned; with Enron, Shell, and Spain's Gas Natural among the major stockholders.

The country's 19 remaining companies have mixed ownership; in many cases, the state government owns 51 percent of shares (table 3-9). Petrobrás and private companies follow, each owning about 24.5 percent. Private companies with a stake in gas distribution include the UK's BG; Shell; Gaspart (*Gas Participações Ltda.*), the Enron subsidiary; Spain's Gas Natural SDG and Iberdrola; Italy's Italgas and Snam; Argentina's Pluspetrol; and several Brazilian consortia.

Brazil's underdeveloped distribution network currently has about 8,400 km of distribution pipeline. São Paulo's Comgás and Rio de Janeiro's CEG are the only companies with large distribution networks. Moreover, they are the country's only gas distributors with a significant number of clients in the residential and commercial sectors. All other distribution companies focus on large-volume markets (power plants and heavy industry). São Paulo is by far the largest natural gas consumer, followed by Rio de Janeiro and Bahía. Comgás, gas distributor for metropolitan São Paulo, sells 9 million m^3 per day to 385,433 clients—more than the total sales of CEG and CEG-Rio combined (less than 7.5 million m^3 per day).

With the exception of CEG—serving greater metropolitan Rio de Janeiro—the discrepancy between the number of municipalities served and the number in the concession area is enormous for all distributors. For example, Comgás, Brazil's largest distributor, serves less than 25 percent of the municipalities within its concession area. Bahiagás, Brazil's fourth largest distributor, supplies gas to only 6 of the 417 cities it is legally eligible to supply. Gasmig (*Companhia de Gás de Minas*

Gerais) serves only 10 of the 853 municipalities under its concession. Furthermore, the company has no residential clients. Given the population of its concession area, Gasmig could potentially supply about 3.5 million households.

Distribution Network Expansion

One major obstacle to expanding Brazil's natural gas market is the relatively low level of investment in the distribution network. One barrier to such investment is the privatization model created by Rio de Janeiro and São Paulo states. Although the concession contracts for CEG and Comgás, signed in 1997 and 1999, respectively, stipulated a minimal expansion obligation, state governments evaluated bidders for the distribution concession (and even greenfield concession areas) according to price; that is, rather than evaluate bidders according to a wide range of criteria, including investment proposals and quality of investment projects, state officials in charge of privatization simply handed off the concession to the highest bidder. In doing so, Rio de Janeiro and São Paulo traded off greater investment in the network for a lump-sum tax.

Another barrier to distribution-sector investment is the ownership structure of not-yet-privatized distribution companies. The states generally lack the financial resources to make the needed investments in such companies. In addition, the companies have difficulty obtaining financing in the domestic market. The BNDES has not financed state-owned companies for some time; thus, state-owned distribution companies have had weak investment capacity over the past five years. Currently, BNDES is not prohibited from financing state-owned companies; however, the credit volume is restricted because of the policy of public deficit control. Investments made by state-owned companies are considered public-sector expenses; thus, such investments add to the public deficit.

In addition to restrictions on financing state-owned companies, distribution companies face difficulties in providing guarantees required by public or private financial institutions. Most distribution companies

have a poor cash flow due to their incipient phase of development. In addition, state governments, the main stockholders in the distribution companies, have no capacity to invest. Therefore, distribution companies often are unable to provide equity to new investments, which explains why Brazilian distribution companies have a low level of obligations. Most distribution companies have a low debt-to-assets ratio (30 percent, on average), and six of the operating companies have no financial obligations.

Distribution companies' investment plans show that investments are not in line with potential market growth. In 2004, distribution companies planned to invest only about US$270 million (their 2005 figure is the same). Comgás, CEG, and CEG-Rio have the most significant investment programs. Gas Natural SDG (owner of CEG and CEG-Rio) plans to invest about US$270 million by 2007, primarily in conversion from manufactured to natural gas and expansion of the client base. Comgás plans to invest US$170 million during 2003–05. The investment programs of most other distribution companies are limited to their potential markets. Such companies as Compagás, Copergás, Sulgás, and Bahiagás plan to invest less than US$10 million annually over the next 3 to 5 years.

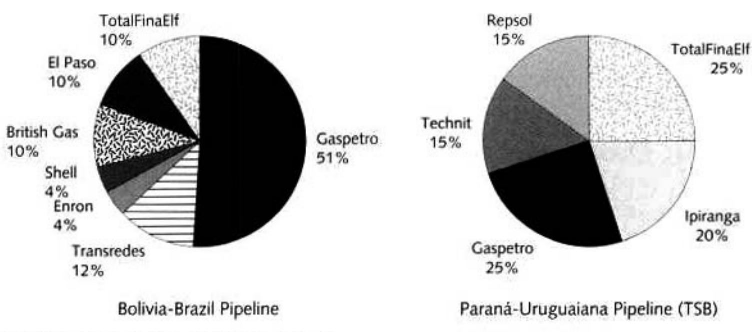
Petrobrás Dominance

Petrobrás, the state energy company, is unquestionably the central player in Brazil's natural gas industry. Virtually a monopolist in domestic gas production and supply, the company controls a substantial portion of the country's gas transmission and distribution network. Petrobrás owns most of Brazil's 230 billion m^3 of proven gas reserves, although Shell and Repsol-YPF have limited associated gas reserves. Currently, Petrobrás is responsible for nearly all of the country's gas production. Maritima (an independent Brazilian company located in the mature onshore gas fields of Bahía) produces small amounts of gas supply (less than 2,000 m^3 per day). Shell will soon become a player in the Brazilian upstream, producing about 1 million m^3 per day of associated gas.

Petrobrás also dominates gas commercialization. By virtue of its control over domestic production, the company dominates commercialization of its own gas production through Gaspetro, its wholly-owned subsidiary. Petrobrás Gas S.A., created in 1998, is responsible for natural gas commercialization. Petrobrás is also the main shipper in the Bolivia-Brazil pipeline, holding the bulk of gas import contracts. Therefore, each of Brazil's 18 distribution companies in operation has take-or-pay contracts with Petrobrás, either for domestic gas or gas imported from Bolivia or Argentina.

Petrobrás dominance also extends to transmission. Through its Transpetro subsidiary and participation in the TBG (operator of the Bolivia-Brazil pipeline), Petrobrás controls 93 percent of the country's transmission network. In addition, it has a 25 percent stake in the international Paraná-Uruguaiana (TSB) pipeline. Figure 3-3 shows the ownership structure of Brazil's two main international pipelines.

FIGURE 3-3. OWNERSHIP STRUCTURE OF INTERNATIONAL PIPELINES



Source: National Petroleum Agency (ANP) (2002b).

Although Petrobrás controls nearly all of Brazil's gas transmission capacity, its dominance is not as strong if one considers pipeline capacity and company share in the capital of the transmission segment. By this type of measure, Petrobrás controls 52 percent of transport capacity, followed by BG (12%), Enron (8%), and TotalFinaElf (8%).

Petrobrás will coordinate virtually all of the Malhas Project, Brazil's next major pipeline expansion project. Although Japanese investors control

NTN and NTS, the two companies charged with heading the Malhas Project, Petrobrás will likely retain operational control of the pipelines because the project builds on the existing gas pipeline network, all of which Petrobrás owns.

Brazil's other major expansion project, still in the early stage of discussion, is the Northeast-Southeast pipeline. It will connect the country's largest production and consumption region (Southeast) with its second largest gas-consumption region (Northeast). Although international investors will participate in discussions, Petrobrás will dominate.

Finally, Petrobrás dominates Brazil's gas distribution (table 3-9, p. 101). The company is a major shareholder in 18 of Brazil's 24 distribution companies. Of the 18 distributors in operation, only 5—CEG (Rio de Janeiro), Comgás, and Gas Brasiliano (São Paulo), Gasmig (Minas Gerais), and Gas Natural SPG—are independent of Petrobrás. Currently, the company is negotiating the purchase of 25 percent of Gasmig. Therefore, the only gas markets Petrobrás will not control are São Paulo and metropolitan Rio de Janeiro.

Of Brazil's 18 operating gas-distribution companies, only two—BG (owner of Comgás in São Paulo) and Sulgás (Rio Grande do Sul distributor)—import gas directly through affiliated companies. Only small amounts of the companies' gas imports, however, are being commercialized (BG imports gas from Bolivia, while Sulgás purchases gas from Argentina). BG is authorized by the ANP to import 3 million m^3 per day of Bolivian gas; currently, however, it imports less than 1 million m^3 per day. With regard to Sulgás, BR Distribuidora, another wholly-owned subsidiary of Petrobrás, owns 49 percent of the distribution company, while the state government of Rio Grande do Sul owns the other 51 percent.

Thus, despite private companies' legal right to commercialize natural gas, Petrobrás plays a major role in all gas sales to distribution companies. Clearly, Brazil's current industry structure poses obstacles for gas competition. It is difficult to implement cross-border gas trade projects without Petrobrás leadership. The company's market power is sufficiently

strong to virtually bar rival projects. As the following section shows, Brazil's regulatory framework fails to tackle obstacles related to industry structure.

Regulatory Framework

Before the 1980s, Brazil's energy authorities focused little on the NGI—part of the Petrobrás monopoly in the hydrocarbons sector. Traditionally, Petrobrás underestimated the role gas plays in the Brazilian energy sector; the company's priority was to increase Brazil's security of liquid-fuels supply. It viewed natural gas as competing with the company's fuel-oil production and for scarce financial resources available for oil-sector investment. Before 1988, the NGI regulatory framework was not well established, particularly with regard to division of responsibilities in the downstream sector. Petrobrás supplied gas directly to large industrial users, thereby reducing incentives to develop distribution companies to invest in the pipeline network.

Brazil's Federal Constitution of 1988, the foundation of the country's current regulatory framework, clearly distributes regulatory responsibility among federal, state, and municipal governments. According to the Constitution, the federal government is in charge of regulating the upstream and midstream of the gas industry, while states are responsible for regulating the distribution segment. The Constitution also allows state governments to give concessions for public or private companies to explore gas distribution concessions.[20]

The current regulatory framework establishes clear boundaries and responsibilities between NGI planning and regulatory activities. The MME and the National Energy Policy Council (CNPE) are in charge of planning. The ANP and state regulatory agencies are responsible for regulating the industry (ANP 2002a).

20. Although the separation of federal and state responsibilities is a step forward, certain regulatory points remain unclear. The Federal Constitution establishes that the states, through concessions, provide local gas-supply services. The complementary Law 9478 of 1997 does not establish a clear concept of statewide gas supply. Therefore, some argue that these services do not include high-pressure pipelines. This interpretation of the law advocates not requiring high-volume gas consumers to purchase from the distribution company since they can obtain gas directly from the transmission pipeline. To date, regulators and energy authorities have not accepted this interpretation.

TABLE 3-9. OWNERSHIP STRUCTURE OF BRAZIL'S GAS DISTRIBUTION COMPANIES
(percent)

Company, by region	Petrobrás	State	Others
Northeast			
Algas	41.5	17	Gaspart, 41.5
Bahiagás	25.0	51	Gaspart, 25.0
Cegás	25.0	51	Textilia, 25.0
Copergás	41.5	17	Enron, 41.5
Emsergás	41.5	17	Gaspart, 41.5
Gasmar	23.5	25.5	Termogás, 51
Gaspisa	37.3	25.5	Termogás, 37.25
PB Gás	41.5	17	Gaspart, 41.5
Potigás	41.5	17	EIT, 20.75; Gaspart, 20.75
Southeast			
CEG	0	0	Gas Natural, 53; BNDES-Par, 35; others, 12
CEG-Rio	25	0	Gas Natural, 38.0; Enron, 34; BR, 25; Pluspetrol, 3.0
Comgás	0	0.06	BG, 62.69; Shell, 15.56; others, 21.75
Gas Brasiliano	0	0	Snam, 51; Italgas, 49
Gasmig	0	0.4	Cemig, 95.2; MG Part., 4.45
Gas Natural São Paulo Sul, S.A.	0	0	Gas Natural, 100
Petrobrás (Espírito Santo)	100	0	0
South			
Compagás	24.5	0	Dutopar, 24.5; Copel, 51
SCGás	41	18	Gaspart, 41
Sulgás	49	51	0
West-central			
Cebgás	32		Brasília Gas Group, 51.0; CEB, 17.0
Goiasgás	28.2	17.0	Consorcio Gasgoiano, 47.0; others, 12.8
MSgás	49	51.0	0
North			
Cigás	0	100	0
Rongás	24.5	51	Termogás, 24.5

Source: Petrobrás and company web sites.

Federal Regulations

A 1995 constitutional amendment broke Petrobrás' monopoly in the upstream sector of the oil and gas industry. That same year, Law 8987 was approved, subjecting all public services to competitive bidding; thus, competition for investing in the public-services industries was introduced.

During 1996–97, two independent regulatory bodies were created. In 1996, Law 9427 created the National Electric Power Agency (ANEEL), the electricity-sector regulator. The following year, Law 9478 created the ANP, the regulator for the oil and gas industry.[21] This law also created the CNPE, which was responsible for determining the main focus of national energy policy.[22]

Law 9478 gave the ANP a range of NGI duties: organizing the bidding process for new exploratory blocks and signing corresponding concessions contracts, preparing and signing production concessions contracts, controlling the quality of traded gas, authorizing gas imports, authorizing construction of new transmission pipelines and gas-processing plants, authorizing distribution of CNG and LNG, establishing policies for transport services tariffs, and setting rules for promoting competition.[23] Despite such large regulatory power, Brazil lacks a set of coherent regulations to promote competition. Moreover, certain regulatory practices give market power to dominant firms and prevent new entrants.

Regulation of Distribution Segment

State-level agencies regulate natural gas distribution, along with other public services (e.g., water, sewage, and public transportation). Currently, 16 Brazilian states have regulatory agencies. For the other 11

21. These new regulatory agencies have dual responsibilities: organizing auctions to assign concessions to public and private utilities and regulating the market, establishing technical and economic rules for concessionaires.
22. It should be noted that Law 9478 regulates oil and gas. Several gas specialists argue that this law aimed to deal with problems in Brazil's oil industry, treating natural gas as a secondary fuel or oil byproduct. For this reason, the law ignored several key gas-industry issues.
23. Brazil's regulatory framework distinguishes between concessions and authorizations; concessions must be preceded by an open bidding process, which authorizations do not require.

states, the respective states' secretaries of energy are in charge of signing concession contracts with distribution companies.

The Federal Constitution of 1988 provided the juridical foundation for states to offer distribution companies concession contracts. In the early 1990s, most states adopted the same distribution-sector model, offering similar concession contracts and ownership structures. State governments generally held 51 percent of shares, while Petrobrás and private companies acquired 25 percent and 24 percent, respectively. As table 3-9 illustrates, most distribution companies remain under public control. State governments indirectly control certain distribution companies. For example, the state-owned power companies Cemig and Copel control Gasmig (Minas Gerais) and Compagás (Paraná), respectively. Petrobrás wholly controls the Espírito Santo distribution company.

Most state-owned companies have the same concession contracts. Signed before passage of Law 9478, these contracts are an obstacle to introducing a market-oriented regulatory framework in the distribution segment. The contracts were signed directly by state governments, which hindered the creation of independent, state-level regulatory agencies for the gas sector since the agencies' role was not stipulated.

In addition, these contracts grant territorial monopolies for the entire, 50-year concession period; thus, there are no provisions for introducing long-term, open access to the grid. A traditional, cost-of-service tariff scheme was adopted. Therefore, the gas costs are automatically passed on to final prices, and tariff adjustments are made annually or when needed to guarantee companies' financial equilibrium. The contract guarantees a 20-percent yield on companies' own capital. Companies are not obligated concerning minimal investment rates; they only have to consider projects with 20-percent rates of return.

Five other distribution companies in the states of Rio de Janeiro (CEG and CEG-Rio) and São Paulo (Comgás, Gas Brasiliano, and Gás Natural Sul) have been privatized. These privatized companies follow a different

regulatory framework since their concession contracts were signed after passage of Law 9478. The main characteristics of their concession contracts are: 1) market exclusivity is guaranteed for only part of the concession period (10-12 years), after which time, third parties can supply large consumers; 2) the final gas tariff is fixed by the price-cap system to induce efficiency; 3) the tariff is revised every five years and realigned annually, according to the wholesale price index; and 4) the concession period is limited to 30 years.

São Paulo's distribution company contracts contain provisions that establish a minimum level of investment for the first 10 years. Moreover, distribution companies must expand the network when economically feasible. When the project is not economical, end-users have the right to participate financially in order to make it viable.

Competition

Law 9478 eliminated all institutional barriers to entry in the upstream and midstream segments of the industry. Gas imports and new pipeline construction depend solely on ANP authorization. Similarly, all companies can participate in annual public bidding for the concession of exploratory areas. Competition is allowed in gas production, importation, and bulk trade. However, suppliers must sell their gas to the distribution companies operating in the country because all final consumers, including power plants, are captive to the distribution companies.

The ANP has attempted to stimulate competition by conceding new exploration areas for private companies and authorizing construction of new pipelines. Authorization of contracts for gas imports from Argentina and Bolivia also attempts to stimulate midstream competition. However, as current production remains concentrated in the hands of Petrobrás, the scope for competition is limited.

Law 9478 clearly states that the ANP is in charge of promoting competition in the gas sector through implementing third party access (TPA) to the transmission pipelines; however, it does not include

distribution pipelines. The ANP has attempted to establish rules for open access to transmission pipelines[24] (Almeida and Alveal 2001).

Open-access Regulation

Law 9478 establishes that access to transmission pipelines lines should be based on negotiations between the companies involved. In 1998, the ANP approved Act 169, establishing criteria for and forms of access to pipelines, preserving the principle of negotiation between companies to fix tariffs and conditions of access. Act 169 requires the pipeline transporter to announce annually the available capacity for commercialization, which should be traded on a nondiscriminatory basis. The Act also required transporters to offer the capacity contracted, but not used, as nonfirm transport service; it prohibited capacity resale by shippers, blocking development of a secondary capacity market (Almeida 2000a and b).

Shippers interested in acquiring TPA contracts must agree with the transporter on the terms of the contract. Negotiated open access has presented an obstacle to developing TPA contracts, primarily because Petrobrás has contracted virtually all transmission capacity for domestic pipelines. Moreover, the company has used its control of transmission and distribution companies to defend its contracts (particularly the contract to import natural gas from Bolivia). Because of the difficult negotiating environment, few companies have managed to obtain TPA contracts; when negotiations have stalled, the ANP has been called to resolve these conflicts.

Until now, only two companies have tried to acquire TPA contracts in Brazil: Enersil, a subsidiary of Enron, and BG. These companies have not succeeded in negotiating the terms of these contracts with TBG, operator of the Bolivia-Brazil pipeline. The ANP resolved the conflict, setting favorable conditions for the TPA. As a result of ANP intervention, Enersil and BG obtained TPA contracts to import Bolivian gas to distribution subsidiaries in São Paulo.

24. Several international companies are trying to commercialize their Bolivian gas in the Brazilian market. For this type of operation, open access to the Bolivia-Brazil pipeline is a necessary condition since Petrobrás has preferential access to this pipeline. Petrobrás bought transport services from TBG with long-term contracts to give guaranties for project financing.

Given the low level of interest in TPA contracts, the ANP attempted to revise open-access regulation (Act 196/98). A new act was submitted to public consultation in 2001, defining new conditions for open access, including rules for selling new capacity after pipeline expansion or construction. Although the changes created much interest during the public consultation process, the electricity-sector crisis forced the ANP to abandon the process. Thus, the ANP suspended Act 169/98, and no new legislation was put in place to regulate open access.

In 2001, the ANP approved an act regulating the process for selling new capacity created after pipeline expansion. This act required transmission companies to organize open-season rounds to sell new capacity on a nondiscriminatory basis. Given the projected growth in gas demand (because of the rush toward thermal generation projects), TBG launched an open-season bid to expand pipeline capacity. Twelve companies submitted proposals for contracting firm transport capacity, totaling 21 million m^3 per day. This bidding process would not only permit increased imports of Bolivian gas; it would also increase the level of wholesale-market competition since the number of gas suppliers would increase dramatically. However, uncertainties regarding the gas market for power generation postponed the bidding process.

In 2002, the ANP decided to regulate open access through a set of five acts submitted to public consultation. These acts concerned issues of open-access conditions, procedures for capacity resale, procedures for ANP conflict arbitration, information that transporters must provide the ANP, and criteria for tariff calculation. As of December 2003, only two acts had been approved (procedures for ANP conflict arbitration and information that transporters must provide the ANP).

The acts submitted to public consultation proposed four major changes in the regulatory framework:

– New pipelines (up to four years old), as well as those serving emerging markets,[25] would not be eligible for open access. Pipelines serving the

25. A market is considered emerging if its first long-term gas supply contract is less then eight years old.

productive southern markets (Paraná, Rio Grande do Sul, and Santa Catarina), as well as Mato Grosso, Mato Grosso do Sul, and western and southern São Paulo, would be ineligible for open access in the transmission network before 2007–10 (depending on the state). Immediate open access would be permitted only in Minas Gerais, Rio de Janeiro, part of São Paulo, and northeastern Brazil.

– Pipeline companies would offer, through open-season rounds, all available capacity. Public-bidding rules would be transparent and nondiscriminatory. Furthermore, the ANP would have to be notified of these rules and verify their accordance with the act.

– All firm transport contracts could be reallocated to third parties, either temporarily or permanently. Reallocation of capacity for periods longer than two years would be transparent and nondiscriminatory, through open-season processes.

– Rules would be introduced for establishing tariffs for gas transport services.

The ANP did not approve the proposed acts at the end of the public-consultation period. In 2004, the Ministry of Mines and Energy (MME) decided to revise the overall regulatory framework of the gas sector through a specific gas-sector law; considering the immanent change, the ANP and MME decided to incorporate the proposed acts into this new law.

Price Discrimination: Domestic versus Imported Gas

Import prices are freely established in bilateral negotiations between commodity suppliers and purchasers (e.g., Bolivia and Petrobrás); however, the government fixed the maximum price of domestic gas produced by Petrobrás until January 2002, which made the commodity price of Brazilian gas more expensive than that of Bolivia; however, the transport prices to bring Bolivian gas to consumer markets were higher than those to bring domestic gas to consumers markets. As a result, domestic gas was cheaper than imported Bolivian gas. The price difference between domestic and imported gas has led to disputes between local distribution companies over the right to buy domestic gas (e.g., companies in

southeastern Brazil that have access to both domestic and imported gas). Gas-based power generation companies have also pressed the government for access to domestic gas to run new thermal power plants (Santos 2002).

Although Act 003 established that state regulators should implement cross subsidies in the final gas price, in practice, price discrimination and cross subsides are set without state regulatory authorization because gas suppliers negotiate special prices with distributors for specific markets. For example, until 2003, Petrobrás offered CNG a discount on gas transport; the company has a similar, though controversial, policy for thermal generation.[26] During the electricity sector crisis, the government, under the PPT, induced Petrobrás to offer reduced natural gas prices (US$2.5 per million Btu) for qualified projects.

Transport Prices

According to Law 9478, shippers and transporters should fix transport tariffs through direct negotiation. However, the ANP is responsible for arbitrating conflicts between shippers and transporters, approving such tariffs, and verifying their accordance with the market.

Brazil uses two tariff systems: postal structure and proportional to distance. Transport through the Bolivia-Brazil pipeline uses the postal structure (the tariff is not proportional to distance). On the other hand, Act 003 of 2000 determined that the ANP should take distance into account for domestic pipelines. As a result, the ANP approved Act 108, which adjusted the tariff policy practiced in pipelines operated by Transpetro in 2000. Since then, the ANP has determined the maximum price of transport tariffs in the Transpetro pipeline system.

The pricing policy that the ANP adopted separates pipeline costs into two components: fixed and variable (the volume transported). Fixed costs are divided into injection, transport, and withdrawal costs (the latter vary by distance between gas zones). Because each state is defined as a gas zone, city-

26. Many argue that this commercial procedure creates market barriers for new gas suppliers, who cannot always supply specific markets with cheaper prices.

gates of the same state are considered equidistant from the gas origination point. Thus, the gas transport tariff is the same throughout each state, regardless of the transport distance. (According to Act 108/2000, distance will progressively carry more weight in calculating tariffs. The tariffs will start with a weight of 30 percent; currently, distance accounts for 60 percent of transport cost. This policy applies only to firm transport contracts.)

Contracts for non-firm transport services, especially TPA contracts, are not regulated. The ANP has determined that this type of contract should not have capacity charges; rather, all fixed costs should be allocated to firm transport contracts. However, industry agents and ANP officials have not yet agreed on a fair price for the volume transported.

In 2002, the ANP submitted for public consultation a new act establishing the pricing policy for gas transport services. This act introduced a clear policy for contracts resulting from pipeline expansion: The price for transport services using new capacity is the maximum price for either incremental or roll-in tariff.[27] This policy aimed at protecting established shippers; thus, if the incremental cost were lower than the average cost, the reduction would be shared with the shippers. If not, new entrants would be responsible for all incremental costs. This meant that expansion of pipeline capacity would never result in new entrants paying less than established shippers for transport services.

Although this act represents significant progress in the tariff policy for gas transport services, certain bottlenecks remain. For example, with regard to pricing policy for TPA contracts, gas transport companies charge only for the volume of gas transported; however, it is unclear which types of costs they can allocate to this service, raising the potential for open-access conflicts. Moreover, no definition is available on development of a secondary market for transport services contracts.

27. The roll-in tariff is the average cost, including cost of expanded capacity. The incremental tariff is the average cost of the expanded capacity, excluding already-existing capacity.

Vertical Integration: Provisions and Unbundling

Unbundling requirements in Brazil's natural gas industry are weak. Law 9478 requires corporate separation between gas shippers, transporters, and distributors. Transporters are prohibited from buying or selling gas, except for their own consumption. However, the ANP allows for cross ownership, requiring only that it be disclosed and that gas transactions between companies have at least one common stockholder. Some concession contracts in the distribution segments limit gas purchases from companies holding shares in the distribution company.

Vertical integration is also limited by the ANP's decision to restrict dominant-shipper control over new capacity to 40 percent;[28] however, the restriction holds only if demand among non-dominant shippers for the additional capacity offered is at least 60 percent. Otherwise, the dominant shipper can buy more than 40 percent of the new capacity.

Although Law 9478 places the ANP in charge of promoting competition in the NGI, the Agency cannot promote structural separation by forcing companies to divest. The only regulatory agency empowered to do so is Brazil's Administrative Council for Economic Protection (CADE). Nonetheless, the ANP can recommend that CADE thwart non-competitive behavior or transactions.

Challenges for Regional Market Integration

Regional integration of gas markets in the Southern Cone requires enormous investments in transport and distribution pipelines that bear large market and regulatory risk. To ensure the investments required for effective market integration, regional governments must clarify the scope and path of energy integration. To this end, Mercosur members must work together to define and coordinate energy policy. Mercosur should make confronting regulatory asymmetries within Southern Cone countries a priority. Regulatory convergence is particularly important in establishing policies to promote competition (World Bank 2000, IEA 2003a).

28. A shipper that contracts more then 50 percent of pipeline capacity is considered a dominant shipper.

Mercosur's current institutional diversity complicates inter-institutional planning and regulatory coordination among member countries. Clearly, such obstacles must be overcome if Southern Cone countries are to promote meaningful energy integration. A regional agency is needed to act as a permanent forum to coordinate energy-sector planning and regulation. Although the Mercosur Treaty does not provide for entities with supranational decision-making power, it is possible to create a communal institution based on voluntary negotiation between countries.

As competition becomes a regional and global phenomenon, competition policies based solely on national priorities could hinder new investment and the formation of strong regional companies. Nevertheless, gaining a Brazilian perspective on the challenges to creating truly competitive gas markets is a necessary step since gas trade in the Southern Cone depends largely on Brazil's energy policy. In fact, Brazil is the largest consumer market for international gas trade in the Mercosur zone.

Industry Structure

Petrobrás dominates Brazil's NGI. This vertically integrated player has implemented an aggressive strategy of an internationally diversified portfolio, focused on the Mercosur region. In 2002, Petrobrás' acquisition of Pérez Companc and Santa Fe Petroleo placed the company among Argentina and Bolivia's most significant players. Petrobrás' key role in the Southern Cone significantly affects cross-border gas trade; since the company competes with other players to monetize its Argentinean and Bolivian gas, it can be expected to use its market power to prevent competition

Petrobrás' capacity to prevent competition is based on its enormous share of natural-gas production assets and control of transport and distribution systems. Over the short term, the company will retain its dominant status in production; however, medium-term competition is possible, given that 50 private companies have exploration rights over blocks in Brazilian basins. However, most such companies are in partnership with Petrobrás. Moreover, regulation does not fully unbundle competitive and non-competitive segments of the gas industry; it only requires legal

separation between segments,[29] making it difficult to avoid discriminatory behavior in operating non-competitive segments. Finally, such competitors as Shell—the first private company to begin producing significant volumes of gas in Brazil—will not survive long if gas demand remains below Petrobrás' current production capacity.

Petrobrás' market power can reduce its own investment risk in the Brazilian market; however, private investors perceive the company's market power as a high risk, which discourages investment. Potential producers not only must compete with Petrobrás' impressive production capacity; they must negotiate almost exclusively with Petrobrás to sell their gas. For example, to pipe gas to consumption centers, private companies must negotiate with Transpetro. To sell gas, they must either negotiate with Gaspetro, Petrobrás' gas commercialization company, or attempt to sell gas on their own. If they opt for the latter, they must negotiate with state distribution companies, almost all of which Petrobrás owns entirely or in part. Clearly, with such monopoly/monopsony power throughout the market, it is easy to see how Petrobrás could discriminate against competitors and favor its own production.

Reducing Petrobrás' market share is not a viable option in the short term. Most analysts argue for a more intensive unbundling process, with Petrobrás creating greater distance between itself and its various subsidiaries—including Transpetro, Gaspetro, BR Distribuidora—throughout the industry. A complementary action would be to require distribution companies to diversify their portfolio of gas supply contracts. Strong, enforceable regulation of dominant behavior is a necessary condition for reducing the perception of risk among Petrobrás competitors.

Regulatory Framework

Brazil's current regulatory framework poses various obstacles to allowing market integration with other Mercosur member countries. Significant regional asymmetries create high regulatory risks for cross-border

29. This means that the same company can have assets in transport, distribution, and production segments.

gas projects.[30] In the Brazilian context, key regulatory issues are 1) prevention of abuse of dominant position and enforceability of prevention, 2) compatibility between federal and state regulatory frameworks, 3) unbundling of competitive and non-competitive segments, 4) development of gas-transport sector policies and rules, and 5) compatibility between gas and electricity regulatory frameworks.

The current regulatory framework fails to address the potential problems concerning Petrobrás' dominant NGI role. Rules on open-access conditions, network system operation, and distributor procurement do not prevent discriminatory behavior. Current legislation (Law 9478) leaves little room for the ANP to tackle this problem. Competition law is insufficient to manage these problems.

Compatibility between federal and state regulatory frameworks should be reviewed. As mentioned above, the ANP's responsibility for industry regulation does not extend beyond the city-gates. The states, which often lack sufficient regulatory capacity, regulate the distribution segment.[31] The concession of territorial monopolies for distribution companies adds another layer of difficulty for a market-oriented regulatory framework. Large Brazilian consumers and power plants are unable to buy gas directly in wholesale markets; rather, they must purchase it through distribution companies, whose market monopoly hinders gas-reserve owners from implementing monetization strategies through thermal power plants. Although distribution companies' monopoly of gas supply is often considered a stimulus for distribution network investment, such justification is far from clear. Gas-based power plants are usually located near transport pipelines, requiring few investments in the distribution network.

Because current legislation does not clearly define transport and distribution pipelines—although their regulatory regimes differ—regulations are often applied inconsistently. Ambiguity surrounds such key questions as who

30. Chapter 6 discusses asymmetries between country regulations.

31. Only 16 out of 27 states have regulatory agencies, most of which lack experience, having been created only within the last five years.

should build what types of pipeline or whether Petrobrás can sell CNG or LNG directly to end-users, thereby bypassing the distributor?[32] Lack of legislative clarity regarding the separation of federal and state responsibilities is at the root of regulatory conflicts and industry instability.

Lack of unbundling between competitive and non-completive segments is a major obstacle for market integration. Indeed, experience has demonstrated that extensive unbundling is essential for developing effective competition. Legal unbundling involves the creation of legally separate subsidiaries to undertake the various functions of transmission, distribution, and supply. Management unbundling entails a clear division of infrastructure and human resources by business services. Economic unbundling prevents or limits cross participation. Although full economic unbundling may not be feasible in the short term, limits to cross participation should be established to make market integration viable.

Gas-transport regulations create severe obstacles for integrating Brazilian gas markets into regional ones. First, in Brazil, open-access conditions result from free negotiations between transporters and shippers; however, negotiated access has been proven inefficient for countries with a dominant firm because of that firm's incentive to obstruct new market entrants. Negotiated access in Brazil represents a significant regulatory asymmetry in the Southern Cone region since ENARGAS regulates open access in Argentina, Mercosur's main gas market. Second, the framework for the parties to calculate and agree on transport tariffs varies by pipeline system, generating enormous price distortions and preventing potential trade and competition. Although the ANP has enacted a new rule that calculates tariffs according to the distance gas travels, this rule is not valid for the Bolivia-Brazil pipeline. It is important to homogenize the rules for calculating the tariffs for all transport pipelines to avoid distorting the final gas price. The new law should explicitly require the ANP to regulate tariffs for gas transport services. Third, the transport

32. The ANP considers that the state-level monopoly for gas supply concerns only pipeline supply. For this reason, the Agency has published acts establishing rules for LNG and CNG distribution. However, some distribution companies, state regulators, and Petrobrás officials do not recognize the potential for physical bypass. The only CNG distribution project in operation in Brazil—from Joao Pessoa to Campina Grande in Paraiba state—involves participation of the local distribution company.

system operation practices free negotiations between transporters and shippers—these rules are fixed in the transport contracts—giving transporters a significant margin for discriminatory behavior.[33]

Finally, the gas sector's regulatory framework should be compatible with that of the electricity sector. The need for investment to avoid power-shortage crises forced the government, in 1999, to implement the PPT, which has offered all investors the same conditions under which gas is supplied. Establishing a single gas price that only Petrobrás offers nullified the idea that gas competition could lead to power competition. Moreover, the PPT reinforced Petrobrás' power in the gas market since the company was forced to position itself as a de facto, gas-supply monopolist.

Market Risk

A major obstacle to investing in cross-border gas trade is market risk. Given that most Brazilian reserves are associated with oil, increased oil production tends to increase gas supply. The most important gas reserves are located close to major markets in southeastern Brazil and have significantly lower transport costs than imported gas. In a scenario of slow demand growth or increased domestic production, imported gas can hardly compete with domestic supply.

Petrobrás currently produces 41.5 million m^3 per day, but sells only about 13.3 million m^3 per day. To curtail flaring, Petrobrás has increased gas reinjection and its own consumption. In fact, own consumption, at about 14 million m^3 per day, surpasses gas sales. Another 9.2 million m^3 per day are reinjected and about 5 million m^3 per day are burned in flares. These figures clearly show that, if domestic production increases more rapidly than demand, Petrobrás will use its market power to increase domestic gas sales. It will be difficult for Petrobrás to significantly increase gas flaring or own consumption. The opportunity cost of selling associated gas is relatively low, since when not selling gas,

33. This practice has been a point of contention between Petrobrás and new NGI entrants. Companies that obtained TPA contracts have had difficulty dispatching gas because the procedures adopted by the transporter, TBG, favor contracts with the dominant firm, Petrobrás.

Petrobrás must invest in reinjection. Thus, as Petrobrás increases oil production, it tends to increase gas sales. In short, increased domestic gas supply poses a challenge for imported gas.

Stabilizing the gas market requires a new arrangement for gas power plants and a large base of domestic consumers. One potential arrangement for power plants is to ensure minimal dispatching for gas-based generation capacity to enable gas shippers and thermal plants to sign long-term contracts needed for gas-supply investments. This minimal dispatching rate will depend on the type of power plant and electricity market. Recent experience of the Brazilian electricity market shows that coexistence of gas- and hydro-based power stations requires specific market rules.

Increasing the number of final gas consumers requires enormous investments in the distribution network; at the same time, newly created distribution companies lack capacity to undertake such investments because of their short credit history. In addition, the main stockholders—state governments—are in poor financial shape. Permitting broader participation of private shareholders in distribution companies will increase their financial capacity and the number of relevant players.

Summary and Recommendations

Over the past five years, Brazil's natural gas market has not developed as expected. At the same time, domestic gas supply has increased rapidly, and recent gas discoveries have created enormous potential for domestic supply growth. The potential for gas imports depends on the pace of demand growth. To promote international gas trade in the Southern Cone region, it is important to confront the obstacles to achieving potential consumption growth in Brazil, most of which require direct government action through energy policy.

Half of Brazil's potential demand growth is related to gas-based, power-generation projects. These projects face serious economic difficulties under current market conditions and the electricity sector's regulatory framework. Given the short-term marginal costs of hydro-based power generation, the economic risks of gas-based generation competing with hydro-based

generation are high. In addition, current excess capacity in generation makes it difficult to dispatch gas-based power plants. As gas demand slows, investments in transmission networks stall. Thus, to reduce demand volatility in the power generation sector, it is important to establish electricity-market rules that allow for gas-fired power plants to coexist with hydropower plants. In short, electricity-sector policies and rules should consider gas-sector limitations. Defining minimal dispatching rates for some gas-based power plants could stimulate investment in the gas chain. Thus, energy policy should define clear targets for gas share in power generation, as well as appropriate instruments for reaching them.

With regard to gas consumption in other segments, the investments required for end-user distribution face important challenges. Gas distribution companies have difficulty acquiring appropriate financing; most are state-owned and, consequently, are in poor financial shape. Because most Brazilian states are not capable of contributing to companies' capitalization, the massive distribution-network investments needed for appropriate demand growth require changes in the distribution segment's ownership structure and increased public funding. To overcome the current obstacles, it is crucial to establish a policy for gas demand growth and cross-border trade.

Petrobrás' market power increases risk of cross-border gas projects involving other private companies. Restrictions to vertical integration in Brazil are weak. Law 9478 does not limit cross ownership, making it difficult for regulators to avoid discriminatory behavior in non-competitive segments of the industry.

Brazil's federal gas regulation has limited power to implement market-oriented rules. Regulators cannot directly interfere in the industry structure and have no say in the rules governing open access negotiated between transporters and shippers. In addition, Brazil's regulatory framework is incomplete. Open-access regulation, capacity reallocation, and transport tariffs remain under debate. The concession of territorial monopolies for distribution companies represents an added difficulty for creating a market-oriented regulatory framework in the NGI upstream. This monopoly is an obstacle to gas-monetization strategies involving investments in thermal power plants.

To support integration projects in the natural gas sector, governments must take a clear position on the role of cross-border gas trade in their national energy policies. In Brazil's case, surmounting key obstacles to increasing gas imports requires direct government action. Thus, it is critical that the Brazilian government clarify the role of gas integration in shaping the country's national energy sector.

To build an appropriate regulatory framework, policymakers must design a new law specifically for the gas sector. The major changes that this law should incorporate are:

- establishing a clear division of labor between federal and state governments;
- having the ANP regulate the conditions of system operation;
- regulating, rather than negotiating, open access;
- having tariffs for gas transport services follow a single, ANP-established rule, regardless of the pipeline system (all valid contracts should be adapted to the same rule); and
- introducing explicit barriers to discriminatory behavior by the dominant player.

In closing, the new gas law would give the Brazilian government an opportunity to clearly position itself with regard to the intended shape of the gas industry. Of particular importance is the government's position on market integration with Mercosur partners and competition's role within it.

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Chapter 4

Chile: Energy Dependence

Felipe Balmaceda and Pablo Serra

To date, the interconnection of Chile's geographically separated natural-gas markets—northern, central, southern, and austral—has not proven profitable. All four markets import gas from Argentina. Only the austral market is supplied, in part, by Chile's sole domestic producer, the state-owned ENAP (*Empresa Nacional del Petróleo*).

Overview

Liberalization of Argentina's gas market and the Gas Protocol signed by Chile and Argentina in 1995 helped to ease Argentine gas imports. The first two pipelines connecting Chile and Argentina became operative in 1996 and 1997; they carry gas to the austral and central markets, respectively. Five other pipelines connect the two countries: two serving the northern zone, two the austral zone, and one the southern zone.

Consumption Growth

The arrival of Argentine gas allowed for rapid expansion of Chilean consumption, which more than quadrupled during the 1996–2001 period (table 4-1). Then, in 2002, gas consumption stagnated; no new gas-powered plants became operative, and the country's economy slowed. However, over the next decade (2003–12), consumption is projected to more than double (table 4-5).

While pipeline construction in the austral zone supported expansion of a methanol plant (Methanex), potential demand in the electricity sector made pipeline development in the other three zones economically feasible. In 2002, Methanex consumed more than 38 percent of national production, while power-generation plants used another 32 percent (table 4-2). Rapid

growth in electricity demand during the 1990s—average annual growth rate was 7 percent—triggered the search for new sources of electricity generation. In the early 1990s, development of highly efficient, combined-cycle, natural-gas plants made power generation using Argentine gas attractive.

TABLE 4-1. CHILEAN GAS CONSUMPTION BY SECTOR, 1991–2002
(millions of m^3)

Year	Transport	Industry and mining	Residential, commercial, and public sector	Transformation centers	Total
1991	8	6	188	1,261	1,463
1992	5	7	195	1,469	1,676
1993	6	6	200	1,404	1,616
1994	7	12	202	1,466	1,687
1995	7	11	210	1,415	1,643
1996	7	13	215	1,420	1,655
1997	6	310	232	2,028	2,576
1998	7	338	224	3,014	3,583
1999	7	410	272	4,237	4,926
2000	9	799	357	5,218	6,383
2001	12	872	449	5,911	7,244
2002	27	990	442	5,844	7,303

Source: National Energy Commission (CNE).

Gas-powered generation grew over a short period of time, generating 28.6 percent of electric power by 2002. The country's independent interconnected electricity systems—Central Interconnected System (SIC) and Northern Interconnected System (SING)—generated 75.0 percent and 24.4 percent, respectively, of the national total in 2002. Two integrated local systems in the southern and austral zones generated the remaining 0.6 percent. The central-zone pipeline supplies electricity plants in the SIC, while the two northern-zone pipelines supply those in the SING. In 2002, gas-powered plants generated 17.8 percent of SIC production and 62.4 percent of SING production.

City-distribution projects developed since 1997 have augmented coverage of gas distribution networks in Chile's three largest metropolitan zones: Santiago, Valparaiso, and Concepción. Firms that had produced and

zones: Santiago, Valparaiso, and Concepción. Firms that had produced and distributed manufactured gas became natural-gas distributors, and older gas-producing plants were closed. The Santiago distribution firm retained a portion of the marginal production and distribution of manufactured gas, although production (which uses natural gas) declined as the older network was converted or replaced. Between 1995 and 2003, the number of residential consumers served by natural-gas distribution companies increased nearly ninefold (table 4-3).

TABLE 4-2. GAS CONSUMPTION IN CHILE'S TRANSFORMATION CENTERS, 1991–2002 (millions of m^3)

Year	Electricity	City gas	Oil refineries	Methanol	Total
1991	81	0	550	630	1,261
1992	83	0	551	835	1,469
1993	84	0	509	811	1,404
1994	88	0	503	875	1,466
1995	89	0	481	845	1,415
1996	90	0	449	881	1,420
1997	197	0	452	1,379	2,028
1998	961	0	425	1,628	3,014
1999	1,357	0	419	2,461	4,237
2000	1,966	56	441	2,755	5,218
2001	2,661	42	510	2,698	5,911
2002	2,363	34	670	2,777	5,844

Source: National Energy Commission (CNE).

Since the natural-gas sector was created, market forces have guided its development. Private investors have financed and implemented the construction of gas pipelines and distribution networks. Regulation established a nondiscriminatory framework for awarding transport and distribution concessions, as well as technical operational standards, but left prices unregulated. The sole exception was the austral zone, where, in the 1950s, the ENAP began developing production, transport, and distribution infrastructure. In 1981, the distribution network serving major vendors in the zone was privatized; since then, however, distribution rates have been regulated.

Regulation of gas transport rates was considered unnecessary since it was believed that competition between investors willing to build pipelines would

ensure that prices reflected market conditions. Because of the heavy economies of scale involved in gas transport, construction of only one gas pipeline would be justified for each market. Also, because of the project's high cost, the financial system would require investors to have signed contracts with high-volume consumers before approval of financing. Since users would award their gas-transport contracts to whichever potential suppliers offered the best conditions, the pipeline project offering the lowest rates would be the one built.

TABLE 4-3. CLIENTS OF CHILEAN DISTRIBUTION COMPANIES, 1995–2003

Year	Number of clients			Annual growth (%)
	Residential	Other	Total	
1995	37,175	934	38,109	–
1996	37,897	955	38,852	1.9
1997	41,144	1,186	42,330	9.0
1998	75,745	1,897	77,642	83.4
1999	152,667	4,327	156,994	102.2
2000	224,077	6,272	230,349	46.7
2001	274,852	7,577	282,429	22.6
2002	316,329	7,735	324,064	14.7
2003	323,010	8,450	331,460	2.3

Sources: Superintendency of Electricity and Fuels (SEC) and respective firms.

Transport and Distribution Competition

As authorities expected, gas-transport competition has worked reasonably well. Each time new potential demand for imported natural gas emerged, at least two consortia competed to build the pipeline. In the central zone, Gas Andes competed successfully against TransGas. In the northern zone, neither of the two competing consortia yielded, leading to construction of two pipelines: Gas Atacama and NorAndino. Although two consortia competed initially in the southern zone, the limits of potential demand led both to join forces and construct one pipeline (Gas Pacífico). In all cases, prices were set through an open-season process, and have been used in new contracts. Initially, only take-or-pay contracts were signed, given the need to have firm contracts to ensure pipeline construction; currently, however, spot rates are also available, with a surcharge of up to 50 percent over the take-or-pay contracts.

With regard to gas distribution, liquefied gas (LG) companies—and, to a lesser extent, diesel oil and wood companies (used mainly for heating)—are expected to compete for residential clients.[1] LG companies own the natural-gas distributors; although this arrangement reduces the scope for competition, it has not posed a problem to date. To extend their networks, natural-gas distributors have offered potential customers attractive rates. For industrial consumers, the closest substitutes are diesel oil and LG, and fuel conversion poses no obstacle.

Few firms buy gas directly from Argentina. The central zone has had four purchasers (a fifth joined recently). Initially, these firms only had long-term, take-or-pay contracts to meet all of their demand. However, the spot market has partially met additional needs. Long-term contracts usually guarantee supply at a lower rate; however, clients risk paying for unneeded gas, although they have the flexibility to transfer consumption from one year to another. Contracts have indexing clauses that link the natural-gas price to the basin price (an average of prices in contracts with similar characteristics involving Argentine purchasers), as well as to the price of oil and other US price indices.

Two international pipeline heads are in the Argentinean Transport System (ATG); hence, Chilean gas purchasers using these pipelines must also contract transport services in Argentina, where gas transport is an open-access, price-regulated public service. Contracts can be on a firm or interruptible basis. Usually, interruptible contracts are restricted during winter, when clients are likely to make full use of their contracted capacity. Initially, Chilean clients only signed firm contracts, but certain new ones are interruptible.

An incipient spot market has emerged, whereby firms—mainly power generators—sell their gas and transport surplus to distribution companies and other major consumers.

Bolivia's 2003 popular revolt, which forced that country's president to resign, ended an international consortium's plans to export Bolivian natural

1. Fuel conversion entails significant costs for low- and middle-income families.

gas to the western United States via a port in northern Chile (see chapter 2).[2] That delay led U.S. purchasers to sign contracts with Indonesian suppliers. Currently, the fate of Bolivian natural-gas reserves is unclear; however, political tensions make it unlikely that Bolivia will export gas to Chile.

Owing to its recent internal supply crisis, Argentina has severely restricted natural-gas exports to Chile. Recent restrictions have amounted to 34 percent of total exports, reaching 58 percent in the northern market. Argentina's populist economic policies have left Chilean consumers caught in the crossfire between the Argentine government and producers. These events, in turn, have forced Chilean consumers and authorities to reevaluate their options.[3]

History of Domestic Production

Since Chile began natural-gas production in 1950, more than 20 gas fields have been discovered in the austral zone's Magallanes Basin; more than half have reserves that exceed 1,600 m^3. In early 2002, Chile had proven reserves of 67,780 million m^3 in the Magallanes zone,[4] projected to last 25 years. Explorations in other regions led to a few discoveries with no commercial value. As table 4-4 shows, domestic production is declining. The National Energy Commission (*Comisión Nacional de Energía*) (CNE) estimates that domestic production will fall 21 percent between 2003 and 2012 (table 4-5), unless sizeable reserves are discovered.

Import Reliance

As box 4-1 shows, Chile rapidly became the main importer of natural gas from Argentina and now depends on imports to meet its energy needs. Natural gas accounts for 25 percent of Chile's energy matrix. The CNE estimates that, from 2003 to 2012, natural-gas consumption in Chile will grow by 133 percent; it is estimated that the country's dependence on Argentine gas will increase to 90 percent of total consumption by 2012 (up from 71 percent in 2002).

2. A national referendum was to decide the future of Bolivian natural gas.
3. This chapter's analysis predates those events.
4. According to the CIA World Factbook.

TABLE 4-4. CHILEAN NATURAL GAS PRODUCTION, 1981–2002
(millions of m^3)

Year	Production	Reinjections, flaring, losses, and statistical errors	Imports	Consumption
1981	5,079	n.a.	0	n.a.
1985	4,638	n.a.	0	n.a.
1990	4,198	n.a.	0	n.a.
1991	4,067	2,604	0	1,463
1995	3,783	2,072	-68	1,643
1996	3,632	1,942	-35	1,655
1997	3,211	1,292	657	2,576
1998	3,074	1,481	1,990	3.583
1999	2,957	1,822	3,791	4,926
2000	2,702	680	4,361	6,383
2001	2,683	666	5,227	7,244
2002	2,543	513	5,273	7,303

n.a. = not available.
Source: ENAP.

TABLE 4-5. DOMESTIC PRODUCTION AND IMPORT PROJECTIONS, 2003–12
(millions of m^3)

		Imports from Argentine basins			
Year	Magallanes production	Austral	Neuquina	Noroeste	Total
2003	2,077	1,737	2,685	1,701	8,200
2004	2,096	1,789	3,035	1,915	8,835
2005	2,208	2,358	3,605	2,031	10,202
2006	2,219	2,369	4,055	2,127	10,770
2007	2,230	2,381	4,593	2,347	11,551
2008	2,241	2,394	5,486	2,541	12,661
2009	1,596	3,051	6,182	2,617	13,446
2010	1,608	3,052	7,010	2,714	14,385
2011	1,621	3,053	7,480	2,797	14,950
2012	1,633	3,054	8,290	2,902	15,878

Source: National Energy Commission (CNE).

BOX 4-1. NATURAL GAS RESERVES IN LATIN AMERICA AND THE CARIBBEAN

Latin America and the Caribbean (LAC) is home to 4.5 percent of the world's proven natural-gas reserves (see table below). Venezuela boasts the region's largest reserves, which, at current consumption rates, are projected to last more than 100 years. Recent discoveries in Bolivia make that country an important potential supplier to Chile. Likewise, discoveries in Argentina and Peru have allowed those countries to satisfy their internal demand and begin exporting to such countries as Chile and Brazil. In 2002, Argentina was the region's major exporter, with 5.84 million m^3; Bolivia followed, with 3.95 million m^3. Most of Argentina's export production goes to Chile (5.34 million m^3), while the remainder goes to Brazil and Uruguay; currently, Bolivia exports only to Brazil.

REGIONAL RESERVE ESTIMATES
(trillions of m^3)

Country	Jan. 2002	Dec. 2002
Argentina	0.77	0.76
Bolivia	0.73	0.68
Brazil	0.22	0.23
Chile	0.08	n.a.
Colombia	0.13	0.13
Ecuador	0.11	n.a
Mexico	0.97	0.25
Peru	0.25	0.25
Trinidad & Tobago	0.61	0.66
Venezuela	4.20	4.19
Other	n.a.	0.18

Sources: CIA World Factbook, 2002 (Jan. 2002 est.); BP Statistical Review of World Energy, 2003 (Dec. 2002 est.)

The Austral Basin supplies Chile's austral zone, the Neuquina Basin services the central and southern markets, and the Noroeste Basin serves the northern market. Assuming that Chile imports its gas solely from Argentina, according to the projections presented in table 4-5, the Neuquina Basin will

increase its participation in Chilean gas consumption from 33 percent in 2003 to 52 percent in 2012, while the participation of the Austral and Noroeste basins will decline from 21 percent to 19 and 18 percent, respectively.

Accumulated Chilean demand over the next decade represents a significant percentage of proven reserves in the Argentine basins: Austral, 17 percent; Neuquina, 15 percent; and Noroeste, 18 percent. This demand will require the approval of new export permits for about 5 billion m^3 per day. Total authorized exports to Chile amount to 175 billion m^3. Based on available information, one can conclude that Argentine producers can likely satisfy Chilean natural-gas requirements for at least a decade; thus, the legal and regulatory systems that govern Chile's interconnection with Argentina require few modifications.

The Gas Andes pipeline connects to the West-central pipeline of Argentina's transport system, the ATG, which connects the Neuquina Basin and Buenos Aires. The Neuquina-La Mora pipeline has a transport capacity of 31.93 million m^3 per day, of which 8.3 million m^3 per day (26 percent) is contracted to Chilean users in the take-or-pay mode. The NorAndino pipeline connects Pichanal to the northern pipeline, which transports gas from the Noroeste Basin to Buenos Aires; in this segment, about 10 percent of transport capacity is contracted to Chilean users. Other pipelines that transport natural gas to Chile start at wellheads; thus, gas importers that use those pipelines do not use the ATG.

Since the internal bylaws of Argentina's dispatch centers were enacted in 1995, the West-central pipeline has not experienced emergencies leading to restriction of take-or-pay contracts. Nonetheless, Argentina's current economic crisis and its potential effect on future development of the country's gas industry are cause for concern.

Although Bolivia's significant natural-gas reserves are located 2,300 km from Chile's central zone (the austral region is even more remote), Bolivia is a potential exporter to Chile. A consortium planning to export

Bolivian natural gas to the western United States could build a pipeline connecting reserves and Caleta Patillos in Chile's northern region and a liquefaction plant in Patillos. Although this infrastructure would be built to export gas to the United States, it could also serve Chilean markets.

In Chile's northern zone, the price of Bolivian natural gas would be cheaper than that from Argentina's Northeast basin, if set as the netback to wellheads from the California price. This scenario could provide an incentive to install gas-powered plants in Chile's northern zone to serve the country's central region. Project feasibility would depend on economic incentives to build a transmission line, which, in turn, would depend on the transmission pricing system, whose modification parliament is currently discussing. Another option would be to build a regasification plant in the central zone to inject Bolivian gas transported by vessels to the central gas-transmission system. Political tensions between Chile and Bolivia are the major obstacle to realization of this project.

One alternative would be for Bolivia to export gas to Brazil, with purchasers setting the price. Bolivia could also export gas to Argentina through a currently unused, interconnecting pipeline. This option would reduce pressure on Argentine reserves, but would require normalization of gas prices in that country. At current prices, it is not advisable to export to Argentina; moreover, Argentina is a net exporter. Bolivian gas could reach Chilean markets through pipelines that interconnect Bolivia and Argentina and then flow through existing pipelines that connect Argentina and Chile.

Demand Forecasts

Until the mid-1990s, domestic natural-gas consumption was relatively stable (at about 1,700 million m^3 per year) and located exclusively in the Magallanes region. Beginning in 1996, however, construction of pipelines to import gas from Argentina made it possible to supply new regions, causing consumption to explode. During 1997–2000, total consumption increased at an average annual rate of 35 percent. As of 2001, the growth rate declined because no new investments were

made in gas-powered generation, and the distribution network remained the same.

Current Consumption

Currently, Chile uses natural gas primarily to generate power and convert gas into methanol. In recent years, successive expansion in Methanex's capacity to produce methanol has accounted for a significant portion of aggregate demand growth. This modular change is related to capacity expansion; growth in maximum thermoelectric demand is also modular, but consumption is more variable because of the minimum cost regulation that governs dispatch of plants in electricity systems. Hence, annual hydrology and the price of other fuels used in thermoelectric generation highly influence the use of gas in power generation. The ENAP also uses significant amounts of natural gas in its exploitation work in Region XII and refineries in Regions V and VIII. Residential, commercial, industrial, and vehicular transport sectors use natural gas on a smaller scale.

Explosive growth in industrial consumption occurred in 1997–2000, when the Metropolitan Region's distributor, Metrogas, focused on serving concentrated industrial users. More recently, its growth rate has slowed, as sector coverage is nearly complete in zones reached by the distribution network. Residential consumption grew strongly until 2001, and then stalled in 2002 as a result of economic concerns.

Because gas markets are not interconnected, global figures do not accurately reflect the regional realities described below.

Austral zone. In 2001, the natural gas traded in the Magallanes zone accounted for 52.8 percent of total domestic consumption. This percentage did not include ENAP-produced gas that was either reinjected into wells or consumed internally. With regard to distribution, as of October 2001, Gasco-Magallanes served 43,291 clients, 95 percent of whom were residential consumers. Residential customers comprised 59 percent of total consumption, followed by the three power-generation plants, representing 22 percent of consumption. The region's low

temperatures, combined with affordable cost to residential consumers, meant that household coverage was high and relatively stable (about 97 percent in 2001).

Southern zone. The ENAP refinery, the southern zone's main client, represents 50 percent of total demand. The industrial sector accounts for another 41 percent, while distributor GasSur represents the remaining 9 percent. GasSur uses 87 percent of its consumption to produce city gas as methane-air, which is distributed mainly to residential and commercial clients (it does not supply industrial clients). In October 2001, GasSur supplied 792 residential clients and city gas to another 15,058 residential customers. Network distribution, including natural and city gas, is estimated at 13 percent of households in metropolitan Concepción and Talcahuano.

Central zone. In 2001, this zone's main client was Metrogas; the distributor represented 31 percent of total consumption (excluding its sales to distributors in Region V), although power generators—Santiago, San Isidro, and Nehuenco—accounted for 55 percent of total consumption. The two distributors in Region V accounted for 6 percent of total demand, even less than the 7 percent provided to the ENAP refinery.

By December 2003, Metrogas distributed gas to 301,457 customers, about 98 percent of whom were households. In 2003, 70.2 percent of Metrogas sales went to industry, 28.3 percent to residential and commercial consumers, and 1.4 percent was sold for vehicles. In October 2001, the natural-gas distribution network reached about 10.5 percent of the Metropolitan Region's urban households. Currently, Metrogas distributes city gas manufactured from natural gas and biogas extracted from garbage dumps. Residential customers who receive city gas (64,263 in October 2001), combined with those supplied natural gas, put residential coverage at 15 percent of the distribution network. Metrogas has gradually transformed its city-gas network to distribute natural gas; according to the firm's plans, all city-gas customers will switch to natural gas before 2008.

Region V distributors, GasValpo and Energas, have similar numbers of customers and sales volumes. Combined, these firms have about 70,000 residential customers. Energas, the only natural-gas distribution company that previously did not distribute city gas, concentrates more on the industrial sector. GasValpo has a more diversified portfolio of customers, although the industrial sector is the most important in terms of volume (its main client is Enami). Taking GasValpo and Energas together, the industrial sector accounts for 82.3 percent of total distribution.

Northern zone. In 2001, gas sold in Chile's northern zone accounted for 12.4 percent of the country's traded natural gas. Most consumption was thermoelectric, since industrial and mining consumption accounted for less than 1 percent of the total. In 2000, Nopel was the most important generator, with 63 percent of demand, followed by Edelnor, with 20 percent. That year, ElectroAndina consumed less (having become operative late in the year); however, its current consumption is similar to that of Edelnor. In 2000, the Taltal generator, which is connected to the SIC, accounted for 7 percent of northern-zone demand.

Projected Consumption (2003–12)

Chile's natural-gas consumption is still in a developmental stage, competing with other fuels (except when used as raw material). Its evolution depends on many factors, ranging from the country's economic growth, price evolution of substitution fuels, development plans of major consumers (e.g., thermoelectric firms, oil refineries, petrochemical plants, natural-gas liquefying plants), and authorities' decisions with regard to specific sector development (e.g., transport) or regions (especially those not yet supplied by pipelines).

At this stage, the most reliable way to project demand is to aggregate projections of all major agents: carriers, distributors, main users, and government. These projections usually consist of private information that cannot be accessed. However, in August 2003, the CNE published its projected natural-gas demand for 2003–12, based on 1) projections of natural-gas sector firms (distributors and carriers), 2) CNE's power-

generation projections used to estimate regulated power (node) prices in April 2003, 3) scenarios of firewood replacement and environmental effects on the country's southern-zone cities (based on CNE projections), and 4) information provided by major consumers.

Projected consumption by residential, commercial, industrial, transport, refinery, and petrochemical sectors are relatively reliable, as they aggregate projections of all major consumers (table 4-6). Because gas consumption will become more relevant in the power-generation sector, projected consumption is more uncertain since it is based on criteria that the regulator is legally compelled to use for estimating regulated node prices, which have not necessarily been matched to investor decisions.

TABLE 4-6. PROJECTED NATURAL GAS CONSUMPTION BY SECTOR, 2003–12 (millions of m^3)

Year	Northern	Central	Southern	SIC power generation*	Austral	Total
2003	1,701	2,227	459	0	3,814	8,200
2004	1,915	2,515	520	0	3,885	8,835
2005	2,031	3,053	552	0	4,566	10,202
2006	2,127	3,438	629	0	4,577	10,770
2007	2,347	3,567	679	372	4,588	11,551
2008	2,541	3,651	766	1,105	4,599	12,661
2009	2,617	3,841	803	1,575	4,611	13,446
2010	2,714	3,992	837	2,219	4,623	14,385
2011	2,797	4,069	867	2,581	4,636	14,950
2012	2,902	4,186	896	3,246	4,648	15,878

* SIC thermoelectric-plant consumption that overlaps with central and southern markets.
Source: National Energy Commission (CNE).

A significant increase in natural-gas consumption, including its relative participation in the domestic energy matrix, is expected. Tables 4-6 and 4-7 show consumption projections by sector and zone, respectively. Underlying consumption projections are an implicit assumption about national economic growth, which is highly influenced by the low growth rates of recent years. Thus, if economic activity regains the strength of the 1990s, gas consumption will exceed all sector projections.

TABLE 4-7. PROJECTED NATURAL GAS CONSUMPTION BY ZONE, 2003–12
(millions of m^3)

Year	Residential	Commercial	Industrial	Electricity	Methanex	ENAP	Transport	Total
2003	425	95	1,167	2,688	3,051	753	22	8,200
2004	472	107	1,486	2,880	3,112	753	25	8,835
2005	520	117	1,717	3,281	3,782	753	32	10,202
2006	597	134	1,792	3,675	3,782	753	38	10,770
2007	660	145	1,846	4,323	3,782	753	43	11,551
2008	727	159	1,938	5,258	3,782	753	45	12,661
2009	785	167	1,994	5,917	3,782	753	48	13,446
2010	842	175	2,053	6,730	3,782	753	50	14,385
2011	894	183	2,103	7,184	3,782	753	53	14,950
2012	945	190	2,154	7,999	3,782	753	55	15,878

Source: National Energy Commission (CNE).

National consumption is expected to grow at an average annual rate of 7.6 percent (increasing from 8.2 billion m^3 in 2003 to 15.9 million m^3 in 2012). It is anticipated that the austral zone (Magallanes Region) will reduce its participation in national consumption (from 47 percent in 2003 to 29 percent in 2012). The central zone will likely become Chile's major gas consumer. A significant proportion of combined-cycle plants to be installed in the SIC will probably be located in this zone. This scenario would change, however, if a pipeline were constructed to interconnect the central and southern markets.

Regarding sector-consumption estimates for 2003, petrochemical and thermoelectric sectors were the most important users, with 37 and 33 percent national-consumption participation, respectively, followed by industrial (14 percent), refineries (9 percent), residential (5 percent), and commercial (1 percent). As 2012 approaches, a substantial change will occur, as thermoelectricity participation is projected at 50 percent, while petrochemical participation is expected to fall to 24 percent (provided that no petrochemical projects related to hypothetical Bolivian imports come to fruition in Region II).

Sector Structure

Transport

Chile's current transport system has an import capacity of 32.7 million m^3 per day. Without new pipeline investment, this capacity is projected to satisfy demand in both aggregate and regional terms until 2010; that is, each system will be able to satisfy demand until 2010. After that date, the most likely scenario is expansion of the Gas Andes pipeline to supply greater central-zone demand.

Austral zone. Since 1961, the ENAP has built 1,400 km of pipeline in the austral zone, most of which transports natural gas from fields to processing facilities in Cullén and Posesión. The first pipeline, Posesión-Cabo Negro, began operating in 1971. Its clients were thermoelectric plants and residential consumers in Punta Areas and intermediate locales. In 1996, the Bandurria pipeline became operative; the first one to interconnect Chile and Argentina, it carries Argentine gas to satisfy additional demand from the expanded Methanex plant. In 1999, a partial extension of the Posesión-Cabo Negro pipeline became operative, as did two new interconnections with Argentina in the Estrecho de Magallanes continental sector (Dungeness-DAU No. 2 and Condor-Posesión) (table 4-8).

Central zone. Gas Andes, the central zone's first pipeline, began operations in August 1997. The pipeline connects La Mora in Mendoza Province to Santiago. In La Mora, the pipeline connects to the TGN-owned West-central pipeline, which carries gas from the Neuquina Basin to Buenos Aires. In September 2003, Gas Andes built an extension to Requinoa and a branch (6 inches in width and 19.4 km in length) reaching to Caletones in Region VI, with the aim of feeding El Teniente Foundry and a thermoelectric plant to be installed. The ElectroGas pipeline, which carries gas from Gas Andes' Chena Station to Region V, began operations in 1999 (table 4-9).

Northern zone. Two international pipelines, NorAndino and Gas Atacama, built in 1999, are the backbone of the northern zone's transport

TABLE 4-8. AUSTRAL ZONE TRANSPORT INFRASTRUCTURE

Pipeline	Year	Segments (origin/destination)	Country	Diameter (inches)	Capacity (millions of m^3 per day)	Length (km)
Sara-Cullén	1961	Planta Sara (Sector Cerro Sombrero)/Planta Cullén (Tierra del Fuego)	Chile	$10^{3/4}$	0.7	45
DAU No. 1-Posesión	1962	DAU No. 1/ Planta Posesión	Chile	12	3.8	4
DAU No. 2-Posesión	1962	DAU No. 2/ Planta Posesión	Chile	$12^{3/4}$	5.0	6
Dungeness-DAU No. 2	1964–70	Dungeness/ DAU No. 2	Chile	6-10	4.0	42
Posesión-Daniel	1970	Planta Posesión/ Sector Daniel	Chile	$10^{3/4}$-$8^{5/8}$	1.5	18
Tres Lagos-Cullén	1976	Tres Lagos (Tierra del Fuego)/ Planta Cullén (Tierra del Fuego)	Chile	$8^{5/8}$	27.5	18
BRC-Cullén	1976	Batería de Recepción Catalina/ Planta Cullén	Chile	$8^{5/8}$-$6^{5/8}$	0.3	42
Daniel-DAU No. 1	1982	Sector Daniel/DAU No. 1 (Sector Planta Posesión)	Chile	8	1.0	20
Posesión-Cabo Negro	1987–99	Planta Posesión/Planta Cabo Negro Kimiri Aike/Planta Cabo Negro	Chile Chile	18 20	6.3 2.9	180 170
Marazzi-Cullén	1988	Sector Marazzi/ Planta Cullén	Chile	$10^{3/4}$-$5^{1/2}$	0.04	78
Calafate-Punta Daniel	1992	Sector Calafate/Sector BRC/DAU No. 1/Playa Posesión (Sector BRP)	Chile	$10^{3/4}$	2.8	54
Bandurria	1996	San Sebastián (Tierra del Fuego)/ Paso Bandurria (Frontera) Paso Bandurria (Frontera)/Planta Cullén (Tierra del Fuego)	Argentina Chile	14 14	2.0 2.0	48 35
Cullén-Calafate	1996	Planta Cullén/ Sector Calafate	Chile	$12^{3/4}$-$6^{5/8}$	3.2	25
Punta Daniel-Daniel Central	1996–97	Punta Daniel (Frontera)/ Sector Daniel Central	Chile	12	2.8	5
Dungeness-DAU No. 2	1999	Dungeness/Daniel Este Daniel/DAU No. 2 (Planta Posesión)	Argentina Chile	8 10	2.8 2.8	13 20
Condor-Posesión	1999	El Condor/Frontera Frontera/Planta Posesión	Argentina Chile	12 12	2 2	8 1

Source: National Energy Commission (CNE).

system (table 4-10). Both pipelines transport gas from Argentina's Northeast basin to Region II, but they are not interconnected. Gas Atacama has its wellhead in the Salta fields. It carries gas directly to the Nopel generator and indirectly to industries and mines through the trader Progas, for which special branches have been built. The Taltal pipeline, which began operations in 2000 as an extension to Gas Atacama, carries natural gas to a thermoelectric power plant in Paposo, which, unlike other northern plants, is connected to the SIC.

NorAndino connects with the Northeast basin through TGN's Northern pipeline in Pichanal, about 100 km downstream from the Northern pipeline. Its several branches supply electric power generators ElectroAndina (Tocopilla) and Edelnor (Mejillones). In addition, it indirectly supplies industries and mines through the ElectroAndina-owned Distrinor trading firm, for which it has built special branches.

TABLE 4-9. CENTRAL AND SOUTHERN ZONE TRANSPORT INFRASTRUCTURE

Pipeline	Year	Segments (origin/destination)	Country	Capacity (millions of m³ per day)	Length (km)
		La Mora (Mendoza, Argentina)/Frontier Paso Maipo	Argentina	9.0	313
		(Frontier)/City Gate II	Chile	9.0	150
		Válvula 17/City Gate I	Chile	9.0	4
		San Vicente/El Peral	Chile	5	49
Gas Andes	1997	El Peral/Caletones	Chile	n.a.	20
		San Bernardo/Maipú	Chile	4.55	12
		Maipú/Quillota	Chile	4.55	111
ElectroGas	1998	121-km main line/Est. Colmo	Chile	1.2	15
		Loma La Lata (Argentina)/Frontier	Argentina	9.7	276
		Paso Butamallín (Frontier)/Recinto	Chile	9.7	76
		Recinto/Las Mercedes	Chile	9.7	168
		Las Mercedes/Gasco and Petrox	Chile	6.3	17
		La Leonera/Coronel	Chile	2.1	28
Gas Pacífico	1999	Paso Hondo/Nacimiento	Chile	1	73

Source: National Energy Commission (CNE).

Southern zone. The southern natural-gas transport system, located in Region VIII, is the most recent development. It has an Argentine segment and five national branches to supply the five delivery sites of its sole trading-firm customer, Innergy, which owns a net of small pipeline-supply

industrial consumers. Two other Innergy clients, the distributor GasSur and ENAP's Petrox Refinery, are directly supplied by Gas Pacífico (table 4-9).

TABLE 4-10. NORTHERN ZONE TRANSPORT INFRASTRUCTURE

Pipeline	Year	Segments (origin/destination)	Country	Capacity (millions of m^3 per day)	Length (km)
		Cornejo (Argentina)/Paso de Jama	Argentina	4.5	530
Gas Atacama	1999	Paso de Jama (Frontera)/Mejillones	Chile	4.5	411
		Pichanal (Argentina)/Paso de Jama	Argentina	5.0	450
		Paso de Jama (Frontera)/Crucero	Chile	5.0	260
		Crucero/Tocopilla	Chile	1.6	79
		Crucero/Quebrada Ordóñez	Chile	5.0	252
		Quebrada Ordóñez/Mejillones	Chile	3.9	35
NorAndino	1999	Quebrada Ordoñez/Coloso	Chile	1.6	104
		Mejillones/La Negra	Chile	2.45	89
Taltal	2000	La Negra/Paposo (Taltal)	Chile	2.45	135

Source: National Energy Commission (CNE).

The pipelines that transport gas from Argentina carry a certain risk as they must traverse the harsh terrain of the Andes. In 2000 and 2001, NorAndino pipeline interruptions lasted one month. They caused no problems because, although northern-zone pipelines are not interconnected, existing northern overcapacity—both transport and electricity power generation—allows a pipeline and the stations connected to it to absorb other pipeline demand. The central and southern zones have only one pipeline, whose interconnection would reduce the risk of interruption.

Distribution and Trade

Gasco-Magallanes, whose distribution network extends 1,070 km, has operated in the austral zone since 1981, when ENAP's distribution assets were privatized. Gasco-Magallanes supplies the cities of Punta Arenas, Puerto Natales, and Porvenir. It purchases natural gas directly from ENAP at three sites: Cabo Negro (for Punta Arenas), Clarencia (for Porvenir), and Tranquilo (for Puerto Natales) (table 4-11, p. 141).

Metrogas, located in the central zone, is the country's major distributor; its network includes a 192-km ring and tertiary lines extending 4,007

km (table 4-11). The network has the capacity to supply most areas in greater Santiago districts, although, to date, it has concentrated its efforts in the industrial areas of the city's periphery and in middle- and high-income residential areas. It also supplies Buin, Paine, Talagante, Lampa, Colina and San Bernardo suburbs. It receives gas from Gas Andes city-gates in Puente Alto and San Bernardo. In Argentina, Metrogas purchases gas directly from UTE Agua Pichana and San Roque to meet its own distribution needs and fulfill its role as a trader for distribution companies in Region V.

Region V distributors, GasValpo and Energas, began operations in 1998 (although GasValpo distributed city gas previously). GasValpo supplies the coastal cities of Valparaiso, Viña del Mar, and Concón, with a 450-km distribution network; while Energas' 1,170-km network supplies part of Viña del Mar and other towns in the region. Both firms distribute natural gas purchased exclusively from Metrogas at the Electrogas pipeline head in Chile (table 4-11).

In the northern zone, Progas and Distrinor currently trade gas to the zone's major industrial and mining companies. Both firms are linked to the Gas Atacama and NorAndino pipeline owners, respectively, and trade gas purchased from electric power generators, with which they are historically linked. Each carrier constructs high-pressure, branch extensions to their original concessions, which are usually several kilometers in length.

Currently, the northern zone has no distribution networks; however, Redgas, an independent firm, is developing a distribution project (related to population transfer) from the Chuquicamata mining area to Calama city, which Progas will supply. In addition, Distrinor sells natural gas in the city of San Pedro de Atacama.

The southern zone has two separate distribution operations, one in Region VIII and another in Region IX. Region VIII has both distribution and trading. GasSur distributes to residential and commercial customers in the cities of Concepción, Talcahuano, San Pedro de la Paz, and Chiguayante (table 4-11). Currently, GasSur distributes natural gas mixed with air in the pipelines previously used to distribute city gas, while newer lines distribute natural gas. Innergy sells all of the

gas consumed in Region VIII, both by GasSur and other major clients. Innergy supplies gas through its transport network or directly from the Gas Pacífico pipeline. Its major industrial client is ENAP's Petrox refinery; its other industrial clients are located in the cities of Concepción, Talcahuano, Penco Lirquén, Laja, Nascimiento, and Coronel. In Argentina, it purchases gas from UTE Chihuidos.

TABLE 4-11. DISTRIBUTION AND TRADING FIRMS, 2002

Company type	Region	Number of clients	Market segments	Gas type	Network length*	Year operations began
DISTRIBUTION						
Metrogas	MR	221,127 (natural gas) 54,570 (city gas)	Residential, commercial, industrial, CNG	Natural gas, city gas	192 km (HP); 4,007 km (LP) of which 800 km is city gas	1997
GasValpo	V, VI	33,323	Residential, commercial, industrial, CNG	Natural gas	450 km	1998
Energas	V	34,650	Residential, commercial, industrial, CNG	Natural gas	170 km (HP); 1,000 km (LP)	1998
GasSur	VIII	2,534 (natural gas) 17,605 (methane-air)	Residential, commercial	Natural gas, vaporized methane	n.a.	1999
Intergas	IX	2,574	Residential, commercial	Vaporized propane	n.a.	2001
Gasco-Magallanes	XII	44,009	Residential, commercial, industrial, CNG, generation	Natural gas	154 km (HP) 809 km (LP)	1981
TRADING						
Innergy	VIII	26	Industrial, refinery, distribution firms	Natural gas		1999
Distrinor	II	6	Industrial, mines	Natural gas		1999
Progas	I	2	Industrial, mines	Natural gas		1999

*HP= high pressure, LP= low pressure
n.a. = not available.
Source: SEC.

In Region IX, the gas network in the city of Temuco has distributed vaporized propane since 2001 (table 4-11). Intergas manufactures and distributes gas. The network was designed to supply future natural gas, as zone consumption would justify constructing a pipeline to interconnect with the Gas Pacífico pipeline in Region VIII.

Finally, Region XI has network distribution projects in Coyhaique. During the first half of 2003, GasAisen and GasAustral applied for concessions to distribute vaporized propane through networks; however, projects remain at an early stage. An interconnection with Argentina could eventually supply natural gas to the region.

Future Projects

Because Chile has no current or anticipated technical or financial restrictions for pipeline expansion, evolving demand will mainly determine future infrastructure. Transport capacity will continue to grow through expanding current pipelines, either by compression or loops, as new consumers willing to contract firm capacity emerge. The same conditions apply to new pipelines that could supply the country's Central Valley (Regions VI and VII) and southern zone (Regions IX, X, and XI). Large petrochemical and thermoelectric projects will push expansion of the transport network. Network distribution projects in new cities will emerge as the transport network develops; taken alone, such projects usually cannot justify pipeline construction (see Appendix).

Regulatory Framework

Chilean legislation establishes that hydrocarbon fields belong to the state, which can explore and exploit gas fields directly through the ENAP or tender them to the private sector through administrative concessions or special operational contracts (CEOP). Decree No. 1.089, which establishes CEOP norms, was promulgated in 1975. Since then, 18 exploration contracts with national coverage have been signed. Only one succeeded in finding gas in significant quantities (Lago Mercedes); however, its remote location has made exploitation unprofitable.

In 1989, enactment of Chilean Law No. 18.856 modified the 1931 law regulating the gas industry (DFL No. 323). Law No. 18.856 assures any private party the right to participate in natural-gas transport, distribution, and commercialization. Decree No. 263 of 1995 establishes rules governing concessions for gas transport and distribution, while Decree No. 254 sets safety standards for transport and distribution.

Concessions

If a company is interested in providing gas distribution services for a given geographical region, it must have a permanent concession that allows its holder to build, maintain, and conduct distribution activities. Conversely, a company interested in providing gas transport services through a pipeline or integrated network between a begin- and end-node must have a permanent concession that allows its holder to build, maintain, and conduct transport activities.

The decree allows for overlapping distribution concessions within a given geographical region and for multiple transport concessions between the same begin- and end-nodes. Thus, the regulatory authority cannot reject a concession request that complies with the legal, technical, and economic requirements. A transport concessionaire must operate under an open-access policy, understood as the obligation of each transport company to offer its available capacity under the same economic, commercial, technical, and informational conditions to any individual demanding transport services. Furthermore, the decree establishes that the price regime will be the one set forth in Decree No. 323.

Pricing Policy

Decree No. 323 establishes that transport and distribution prices are freely set through bilateral negotiations between the parties involved. Distribution prices should conform with two conditions: 1) the same price is set for consumers who demand similar amounts and 2) the company should inform clients of price changes in advance through the media or customer bills. The law, however, allows the Antitrust Regulatory Commission to require the Ministry of the Economy to set

prices in a given concession area for all clients whose monthly consumption does not exceed 100 gigajules. This request can only be made to those concessions whose prices set by the concessionaire result in an economic return above 5 percent of the concessionaire's annual cost of capital. The Ministry of the Economy considers the systematic risk of the distribution business, free-risk market rate, and market risk-premium to calculate the latter. The annual cost of capital, however, cannot fall below 6 percent.

By law, a concessionaire obtains an economic return above 5 percent of the annual cost of capital when the net flows calculated for the previous year are positive. The net flow is defined as the difference between annual revenue from natural-gas distribution and the sum of exploitation and investment cost, plus the profit tax.[5]

Investment costs are computed by converting the replacement value of the investment goods into annual investment costs of equal amount (considering its useful life, a zero residual value, and a replacement rate equal to the current annual cost of capital rate, plus 5 percentage points). Finally, the natural-gas price considered in the exploitation costs should be calculated on the interconnection node between either the production node or the end-node of the transport network and the begin-node of the distribution network. At this point, the natural-gas price corresponds to the best price the distribution company pays at the delivery point. If there is no price, the distribution company sets a price that cannot exceed, by more than 10 percentage points, the average annual price of the five largest industrial customers in a vicinity of the interconnection point. Each customer's price must be adjusted by the transport cost between the interconnection point and its respective facilities.

However, the law establishes that the distribution price is regulated in the austral region. The price paid by final consumers has two components: 1) price at which the distribution company of the region (Gasco) buys gas from ENAP and 2) added value of distribution, which is regulated. The

5. Exploitation cost is defined as the sum of operation, maintenance, and general outlays; the price paid for natural gas; and all costs related to concessionary goods that differ from investment costs and profit taxes.

price final consumers pay is determined, using the same pricing guidelines for the concessions that meet the conditions mentioned above.

Vertical Integration

Chile's current legal framework does not restrict the degree of vertical or horizontal integration or nationality of companies operating in any market segment; that is, a company can operate in every segment (production, transport, distribution, and commercialization) and can participate in related sectors (e.g., electric power generation). Moreover, no legal barriers to entry exist beyond the minimal legal, economic, and technical requirements awarded a concession. The current regulatory regime allows for a wealth of transaction possibilities (e.g., integrated companies competing with totally unbundled companies). This potential can be explained by the open-access policy adopted and because regulation imposes no restrictions on vertical and horizontal integration.

Service Quality

To safeguard quality of service, the Decree also establishes sanctions for transport and distribution companies that fail to supply the amount stipulated in their contracts. This sanction corresponds to a daily payment of 50 UTM when the problem continues beyond the days needed to correct the problem.[6] If the problem is severe, the Ministry of the Economy can authorize the SEC to take needed corrective actions. If the concessionaire is not capable of restoring supply after three months of SEC intervention, the concession can be revoked.

Interconnection and Current Regulatory Regime

The Gas Protocol between Chile and Argentina, signed in November 1995, regulates gas interconnection between the two countries. The most significant rules are:

6. In September 2003, 1 UTM was equivalent to US$42 (the UTM evolves according to the consumer price index).

– Neither party can impose export restrictions based on appropriately certified, natural-gas reserves and availability.

– Buyers and sellers are free to set prices, contract duration, quantities supplied per unit of time, guarantees involved, and any other condition the trading parties deem necessary.

– The parties have open access to pipelines.

– The nondiscriminatory principle holds.

– Buyers, sellers, and carriers must obey tax and customs legislation of the country in which they operate.[7]

– Conflicts are resolved through negotiations between the Chile's CNE and Argentina's Energy Secretariat.

The nondiscriminatory principle states that all consumers should be treated alike, regardless of geographical location, even if an unforeseeable contingency temporarily affects the infrastructure used to export gas from Argentina to Chile. However, the Argentine dispatch bylaw establishes that residential consumers have priority over other consumers. This bylaw would negatively affect Chilean customers because residential consumers have a lower weight in Chile than in Argentina. Argentina's position is that dispatch-bylaws priorities do not contradict the Gas Protocol because they apply to Argentine and Chilean consumers alike. However, during emergency periods, restrictions on exports have occurred; moreover, according to Argentine authorities, within Argentina, the dispatch bylaw has a higher legal standing than does the Protocol because the former is based on Law No. 24.076 regarding the gas sector, and congress has not yet approved the Protocol.

Chile's position is that the Gas Protocol was signed within the context of an economic integration agreement signed by both countries, which, in

7. For example, the import tax cannot exceed the repective country's tax on oil-based products or be lower than that of final products that use natural-gas inputs; the same conditions hold for exports.

turn, is registered in Aladi. Hence, no parliamentary ratification was required. Otherwise, the Chilean argument would question the purpose of signing protocols. Moreover, Article No. 7 in the Gas Integration Protocol between both countries safeguards geographical proportionality, even during emergency periods, and henceforth, potential priorities within each country would apply only after the transport capacity had been allocated between both countries according to existing contracts. Moreover, accepting the Argentine point of view would imply the extraterritoriality of Argentine laws, as they would require that Argentine authorities supervise their application in Chilean territory. In addition, the Argentine classification of consumers does not exist in Chile.

Another discriminatory issue involves differences in gas transport prices. In January 2002, the Argentine government enacted the Emergency Law, which triggered the collapse of the peso relative to the dollar over the following six months. Anticipating the peso collapse, the government froze domestic transport tariffs in Argentine pesos, but allowed investors to calculate export tariffs in constant US dollars. For example, a pipeline company charged a tariff of US$1 for both domestic transports and exports before January 2002. After that time, the same company could continue to charge US$1 for exports, now worth considerably more than AR$1; by law, however, the company could charge more than AR$1 for domestic transport.

Challenges to Regional Integration

Chile's integration into the Southern Cone regional market has required interconnecting Chilean gas systems with those of neighboring Argentina and Bolivia. Moreover, each Chilean natural-gas system is interconnected with an Argentine basin. Although interconnection is still relatively new, Chile considers it a success. This claim is substantiated by the growing importance of natural gas in the Chilean energy matrix and decline in the average nodal price of electricity,[8] since Argentine natural gas was added to the Chilean market in 1996.

8. The Chilean system is about 30 percent integrated.

Trade with Argentina relies on the 1995 Gas Protocol, which meets the most basic principles for promoting market integration. Nevertheless, to promote competition, two issues should be reviewed: 1) increasing requirements for unbundling and 2) establishing a regulated rate for transport access. European experience shows that market integration requires unbundling transport and supplier activities and regulated open access. Moreover, the lower the unbundling requirements, the greater the need to regulate price access since negotiated access prices give integrated suppliers the opportunity to manipulate markets through sophisticated price-discrimination systems.

Chile has not yet achieved integration with Bolivia. Working toward an agreement to import Bolivian natural gas is a long-term project; in the interim, Chile may attempt to establish an agreement for transporting Bolivian gas through Argentina, taking advantage of its interconnection protocol with Argentina, which guarantees open access under conditions equal to those under which Chilean companies operate. Alternatively, Chile is discussing the potential for market integration with Bolivia within the context of regional integration.

Appendix: Future Natural Gas Projects

Transport

Pipeline interconnecting central and southern markets: This project, a 500-km pipeline, depends on installation of thermoelectric plants in the Central Valley. It would supply the distribution companies that, in turn, supply retail sites in the Valley. Installation of gas-powered thermoelectric plants would determine project scheduling.

Southern zone pipeline (Regions IX and X): This project, tentatively scheduled for 2006–07, is a 500-km pipeline connecting Region VIII with Regions IX and X. Intergas, the distribution company serving Temuco city, is studying project feasibility. Installation of a thermoelectric plant in Region IX would contribute to viability.

International Coyhaique pipeline (Region XI): Tentatively scheduled for 2005–06, this 300-km pipeline project would connect Sarmiento in Argentina and Coyhaique in Chile. Public support is crucial.

Natural-gas liquefaction plant (Region I): This proposed plant, with 6.6 million m^3 tons per year and an average daily consumption of 22.7 million m^3 tons, would likely be located in Caleta Patillos and would start operations in 2007. Pacific LNG, which will sell Bolivian gas to the western U.S., is pushing the project forward. Sempra Energy would be the purchaser. The project would require construction of an 800-km pipeline connecting Bolivian gas fields with Caleta Patillo. Due to recent political events in Bolivia, however, the project has been delayed.

Regasification plant in the central zone: This project is linked to the construction of a liquefaction plant in the northern zone and gas demand growth—especially power generation—in the central and southern zones. It would compete with Gas Andes and Gas Pacífico, and with the Neuquén's Argentine gas. Project feasibility is uncertain; currently, there are no interested clients.

Distribution Infrastructure and Gas Sales

Central Valley gas distribution (Regions VI and VII): This project is tied to construction of a pipeline through the Central Valley. It could reach such cities as San Fernando, Curicó, Talca, and Linares, as well as major industrial consumers located in route. Initial potential consumption is estimated at 0.7 million m^3 per day, reaching 1.1 million m^3 per day in 10 years. No information is available on interested clients.

Interior gas distribution (Region VIII): This project involves Temuco's Intergas and Concepción's GasSur (distribution firm). Its objective is to cover, by 2004, the cities of Chillán and Los Angeles, by connecting to Gas Pacífico. Potential demand is 0.2 million m^3 per day.

Natural gas distribution (Regions IX and X): This project of Temuco's Intergas is tied to construction of a pipeline connecting Regions IX and X to the pipeline that carries Argentine gas to Region

VIII. As of 2004, it aimed to cover the cities of Temuco (currently with propane-air distribution), Valdivia, Osorno, and Puerto Montt, in addition to intermediate urban cities. Potential demand is 0.5 million m^3 per day.

Natural gas distribution (Region XI): GasAustral, GasAisen, and Gasco-Magallanes are studying the feasibility of this project, which would begin with propane-air or vaporized propane. Potential demand is 0.1 million m^3 per day. Because the pipeline is not privately profitable, its feasibility will depend on government financing. The Chilean president has hinted that public subsidies could be available.

Other Projects

Power plants: According to planning information provided by authorities in April 2003, nine combined-cycle plants of 370 MW each would be required, with estimated consumption of 1.7 million m^3 per plant, to satisfy Central Interconnected System (CIS) power demand over the next decade.

Petrochemical project (Region I): Subject to gas imports from Bolivia, a petrochemical cluster could be installed in Patillos, taking advantage of eventual gas and salt availability (significant exploitation of salt is occurring in the same area). This would imply an adjustment of demand projections for the northern zone.

Methanex expansion: Methanex announced plans to construct a methanol plant with an annual capacity of 840,000 tons; operations will start in 2005. This new plant, combined with three existing plants, would have a total annual capacity of 3 billion tons. Project cost is US$275 million. The new plant will consume approximately 750 million m^3 per year and supply has already been contracted for the next 20 years.

CNG for Santiago public transport: This project is highly dependent on authorities' environmental plans. Converting half of the bus fleet in Santiago would require about 0.8 million m^3 per year.

Cutbacks on Argentine Supply

In April 2004, Argentina began restricting natural-gas exports to Chile. Supply restrictions have been sizeable, reaching 34 percent of normal shipments in May (58 percent in the northern market). On certain days, cuts have reached 47 percent of normal demand (81 percent in the northern zone). Table 4-A summarizes the monthly average of supply cutbacks. Argentine production has become insufficient to satisfy both domestic demand and export contracts, and Argentina's government has forced local natural-gas producers to prioritize domestic demand over exports, independent of standing contracts.

TABLE 4-A. CUTBACKS ON ARGENTINE NATURAL-GAS EXPORTS TO CHILE IN 2004

Market	Normal monthly consumption (millions of m^3)	April cutbacks		May cutbacks		June cutbacks	
		millions of m^3	%	millions of m^3	%	millions of m^3	%
Northern	4.7	1.0	20.5	2.7	58.2	2.0	43.3
Central-Southern	12.7	1.3	10.3	4.1	32.1	1.8	14.6
Austral	5.7	0.0	0.0	1.0	18.3	1.4	23.8
Total	**23.0**	**2.3**	**9.8**	**7.8**	**34.0**	**5.2**	**22.7**

Source: National Energy Commission (CNE).

Argentina's Emergency Law, signed in January 2002, fixed prices of public services in Argentine pesos, including gas and gas transport prices. Meanwhile, the Argentine peso suffered a 65-percent devaluation. As a result, utility providers are confronting a mismatch between reduced revenue flows in dollars and operating and debt-servicing costs, which are largely dollar-denominated.[9] In response, Standard and Poor's downgraded the Argentine infrastructure-sector rating from BBB (investment grade) to CCC or D, effectively shutting off all new access to capital. Consequently, all investments—barring the most critical—have been slashed, with investment levels falling dramatically to an estimated US$200 million in 2002, down from US$5.2 billion in the 1990s.

9. The consumer price index increased about 40 percent, while wholesale prices rose more than 80 percent.

Until recently, this situation posed no critical problems for Chilean consumers. In fact, in mid-2003, executives of electricity and natural-gas distribution companies did not foresee supply restriction. They argued that available reserves were sufficient to satisfy demand over the coming years, quoting Argentinean Energy Secretariat estimates that showed proven reserves, at 2002 consumption levels, would last 17 years. These executives considered that production capacity was sufficient to satisfy demand until 2005. Although they believed the transport system could become a bottleneck without new investments, they did not consider this scenario an insurmountable difficulty for Chile. Certain pipelines connecting Argentina and Chile have their wellheads in gas fields; in other cases, Chilean investors could finance expansion of pipelines used to transport natural gas to Chile. Moreover, as Chilean consumers were paying prices three times higher than their Argentine counterparts, they believed that producers would make every effort to honor their standing export contracts. Finally, the Gas Protocol of 1995 guaranteed nondiscrimination of Chilean consumers.

What had been overlooked was a rapid expansion in Argentine demand, partly explained by the sharp decline in the real price of natural gas in the Argentine market. During 2002–03, natural gas production increased 10.4 percent; in the first three months of 2004, production grew 15.7 percent. Natural-gas companies, dissatisfied with selling reserves at below-market prices, have attempted not to validate further demand expansions; in retaliation, Argentina's government has limited exports.

A long-term solution will require Argentina's government to raise natural-gas rates. While it has established the Commission for the Renegotiation of Concession Contracts for all utilities, no agreements have yet been reached.[10] A major obstacle to renegotiation has been the social sensitivity surrounding utility rate increases, given the income decline that a large proportion of the population suffered. Argentina's government has offered to raise prices starting in 2005; however, time-

10. Private concessionaires' growing frustration with delays in renegotiation prompted nine of them to file claims with the International Center for the Settlement of Investment Disputes (ICSID).

consistency analysis destroys the credibility of this offer. Moreover, even if tariffs are normalized, the high risk will make it difficult for natural-gas companies to access financial markets.

Uncertain Future of Imports

Argentina's government has stated that it will shift its role from natural-gas exporter to importer. Internal consumption has increased significantly, while exploration has virtually stalled. Existing reserves have declined significantly over the years, although no official figures are available (explained, in part, by the reserves tax). If Argentina's natural-gas policy remains unchanged, the country could become a net importer of natural gas; information is insufficient to determine the supply balance under more rational economic policies.

In sum, Argentina is no longer a reliable natural-gas provider. The most that Chile can expect is that Argentina will honor its standing export contracts; however, it is unlikely that its government will authorize additional exports. Thus, Chile must search for new energy sources. The Chilean government is promoting construction of a regasification plant in the central zone. The ENAP is leading the project, and all major consumers—Metrogas and electricity firms—are participating. Project cost will range from US$100 million to US$800 million, depending on capacity. This could make the price of natural gas so high that other alternatives would become more attractive. Currently, the residential prices of natural and liquefied gas are similar. Industrial plants could use diesel, and new thermoelectric plants could use coal. Moreover, hydroelectric plants are regaining in attractiveness, and non-conventional electricity-generation sources are being carefully watched.

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Chapter 5

Peru: Potential Role for the Region

Geoffrey Cannock[*]

Peru's relatively undeveloped, natural-gas market is characterized by significant demand for electricity generation; six large industrial clients; and the commercial, residential, and transport sectors in the departments of Lima and Callao. The greenfield Camisea Project, begun in August 2004, is expected to gradually develop the country's domestic and export markets. The liquefied natural gas (LNG) project is the only one that can create a substantial increase in short-term demand. Other than the north-coast and central-jungle fields, which are significantly smaller than Camisea, the only other known field is Pagoreni with reserves estimated at 85 billion m^3. Although the state has not yet defined its future use, it is the only source of potential competition for the operator of Camisea.

The country's regulatory framework for natural gas was designed to encourage private participation, taking the potential domestic market into account. Law No. 27133, enacted in 1999 to promote the natural-gas industry, includes measures such as guaranteed revenues for transporters. These cover the difference between transport revenues and investment costs and operation and maintenance of the transport network, through a user-provided subsidy of the electricity sector (the additional charge for electricity transmission is the Main Network Guarantee [MNG]). Thus, transport regulation is similar to a public-works contract since the concessionaire receives a revenue flow over time that guarantees investment recovery at a set discount rate.

Although this regulation established open access to transport and distribution networks, the producer was awarded provisional exclusive

* The author wrote this chapter while serving as competition and regulation manager at Apoyo Consultoría. He acknowledges Santiago Dávila for his support.

rights for use of transport capacity. Exclusive rights for distribution and commercialization in Lima and Callao were also awarded the distribution concessionaire. While Camisea has potential competition (the Pagoreni field), awarding of exclusive rights hinders its development and could discourage exploration if fields close to it cannot use existing transport until the exclusive rights expire.

This chapter analyzes the structure and regulatory framework of Peru's natural-gas market to determine what factors could impede a future regional network or create trade barriers. The analysis includes an evaluation of the internal market structure that will develop through the Camisea Project (the only project large enough to be relevant).

Considering the region's projected balance between supply and demand, Peru is not envisioned as a supplier of natural gas through pipeline trade like the Southern Cone countries. Nonetheless, Peru could play a key role as a natural gas exporter to Mexico and the western United States. In addition, Bolivian gas exports from the Tarija field could use a Peruvian port, implying, at a minimum, a bi-national agreement for pipeline rights of way and use of port facilities.

Reserves, Production, and Demand

Peru's natural-gas reserves are located mainly in unexplored fields, of which Camisea is the most important (229 billion m^3) and represents nearly 18 times currently exploited, proven reserves. In addition to north-coast fields, the Pagoreni field, adjacent to Camisea, has reserves estimated at one-third those of Camisea (table 5-1).

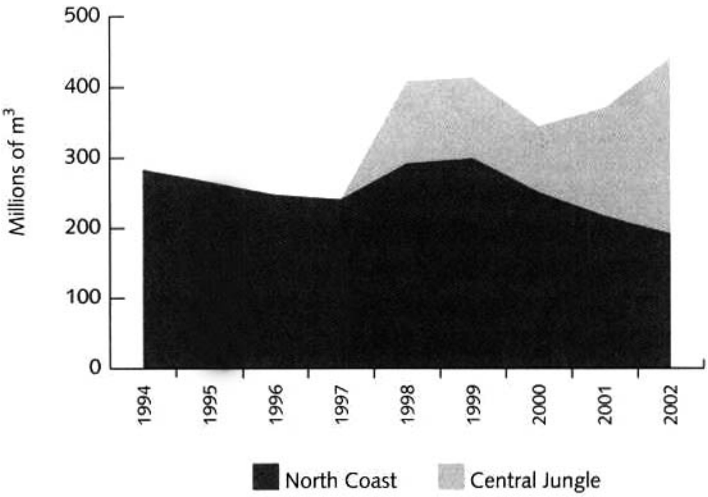
Peru's natural-gas production is still for domestic consumption and, until 1997, was limited to the north-coast region (figure 5-1). North-coast production occurs in petroleum operations (e.g., Talara Refinery); thermoelectric plants (e.g., Piura Electric Company); and, to a lesser extent, the residential sector (e.g., Punta Arenas, Talara). In the central jungle, production is for fuel to generate electricity (e.g., Aguaytia Thermal Plant), while north-jungle production centers exclusively on oil operations.

TABLE 5-1. PROVEN NATURAL-GAS RESERVES, 2000
(millions of m^3)

Zone	Natural gas	Percent
North coast	4,269.79	1.8
Zócalo	327.79	0.1
Central jungle	8,028.11	3.3
South jungle (Camisea)	229,118.97	94.8

Source: Ministry of Energy and Mines (MEM).

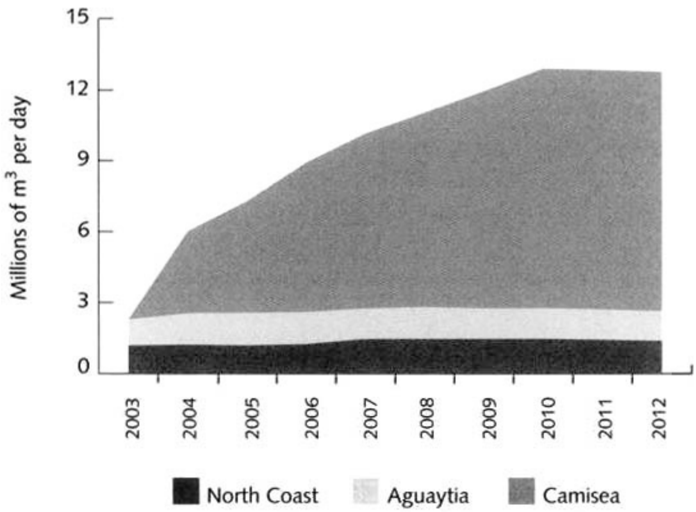
FIGURE 5-1. REGULATED NATURAL-GAS PRODUCTION, 1994–2002
(millions of m^3)



Source: Ministry of Energy and Mines (MEM).

Three companies control north-coast production, while only one, Aguaytia Energy, controls central-jungle production. Aguaytia Energy maintains an integrated vertical structure, from gas extraction through LNG production and electricity generation. Figure 5-2 provides a conservative estimate of increased Peruvian production during 2003–12 through the Camisea Project. Gas from north-coast and central-jungle fields will be freed up because of Camisea's higher production volume and its gas consumption for power generation, which could stimulate development of natural-gas projects in these zones.

FIGURE 5-2. SUPPLY PROJECTIONS BY ZONE, 2003–12
(millions of m³ per day)



Source: Ministry of Energy and Mines (MEM).

Future north-coast and central-jungle projects are envisaged to increase industrial, commercial, and residential consumption within the area of influence of these fields. Thus, they would not directly affect trade.

Industry Structure: Camisea Project

The Camisea Project consists of two fields—San Martín and Cashiriari—both located in the Amazon jungle, about 500 kilometers (km) east of Lima. In Las Malvinas (40 km from the fields), gas liquids are separated and given to the transporter, which is currently building a 700-km gas pipeline to Lima's city-gate, Lurín (30 km south) and a 540-km pipeline to transport LNG to Pisco (260 km south). A fractionation plant will be built in the Bay of Paracas (Ica) for LNG production. In addition, a plant to produce LNG for export will be built in Cañete (180 km south).

The Camisea ownership structure consists of three consortia, with a significant degree of cross-ownership between the field-operations and transport consortia (figure 5-3). The distribution company also has an ownership stake in the transport company.

FIGURE 5-3. CAMISEA OWNERSHIP STRUCTURE

Exploitation
Consortium

Company	Participation (%)	Country
Pluspetrol	36	Argentina
Hunt Oil	36	United States
SK	18	South Korea
TecPetrol (Technit)	10	Argentina
Total	**100**	

Transport
TGP (Transportadora de Gas del Perú)

Company	Participation (%)	Country
TecGas (Technit)	31	Argentina
Pluspetrol	19	Argentina
Hunt Oil	19	United States
Sonatrach	11	Algeria
SK	10	South Korea
Tractebel	8	Belgium
Graña y Montero	2	Peru
Total	**100**	

Distribution
GNLC (Natural Gas of Lima and Callao)

Company	Participation (%)	Country
Tractebel	100	Belgium
Total	**100**	

Source: TGP.

Total estimated investment to develop the Camisea field, transport, and distribution exceeds US$2.6 billion. Until commercial operations begin, an investment of about US$1.5 billion is expected (table 5-2).

TABLE 5-2. CURRENT AND PROJECTED INVESTMENT (as of 2003)
(millions of US dollars)

Activity	Initial*	Additional	Total	Invested
Exploitation	600	400	1,000	516
Transport	810	500	1,310	510
Distribution	100	100	200	30
Total	**1,510**	**1,000**	**2,510**	**1,056**

* From start-up of commercial operations.
Source: TGP.

By 2006, natural-gas exports are estimated to reach 18 million m³ per day, an amount significantly greater than current domestic consumption. Based on projected gas exports, Camisea's field will be depleted by about 2026.

Industrial Demand

Six large industrial customers guarantee initial demand for Camisea, which currently maintains supply contracts with these customers (table 5-3).

TABLE 5-3. INITIAL INDUSTRIAL-SECTOR CLIENTS

Customer	Industry type	No. of Plants	Contracted volume (millions of m³ per day)	Take-or-pay volume (millions of m³ per day)	Duration (years)
Cerámica San Lorenzo	Ceramics	1	0.04	0.03	10
Cerámica Corporation	Ceramics	2	0.03	0.02	10
Vidrio Industries	Glass	2	0.04	0.04	10
Cerámica Lima	Ceramics	2	0.10	0.07	10
Alicorp	Food	2	0.06	0.03	6
Sudamericana de Fibras	Chemical	1	0.08	0.05	5

Sources: TGP and Pluspetrol.

The remaining industrial demand for Camisea gas consists of 67 companies, with a total demand of 422 million m³ per day. Three other companies have projects with significant potential demand, but low probability of success (table 5-4).[1] Figure 5-4 shows expected industrial demand of Camisea gas through 2033.

Commercial and Residential Demand

Figure 5-5 shows that demand growth was slow during the initial years of commercial operation; this resulted, in part, from expansion of the local distribution network. During 2006–11, it is expected that growth in both commercial and residential demand will increase significantly, subsequently tapering off to 1-3 percent.

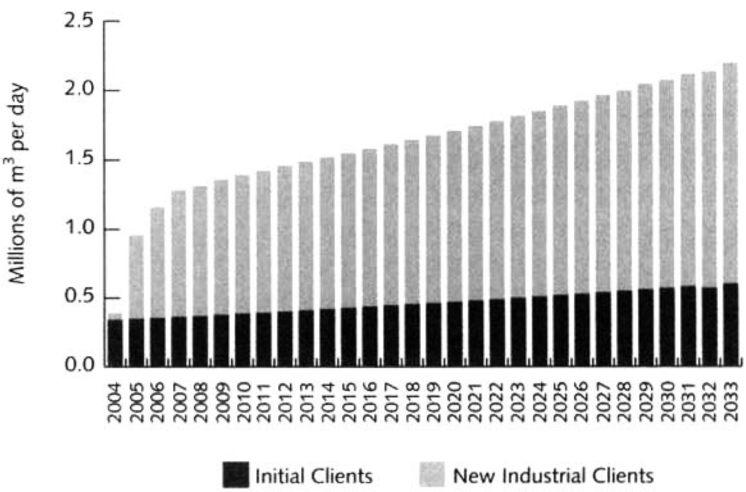
1. One of the 67 companies is a large cement firm. The additional companies are EXSA, Ammonia Nitrate Plant (1.4 million m³ per day), Aceros Arequipa, Sponge Iron Project (736 thousand m³ per day), and Mapsa (45 million ft³ per day).

TABLE 5-4. OTHER INDUSTRY DEMAND

Industry type	No. of Plants	Average daily demand (millions of m³)	Annual demand (millions of m³)
Small	37	2.9	38,496
Medium	19	9.9	68,950
Large	10	22.6	82,672
Lima cement	1	386.6	141,118
Total	**67**	**422.0**	**331,236**

Sources: Pluspetrol.

FIGURE 5-4. EVOLUTION OF INDUSTRIAL-SECTOR DEMAND BY CUSTOMER TYPE, 2004–33
(millions of m³ per day)



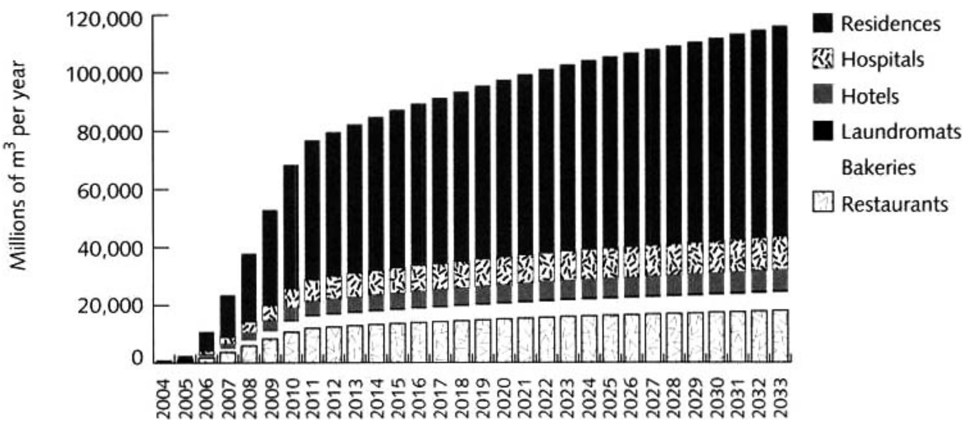
Source: OSINERG.

Transport Demand

By 2008, major discrepancies between the TGP transport company and the regulatory agency are projected with regard to transport-sector demand. The regulatory agency used Pluspetrol as the basis for projecting demand for vehicular gas for the strategic field operator, based mainly on corridor development between Lima and Ica departments (figure 5-6, p. 163). According

to OSINERG (*Organismo Supervisor de la Inversión en Energía*), Pluspetrol will begin developing a natural-gas market, with installation of service stations along the corridor. These stations will later be transferred to other operators, with the final goal of concentrating field operations.

FIGURE 5-5. CAMISEA COMMERCIAL AND RESIDENTIAL DEMAND, 2004–33
(millions of m³ per year)



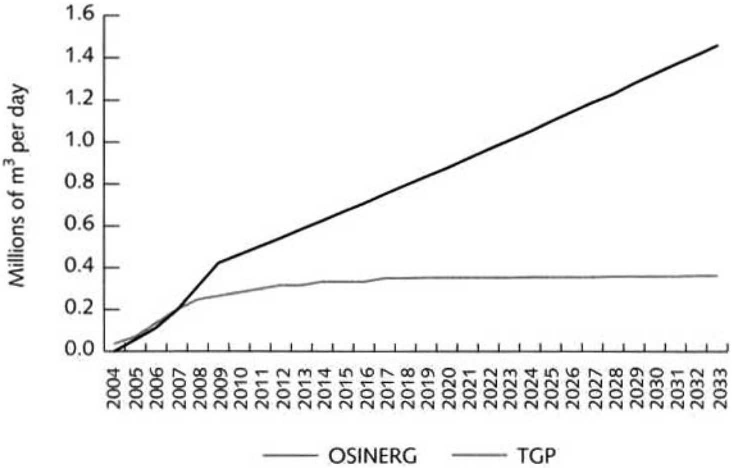
Electricity Demand

Currently, Peru's power-generation capacity is about 4,383 megawatts (MW); of this total capacity, 60 percent is hydroelectric and 40 percent thermal. Although electricity production is predominantly hydroelectric,[2] thermal centers are used on high demand days, using either diesel or residual oil.

Camisea development is closely linked to the dynamics of the power-generation industry. The electricity sector is not only the major source of domestic natural-gas demand; it also provides a portion of transporters' income through the MNG electricity end-users pay to ensure the transport consortium recoups its costs. Use of natural gas for power generation not only reduces generation cost, it also lowers use of more polluting fuels, such as diesel and residual oil, which Peru imports.

2. 2001 statistics show that hydroelectric generation accounted for 91.03 percent of demand for 16,807.05 GWh (gigawatt hours), while thermoelectric generation comprised 8.97 percent.

FIGURE 5-6. CAMISEA DEMAND FOR VEHICULAR CONSUMPTION, 2004–33
(millions of m³ per day)



Source: OSINERG.

It is noteworthy that the Camisea Project influenced electricity rate levels long before field operations started. The resason is that the regulatory mechanism used to determine the cost of generating power computes the present value of marginal costs of production with a 48-month time horizon, taking supply and demand into account. The Camisea Project has affected the fixing of generation rates since 1997.

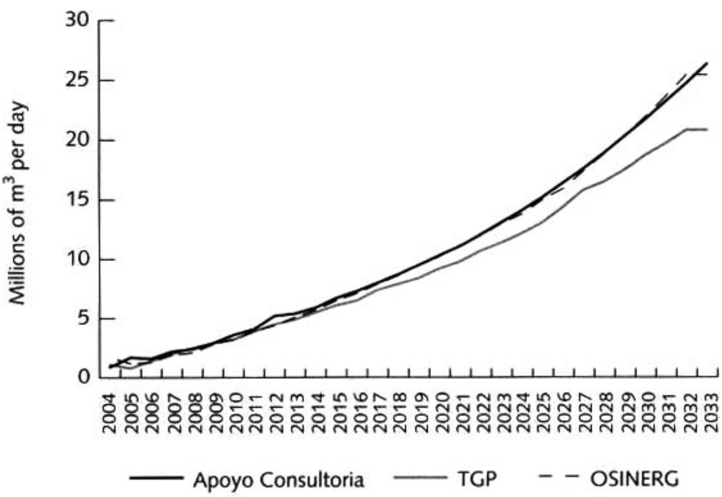
Figure 5-7 shows TGP's projected evolution of natural gas demand for power generation within the framework of the rate-fixing process for the main network. It also shows OSINERG's estimate of demand in the regulatory process (which is greater than the firm's estimate), which is consistent with Apoyo Consultoría's recent projection.

During initial Project years (2004–06), Etevensa (Endesa Group) will be the electricity sector's main natural-gas customer. Electro Perú's contract with Camisea's upstream consortium for 2.0 million m³ per day was transferred to Etevensa.[3] In addition to Etevensa's investment to convert its facility into a

3. Transfer of the contract forces Etevensa to reconvert its installations to operate with an open cycle (250 MW) within 15 months and a combined cycle within 36 months (125 MW in simple cycle and 187.5 in a combined cycle). Electro Perú will purchase Etevensa-produced energy over a seven-year period.

combined cycle, entry of only one key hydroelectric plant, Yuncán (130 MW), is expected during this initial period because of high investment costs and the abundance of natural gas. Future expansion would be based strictly on combined-cycle plants.[4]

FIGURE 5-7. PROJECTED NATURAL-GAS DEMAND FOR ELECTRICITY GENERATION, 2004–33
(millions of m³ per day)



Source: OSINERG.

Using natural gas to generate power will reduce the marginal cost of generation and provide a substitute in less efficient plants. Over the next decade, it could also lead to regulatory changes designed to develop a more competitive electricity market. The Ministry of Energy and Mines (MEM) and OSINERG plan to review the regulatory framework for generation to evaluate the feasibility of moving toward a tender-based system.[5]

4. A major project proposes to install a 500-MW hydroelectric plant; however, the required investment could be justified only in the absence of natural gas or by eventual demand growth for electricity beyond historic levels.
5. Public and private sectors discussed certain changes in design of the wholesale electricity market within the framework of a series of MEM meetings on Second Generation Reforms in the Electricity Sector. Both MEM and OSINERG may review the regulatory framework for the generation market, with the aim of improving competitive performance.

Although Peru is not expected to become a pipeline exporter of natural gas in the region, it could export natural gas as electric power. This would become possible if regional interconnection increases demand for Peru-produced electric energy. Despite progress made in electricity interconnection with Ecuador, this connection is unlikely to represent significant demand for Peru—at least over the short term—because the interconnecting transmission line has a maximum transport capacity of only 100 MW, which is insufficient to attract investment in new generation capacity of Peru's electricity sector.

Other Natural-gas Projects

Two natural-gas projects will likely be implemented: 1) LNG Production Project and 2) LNG Export Project. The first project will produce LNGs—diesel, naphtha and liquefied petroleum—for local and export markets, while the second will export LNG to Mexico and the western United States (California). These projects are described below.

LNG PRODUCTION PROJECT

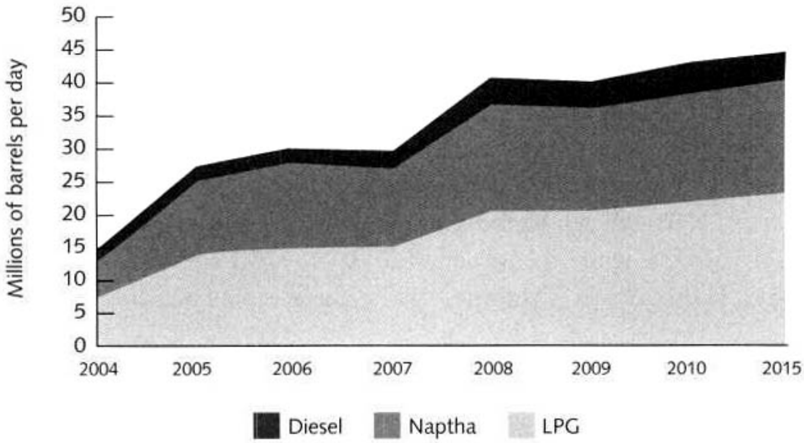
During the gas-field phase, part of the Camisea Project involves LNG extraction for local and export markets. The gas is transported through a pipeline to Lobería Beach in Paracas (Ica). There, liquefied petroleum gas (LPG) (propane and butane), diesel, naphtha, and jet fuel (for airplane use) will be produced and distributed over land and by sea.

The fractionation plant has onshore and offshore components. The onshore component includes entry facilities, fractionation plant, distillation unit, storage tanks, and truck-loading zones. The offshore component includes a tanker-loading terminal for large tankers with a deep draft and four underwater transport pipes: two for propane and butane, one for naphtha, and one for diesel.

Figure 5-8 shows projected LNG production volume through 2015. It is estimated that about 40 percent will be exported to Chile and Ecuador, while 60 percent, for local consumption, will be sold mainly to large LPG wholesalers, such as Repsol Refinery and Zeta Gas. (These wholesalers

have already established LPG retail chains.) All naphtha production will go to the export market—mainly the eastern U.S.—and, eventually, depending on price, northern Brazil and Japan. All diesel production will go to the local market, mainly to wholesale distributors (Repsol, Shell, Mobil, and Petro Perú).

FIGURE 5-8. LNG PRODUCTION, 2004–15
(millions of barrels per day)



Source: Pluspetrol.

LNG EXPORT PROJECT

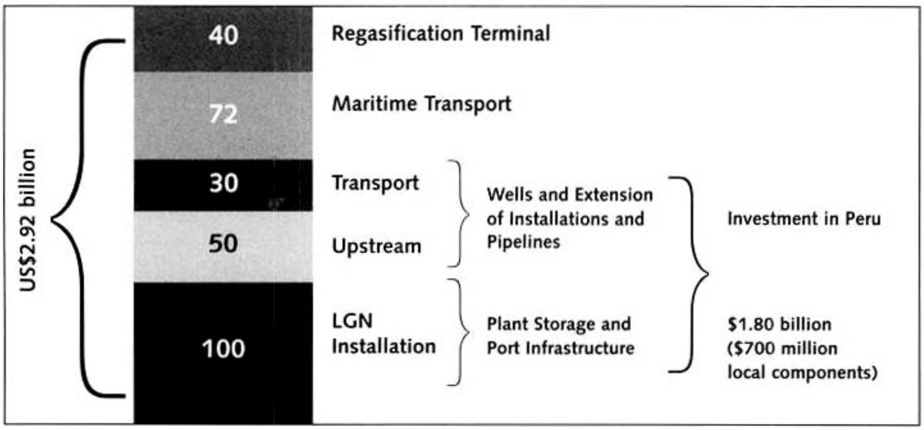
LNG plant construction is a major development project linked to the Camisea Project. This plant proposes to export LNG to Mexico and the western U.S. Shareholders of the project's developer, Peru LNG, are Hunt Oil (70 percent) and SK Gas Company (30 percent). Both firms are also partners in Camisea exploitation and transport phases. The project should begin operations by late 2007.

The project is located south of Lima in Cañete, an arid coastal area of 521 hectares (ha), known as Pampa Melchorita (situated on the west side of the Panamerican Highway, between 167 and 170 km). The project includes building and operating an Export and Liquefaction Plant, with an annual capacity of 4.4 million metric tons. It also involves developing

port facilities for tankers and other needed investments, such as drilling of new wells, increasing separation capacity of the Las Malvinas plants, and increasing long-term transport capacity.

According to Peru LNG, project development would require an investment of about US$2.9 billion, of which US$1.8 billion would correspond to investment in Peru (the local component is US$700 million), while the remaining US$1.1 billion would be invested in a regasification terminal and acquisition of methane tankers for LNG transport (figure 5-9).

FIGURE 5-9. PROJECTED INVESTMENTS FOR LNG EXPORT PROJECT



Source: Hunt Oil.

In addition to generating investment, the export project would reduce MNG: maximum pipeline capacity would be reached earlier because of LNG exports. Other advantages would be creating incentives to explore new fields and the potential for covering growing demand in the external market.

The LNG export project is not part of Camisea Project design (even though two shareholders in the production and transport phase (Hunt and SK Gas Company) direct the export project). From a legal standpoint, the LNG export project is viewed as an independent consumer, meaning that it canacquire natural gas directly from the producer, vendor, or distribution

concessionaire, as long as volume exceeds 30,000 m^3 per day. This legal status may imply that the LNG project is not under energy regulatory powers.

Proposed Pipeline Projects

Three pipeline projects for regional interconnection have been suggested. Two of these projects were proposed as Camisea export options through 2000: 1) Peru (Camisea) to Bolivia (Carraco) and 2) Peru (Camisea) to Brazil (São Paulo). Given current regional perspectives, however, their implementation is unlikely in the near future.

The third option is to construct a pipeline from Bolivia (Tarija) to Peru and set up an LNG plant in the Ilo port. Located 1,000 km south of Lima near the Chilean border, Ilo would give Bolivia an alternative to the Chilean port for exporting gas to Mexico and the western U.S. If Bolivian gas were piped to Ilo, another option would emerge: constructing a pipeline to Lima, which shares the Peruvian project's LNG plant, instead of building another LNG plant in Ilo.

Finally, domestic extension of the gas distribution network through the Ica, Cuzco, and Ayacucho regions may be feasible, given their proximity to Camisea's main pipeline. However, it is likely that the central or regional government would need to participate in developing these initiatives, given these regions' low demand.

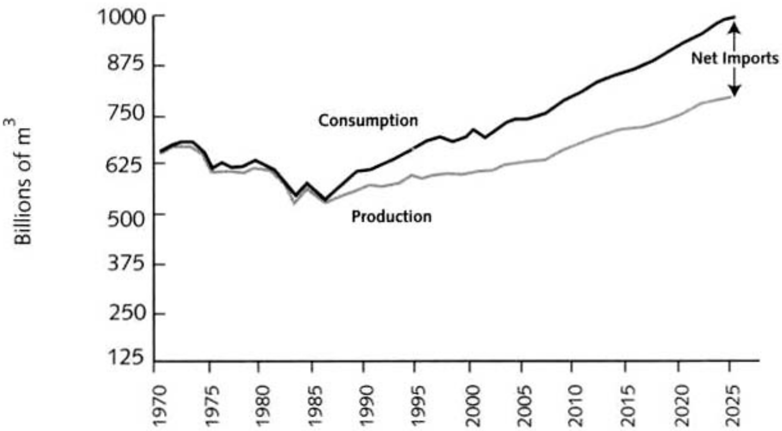
Export Perspectives

U.S. and Mexican Markets

The market for Peruvian LNG is based on growing demand in the U.S. and Mexico. The gap between U.S. consumption and production is currently covered by natural-gas pipeline imports (mainly from Canada) and, to a lesser extent, through LNG imports (from Algeria, Trinidad and Tobago, and Qatar).[6] LNG imports should become even more important in terms of demand coverage (figure 5-10).

6. EIA (2001, 11–12).

FIGURE 5-10. U.S. PRODUCTION, CONSUMPTION, AND IMPORTS, 1970–2025 (billions of m^3)



Source: Energy Information Administration (EIA).

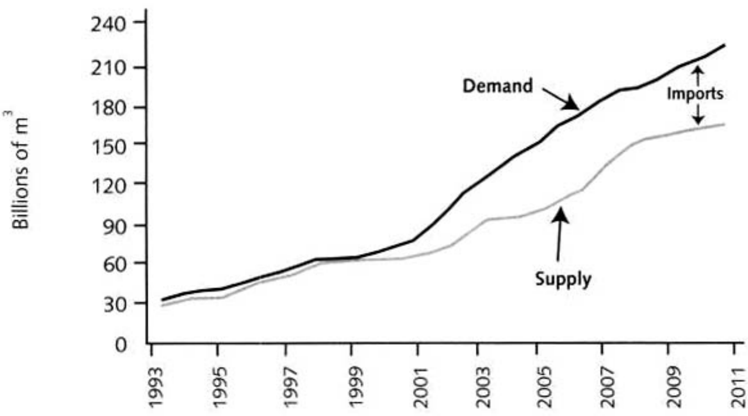
Recent policies to reduce use of fossil fuels imply that Mexico will also use an increasing volume of natural gas in the future.[7] According to the National Energy Commission, by the year 2011, Mexico will need about 51 billion m^3 of imported natural gas to cover projected demand (figure 5-11).

Favorable projected prices for LNG imports in the U.S. and Mexico increase prospects for building regasification plants in both countries. As figure 5-12 shows, after a period of mild stability LNG prices should begin to recover gradually by 2006.

The trend toward increased LNG demand and prices has encouraged proposals to U.S. and Mexican authorities for building new terminals. The Mexican Energy Regulatory Commission, amid strong opposition, recently approved such projects (e.g., LNG terminals in Altamira, Taumalipas and Baja California, Ensenada).

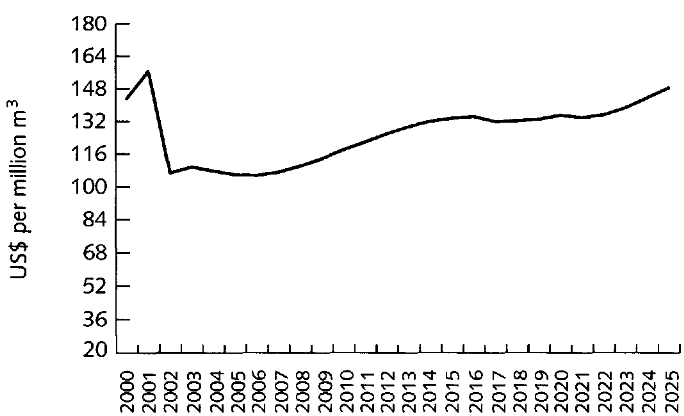
7. The Mexican strategy to reduce fossil fuel use has four components: 1) building thermal generation plants using combined-cycle natural gas; 2) converting generation plants from oil to natural gas; 3) increasing the industrial use of natural gas, in accordance with 1998 environmental standards; and 4) promoting domestic and commercial use of natural gas.

FIGURE 5-11. MEXICAN PRODUCTION, CONSUMPTION, AND IMPORTS, 1993–2011
(billions of m³)



Source: National Energy Commission.

FIGURE 5-12. AVERAGE LNG IMPORT PRICE TO U.S., 2000–25



Source: Energy Information Administration (EIA).

U.S. and Mexican natural-gas markets have the capacity to absorb Peruvian LNG exports; however, the Peruvian project faces potential competition from other projects, particularly the Sakahlin Project (Russia) and the Tarija Project (Bolivia).

The Sakahlin Project has on-site reserves of about 566 billion m^3 of natural gas and 1 billion barrels of petroleum to meet Asian demand, although part of this production could be directed to the California market. The Sakahlin Project has the advantage of a guaranteed Asian market, which can be leveraged for commercial expansion in the U.S. Project sponsors are Shell, Mitsui, and Mitsubishi. The Project will be implemented one year before the Peruvian project.

Tarija Project reserves, estimated at 1,275-1,415 billion m^3, far exceed Camisea reserves and are substantially greater than current demand in Bolivia and Brazil (the main purchaser of Bolivian gas). The Project's main challenge is political; that is, the Bolivian public would prefer that gas be exported from a Peruvian, rather than a Chilean, port.

Clearly, the Bolivian alternative involves a higher netback price in the wellhead; however, the Project's economic effect depends not only on sale price for export, but also on royalties producers must pay and markets that allow them to obtain higher profits. In the case of Peruvian gas, for example, Camisea's economy has already been consolidated because of internal demand, meaning that LNG export can be viewed as a plus in terms of project economy. In the Bolivian case, however, the local market is not large enough for the Project to be profitable on its own; thus, sustainable exploitation requires the support of an export market.

Finally, long-term contracts that guarantee product purchase over time are an important aspect of competition for greenfield gas projects. It has recently been disclosed that Hunt Oil and Tractebel[8] (a natural-gas distributor in Lima) have signed a Memorandum of Understanding to purchase a significant volume of natural gas for export to Mexico, representing about two-thirds of total export supply. Camisea export supply will amount to 13 percent of projected U.S. demand over the next decade, after which its share will drop to about 10 percent. Hence, the remaining supply of Peruvian gas export is likely to find a U.S. market.

8. Tractebel has regasification plants in the U.S., as well as facilities in Mexico; currently, it is the main LNG importer to the U.S.

Regulation

The legal and institutional framework for the Peruvian natural-gas industry has been directed mainly toward creating an internal market for gas from the Camisea field. In light of limited local demand, mechanisms to encourage private-sector participation were designed to enhance project feasibility.

Legal and Institutional Framework

The legal framework for Peruvian natural-gas exploitation, transport, distribution, and commercialization involves three general laws:

- Law No. 26221. Organic law governing hydrocarbon activities in the national territory.

- D.S. No. 041-99-EM. Regulation of hydrocarbon transport by pipeline network.

- D.S. No. 042-99-EM. Regulation of natural-gas distribution by pipeline network.

In the case of Camisea and other projects developed through licensing or service contracts involving Law No. 26221, the following licensing and concession contracts are applied:

- Licensing contract for exploitation of hydrocarbons in Block 88 (Camisea),

- Build-Own-Operate-Transfer (BOOT) contract for natural-gas transport by Camisea pipelines to the city-gate,

- BOOT contract for LNG transport via Camisea pipeline to the coast, and

- BOOT contract for natural-gas distribution concession via pipeline networks in Lima and Callao.

Two additional laws with regard to private-sector participation and industry promotion complete the sector framework:

– Law No. 27133. Law that promotes development of the natural-gas industry.

– D.S. No. 040-99-EM. Regulations of the Law to promote development of the natural-gas industry.

No specific environmental protection law covers natural gas; rather, a general law applies to all energy activities. Any company that develops activities in the hydrocarbon sector (including natural-gas exploitation, transport, and distribution) should refer to D.S. No. 046-93-EM (Regulation of Environmental Protection for Hydrocarbon Activities), which specifies issues involving presentation and content of Environmental Impact Studies and programs.

With regard to foreign trade of natural gas, export and import transactions fall under general foreign-trade laws that establish free private initiative, which implies unregulated foreign trade. Only Law No. 26221 (hydrocarbons law) requires that field operators indicate the number of years they are committed to supplying natural gas to the local market at the time they sign the export contract.

The gas sector's institutional framework contains both public and private institutions that share various functions and responsibilities. In general, the MEM and OSINERG, are the most important institutions. MEM is the executive body charged with designing general policy for the sector and granting concessions to carry out sector activities. Through the Directorate of Environmental Affairs, MEM is also responsible for approving Environmental Impact Studies related to all energy sector activities in general and the natural-gas industry in particular.[9]

The regulatory agency, OSINERG, has economic and functional autonomy. It regulates gas transport and distribution rates and oversees concessionaires' compliance with their contractual obligations and laws. It also oversees safety and quality issues.

9. In the case of gas activities involving nature reserves, Environmental Impact Studies consider the technical opinion of the Institute of Natural Resources (INRENA).

Two provisional institutions relate specifically to the Camisea Project: 1) Interinstitutional Technical Coordinating Group (CGTI) and 2) Camisea Ombudsman's Office. A third, more general entity, created at the same time as the LNG fractionation plant in Paracas, is the Commission for Sustainable Development of Paracas Bay.

Vertical and Horizontal Integration

With the exception of the electricity sector, Peru has not had control systems in place for mergers and acquisitions. In addition, the country places no limits on vertical integration. There is a high degree of integration between the field and transport operator and, to a lesser extent, between the distribution and transport operator. According to Peruvian antitrust law, only abuse of monopoly power is illegal.

No regulation covers joint ownership of gas and electricity activities. For example, the firm in charge of natural-gas distribution also has shares in power generation.

In the case of Camisea, the industry structure initially considered was not vertically integrated in its gas field, transport, and distribution components. Although this structure led to development of four contracts—gas-field licensing (1), gas and liquids transport (2), and distribution (1)—a significant degree of ownership linkage occurred between the field-operations consortium and the transport operator and, to a lesser extent, between the distribution firm and transport operator (figure 5-3). These arrangements are common in the gas industy because of the high specificity of their assets, high sunk costs, and risk patterns.

With a single producer, the effects of ownership linkages on competition in domestic and export markets are limited, at least in the short term. If other fields are discovered, the potential negative effect of vertical integration on competition will be limited through adequate regulation of open access to transport and distribution networks, complemented by unbundling obligations of services and provisions to legally separate business units or accounting systems.

Camisea Exclusive Rights: Use of Transport Capacity

The licensing contract for exploitation establishes that the producer has an exclusive right to use pipeline capacity for a period of 10 years, beginning the day that the project begins commercial operations, expected to run until 2014. However, exclusivity is not completely eliminated after 10 years since the licensing contract establishes that the producer will have preferential access, with conditions equal to third parties, until 12,750 trillion m^3 per day is reached.

Producer exclusivity over the pipeline clearly restricts access of potential upstream competitors. It could also make concessions located near Camisea, such as Pagoreni, difficult. If the state opts for turning over this field to a new operator, exclusivity could even discourage new exploration by third parties, who would be unable to effectively transport gas to the main center of domestic consumption (Lima and Callao) or to the coast for export (at least during the exclusivity period and until a capacity of 12,750 trillion m^3 per day were reached).

From this perspective, the transport exclusivity awarded the producer creates a significant barrier to entry and implies effective monopolization of natural-gas production for the area surrounding Camisea. Other producers must have their own pipelines or use more than 12.7 million m^3 per day of available capacity.

The awarding of such exclusive rights might be questioned from a legal standpoint, since, according to Article 61 of Peru's constitution, no law or agreement can authorize or establish monopolies. A group of congresspersons recently asked the Constitutional Court to declare Law No. 26285 unconstitutional, because it created an exclusivity period for Telefónica del Perú. Although the Constitutional Court did not repeal the law, its action was based only on procedural grounds since Telefónica's exclusivity rights had already expired; thus, it is still unclear whether it is feasible to establish a legal exclusivity right based on an investment-promotion objective.

The debate over exclusivity could become more relevant with development of prospects for exporting natural gas, to the degree that

other companies are interested in exploring and exploiting fields for export. However, it should be noted that these exclusivity rights were granted ex ante; an ex-post change could imply a change in the rules or be interpreted as opportunistic behavior by the state.

Exclusivity for Distribution and Commercialization: Lima and Callao

Lima and Callao are at the center of Peru's commercial and residential natural-gas markets. With regard to promotion, Law No. 27133 (Law of Promotion of Transport and Distribution Contracts) foresees the possibility of commercial bypass for regulated consumers (those who buy volume equal to or less than 30,000 m^3 per day) and independent customers (purchasers of volumes greater than 30,000 m^3 per day).[10] However, according to Law No. 27133, these provisions will not apply until 2012.

Although physical bypass is possible, it cannot affect the concessionaire's exclusivity over building facilities within the concession area. Thus, any third-party extension of the distribution network (e.g., a client outside the distribution network but within the concession area) should later be transferred to the distribution concessionaire, who will pay a fair price. Finally, it is not possible to incorporate sub-areas of distribution within theconcession zone until 12 years after commercial operations begin (2015 in the case of Camisea).[11]

Current potential for downstream competition is limited since there are no other sources of production or gas transport, independent of exclusive rights granted the distributor. Even if entry of companies that sell natural gas to the Lima and Callao markets were possible, these firms would have to deal with the sole producer and transporter, which would limit their differentiation possibilities compared to those of the

10. In the first case, regulated consumers may purchase gas only from the distribution concessionaire or merchant. In the second case, independent consumers may purchase gas only from the producer or merchant (in this case, both transport and distribution networks have open access).

11. Any other concession bid within Lima and Callao for areas in which the concessionaire has not worked should have, as of this date, a minimum extension of 10 hectares, with the concessionaire maintaining preferential right to distribution (as long as the concessionaire offers the same or better conditions as those of the interested party).

distributor, who would also buy gas from the sole producer. Entry of firms will also depend on the potential for retailing, which is still unregulated,[12] and future competition from other fuels.

Thus, effective competition within the Lima and Callao concession zone is highly unlikely until 2012, at least for regulated clients. The same conditions hold true for independent clients (despite open-access provisions for distribution networks) since there is only one producer, whose main client is the sole distributor. Thus, no incentives encourage the producer to take clients away from the distributor.

Considering the small size of projected demand and the above-mentioned factors, exclusivity of commercialization and distribution are less detrimental to downstream competition than exclusivity granted the producer for the transport network. In any case, efficient rate regulation for the distributor's end-users could greatly reduce the productive inefficiencies derived from exclusive operation of natural-gas distribution and commercialization.

Rate Regulation

The Licensing Contract for Exploitation established a maximum price scheme for gas, based on the price basket for petroleum products. The maximum prices set were US$1.00 per million Btu for electricity generators and US$1.80 per million Btu for all other users.

Rates for high-pressure transport and distribution (Main Network) were fixed to guarantee the investor a flow of revenue (guaranteed revenues), allowing the investor to recover investment, maintenance, and operational costs (service costs). The rate for transport service is structured as a maximum monthly charge that differs by client type (electricity generators and industrial customers); however, this charge should be homogenous within each client category. These charges give users the right to a determined transport capacity. Depending on the

12. Currently, OSINERG is attempting to determine the distribution and retail margins that the distribution company in Lima and Callao will charge.

degree to which capacity is contracted out, revenues from the sale of capacity are less than guaranteed revenues, which is the difference needed to cover MNG service costs paid by electricity end-users.[13] Main Network transport and distribution rates are shown in table 5-5.

TABLE 5-5. TRANSPORT AND DISTRIBUTION RATES, MAIN NETWORK

Tariff type	Rate (US$ per million m³)
Transport	
Base	28.7883
Regulated	41.0786
Distribution	
Base	4.7371
Regulated	6.3607

Source: OSINERG.

Distribution rates for natural gas are established for four-year periods, based on calculating the margin of distribution and retailing that an efficient natural-gas company would obtain. The regulator should validate investments and costs proposed by the firm using these rates; however, if they are redundant in terms of meeting demand, the regulator is not obligated to consider them.

Challenges to Regional Integration

Peru's contribution to regional integration hinges on implementation of the LNG export project aimed at U.S. and Mexican markets and, to a lesser extent, export of Bolivian gas from the Tarija field using Peruvian rights of way. In the latter case, Bolivian gas may also serve Peru's southern domestic, and even Lima, market.

Both initiatives face interrelated regulatory, political and market obstacles. Major issues for the LNG export project are: 1) availability of

13. In October 2002, the MNG was initially set at a monthly rate of US$1 per kW and has gradually been increased. Once Camisea begins commercial operations, the monthly rate will be US$2.5 per kW.

gas supply for the domestic market, 2) allocation of gas-field rights adjacent to Camisea, and 3) royalty negotiation. It is possible that the government and private sector will sort out these issues.

The Bolivian gas project, using the Peru LNG facility, would require that Peruvian regulation address 1) open-access regulation of LNG facilities, 2) role of regional regulatory agencies in building a harmonized regulatory framework, and 3) competition policies for the domestic market.

Domestic Market Supply

According to domestic- and export-demand projections, Camisea fields will be depleted in about 20 years. Without the LNG export project, these fields would meet domestic demand for at least the next 60 years. Initial regulation required that the gas-field operator guarantee domestic supply for at least 20 years. In 2003, amendment of this regulation (by Presidential order) requires only that the operator state the term for domestic supply in the export contract.

Although Peru's Constitution protects the agreed-on terms of private contracts from such amendments (which imply that the perceived regulatory risk is trivial), this residual risk is still relevant if future political sensitivities arise. One should bear in mind that initial support for building the Camisea Project was based largely on constituents who favored domestic-market development.

Gas Field Rights and Royalty Negotiation

As discussed above, provisional exclusivity rights granted the transport consortium limits third-party interest in exploring and developing new fields. At the same time, there are regulations with regard to government discretion in the awarding of concession contracts. For example, the government is under no obligation to conduct a tender, which would likely fail because of the exclusivity period.

In June 2004, the government disclosed that it had reached an agreement with the Camisea gas-field consortium to develop the Pagoreni field. The royalties (38 percent of sales) will be similar to those negotiated for the Camisea field if the export price is US$4 per million Btu, determined by ex-ante competition through a tender. However, if the price drops below that level, the royalty would be 30 percent.

The government clarified that the Pagoreni field will serve the export markets, while the Camisea field will serve the domestic market, with several decades of coverage.

This agreement avoided the expected renegotiation of Camisea royalties, which were set at a minimum netback price of US$0.6 per million Btu (relatively high in periods of low international prices). Domestic wellmouth prices are regulated.

Although sector regulation aims to segment the export and domestic markets, domestic consumers might challenge this policy on grounds that it may not comply with domestic antitrust rules, which state that firms may not engage in price discrimination.

On the other hand, domestic electricity consumers' MNG payments will diminish with the export market. Thus, domestic prices will tend to converge with international markets,[14] exerting pressure to equate the royalty fees across gas fields, disrupting current royalty agreements.

Third-party Open Access

The Peruvian regulatory framework stipulates open access to the transport network at a regulated rate. However, a comprehensive regulatory framework of open-access terms and conditions has not yet been developed. Moreover, sector regulations do not envisage gas interconnections with third-party firms residing in neighboring countries, although experience from the Ecuador-Peru electricity-sector

14. In this scenario, regulation of domestic rates is weaker since gas becomes a tradable commodity.

interconnection suggests that the energy regulator would likely become involved in negotiating open-access regulations for the gas industry.

Open-access terms do not cover storage facilities since such infrastructure is non-existent and because of the small domestic market and lack of seasonal demand.

Regulations for open access to LNG terminals have not been drafted since these facilities are considered large consumers. Open access to LNG terminals could become a relevant issue with development of other LNG projects for export markets. In this case, the open-access provision would favor competition between foreign-market, over domestic-market, suppliers, given Peru's condition as a net exporter. However, if most gas from the Camisea and Pagoreni fields is sold under long-term contracts, the incentives for sharing Peru's LGN facility switch from conflict to collaboration.

In the event that Bolivian gas is exported through Peru, the extra cost of laying the 1,000-km pipeline along the coastal strip (from Ilo to Lima, to interconnect with Peru's LNG plant) should be weighed against the savings from building an LNG plant in Ilo, port works, and investment in specialized ships to transport gas to the U.S. and Mexico.

Role of Regulatory Agencies

In an integrated market, regulatory agencies usually play a conflict-resolution role with regard to interstate connections. In the United States, for example, the Federal Energy Regulatory Commission (FERC) plays this role, and one regulatory system is applied to all interstate transporters. In the European Union (EU), however, the regulatory agency of the country in which the transporter in question is located assumes this role because community entities have the right to appeal.

In Peru, this role of the regulatory agency does not exist since the country's industry is directed toward the domestic market and LNG maritime exports. In any case, this proposal is in agreement with Lapuerta (2003) that creation of a regulatory body like the FERC is

unlikely for the Southern Cone region. An integration strategy, similar to that of the EU, would be used, based on general principles and as part of already existing integration agreements (Southern Cone Common Market [Mercosur] and Andean Community[15]).

Domestic Competition

If Bolivian gas is exported using the LNG facility just south of Lima, then serving and competing in the Lima market become an option, thereby ensuring long-term domestic gas supplies. Although this option would likely have a marginal effect on deciding whether to export Bolivian gas through Peru, enforcing competition policies in this sector would be high on regulators' agenda.

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15. The Andean Community has set up a Competition Court that handles cases involving firms that trade within that region.

PART II

Regional Integration Issues

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Chapter 6

Advancing Toward Integration: A Proposal

Carlos Lapuerta

Integrating regional markets in the natural-gas industry is especially challenging. Many other industries that do not depend on infrastructure networks can integrate regionally by relying on market liberalization, privatization, and tariff elimination, followed by the enforcement of antitrust law. Structural measures, such as merger constraints or rulings on abuse of dominant position, are only required a posteriori and as a result of a particular behavior. By contrast, natural-gas markets involve complex pipeline networks, which require advance implementation of restructuring and regulation measures. In Latin America and the Caribbean (LAC), many incumbent gas companies are vertically integrated, simultaneously transporting and selling gas. Effective competition is unlikely to develop as long as incumbents allow their supply businesses to use transport infrastructure on favorable terms relative to competitors.

In South America's Southern Cone region, the efficient development of natural-gas markets faces three key obstacles:

- insufficient requirements to ensure nondiscriminatory access to pipeline infrastructure;

- insufficient requirements for separating gas production, transport, and sales businesses; and

- regulations that distinguish between domestic consumption and exports.

In the case of the United States, a central agency that regulates interstate pipelines facilitated integration of regional gas markets. However, the

LAC region lacks such a central legal authority, which makes the U.S. experience somewhat less relevant. More relevant is Europe's experience. Like the United States, the European Union has a central legal authority; however, the legal links between its Member States are looser than those between U.S. states. The European Gas Directive involves the level of generality typical of multinational treaties among sovereign states. Furthermore, the European experience has shown the importance of continuous dialogue among independent gas-market regulators from each Member State, government ministries, and industry groups to forge a consensus and motivate progress in market liberalization.

This chapter structures a set of recommendations for promoting gas market integration in the Southern Cone region. While the author's general approach relies on European experience, his recommendations recognize the Southern Cone's distinguishing features. In contrast to the United States and Europe, the Southern Cone has:

- sovereign states that lack a regional organization with the legal authority to impose uniform rules or initiate reforms,

- strong export potential for liquefied natural gas (LNG), and

- a far greater proportion of gas consumption by power generators.

The process of market integration in the Southern Cone should begin with broad agreement on certain principles, perhaps embodied in a multilateral treaty whose style might parallel the European Gas Directive, but that would contain substantive provisions tailored to the LAC context. Regional institutions would then work on the details of implementation, as in Europe. Regular meetings would allow independent regulators, government ministries, and market participants from the various countries to discuss implementation details and take specific steps.

This chapter offers six specific recommendations for the Southern Cone (the author focuses on areas where recommendations depart from European and U.S. approaches, in accordance with the unique features of Southern Cone gas markets):

– unbundling gas production and sales from transport;

– eliminating distinctions between domestic consumption and exports;

– implementing open seasons for new pipeline infrastructure, accompanied by commitments to offer unused capacity to third parties;

– simplifying transport rate-setting;

– reducing significantly the scope for derogations from open-access obligations; and

– relying mainly on market forces to address security-of-supply concerns.

Lessons in the Process of Market Integration

In deciding on the most appropriate process for regional market integration, South America's Southern Cone can learn from both U.S. and European experience. In the United States, success over the past few decades has relied on institutional factors that the Southern Cone lacks. For example, a single regulator is authorized to regulate the interstate pipelines that link diverse geographic markets. While operational rules and services differ slightly for each interstate pipeline, the Federal Energy Regulatory Commission monitors and regulates them closely to ensure compliance with detailed orders of national scope.

Conversely, in the EU, market integration has relied on broad agreements between Member States on such principles as transparency and non-discrimination and subsequent political pressure for Member States to implement these principles effectively. Periodic meetings to discuss progress in liberalization have been important, and a variety of institutions have contributed.

This proposal recommends an approach similar to that of the EU for the Southern Cone region. The process could begin with adoption of a multilateral treaty that would commit its members to several broad principles for promoting development of competition and market

integration. The treaty would include details to address specific Southern Cone issues and would seek to avoid the deficiencies of the European Gas Directive. In short, it is recommended that the Southern Cone adopt a multilateral treaty with a process of bi-annual meetings, as in Europe, in which various organizations contribute to the emergence of a consensus on the detailed steps required for implementation.

Lessons from the European Union

The EU's legal framework and the European Commission's monitoring of implementation have proven less important in regional market integration than simple political pressure and involvement of various institutions in promoting dialogue and consensus on liberalization. The original Gas Directive and its subsequent amendments use extremely broad language, permitting a range of differences in implementation.

The Gas Directive contains an important provision that anticipates friction between Member States that might pursue liberalization with varying degrees of vigor. The Directive imposes a schedule with specific eligibility thresholds,[1] while contemplating that certain countries might liberalize significantly faster than required. All consumers in the United Kingdom (UK) had the right to choose suppliers at the same time; in France, however, only the largest consumers could do so. In such cases, the Directive would have permitted the UK government to preclude French gas companies from supplying small British customers, since France did not yet allow anyone to compete for small French customers. This right of reciprocity helps to avoid the popular resentment and political problems that can arise if gas companies with a substantial legal monopoly in one country take advantage of another country's willingness to liberalize the market quickly. The right of reciprocity helps encourage faster liberalization by alleviating the fear that less advanced countries can take advantage of more advanced ones.

1. The Gas Directive imposes dates by which Member States must offer certain consumer segments the legal right to choose a gas supplier. Member States must gradually extend customer choice to smaller customers, covering certain minimum percentages of total domestic consumption. Consumers who can choose gas suppliers are considered eligible customers, and the boundaries that define the groups are eligibility thresholds.

SUCCESS OF THE MADRID FORUM

Progress in liberalizing European gas markets has involved a complex process including various organizations. In 1999, the European Commission initiated the European Gas Regulatory Forum of Madrid, known as the Madrid Forum, to promote effective implementation and harmonization across Member States. The Madrid Forum is a semi-annual meeting attended by national regulators, government ministries, gas pipeline operators, gas suppliers and traders, and consumer organizations from throughout Europe. The Forum provides an opportunity for constructive discussion and communication with regard to implementing the Gas Directive. Attendees discuss specific issues that the Directive does not, such as allocation and management of scarce pipeline capacity. They consistently attempt to reach consensus on the best way to implement the Directive. The Forum publishes conclusions of the meetings and establishes specific goals for further progress.

In addition, the Forum reviews Member States' progress on liberalization, which helps to keep political pressure on those that lag in implementing the Directive. Moreover, the presence of consumer groups—key contributors to the debate on implementation problems in certain Member States—at the Forum maintains pressure on countries that fall behind.

The Madrid Forum has made significant progress with regard to the publication of data. While the Gas Directive states a general goal of transparency, it fails to provide guidance on implementation. At the first Forum in 2000, no consensus was reached on this issue. Initially, an association of gas companies resisted publishing information on available capacity on major interstate pipelines, arguing that capacity was difficult to measure, estimates would be of little value given the complexity of networks, and publication could reveal commercially sensitive information. Subsequent Madrid Forums revisited this issue, making gradual progress until the sixth Forum concluded: "[A]ll relevant information…in particular available capacities shall be published in a transparent and timely manner" (European Regulatory Forum 2002).

FORUM CONTRIBUTORS

The Council of European Energy Regulators (CEER) and Gas Transmission Europe (GTE) contribute significantly to the Madrid Forum. The CEER is a nonprofit organization designed to assist and advise the European Commission with regard to promoting efficient, transparent, nondiscriminatory, and competitive gas markets and establishing common policies among Member States where possible (CEER 2003). The CEER creates working groups of regulators from Member States to examine specific regulatory issues. These working groups develop conclusions about regulatory best practices and recommend common policies to Member States. Recently, the CEER published guidelines for sound practices on access, tariffs, and balancing (CEER 2002). While not legally binding, these guidelines help fill the gaps left by the general language of the Gas Directive. They assure regulators and legislators in particular countries that certain steps promoted are widely supported across Europe. In countries whose legal and regulatory frameworks inadequately support the development of competition, consumer groups can refer to the CEER guidelines to create pressure for reform.

Gas Transmission Group Europe (GTE) is another important contributor to the Madrid Forum. Before July 2000, Eurogas represented Europe's established gas companies, nearly all of which were vertically integrated. The European Commission specifically requested creation of an organization to represent only Europe's natural-gas transmission businesses. In response, GTE was created. The Commission's request provided a way to focus on the Forum's more technical issues. Although Eurogas still sends representatives to the Forum, GTE contributes uniquely by gathering specialists in network operations throughout Europe. GTE has since organized numerous working groups of pipeline executives to examine specific policy issues.

Toward a Southern Cone Approach

It is recommended that Southern Cone countries use a broad multilateral treaty to initiate the process of regional integration and maintain a level of generality similar to that of the European Gas Directive to facilitate

initial agreement. The most important aspects of the Directive are its commitment to developing effective competition in gas supply and eventual creation of a single European market and its requirement to offer third parties nondiscriminatory, transparent, and objective access to network infrastructure. These principles should shape the focus of the Southern Cone treaty. In addition, the treaty should include a mandatory schedule for market opening and the principle of reciprocity to accommodate countries that wish to exceed the mandatory schedule.

While a Southern Cone treaty should maintain a level of generality similar to that of the European Gas Directive, it should, in certain respects, impose stricter requirements. The original Directive permitted vertical integration, and only required integrated businesses to keep separate accounts for transport and supply activities. Furthermore, it permitted Member States to choose between negotiated and regulated access regimes. At present, the international standard involves the creation of separate legal entities with separate management dedicated to transport and supply activities. It is recommended that a Southern Cone treaty include regulated TPA and legal and management unbundling. Indeed, experience shows that no country in the world has successfully developed competition in gas supply without these two components.

Moreover, the treaty should provide more details than the European Gas Directive in five key areas:

- Incorporate specific requirements to eliminate regulatory distinctions between domestic consumption and exports, as Bolivia and Argentina do. While the Directive does not specifically prohibit different regulatory policies for domestic gas consumption and exports, Europe's absence of such distinctions may stem from the general obligations of European law, which prohibit subsidizing domestic industries or impeding exports.

- Promote an open-season policy, whereby regulators would require potential infrastructure projects to offer long-term contracts to third parties. The European Gas Directive does not plumb this depth of detail regarding the regulatory treatment of new projects; however, the issue is important for the Southern Cone because private financing of

new infrastructure will likely play an important role in development of the LAC gas sector.

– Limit the potential scope for exemptions from open-access regulations. The European Gas Directive permits derogations from open-access requirements based on broad principles, some of which involve the construction of new facilities. Europe could accept broad language concerning potential derogations because the issue is unlikely to reduce consumer choice significantly. The European natural-gas network is mature, and distribution networks already reach most consumers. However, similarly broad provisions in a Southern Cone treaty could permit countries to grant unnecessary gas-supply monopolies to potential investors in distribution networks or new pipelines. Thus, this author proposes more limited conditions concerning exemptions from TPA requirements. In particular, the permissible exemption policy should be limited to only a subset of open-access requirements under specific market conditions.

– Provide specific rate-setting policies.[2] Certain European countries still debate whether to set rates by examining the costs incurred for existing investment or by reference to hypothetical replacement costs for new infrastructure or international rate comparisons. It is recommended that regulators set rates for existing pipeline by reference to underlying costs, while allowing regulators to set rates for new pipelines pursuant to competitive tender processes. A Southern Cone treaty should specifically mention these policies because the Gas Directive's avoidance of these issues has prompted considerable uncertainty over the setting of tariffs.

– State specific requirements for publishing information. While the European Gas Directive contains a general obligation of transparency, it fails to establish the importance of information disclosure for effective TPA. While the Madrid Forum has progressed significantly in grappling with this issue, it has taken several years. A statement of publication requirements need not involve great detail, but the treaty

2. While the Gas Directive contains general references to cost-reflectivity, it does not provide specific approaches for setting transport tariffs.

should clarify that nondiscriminatory access requires a level playing field between independent supply companies and the integrated supply affiliates of network infrastructure. Infrastructure owners should be obligated to publish accurate information concerning the technical characteristics and capabilities of their facilities, the amount of capacity dedicated to other users under long-term supply contracts, and historical use of facilities.

Europe's experience also suggests the importance of establishing a forum roughly equivalent to the Madrid Forum, similarly involving regulators, ministries, and industry and consumer groups. Such a forum would seek to establish consensus on details of implementing the Southern Cone treaty and review Member States' progress toward integration. As Madrid Forum experience shows, consumers' presence at such forums is critical because it puts significant pressure on those Member States that may lag in treaty implementation.

Finally, European experience suggests that it would be useful to expand the charter of the Association of Latin American Energy Regulators (ARIAE). Currently, the ARIAE's charter is limited to fostering the exchange of information among regulators. The CEER charter has far more ambitious goals of promoting efficient and competitive energy markets and developing and promoting common policies wherever possible. It is recommended that the ARIAE expand its current charter to match that of the CEER. The ARIAE could commission working groups, consisting of various regulators, to examine specific issues and develop guidelines for sound practice.

Unbundling and Regulatory Authority

The market-integration process will require Southern Cone countries to decide on the extent of unbundling and whether to agree on minimum requirements regarding regulatory authority. European market liberalization began with minimal unbundling obligations, and did not require countries to establish independent regulators. However, experience has since demonstrated that extensive unbundling and independent regulators are essential for the development of effective

competition.[3] The European Commission has responded by promoting the adoption of stricter requirements in recent amendments to the Gas Directive. International experience provides compelling support for requiring strict accounting, management unbundling, and the strengthening of regional regulatory authority.

Although international institutions have already reached a minimum consensus regarding these issues (Beato and Laffont 2002, xii and 97), experience with emerging economies reveals two serious misconceptions. First, many view extensive unbundling as a luxury characteristic of industrialized nations and sophisticated gas markets. Such individuals advocate looser standards for emerging economies or countries lacking domestic gas production or mature gas markets. Second, others view strict unbundling and regulation as suitable for the U.S. and UK institutional model, but suspect that alternative approaches could work in countries with other cultures, economies, and legal traditions. Similar arguments were still prominent in Europe as recently as three years ago, but have quickly become untenable.

European Experience

The 1998 Gas Directive required the separation of financial accounts only between supply and transport.[4] Gas companies were not obligated to publish separate accounts. The Gas Directive required only that regulators or competition authorities have at least access to unbundled accounts to explore the possibility of cross subsidies. In practice, many EU Member States passed national laws and regulations requiring unbundling beyond the Gas Directive's requirements.

The level of unbundling has correlated roughly with the extent of competition in various European countries. The UK was the first EU

3. Legal unbundling involves the creation of legally separate subsidiaries to undertake the functions of transmission, distribution, and supply. Management unbundling entails a clear separation of infrastructure and human resources into business divisions for various services. Legal unbundling need not include management unbundling; for example, it is possible to have the same manager direct a company's transport and supply subsidiaries.

4. Directive 98/30/EC.

Member State to implement full unbundling, which is defined as including the separation of ownership between the transmission system and the gas supply business. The UK "remains the [European] leader in terms of effective competition." By contrast, Germany is the least advanced in unbundling, and has some of the highest network access charges in Europe (European Commission Directorate-General for Transportation and Energy 2003).

In the UK, complete unbundling came only after years of frustration with the slow pace of gas-market liberalization, marked by competition authorities' investigation into the behavior of British Gas (BG). At the beginning of the liberalization process, BG was a vertically-integrated supply, transport, and storage business. The law permitted entry by competitors; however, the government's policy of negotiated access failed dramatically during 1986–93. Third parties and government organizations complained of inadequate access terms and BG's competitive abuse. A combination of strong political pressure, recommendations by competition authorities, and pressure from the energy regulator prompted progressive unbundling. In 1994, BG introduced a detailed Network Code, and unbundled its management. Then, in 1997, BG took a major first step toward full ownership unbundling, splitting transportation from supply. Subsequent ownership unbundling involved the sale of production and storage assets. By 1998, when the first gas Directive went into force, the UK pipeline system was well on its way to full unbundling.

Initially, German government officials preferred an approach that imposed minimum requirements on existing gas companies and did not establish an independent regulator, relying instead on three factors: 1) industry dialogue between user groups and companies, 2) intervention by competition authorities in access disputes, and 3) progress monitoring by government ministries who could threaten interventionist legislation. German pipeline companies prepared separate accounts for gas transport and supply, as required by the Directive, but did not follow the BG's unbundling steps.

By all objective accounts, the German attempt to explore an alternative approach has failed. Potential entrants brought several cases before

competition authorities and at times achieved victories. However, litigation proved an unsuccessful strategy for improving terms of access. Litigation was expensive, time consuming, and competition authorities were legally compelled to make decisions on the narrowest grounds possible.[5] The failure of lawsuits was accompanied by failure of government threats to introduce new legislation and of industry dialogue to promote significant progress.[6]

Germany's liberalization failure has been particularly dramatic, given the numerous factors that favored successful development of competition. Since 1998, all German consumers—even the smallest households—have had the legal option to choose suppliers. The German market is one of Europe's largest and most diverse, importing gas from Russia, Norway, and the Netherlands. On the eve of liberalization, Germany had two large, private gas companies, each with a high-pressure pipeline system that crossed significant parts of the country. Despite these factors, some five years after approving the Gas Directive, only a handful of TPA transactions occurred per year, in a country of approximately 80 million that imports 100 m^3 barrels per year. Most examples of successful TPA involve only short-term transactions among incumbents.

Inadequacy of the Gas Directive divided Europe into two groups: one that voluntarily exceeded the Directive's requirements in an effort to develop effective competition and a second that lagged. This distinction created tensions between countries, and threatened one of the Directive's key goals: creation of an integrated European gas market. After several years, the

5. In one case, German competition authorities ruled that a German gas company had insisted on clearly unreasonable transport tariffs; however, they refused to define an appropriate tariff, explaining that they were not a price-setting authority and that, technically, the only legal issue presented before the court involved the reasonableness of the German company's proposed tariff. This was a narrower question than determining what the optimal tariff should be. The plaintiff in that case found that victory brought little clarification of the issues, leading only to further negotiations that required further threats of litigation. The Gas Directive's principle of non-discrimination is clearly violated when the supply business of Ruhrgas can obtain access to the pipeline network with a simple phone call, while it can take other supply businesses up to a year, coupled with expenditure of several hundred thousand euros in legal fees.

6. For several years, the government threatened legislation that would establish central regulatory authorities, but did not take action. Industry dialogue produced several vague, non-binding guidelines for pipeline tariff methods and access terms. However, the guidelines consistently failed to require pipeline companies to offer third parties the same level of information concerning their networks or the same service flexibility, reliability, or ease of booking and trading capacity as enjoyed by the incumbents' supply businesses. Facing clear legal obligations to maximize the value of their companies for shareholders, senior managers of incumbent gas companies wisely refrained from volunteering pro-active measures to promote competition.

Commission initiated efforts to amend the Directive. Recently passed amendments require the creation of independent regulatory authorities and legal and management unbundling of all gas Transmission System Operators (TSOs).[7]

The revised Gas Directive contains relatively detailed requirements for management unbundling. TSO management may not work for an associated production or supply business and should be capable of acting independently of the supply business. In addition, the parent company should not intervene in decisions involving new connections. Moreover, the Directive requires the TSO to establish a compliance plan to monitor success of unbundling and prevent discriminatory conduct; it must also publish the measures taken to ensure independence.

Table 6-1 summarizes the status of European unbundling. As of 2003, all 15 Member States had separate accounting for transport and supply, and 7 had implemented legal and management unbundling. Several countries followed the UK, separating ownership of the transport network from gas supply. Spain did so most recently, creating a separate company with its own stock shares issued successfully to the market. Shares of pipeline-network owner Enagas now trade actively on the Ibex.

Legal and management unbundling are not confined to the more advanced gas markets of developed European countries. Even such relatively poor Member States as Greece have committed to legal and management unbundling. The accession countries that will shortly join the EU will also face unbundling requirements of the amended Gas Directive. Most already have independent regulators, and all will create regulatory authorities in compliance with the Directive. Most of these countries lack developed gas markets and are considered emerging economies. For example, Latvia has a per capita GDP of US$7,730, similar to that of Brazil (US$7,360), but less than that of Chile.[8] None of these countries had a regulatory tradition.[9]

7. Directive 2003/55/EC, Article 9.
8. These 2001 per-capita GDPs are measured at Purchasing Power Parity; see United Nations Human Development Indicators (2003).
9. It should be noted that the UK had no significant regulatory tradition when it privatized BG in 1986.

TABLE 6-1. STATUS OF EUROPEAN TSO UNBUNDLING, 2003

Country	Accounting	Management	Legal	Ownership
MEMBER STATE				
Austria	Y	Y	Y	
Belgium*	Y	Y	Y	Y
Denmark	Y	Y	Y	
France	Y	Y		
Germany	Y			
Greece	Y	Planned	Planned	
Ireland	Y	Y		
Italy	Y	Y	Y	Y
Luxembourg	Y			
The Netherlands	Y	Y	Y	
Spain	Y	Y	Y	Y
Sweden	Y			
UK	Y	Y	Y	Y
ACCESSION COUNTRY				
Bulgaria	Y			
Czech Republic	Y			
Estonia	Y			
Hungary	Y			
Latvia	Y			
Lithuania	Y			
Poland				
Romania	Y	Y	Y	
Slovakia	Y			
Slovenia	Y			
Turkey	Y			

* Ownership of the Belgian TSO, Fluxys, is separate from Distrigas, the incumbent gas supplier. Common owners hold 83 percent of Fluxys/Distrigas shares; the remaining publicly-traded shares are sufficient to constitute separate ownership.
Note: Y = yes; blank cells = not applicable.
Source: Author's elaboration.

Southern Cone Countries

Of the five countries studied—Argentina, Bolivia, Brazil, Chile, and Peru—Argentina has the most stringent regulatory and unbundling requirements. The country's law requires ownership separation, and regulations specify detailed, nondiscriminatory access arrangements. Consistent with European experience, Argentina's strict approach has

encouraged development of competition. Similarly, Bolivia has effective unbundling and strong regulatory involvement in setting terms of access. By contrast, Chile, Peru, and Brazil have significant scope for improving unbundling.

In Chile, vertical integration between gas transport and supply businesses is not restricted; the country does not require transport and supply businesses to publish separate accounts, and the two businesses may be completely integrated. Chilean law requires pipeline operators to offer TPA under nondiscriminatory terms. However, the regulator cannot enforce this requirement effectively, given its lack of authority to inspect contracts or make them public. Moreover, the regulator is not empowered to specify minimum requirements of transport contracts. In countries with a similar lack of regulatory authority, incumbent pipeline companies have offered third parties inflexible contracts that do not ensure comparable service reliability to the pipelines' integrated supply businesses. For example, many European pipelines have ostensibly offered firm transport capacity to third parties; however, transport contracts relieve the pipeline of nearly all liability for compensation if it fails to deliver the gas. In the early days of gas-market liberalization, the United States witnessed distortions and inefficiencies because the firm transport services offered third parties were not as reliable as the bundled sales delivered on behalf of the pipelines' integrated supply affiliates.

In Peru, the natural-gas law requires only transport and supply subsidiaries to produce separate accounts,[10] and contains a general requirement to offer nondiscriminatory access, whose inadequacies are similar to those of the Chilean law. This author disagrees that Peru's unique industry structure warrants special exemption. An observer might argue that lack of alternative gas sources to the Camisea field makes unbundling and open access less critical. Concerns over monopoly power at a gas basin can compel the use of long-term transport contracts to help finance new infrastructure investment; even so, strict unbundling requirements and regulatory supervision of access terms should be imposed.

10. Supreme Decree No. 041-99-EM, "Regulation of the Transportation of Hydrocarbons by Pipe," Article 82 (issued September 15, 1999).

These recommendations for Peru have three primary reasons. First, a vicious cycle can arise if the lack of alternative gas sources is used to justify policies that might foster competition. Lack of adequate regulation may prevent alternative gas sources from materializing. Second, Peru's lack of established gas-market participants should facilitate the creation of an effective open-access regime. It is always easier to impose unbundling obligations before businesses settle on particular management structures. Third, creating an effective open-access regime will create flexibility for future changes in industry structure. For example, the separation of management accounts and legal structures for pipeline infrastructure would permit a holding company to sell its pipeline or production business with little friction in order to raise future capital. Alternatively, the holding company could sell parts of the Camisea field, permitting new owners to share pipelines by paying regulated tariffs.

In Brazil, negotiated access has failed. Under this experiment, only one new entrant has successfully concluded a TPA agreement, and only after the regulator's ex-post intervention. Bilateral negotiation remains the main channel to decide on the important details of pipeline operation, such as charges and rules for imbalances or compensation for interruption. In Europe, incumbents have imposed such rules as system balancing requirements, which impose disproportionate costs on entrants. This experience underlines the importance of close regulatory involvement in the terms of access.

Brazil has recently moved toward regulated access. With respect to new infrastructure, in 2001, the Brazilian regulator required transport companies to offer new capacity to third parties in open-season bidding. Currently, the regulator is in the process of introducing acts that will address open-access conditions, procedures for capacity resale and conflict arbitration, provision of information, and criteria for tariff calculations.

Weak requirements on vertical separation have aggravated Brazil's problems. The law does not require management or ownership unbundling. Vertically-integrated pipelines must disclose transactions with affiliates, and the law limits the amount of gas that distribution companies can buy from an upstream business partly owned by the parent

company. Nonetheless, there is ample room for progress. The regulator has announced plans to require further separation among gas-industry activities.

Domestic Consumption and Export Rules: Eliminating Barriers to Integration

Currently, Argentina and Bolivia have rules that distinguish between production for domestic consumption and export, which create barriers to the integration of LAC markets. While successful integration need not produce a seamless market with a constant market price across countries, it should lead to market prices across countries that differ only by the amount of transport costs on interconnecting pipelines. In both countries, current rules cause market prices to differ by far more than reasonable pipeline costs imply. Below are outlined the relevant rules in Argentina and Bolivia, the distortions they create, and recommendations for their elimination.

Argentina's Transport Rules

In January 2002, Argentina's government enacted the Emergency Law, which anticipated the collapse of the peso relative to the dollar over the subsequent six months. The government froze domestic transport tariffs in Argentine pesos, but continued to permit investors to calculate export tariffs in constant U.S. dollars. If a pipeline company charged a tariff of US$1 for both domestic transport and export prior to January 2002, then after that date, the same company could continue charging US$1 for exports (now worth considerably more than AR$1), but, by law, could not charge more than AR$1 for domestic transport. Thus, while the price of exports has held constant in terms of U.S. dollars, the price of domestic transport has fallen dramatically (box 6-1).

The International Monetary Fund (IMF) has exerted strong pressure on Argentina's government to lift the current cap on domestic transport tariffs. The IMF's broad concern involves respect for the rights of foreign investors, which is critical to the long-term success of Argentina's economy. The differential treatment of domestic and foreign transport is inefficient; impedes market integration; and, by harming investors in transport infrastructure, can cause long-term damage to the gas markets of both Argentina and Chile.

BOX 6-1. TRANSPORT PRICE DISCRIMINATION: ECONOMIC CONSEQUENCES

One can consider a case in which two pipelines transport gas from a basin in western Argentina—one eastward to Argentine customers and the other westward to Chile—with a delivered market price in both countries of US$4 per million Btu before collapse of the Argentine peso (reflecting a US$2 basin price, plus transport tariffs of US$2 for each pipeline). After devaluation, one can assume that the tariff for domestic transport remained constant in Argentine pesos, but fell to US$1 per million Btu, while the Chilean tariff remained at US$2.

Implications for Argentine and Chilean Gas Markets

In this case, Argentina's industrial consumers will enjoy a substantial competitive edge over their Chilean counterparts. Argentine competitors will receive a substantial reduction in Argentine gas transport costs, while Chileans will continue paying transport tariffs that remain constant in terms of US dollars.

Reduction in Argentine transport tariffs will likely increase Argentine demand for gas, exerting upward pressure on the market price in the Argentine basin. Chilean consumers will then bear the cost of any increase in basin price.

Effects on Country Economies

Argentina's government policy has effectively destroyed the economic value of pipeline infrastructure in the country, driving several companies to the brink of bankruptcy. Thus, any investor will think carefully before financing new pipeline infrastructure in Argentina. When planning new investments, companies will consider the risk of becoming the target of damaging legislation if government mismanagement results in another economic crisis. The higher risks—and costs—of bringing gas to market will make exploration less attractive. Less exploration will mean higher gas prices for both Chilean and Argentine consumers.

Bolivia's Sales Rules

In Bolivia, two rules are relevant to price distortion: 1) a price cap on gas delivered to domestic customers and 2) that players can export gas only after having served a corresponding amount of domestic demand. These rules aim to ensure that Bolivian consumers enjoy the maximum benefits from Bolivia's gas reserves; they pay considerably less than export markets. The prices differ by far more than reasonable pipeline costs imply.

These new rules not only impede market integration; they also hurt the Bolivian economy. Although a desire to help Bolivian consumers may have led to the creation of these rules, Bolivian consumers would be better off without them (box 6-2).

BOX 6-2. EXPORT PRICE DISCRIMINATION: EXAMPLE FROM BOLIVIA

One can consider a case in which the Bolivian government imposes a domestic price cap of US$2 per million Btu and that the prevailing market price at the wellhead is US$3 for export customers. By imposing the US$2 price cap and assigning a priority to domestic demand, the Bolivian government effectively invites all Bolivian consumers who value the gas at US$2 or more to purchase as much as they like. Some Bolivian consumers may place a high value on the gas, while others will still consume it at a value slightly above US$2 per cubic meter ($m^3$). These customers may enjoy the subsidized access, but would prefer exporting gas to Brazil. If a Bolivian consumer assigns an inherent value of US$2.10 to domestic consumption, then the domestic price cap would allow that consumer a US$0.10 benefit. By contrast, the same consumer would receive a US$0.90 benefit by exporting gas. Exporting would provide the consumer revenues of US$3 per million Btu, while requiring him or her to sacrifice domestic consumption valued at only US$2.10, yielding a net gain of US$0.90. Similar logic would apply to Bolivian customers who value gas in the US$2-3 range; that is, they would prefer to export, rather than consume, the gas domestically at the regulated US$2 price.

If the Bolivian government divided gas ownership evenly among all of the country's consumers, one might expect to witness broad popular support for eliminating the domestic price cap and complete liberalization of exports. Bolivian citizens would benefit by selling the gas abroad at high prices, driving up the value of gas retained for domestic consumption. However, no one seriously considers giving all Bolivian consumers a tradable right to a certain amount of gas, which each individual could choose to either keep or sell to export markets. Instead, the government serves as an intermediary between Bolivian citizens and export markets. It is beyond the scope of this chapter to solve the complex political problems associated with the government's role as intermediary in formulating gas policy. However, this proposal supports eliminating both the domestic price cap and the priority assigned to domestic consumption because no Bolivian consumer would favor these policies if he or she owned the gas directly.

International experience shows that perpetuating consumer distinctions by nationality will only undermine the political will necessary to succeed in market liberalization and integration. Currently, Bolivia is negatively affected by insufficient liberalization of the Brazilian gas market. Thus, Bolivia stands to gain significantly from Southern Cone liberalization. It would be contradictory for Bolivia to encourage open markets elsewhere while maintaining domestic rules that impede integration. Removing the domestic price cap and the priority of domestic consumption over exports would give Bolivia a strong, coherent voice with which to argue for full regional liberalization, benefiting Bolivian consumers in the process.

Open Season[11]

Private investors have incentives to propose infrastructure projects that have less capacity than socially optimal for integrating markets. Total market integration implies the elimination of any differences in market prices between interconnected areas. Private investors would never want to finance a pipeline that offered total market integration since the economic value of a pipeline depends on persistence of price differences

11. The term *open season* refers to an invitation for market participants to submit firm bids for long-term capacity rights.

between connected markets. An individual's willingness to pay for pipeline transport depends on his or her ability to command a higher price in the gas export, versus local, market (box 6-3).

BOX 6-3. PIPELINE UNDERSIZING AND MARKET POWER ABUSE

A supplier could profit from buying gas at a low price in one market, transporting it through a pipeline, and then selling it at a high price in a connected market. The value of the interconnecting pipeline depends on the price difference between the two markets. For example, if Market A's price were US$20 per m^3 and Market B's price were US$30 per m^3, the supplier should be willing to pay US$10 per m^3 for pipeline capacity between the two markets.

When considering a potential pipeline between Markets A and B, private investors could deliberately design the pipeline smaller than socially optimal, in hopes of maintaining a high price differential between markets. By restricting supply of cheap gas from Market A, pipeline investors could prop up the prices in Market B. By contrast, a larger pipeline could allow cheap gas from Market A to flood Market B, thereby reducing prices. More pipeline capacity would reduce the price differential between the two areas, which, in turn, would lower the market value for pipeline capacity.

Construction of optimally-sized interconnectors might not permit pipeline investors to recover all investment costs. Economic theory determines the optimal size of a pipeline connecting two markets: the optimal size balances the value of an incremental unit of capacity against marginal cost. However, discrepancy between a pipeline's average and marginal costs creates a problem for private investors. To break even, they must charge a tariff equal to average costs per unit of capacity, where costs are defined to include a reasonable return on invested capital commensurate with the risks involved. The optimal pipeline size would equate the value of capacity to marginal costs, which are lower than average costs.*

Certain private investors might have other motives for building a pipeline smaller than socially optimal. For example, they might be tempted by the prospect of market power, ensuring a small pipeline into a particular area could restrict potential for competition. Sponsors of a new infrastructure project may prefer to reserve all capacity for themselves, using the project's small size relative to their needs as an excuse to deny others access.

* Pipeline construction costs are directly proportional to pipe diameter, while capacity is proportional to the diameter squared. Increasing pipe diameter from 10 to 11 units would increase capacity 21 percent (112 ÷ 102 – 1), but construction costs only 10 percent (11 ÷ 10 – 1). This example suggests that the marginal costs of a pipeline are consistently less than average costs.

Steps in the Process

The recommended open-season approach for the Southern Cone region involves three steps. First, private investors would approach a regulator to discuss the possibility of building a new pipeline. Before granting a license for project construction, the regulator would require investors to publish the proposed pipeline size and tariff and initiate an open-season bidding process. Second, if prospective purchasers of pipeline capacity considered the proposed tariff too high, they would retain the option to offer firm bids at a price lower than the published tariff. The bids would indicate a demand curve for capacity on the proposed project. Third, the regulator would publish the aggregated bid schedule without disclosing the bidders' names and would provide a specified window of opportunity for other potential investors to improve on the initial tariff offered.

One can consider an initial investor who proposes to build a pipeline with a 2 million m^3 per day capacity and a tariff of US$0.20 per m^3. By examining the bid schedule, a second investor might be sufficiently interested to justify a pipeline with 3 million m^3 per day, at a tariff of US$0.15 per m^3. The regulator could grant the license to the second investor. The recommended process would invite investors to propose projects large enough to equate the marginal value of additional capacity

with average construction costs. Equating marginal value to average costs would depart from the theoretical optimum; nevertheless, this compromise would at least permit private financing of new infrastructure and would prevent project sponsors from any undersizing aimed at excluding others or otherwise abusing market power.

Benefits of Approach

The proposed open-season approach would give gas suppliers financial incentive to develop accurate market projections. The offer of long-term capacity rights alone would create strong financial incentives for competing suppliers to analyze the market. A potential supplier would stand to lose a sizeable sum by refusing to participate in open season if the project were efficient and offered competitors a potential advantage. Competition to develop superior projections would ensure more efficient decision-making.

Second, the proposed approach would help reduce political pressures surrounding new infrastructure. If suppliers were too optimistic about the potential for a new pipeline, an open season approach would force suppliers to bear the costs of any excess capacity constructed. In heavily regulated systems, the regulator retains authority over system-expansion decisions, but commits to compensate investors, even if demand does not materialize as anticipated. Traditional regulatory regimes force consumers to bear the costs of excess capacity.

Third, the open-season process would reduce reliance on the regulator to make capacity-expansion decisions. The regulator could have confidence about a proposed project's efficiency if the open-season process demonstrated consumer willingness to commit to capacity payments in advance.

Fourth, an open-season approach would provide a transparent, nondiscriminatory vehicle for allocating capacity. An investor would not simply propose to build a project and retain all capacity without offering it to others. Third parties would learn of the project through the open-season process, and would have an equal opportunity to buy long-term capacity rights on nondiscriminatory terms.

This proposed open-season policy would involve offers of long-term contracts designed to promote competition and maximize infrastructure use. For example, Company A might buy all new pipeline capacity through the open-season process pursuant to a 24-year contract, while signing contracts of varying durations for gas delivery to specific customers. At the end of the fifth year, a particular supply contract to a customer expires, but Company A retains the relevant transport capacity, with 15 years remaining on the transport contract. In this case, it is recommended that the customer be allowed to switch to Company B, which might want to use the same pipeline. If so, the customer could insist on Company A transferring relevant capacity to Company B. Company B would have to compensate Company A for the transferred capacity at the relevant rate under the original long-term contract. It is recommended that such a capacity-transfer mechanism be incorporated directly into the initial open-season contracts. In this example, Company A would effectively have the right to use capacity as long as the customer were willing to purchase Company A's gas, up to a maximum of 20 years. Company A would still face prospective competition from others whenever its gas sales contracts came up for renewal. It is also recommended that particular rules offer third parties, on a daily basis, any capacity that long-term holders choose not to use (Lapuerta and Mosell 2002).

This proposed process would depart from the popular U.S. open-season process in several key aspects. First, it would be designed to indicate the potential demand for more capacity than originally proposed by the investor. If bidders did not like the tariff, they could still make firm offers to buy capacity at a lower tariff. Second, it would create the potential for a larger pipeline with a lower tariff than initially envisioned by permitting third parties to examine the bid schedule and offer a larger pipeline on the basis of more attractive terms than the initial investor. The threat of such offers should motivate the original investor to propose a reasonable tariff initially. Third, it would involve firm tariff commitments by the pipeline investor. By contrast, the U.S. open-season process does not supplant the traditional rate-making process involving the regulator's close scrutiny of costs. The tariffs proposed in the U.S. process are only indicative since the eventual tariffs will depend on the regulator's opinion concerning the prudent costs incurred by the pipeline.

Setting Pipeline Rates

International experience has demonstrated the failure of negotiated access regimes, particularly in the presence of vertical integration, as in much of the LAC region. Regulators should determine tariffs for access to existing pipeline networks by reference to the cost of service.[12] For existing pipelines, this proposal recommends against any attempt to determine rates pursuant to international tariff comparisons or the hypothetical replacement costs of new pipelines. However, for new pipelines, an opportunity is envisioned for adopting a new approach that relies on competitive tender processes.

Tariffs on Existing Pipelines

Both Brazil and Chile have negotiated access regimes combined with vertical integration. Brazil's regulator has already recognized the regime's failure, witnessing complex disputes over access to the Petrobrás pipeline that imports gas from Bolivia. Currently, Brazil is in a state of transition with regard to regulated access.

Chile's tariff approach may appear to avoid Brazil's problems with negotiated access. The country's legal framework contains rules requiring the investor to offer the same pipeline tariffs to all users who seek to transport similar amounts of gas. This approach may rely partly on the hope that, before they are built, pipelines will face effective competition from other projects. If so, such users as large power stations might have the leverage to sign contracts for competitive tariffs before pipeline construction. Perhaps the Chilean approach hopes to extend the benefits of this leverage to other pipeline users who would otherwise fall victim to the pipeline's market power. A key problem, however, involves vertical integration. Many large Chilean power stations have ownership interests in the pipelines, which render the tariff meaningless, except as a tool to block competition (box 6-4).

12. Cost of service refers to an investigation of the pipeline's construction and operating costs, including a reasonable return on invested capital.

BOX 6-4. CHILEAN TARIFFS AND INTEGRATION

One may consider the case of a power station that signs a contract for 10 percent of pipeline capacity and simultaneously buys an equity stake of 10 percent in the pipeline. The station may be willing to accept tariffs that significantly exceed underlying costs. The high tariffs might raise the cost of gas to the pipeline, which would appear to act against the power station's commercial interests. However, the high tariff would, at the same time, raise the value of the power station's equity interest in the pipeline. For the station, a high tariff would represent a largely irrelevant transfer on its financial accounts: High tariffs would raise the costs recorded for transporting gas, but would also raise the profits accruing to the station's shareholding of the pipeline. For this power station, the only meaningful indication of the true cost of gas transport would be the original purchase price of its equity interest in the pipeline. For other power stations, however, high tariffs would represent a true cost with no offsetting benefit accruing to the value of a shareholding. The power station that owns an equity stake in the pipeline may therefore prefer high pipeline tariffs to bar competition in the power market.

The same principles apply to vertical integration between a gas producer and the pipeline. The presence of vertical integration renders ineffective any legal obligation to charge the same prices to all users. While the prices charged to various users may be the same, the costs to integrated and non-integrated companies will differ markedly. Thus, Chilean tariffs derived in the presence of vertical integration cannot be trusted to foster effective competition, despite obligations to offer the same tariffs to other customers. Regulators should consider replacing these tariffs with cost-of-service tariffs. They must investigate the underlying costs of transport for existing pipelines and ensure that tariffs do not exceed them.

Tariffs on New Pipelines

Instead of traditional cost of service, the regulator would ask the project sponsor to publish a proposed tariff and technical parameters of the new facility. The regulator would establish a limited time period during which independent competitors could tender to build the same or larger facility in exchange for a lower tariff. The regulator would award the winner a license to construct and operate the facility, which would contain specific obligations aimed at promoting efficient pipeline use and development of competition. The regulator would prohibit companies from participating in the pipeline project if they were simultaneously involved in gas consumption, production, or sales in relevant markets. This proposed policy would introduce full ownership unbundling, and use the competition that is possible before pipeline construction, to ensure reasonable rates afterward. The license would contain specific obligations to promote efficient pipeline use and development of competition.

This proposal introduces full ownership separation of pipeline transport from gas consumption, production, or sales activities. Although reasonable tariffs could be produced, even in the presence of vertical integration, full ownership unbundling is recommended to avoid problems with post-construction pipeline operation. International experience suggests that vertical integration is a key problem that complicates development of competition in natural-gas markets. This approach views the prospective construction of new infrastructure in LAC as a significant opportunity. Regulators should seek to promote the financing of new pipelines on an unbundled basis.

In addition, this approach should help to finance new projects by removing the scope for inefficient regulation. Competing investors, rather than regulators, would take the initiative to set tariffs. The proposal would eliminate the prospect that regulators might underestimate the returns required to compensate project sponsors for investment risks. Traditional cost-of-service regulation requires the regulator to estimate a pipeline's costs. Pipelines typically have high capital costs and low daily operating costs. Investors are compensated for

their capital costs through annual depreciation charges, plus an allowance for the cost of capital.[13] Experience indicates that the cost of capital is a major element in pipeline compensation, and views vary widely concerning the true cost of capital. Broad debate leaves room for regulator error; errors in measuring the cost of capital will either deter efficient investment or enrich investors unnecessarily at consumers' expense. A competitive tender process would relieve the regulator of the need to measure the cost of capital for new pipes. Despite measurement difficulties, no way is envisaged to relieve regulators of estimating the cost of capital for existing pipes.

Competitive tendering could produce higher tariffs than cost-of-service regulation. When a competitive tender establishes the tariff for a project before its construction, the fixed tariff exposes the project sponsor to the risks of cost overrun, lower volumes than initially anticipated, and prospective fluctuations in interest rates. The pipeline bears all of these risks, and a competitive tender process would produce a tariff sufficiently high to compensate for them. By contrast, cost-of-service regulation typically allocates these risks to consumers. If a facility's construction costs are higher than initially anticipated, the regulator permits the investor to charge higher rates, as long as expenditures are prudent. Similarly, the regulator will raise tariffs if project demand is lower than anticipated or if interest rates rise in the future.

Pipeline investors can probably bear risks more efficiently than consumers. Pipeline investors should be experts concerning the risks of construction cost overruns and should have expertise in prospective development of interest rates, derived from financing assets with long useful lives. The tender process might produce a higher tariff than cost-of-service regulation; however, it would be expected that the tariff difference would be less than the value consumers receive from avoiding the risks of the cost-of-service regime.

13. *Cost of capital* is defined as the minimum return necessary to attract capital in competitive markets, given the risks involved.

Tender Design

Although competitive tenders for new pipelines are attractive, they are complex to design successfully. Regulators would have to insist on a high degree of transparency and publish standard transport contracts for tendering companies in advance. Efficiency might suggest the need for a variety of transport contracts (e.g., firm and interruptible services or short- and long-term contracts). Presumably, different services should command different tariffs; however, asking bidders to propose five tariffs for five contracts would complicate the evaluation of bids. Therefore, a trade-off usually occurs between simple tender terms that keep the bid-evaluation process clear and objective and terms that permit an efficient diversity of services after pipeline construction.

In practice, initial pipeline customers are likely to buy long-term capacity of up to 15-20 years in duration, while subsequent capacity purchasers may only want contracts of up to 1 year. If the competitive tender requested bids on 20-year capacity contracts, it remains unclear whether the regulator should force the pipeline to offer an identical tariff for subsequent 1-year contracts. The risks of 1- and 20-year contracts differ significantly from the perspectives of users and the pipeline; in turn, different risks might justify different prices. Thus, the issue is difficult to address.

A pragmatic solution would be for regulators to focus the tenders on the tariff for long-term contracts, while simultaneously requiring the winning bidder to conduct repeated auctions for future one-year firm capacity contracts. The focus on long-term contracts is consistent with the proposed open-season recommendations. Since pipelines have long useful lives, efficient planning should involve an open-season process that solicits long-term commitments from prospective capacity users. As short-term capacity becomes available, auctions would make sense. In this way, the regulator could allow the market to choose the appropriate price differential, if any, between one-year and long-term rights.

The proposed competitive tender regime would not apply directly to construction of new LNG facilities. International experience suggests

that large, complex construction projects are not amenable to competitive tenders under standard contracts. Instead, such projects tend to require equity partnerships to align the interests of terminal builders and users. While the issue remains empirical, LNG liquefaction facilities apparently present too many design issues and complex interactions with vessels and regassification facilities at export markets. While a regulator could still devise a rough analogue to a competitive tender process for an LNG facility, the focus should involve equity interests rather than construction contracts. The regulator could ask the project sponsor to tender a passive equity stake in the project; for example, by asking someone to pay 30 percent of the costs in exchange for 30 percent interest in terminal tariffs. The regulator would ask potential investors to specify the minimum tariff they could accept. If properly implemented, this approach could help identify the appropriate cost of capital and reasonable tariffs, without causing operational or design problems.

Third-party Access and Derogation Policy

Open access to transportation capacity is a necessary condition for market competition and integration. Nevertheless, some industry observers argue that open access only works in mature gas markets, where gas networks are fully developed. They argue that, in emerging markets, open access could thwart infrastructure development. According to this view, private investors require the security provided by exclusive rights to serve customers.

A cursory reading of the European Gas Directive might appear to support the concept of derogations for emerging markets to help finance new infrastructure. However, this view is fundamentally mistaken. Appropriate implementation of open-access requirements should help facilitate infrastructure development.

Benefits of Open Access and Infrastructure Investment

Some industry observers believe that open access deters investment; instead, they view it as a requirement for investors to reserve large amounts of capacity for short-term offers to third parties. In certain

European countries, the obligation to offer short-term contracts is part of the open-access regime. For example, Italy's energy regulator has considered preventing new LNG terminals from selling more than 80 percent of their capacity, pursuant to long-term contracts. In Spain and the Netherlands, similar limits apply to pipeline capacity. For several years, the UK's regulator prevented the British pipeline network from offering any long-term contracts.

To derive an open-access policy, it is critical to distinguish between long- and short-term contracts. In certain markets, investors might hesitate to build large infrastructure projects under a requirement to sell capacity on a short-term basis, incurring the risks that demand might not materialize as expected. However, the risks of short-term contracts do not warrant derogations from open-access requirements. The proposed open-season policy would effectively implement open-access requirements via long-term contracts offered before construction of large infrastructure projects. Such long-term capacity contracts would permit investors to appropriately share some risk of infrastructure development with third parties.

Moreover, liberalization can facilitate investment. Competitive markets reduce investment risk significantly by providing efficient price signals and liquidity. For example, many petroleum companies invest billions of dollars in exploration, production, and pipelines without the luxury of a captive market. Petroleum companies can invest with confidence because the market is sufficiently competitive to accommodate any new production that can beat the prevailing market price.

One can compare two situations, both of which involve one country with ample gas reserves neighboring a gas-importing country. The first situation involves vertically-integrated monopolies, while the second involves competing supply businesses that share natural-gas infrastructure. Competing supply businesses tend to generate liquidity and transparent price information. Investors can judge the wisdom of a new interconnecting pipeline by comparing the market prices for natural gas in the exporting and importing countries. They are also assured of the ability to sell use of infrastructure to a variety of customers. If any

single customer proves unreasonable, the company can simply search for another. By contrast, vertically-integrated monopolies do not foster liquidity or create transparent price signals. A potential investor will find it difficult to assess the fundamentals of supply and demand, and will confront only one purchaser in the importing country. If the purchaser proves unreasonable, the investor has nowhere to turn. Although monopolies in each of the two neighboring countries may be willing to invest, their monopoly positions create multiple problems that can distort investment efficiency.

In sum, all investors should meet requirements to offer TPA, pursuant to long-term contracts through open-season bidding. The appropriate scope of derogations should involve only one additional open-access requirement: whether to reserve a portion of a facility's capacity for short-term contracts.

European Derogation Policy

It would be a mistake for the Southern Cone region to follow the European precedent for exemptions from open-access requirements. The European Gas Directive was written with the knowledge that few Member States or projects would qualify for derogations. Simply adopting the European policy risks halting liberalization and integration almost entirely. The European Gas Directive cites three conditions that can exempt Member States from imposing open-access requirements on pipelines:

– ***Isolated systems.*** "Member States not directly connected to the interconnected system of any other Member State and having only one main external supplier may derogate from Articles 4, 9, 23, and/or 24 of this Directive. A supply undertaking having a market share of more than 75 percent shall be considered a main supplier. This derogation shall automatically expire from the moment when at least one of these conditions no longer applies."

– ***Emerging markets.*** "A Member State, qualifying as an emergent market, which because of the implementation of this Directive would experience substantial problems, may derogate from Articles 4, 7, 8(1)

and (2), 9, 11, 12(5), 13, 17, 18, 23(1) and/or 24 of the Directive. This derogation shall automatically expire from the moment when the Member State no longer qualifies as an emerging market."

– ***New infrastructure.*** Even if the Member State does not meet the overall criteria for a derogation as an emerging market or isolated system, the regulatory authority can exempt new infrastructure projects from open-access requirements. New projects must satisfy several criteria to obtain an exemption (enhancing competition, contributing to security of supply, and demonstrating that open-access requirements would threaten the ability to secure financing).

The isolated-system concept is irrelevant to the Southern Cone since each country in the region is connected to at least one other. The isolated-system clause identifies one instance that would require long-term contracts for new infrastructure capacity in the region: primary dependence on a monopoly gas source. However, the proposed open-season approach would permit long-term contracts while offering at least third-party participation. Open season is compatible with private financing, even for isolated systems. Furthermore, it makes little sense to define the isolated-system concept in terms of a country as a whole, as opposed to specific infrastructure projects.

Adopting the European emerging-markets clause in the Southern Cone region would bring liberalization to a virtual standstill. Except for Argentina, all countries in the region have emerging gas markets that require significant infrastructure investment before gas can reach a high percentage of the respective populations. Bolivia, for example, hopes to expand its number of connections from 15,000 to 250,000 within a few years.

Permitting derogations for new infrastructure investment is closely related to the emerging market clause. The European Gas Directive permits a derogation of open-access application to new assets if the investor demonstrates that "the level of risk attached to the investment would not [occur] unless an exemption was granted."[14] Unfortunately,

14. European Gas Directive, Article 22, section 1b.

this language is so general that it could be applied to most infrastructure projects in the region. A successful integration policy for the Southern Cone must specify the circumstances under which open access risks infrastructure investment.

When Are Derogations Required?

The analytical case for derogations should compare two scenarios. The first involves an investor with exclusive monopoly over construction of a particular pipe or network that charges competitors in the supply business a fee for infrastructure use. The second involves an investor with two exclusive monopolies: one over facility construction and another over the gas-sales business. An appropriate analysis must ask whether the investor needs the monopoly over the gas-sales business to reduce investment risk.

Monopolies over construction of transport infrastructure can usefully reduce investment risk. However, granting an investor a second monopoly over the associated supply business is generally unnecessary to motivate investment; on the contrary, it will tend to create inefficiency and delay market evolution.

The most important underlying issue related to derogation policy is the distinction between long- and short-term contracts. In two specific cases—insufficient upstream and insufficient downstream competition of the proposed infrastructure—regulators should rely solely on long-term contracts offered in open season and not also require investors to reserve a portion of capacity for short-term contracts. These two cases are described below.

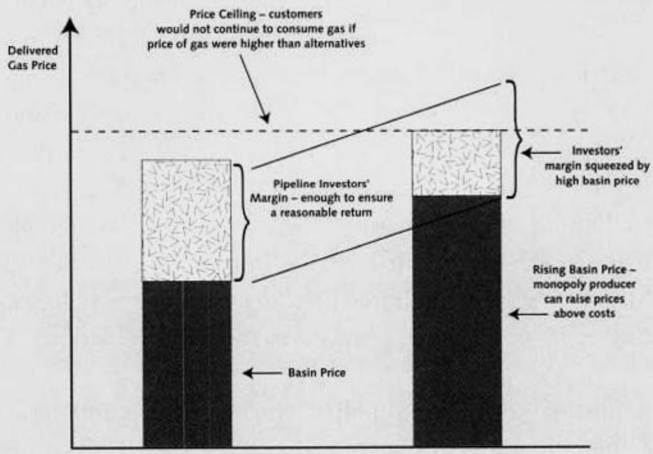
CASE 1: INSUFFICIENT UPSTREAM COMPETITION

If one company controls the majority of production in a gas basin, the company could exploit short-term contracts to abuse potential investors in a new pipeline (box 6-5).

BOX 6-5. WHAT IS PRODUCER PRICE SQUEEZE?

One can imagine an investor that considers building a pipeline connecting the monopolist's gas basin to a new export market. If the investor has an exclusive monopoly over pipeline construction but lacks exclusive access to customers in the export market, then the investor would logically fear abuse by the monopolist gas producer. This feared behavior, known as "producer price squeeze," means that customers will consume gas as long as it costs less than alternative fuels; thus, delivered prices of alternative fuels provide a price ceiling for natural gas (see figure).

ANALYSIS OF PRODUCER PRICE SQUEEZE



Source: Author's elaboration.

The costs of providing the customer natural gas would include the basin price, plus pipeline operating and capital costs, including a reasonable return. However, the monopolist gas producer could abuse the pipeline by raising basin prices well above production costs. The pipeline investor would face a serious investment loss, as many customers would switch to alternative fuels unless the pipeline reduced tariffs. The gas producer, by contrast, would likely profit significantly from such behavior.

In such cases, there are only two ways to protect investors from risk: 1) granting the pipeline exclusive access to customers and 2) permitting the pipeline to sign long-term capacity contracts with the monopolist gas producer before construction. If the pipeline had exclusive access to customers, it could be confident of an outlet without having to sign long-term contracts with customers in advance. The pipeline could therefore make a long-term commitment to purchase gas from the monopolist producer, thereby facilitating creation of a long-term gas contract that would simultaneously protect the pipeline from a potential price squeeze. Alternatively, the pipeline could request that the gas producer sign a long-term contract for pipeline capacity.

Both of the described alternatives would work; however, the alternative involving long-term contracts for all pipeline capacity would not entail legal exclusivity over customers. This proposal relies on long-term contracts in compliance with the proposed open-season process. Before construction, the investor would offer long-term capacity to both the monopolist and any other interested parties who might have access to gas sources in the same basin. The long-term contracts would contain the recommended open-season provisions: facilitating resale of capacity to future competitors and offering unused capacity to others on a daily basis. In this case, the derogation policy would simply relieve the infrastructure owner of any obligation to reserve capacity in advance for sale, pursuant to short-term contracts.

In sum, an optimal derogation policy should relieve infrastructure providers of the obligation to reserve capacity for short-term contracts when confronted by upstream market power.

CASE 2: INSUFFICIENT DOWNSTREAM COMPETITION

One can imagine the potential construction of a large Chilean liquefaction terminal hoping to export LNG to the United States; the Chilean regulator has endorsed an open-season process, and must now decide whether to insist on sale of a portion of liquefaction capacity, pursuant to short-term contracts.

Investors would naturally hesitate to build a liquefaction terminal without the certainty of long-term access to regassification terminals in

export markets. Assuming that the LNG exports were intended for the United States, the builder of the Chilean LNG terminal would hesitate to sell capacity on a short-term basis unless ample short-term capacity at regassification terminals were available to serve U.S. markets. If only one or two had spare capacity, then the owners of the regassification terminals might realize that, as the sole outlet for short-term capacity at the Chilean liquefaction terminal, they have significant market power. As a result, they might insist on unreasonable terms for the exported gas.

Although the formal economic theory of vertical integration has not yet been applied to the LNG industry, the above example illustrates what most economists would recognize as a hold-up problem.[15] Economists widely agree that hold-up problems provide compelling business reasons for long-term contracts.

LNG trade may one day be diverse and mature enough that one could confidently build a liquefaction terminal without signing long-term contracts with a regassification terminal in advance. When that day arrives, regulators could reasonably ask investors to reserve a certain portion of terminal capacity for short-term contracts. In Europe, where the emerging spot market in LNG trade has attracted considerable attention, there is now a diversity of regassification terminals. Although the issue merits empirical study, it is difficult to see how the European LNG market could possess the necessary depth to permit construction of new facilities under short-term contracts. Since the west coast of the United States does not yet have regassification terminals, regulators in the Southern Cone could not reasonably insist on short-term contracts for liquefaction capacity.

Southern Cone Derogation Policy

The Southern Cone should adopt a more detailed policy than that of the European Gas Directive for granting derogations from TPA requirements. The issue is critical because of the Southern Cone's significant reliance on

15. Within this context, the term ***hold-up*** refers to the prospect that someone could exploit monopoly power in one step of a distribution chain (regassification terminal) to abuse a company involved in another step of the chain (liquefaction terminal).

new infrastructure projects to integrate markets. This proposal recommends against any derogation that applies to an entire country, as in Europe, and general language that refers to the risk of new infrastructure without describing the relevant principles in detail.

There is no economic basis for an exemption from open-season obligations that would offer TPA under a long-term contract before facility construction. The only relevant issue is whether to insist on the reservation of capacity for sale, pursuant to short-term contracts. Regulators should not require investors to reserve capacity for short-term contracts under two conditions: 1) upstream market power and 2) downstream market power or hold-up problems, as discussed in connection with new LNG terminals.

Supply Security

Recent power-sector blackouts, use of natural gas for home heating, and general concerns over expected growth in power-sector consumption (requiring significant new investments) have brought supply security to the forefront of the regulatory agenda of various industrialized countries. Many regulators are now considering rules to promote supply security. For example, Spain's legal framework requires market participants to store at least certain amounts of gas. These rules address general concerns that the markets would not provide adequate security.

In the Southern Cone, however, it is believed that the markets alone could provide appropriate security, as long as stable regulatory frameworks encourage investment and development of effective competition. Storage obligations and other measures find their principal justification in the difficulties small consumers face in evaluating security. The Southern Cone can avoid such problems as long as the power sector consumes most gas supplies. Experience indicates that the power sector's sophistication as a gas consumer should help to promote efficient security levels without regulatory intervention.

Long- and Short-term Concerns

International debate over supply security involves two concerns:

– securing sufficient long-term energy supplies and

– meeting short-term consumer demand.

The United States and Europe—both net importers of gas—consider such long-term issues as logical sources of future imports, financing of the infrastructure investment needed to import gas successfully, and political stability of gas-exporting regions. Since the Southern Cone does not import gas, it need not concern itself with the stability of major gas exporting countries, such as Algeria, Nigeria, and Russia. However, the region should share concerns about financing the infrastructure needed to satisfy new demand growth. This issue should be addressed through light regulation of new pipelines.

Both the United States and Europe are concerned about meeting short-term demand. Households represent a significant percentage of total consumption, and many people rely on natural gas to heat their homes. Home heating is a politically-sensitive economic issue. Most economists would agree that an efficient security level involves a balance between the costs of improving reliability and enduring another supply interruption. Regulators should not intervene unless they fear the market cannot balance these parameters appropriately. It is reasonable to suspect that household consumers lack the time and expertise to evaluate security. Furthermore, in an emergency, it is not feasible to interrupt only those households who failed to buy sufficient backup supplies, while continuing to supply their more reliable neighbors. Thus, regulators cannot hold individual households responsible for their own security. Finally, security of household supply involves safety issues that do not apply to large industrial users. Interruption of a distribution system can produce gas leaks that make it hazardous to restart the system, with risk of explosion and loss of life. Thus, this proposal supports regulatory intervention to enhance supply security where household consumers comprise a significant portion of the market.

Dominance of Large Users

By contrast, larger users (e.g. power stations and petrochemical plants) have the resources and financial incentive to evaluate security appropriately and assess the costs of interruptions on their business processes and supply security.[16] They have financial incentives to balance the costs of interruption and additional security to determine the optimum security level. Competition will reward those companies who make the best security choices. Large users can also sign sophisticated contracts that give gas suppliers incentive to improve reliability. If a petrochemical company fears that an interruption would be expensive, it can negotiate a supply contract that may offer the gas producer a high price in exchange for compensation for any interruptions. Presented with such an offer, the gas producer would explore whether backup measures, such as storage or diversification, could efficiently provide the desired reliability. A network operator can also target specific large users for interruption while maintaining service of those who have arranged for appropriate backup supplies. Thus, regulators can trust that natural market forces will motivate large users to obtain efficient security levels.

Regulators would face considerable challenges if they were responsible for determining efficient security levels for large consumers. For example, they would have to form opinions about the cost and effectiveness of various backup measures and interruptions to market participants. The customers themselves are more likely to know the costs. Thus, it makes more sense to allow large users to choose their preferred level of reliability.

In a market dominated by large consumers, the regulator's main goal should be to implement rules that allocate costs appropriately among network users. The regulator does not want one supplier's failure to affect the customers of other suppliers. The regulator should therefore seek to implement rules to address imbalances between end-user consumption and supplier injections into the network.[17] If a pipeline user incurs an imbalance, then the

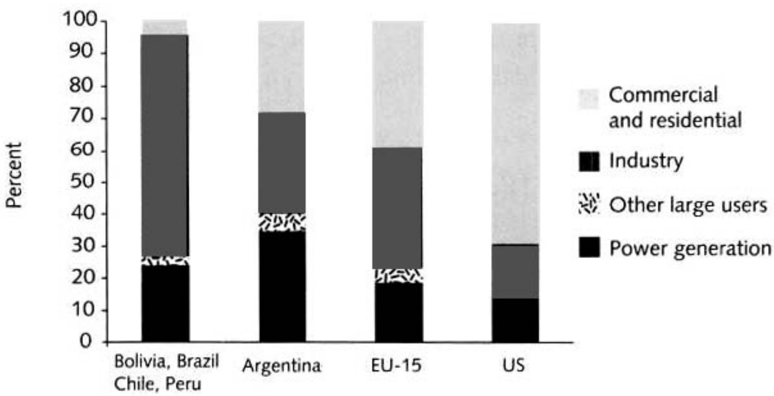
16. They can increase supply security by diversifying among gas suppliers, signing contracts for backup supplies, or storing backup diesel on-site.

17. These rules are termed *balancing rules*.

balancing regime should require the user to pay for the costs of any resulting reasonable measures that the network operator undertook to maintain gas flow. If reasonable measures cannot keep the gas flowing, then the balancing rules should require the network operator to interrupt customers of the unreliable pipeline user. Once the regulator is comfortable with the balancing rules, the remaining security issues are best delegated to the market.

Commercial and residential consumers represent a small percentage of gas demand in Argentina, Bolivia, Brazil, Chile, and Peru, accounting for only 21 percent of total use in these countries (compared to 39 and 69 percent in Europe and the United States, respectively) (figure 6-1).

FIGURE 6-1. COMPARISON OF GAS CONSUMPTION, BY SECTOR



Note: In calculated percentages, the gas used in production and transport is excluded.
Sources: Argentina/Non-Argentina, IEA South American Gas: Daring to Tap the Bounty; EU-15, Eurogas; and U.S., Energy Information Administration.

As figure 6-1 shows, most Southern Cone commercial and residential users are in Argentina, whose mature gas market has many distribution networks. Excluding Argentina, average commercial and residential use drops to only 4 percent. For those four countries, this proposal recommends against regulatory intervention insisting on minimum storage requirements or security levels. Eventually, supply security will become a priority as more distribution networks are constructed. Current regional priorities should focus on the other issues raised: elimination of

distinctions between domestic consumption and exports, greater unbundling, more detailed access regulations, a process for moving forward, detailed derogation policy, and introduction of open season and lightly regulated pipelines.

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Chapter 7

Forces Affecting the Process

Paulina Beato and Juan Benavides

In December 1999, full member countries of the Southern Cone Common Market—Argentina, Brazil, Paraguay, and Uruguay—signed a memorandum of understanding (MOU) on gas exchange. As part of that MOU, the four countries pledged to develop both short- and long-term competitive supply markets by offering gas suppliers and consumers in each country nondiscriminatory treatment and market access. At the September 2000 South American Presidents Summit, held in Brasilia, these governments announced the Regional Infrastructure Integration Initiative for South America (IIRSA).

The Argentina-Bolivia-Chile crisis of 2004 will likely delay market integration initiatives because of certain countries' political resistance to the process; at the same time, countervailing forces are pushing for integration. This chapter analyzes the forces that promote and oppose regional integration. The analysis centers on regional market features, industry structure, and regulatory frameworks. It examines the extent to which the proposal discussed in chapter 6 enhances favorable forces for integration and mitigates unfavorable ones. They also make recommendations for advancing and managing the market integration process.

Market Features[1]

Although gas consumption in South America's Southern Cone is about 60 billion cubic meters (m^3) per year, the region's gas market is not yet sufficiently mature or large enough to attract the enormous investments required for effective market integration. The region's only mature market is Argentina, which has a well-developed infrastructure and a high level of penetration (IEA 2003). Other countries, particularly Brazil, have

1. See Appendix for overview of submarket features.

substantial room for growth. In the year 2000, Brazil's per-capita consumption was 53 m³, compared to Argentina's 984 m³ and Chile's 424 m³. Small increases in per-capita consumption in a country as large as Brazil would significantly alter the market size.

Reserves

Proven natural-gas reserves in Argentina, Bolivia, Brazil, and Chile total about 1,813 billion m³, while production is about 68 billion m³. The ratio of current annual production to proven reserves is about 26 years. However, it varies widely across countries, from 13 years in Brazil to 91 in Bolivia. The ratio of current consumption to proven reserves varies even more widely, reaching 427 in Bolivia (table 7-1).

TABLE 7-1. NATURAL GAS RESERVES AND PRODUCTION IN SOUTHERN CONE COUNTRIES, 2003 (billions of m³)

Country	Proven reserves[1]	Production[2]	Consumption*	Reserves/ production	Reserves/ consumption
Argentina	664	37.7	30.8	18	22
Bolivia	812	8.9	1.9	91	427
Brazil	244	18.5	18.9	13	13
Chile	93	2.5	6.8	37	14
Total	**1,813**	**67.6**	**58.4**	**26**	**31**

[1] As of December 31, 2002.
[2] Includes losses and flaring, but excludes reinjection.
Source: Authors elaboration, based on data from chapters 1-5.

Brazil's natural-gas reserves are key to developing a regional market. In 2003, a major discovery in the Santos Basin of São Paulo implies that, if the reserves are confirmed, this state will contain the country's largest total reserves (increasing from 3.8 billion m³ in 2002 to about 420 billion m³). However, full development of this gas field would take 8-10 years and require enormous investments. Therefore, gas imports from neighboring countries are still necessary, at least in the medium term.

Consumption Growth: Opposing Forces

Two opposing forces affect growth in regional consumption.[2] On the one hand, Southern Cone countries have ample room for growth in energy consumption because gas participation in the energy basket is low compared to other countries. On the other hand, the relative prices of energy and enormous investment in distribution networks may prevent increased gas consumption (table 7-2).

In 2001, the Southern Cone's per-capita energy consumption was 0.6-1.6 tonnes of oil equivalent (toe). Argentina had the highest level of per-capita consumption, while Bolivia had the lowest. For the same year, Europe's average per-capita consumption was 3.2 toe, while the United States' was 6.7 toe. Although energy consumption reacts to a range of variables (e.g., income or structure of industrial production) and extrapolating it requires a detailed analysis, these figures indicate the potential for increasing regional consumption. An examination of gas usage as a proportion of total energy consumption also shows that ample room is available for consumption growth. In Brazil, consumption is only 4 percent of total energy consumption, compared to as much as 50 percent in Argentina and 22 percent in Chile.

Natural gas' late entry into the regional energy market forces it to compete with such well-established resources as coal, fuel oil, and other oil products. Consumers are often reluctant to switch to natural gas because of the investment required. In order for a consumer to be willing to make the switch, the expected value of energy savings should be larger than the investment required. This means that gas prices should be significantly lower than alternative energy prices over an extended period. However, in most countries, gas prices are not conducive to the substitution of gas for other energy sources in already established industries and residences. Moreover, relative prices do not favor the switch, even for new industries and homes. Thus, for a gas market to develop rapidly, gas prices must become competitive with other energy options.

2. Regional consumption is about 59 billion m^3, while effective power plant, industry, and residential consumption is some 42 billion m^3 (table 7-2). This level of consumption is insufficient to financially sustain the level of investment required for effective market integration. Thus, market integration depends on opportunities for growth in regional consumption.

Increasing consumption of households and small- and medium-sized enterprises requires large distribution networks, which, in turn, require large investments. However, investments will not be made unless expected demand is larger. Increasing the consumption of large industries and power plants also requires investments; however, this is a good option for monetizing reserves and increasing gas companies' cash flow; supply competition would be an effective option for doing so.

TABLE 7-2. NATURAL-GAS CONSUMPTION IN THE SOUTHERN CONE, 2002 (billions of m^3)

Country	Power plant	Industry	Residential	Other*	Consumption*
Argentina	8.7	10.7	8.755	2.645	30.8
Bolivia	0.5	0.6	0.008	0.792	1.9
Brazil	2.1	6.6	0.196	10.004	18.9
Chile	2.4	1.0	0.442	2.958	6.8
Total	**13.7**	**18.9**	**9.401**	**16.399**	**58.4**

* Includes losses and flaring, but excludes reinjection.
Source: Authors' elaboration, based on data from chapters 1-5.

Southern Cone Trade

Brazil and Chile are the region's net gas importers, while Argentina and Bolivia are its net exporters (table 7-3). Imports by other Southern Cone countries, such as Uruguay and Paraguay, are not yet relevant. Therefore, the case for regional market integration relies on the capacity of producers to export gas to Brazil and Chile. The structure of Chile's gas sector ensures free trade, and there are no great obstacles for importing gas. However, Petrobrás' dominance of Brazil's industry structure is an obstacle for free trade and integration.

Industry Structure

Upstream Incumbents

A handful of multinationals controls more than 80 percent of the Southern Cone region's natural-gas reserves, nearly 70 percent of its gas

production, and 51 percent of its gas transmission (table 7-4). Therefore, these global players' decisions will determine cross-border trade in natural gas and the extent of regional market integration.

TABLE 7-3. NATURAL-GAS BALANCE IN SOUTHERN CONE COUNTRIES, 2003 (billions of m^3)

Country	Production	Export	Import
Argentina	37.7	3.9	n.a.
Bolivia	8.9	4.9	0
Brazil	18.5	0	5.9
Chile	2.5	0	5.2
Total	**67.6**	**8.8**	**11.1**

n.a. = not available.
Source: Authors' elaboration, based on data from chapters 1-5.

Several sectoral forces promote the integration of natural-gas markets in a competitive environment:

– Global players' financial capacity and incentive to undertake needed investments;

– Global players' knowledge about how to handle the integration process, including business strategies that rely on opportunities to achieve synergies through natural-gas trade in competitive markets; and

– Presence of seven large companies and a market sufficiently large to provide an adequate environment for effective competition.

Although industry structure encourages integration, countervailing forces may prevent it, including the market power of Petrobrás and Repsol YPF (*Yacimientos Petrolíferos Fiscales*). Petrobrás owns nearly 819 billion m^3 of natural gas, while Repsol YPF has 400 billion m^3. Petrobrás has complete control over Brazilian reserves and a significant portion of Argentine and Bolivian reserves. Repsol YPF has a dominant position in the reserves of Argentina and Bolivia. Petrobrás controls imports to Brazil, while Repsol YPF controls exports from Argentina.

TABLE 7-4. COMPANY RESERVES, BY SELECTED COUNTRY
(billions of m^3)

Company*	Argentina	Brazil	Bolivia	Total
British Gas	-	-	154.8	154.8
British Petroleum	76.3	-	107.1	183.4
El Paso	9.4	-	-	9.4
Petrobrás	60.0	650.0	109.8	819.8
Repsol YPF	203.4	-	203.4	406.8
TotalFinaElf	166.7	-	119.7	286.4
Total global players	516.0	650.0	695.0	1,861.0
Total country	730.0	650.0	900.0	2,280.0
Global player participation (%)	70.7	100.0	77.2	81.6

* All company figures are for 2001, with the exception of Petrobrás, which are for 2003.
Source: Almeida et al. (2002).

British Gas (BG), British Petroleum (BP), and TotalFinaElf have the financial capacity and incentive to undertake investments to increase regional consumption; however, they may be reluctant to invest because of concerns regarding the strategies of Petrobrás and Repsol YPF. Although the potential market power of both dominant players is large, Petrobrás' decisions will have a greater effect on the integration process because integration depends on growth of Brazilian markets, which Petrobrás has the power to control.

Downstream Industry

Gas distribution in the Southern Cone, as in most world regions, has traditionally been organized as a geographic monopoly franchise. Historically, this structure has been justified on natural monopoly grounds and its corollary that economies of scale and large sunk costs may discourage investment in the presence of free entry. As a result, a single enterprise generally owns the distribution network in a particular geographic area. This means that the impetus toward integration of distribution should be analyzed within the framework of the local distribution franchise. Although a distribution franchise for all consumers in a given area may be justified on economic grounds, a distribution and supply franchise in a given area is not always justified.

Moreover, consumers' ability to choose their supplier is a key factor pushing toward market integration because foreign producers and large consumers must find opportunities for trade outside the distribution company. Conversely, potential collusion between downstream and upstream activities and the size of distribution networks are potential barriers to integration.

Three distribution features are relevant for regional integration: 1) consumer choice, 2) potential for collusion, and 3) network size. Consumer choice is only possible in Argentina and Chile. The distribution segment in Brazil and Bolivia is organized as a double franchise for both distribution and supply, and consumers cannot choose a supplier. For example, Brazilian consumers who do not need the distribution network (e.g., power plants) must buy gas through a distribution company.

While potential for collusion is low in Argentina, Bolivia, and Chile, it is high in Brazil. Argentina has eight distribution companies that operate as a monopoly in a geographic area, but not as a supplier monopoly. In addition, regulations limit the degree of vertical integration and cross-ownership. For example, no investment group can purchase more than two distribution companies, or can purchase more than one transport and one distribution company. In addition, regulations forbid companies in one industry segment from holding more than a minority stake in companies in another segment. Bolivian regulations require that distribution and upstream activities be kept legally—but not economically—separate. In practice, however, Bolivian distribution companies do not have ownership relations with upstream companies. While Chilean regulations allow for full vertical integration, distribution and upstream activities are not bundled in practice. In Brazil, however, Petrobrás enjoys a significant degree of participation in most distribution companies, which may lead to collusion between upstream and downstream activities.

Argentina and Chile have complete distribution networks in all major cities, while networks are virtually non-existent in Bolivia. Brazil has about 8,400 kilometers (km) of distribution pipeline heavily

concentrated in the states of Rio de Janeiro and São Paulo, where more than 70 percent of the country's distribution pipeline infrastructure is located. Private investors control São Paulo's Comgás, Gas Brasiliano, and Gas Natural del Sul and Rio de Janeiro's State Gas Company (CEG) (*Companhia Estadual de Gás*). Public-sector entities control the remaining 18, active distribution companies. In many cases, the state government owns 51 percent of shares, and Petrobrás and private companies often own 24.5 percent each. Private stakeholder companies include the UK's BG and Shell, the Enron subsidiary Gaspart (*Gás Participações Ltda.*), Spain's Gas Natural Sdg and Iberdrola, Italy's Italgas and Snam, Argentina's Pluspetrol, and several Brazilian consortia.

Petrobrás Dominance

Until 2003, Petrobrás owned nearly all of Brazil's proven gas reserves, estimated at 244 billion m^3, roughly 13 percent of Southern Cone reserves. These reserves were considered insufficient to cover expected domestic demand, making it necessary for Brazil to import natural gas. However, that same year, Petrobrás discovered a giant offshore gas field in the Santos Basin, with an estimated volume of about 420 billion m^3. Although the exact volume still must be confirmed, this discovery reduces the need for medium- and long-term imports because, according to Petrobrás, these reserves have the capacity to produce about 50 million m^3 per day for 20 years (about 10 million m^3 more per day than the current production rate). Nonetheless, full development of this gas field is likely to take more than a decade, requiring that Brazil continue to import natural gas from neighboring countries over the short term. A business strategy based on limiting Brazilian market growth during the period before Santos Basin production begins would jeopardize regional integration, but might provide Petrobrás long-term market control. The issue is whether Petrobrás has the capacity to limit internal market growth. Given current regulations and market structure, Petrobrás appears to have the market power to do so. Because Petrobrás is an oil company, when considering the opportunity cost of investing in oil or gas, it will choose oil, the source of its major profits.

Petrobrás holds a virtual monopoly of the Brazilian market, controlling both internal production and imports. Its control over domestic production allows

it to dominate commercialization of its own gas production through its wholly-owned subsidiary, Gaspetro. At the same time, Petrobrás is the main shipper in the Bolivia-Brazil pipeline, holding the bulk of gas-import contracts. As a result, each of Brazil's 18 distribution companies has take-or-pay contracts with Petrobrás.

Petrobrás controls 93 percent of Brazil's transmission network through its subsidiary Transporte S.A. (Transpetro) and its participation in TBG (*Transportadora Brasileira Gasoduto*), operator of the Bolivia-Brazil pipeline. In addition, Petrobrás has a 25 percent stake in the international Paraná-Uruguaiana pipeline. Competition in transport services through pipeline expansion is unlikely because Petrobrás is expected to control the two projects currently envisioned (Malhas Project and Northeast-Southeast pipeline).

Control of internal supply and transmission systems are sufficient tools for Petrobrás to limit short-term market growth. Moreover, the company's position in the distribution segment means that it can control market growth according to its own business strategy.

Regulatory Issues

Trade Liberalization

The first condition for market integration is trade liberalization. This entails economic agents' freedom to buy and sell natural gas from national- or foreign-market players with equal treatment, regardless of gas origin or destination. As explained in the country analyses (chapters 1-5), all Southern Cone countries have enacted laws liberalizing natural-gas trade, which will positively affect market integration. However, certain countries persist in discriminatory legal treatment because of gas origin or destination, which may negatively affect the integration process. For example, in Bolivia, a price cap is set on gas delivered to domestic customers, while prices on exports have no cap. The result is that Bolivian consumers pay much less for gas than do export markets. In 2002, Argentina's government froze domestic transport tariffs in Argentine pesos, but allowed export tariffs in constant U.S. dollars. The result was different transport prices for domestic consumption and export, biased against gas exports.

Although discriminatory regulations with regard to gas use and source will obviously restrain the regional integration process, the social and political costs of removing such obstacles are high. Bolivia will likely be reluctant to eliminate discriminatory treatment between domestic consumption and exports. However, since domestic consumption is currently low, the effect of such discrimination would not be strong over the short term. Nevertheless, attention should be given to the transition scheme to avoid social disruption when eliminating the subsidy implicit in the current discriminatory regime. The final effect of Argentina's unilateral reduction in exports to Chile in 2004 on the integration process cannot yet be estimated.

Open Access Application

The principle of third party access (TPA) refers to open, nondiscriminatory access to transport and distribution networks by all parties to allow for market competition, while taking advantage of scale economies of transport and distribution networks. Around the world, most countries start by establishing open access to transport networks for large market participants. During a second stage, they gradually establish open access to distribution networks. Thus, priority is given to consumers having reached a certain consumption threshold. As this threshold diminishes, more consumers are given the option of choosing their supplier and bypassing the distribution company in successive steps.

The regulatory frameworks of Argentina, Bolivia, Brazil, and Chile have established the principle that third parties have open and nondiscriminatory access to the natural-gas transport network; only Argentina and Chile have also established open access to distribution networks. Brazil's regulations grant network distributors the exclusive right to sell gas in their geographic areas, even to such consumers as large gas-based generators, who do not need the distribution network to receive their gas supply.

Most Southern Cone countries have shown regulatory weakness in applying and enforcing the open-access principle to transport pipelines.[3]

3. Although the open-access principle applies to both transport and distribution networks, the authors focus on obstacles to transport facilities.

Argentina and Bolivia, for example, have an entire set of regulations to ensure open, nondiscriminatory access; however, these regulations do not apply precisely to cross-border pipelines because most of Argentina's international pipelines are under a concession regime, whereby open-access duties are loosely regulated; while its domestic pipelines are a under a license regime, with complete open-access regulation and unbundling from commercialization activities. In Bolivia, GTB (*Gas Transboliviano*), the transport pipeline to southeastern and southern Brazil, is not subject to gas regulations, but to a contract agreed on by the parties.[4] This contract limits open access to third parties; all capacity is contracted by Petrobrás, whose authorization is required for transporting gas of other shippers, even though Petrobrás is not using it. Brazilian law also establishes the open-access principle, but the regulatory agency has experienced difficulty in attempting to set specific regulations; the parties have agreed to open-access terms and conditions, but conflicts often emerge.

Some market participants believe that exclusive concession contracts provide a critical vehicle for financing new infrastructure and developing gas markets. However, these participants often fail to differentiate between giving exclusive transport rights to a concessionaire and giving the right to choose the gas transported through the pipeline. While exclusive transport rights can help attract private investment in infrastructure, long-term, exclusive transport rights should not coexist with the capacity to choose who may use the transport systems or long-term exclusive rights for selling gas. Moreover, supplementing exclusive transport rights with a monopoly on gas sales may discourage new investment.

Unbundling Options

Separation of ownership between competitive and non-competitive segments is the best way to ensure that market participants have nondiscriminatory access to competitive segments. However, the Southern Cone's regulatory frameworks are far from requiring economic unbundling.

4. The contract was signed before regulations were put in place.

While Argentina's regulations require economic unbundling for domestic pipelines, it is not required for cross-border pipelines. Legal unbundling—that is, independent legal entities must own transport facilities—is already established in Argentina, Bolivia, and Brazil, but not in Chile and Peru.

Advancing toward regional integration through full economic separation of competitive and non-competitive segments is not a viable option for the Southern Cone since country authorities and integrated regional companies would oppose it. Major vertically-integrated players in particular would oppose divestiture proposals. Petrobrás would make economic unbundling non-viable. Because Petrobrás is Brazil's most profitable company and one of its largest employers, full economic unbundling would create fear of privatization and the possible handover to multinational interests. Similarly, imposing economic unbundling on Chilean regulation would likely face political opposition. Moreover, Chilean authorities would likely resist establishing legal unbundling. As discussed in chapter 4, Chile's current legal framework does not restrict on the degree of vertical or horizontal integration, and no conflicts over discriminatory treatment have been reported.

One option for ensuring effective open access without requiring ownership unbundling is requiring legal and managerial unbundling, whereby economically integrated companies contract a specialized operator to manage and operate transmission facilities, including large storage facilities when necessary. The operator could be assigned for a fixed period of time and removed only under well-specified conditions. An efficient option would be to have one or two operators for the entire region; however, a more easily acceptable scheme would be one operator for each country system.

In addition to ensuring secure, reliable, and efficient system operation and maintenance, the system operator would assign storage and transmission capacity without discriminating between system users or classes of users, particularly those biased toward its undertakings. The system operator would provide other system operators sufficient information to ensure that transport and storage are carried out in a manner compatible with the secure and efficient operation of the

interconnected system. They would also provide users information to enable their efficient access to the system.

Country authorities and incumbent companies may be reluctant to accept managerial unbundling, despite experience showing that independent management can allow nondiscriminatory TPA without losing the financial stability of integrated companies. Moreover, implementing managerial unbundling may be costly. Given these potential constraints, market participants might consider giving integrated companies a choice between two regimes during the initial transition period. One regimen would be legal and managerial unbundling, with an independent system operator; while the other would be legal unbundling supervised by an ad-hoc regional committee with mayor player participation. A company under the supervisory regime would be committed to legal and managerial unbundling if the regional committee observes and documents discriminatory user treatment. This approach would allow for a smooth transition from a managerial unbundled regime and require that players discuss relevant issues with a regional supervisory committee.

Open-access Transport Regulation

Most Southern Cone countries embrace the open-access principle for gas transport facilities, which is a step toward market integration. However, Brazil and Chile have negotiated access, while Argentina and Bolivia have a regulated regime for transport access (but regulations do not apply to cross-border pipelines). Negotiated regimes are an obstacle to effective, nondiscriminatory access to transport facilities and thus market integration. The IEA (2000) and the 2003 Gas European Directive recommend regulated TPA.

Four major factors, discussed below, shape the regulation of open-access transport in Southern Cone countries. That most countries do not effectively regulate these factors does not prevent efficient use of transport facilities in Chile, but does in Argentina, Bolivia, and Brazil. Differences in sector structure—particularly vertically-integrated companies in Argentina, Bolivia, and Brazil—may explain differences in performance.

ALLOCATING CAPACITY

Regulations should set rules and procedures to make spare capacity available to all potential users. These rules should include the operator's role in determining spare capacity, taking into account long-term contracts and the relationship between the operator and transport-facility owners. Regulations should also establish that, at announced points in time, the operator will allow natural-gas undertakings and eligible customers to reserve the right to use spare capacity in the upstream pipeline network for specified periods. Reservation of spare capacity may occur on both short- and long-term bases. In addition, regulations should establish how to distribute capacity if reservations exceed spare capacity. Criteria for such distribution should be carefully designed to prevent market incumbents from requesting large reservations to avoid competition.

Establishing regulatory guidelines for capacity allocation is a difficult task, and such guidelines are currently unavailable in the four Southern Cone countries reviewed. However, advancing toward integration demands such clear, stable rules. The proposal set forth in chapter 6 recommends a two-step process. First, countries agree on setting guidelines for capacity allocation and giving regulators power to supervise and enforce them. Second, an ad-hoc group composed of relevant technical and economic agents prepares the guidelines and establishes the pace of implementation. In addition, a supranational enforcement mechanism should be designed, with the ad-hoc group serving as a moral mechanism to enforce the guidelines.

SETTING TRANSPORT TARIFFS

Setting clear transort tariff regulations is the most critical step in establishing open access. Within the context of vertically-integrated companies and lack of pipeline competition, poor tariff regulations are equivalent to TPA failure. In Europe and the United States, regulators focus on cost measurement and financial accounting techniques to set rates. Moreover, in Europe, the 2003 Gas Directive requires countries to have independent regulators who set transport tariffs. Although most

Southern Cone countries have regulatory agencies in place, Brazil and Chile set transport-facility tariffs by party agreement. In Bolivia and Argentina, regulators set prices for domestic pipelines, while parties negotiate international pipeline prices.

Advancing toward market integration requires a harmonized system for setting transport prices that follows well-accepted accounting and financial standards. The basic principle should be recovery of operational and investment costs. The regulation should also establish appropriate rules for compensating capital and the number of years for recovering costs. In addition, the tariff structure should be regulated. Certain pipelines may charge tariffs according to distance between entry and exit points, while others may charge stamp tariffs. Although using a distance tariff structure for end-up pipelines and stamp tariffs for integrated pipelines is well accepted, regulations should clearly establish the regime that applies to each pipeline. For new pipelines, competitive tenders may be used to reduce the degree of regulatory discretion. When proposing new pipeline projects, individual investors should propose the corresponding tariffs. After the regulator publishes a detailed project description and proposed tariffs, competitors would then step forward; the winning concession bidder would be willing to accept lower tariffs than those proposed by the initial project sponsor. As a mechanism for setting tariffs, the bidding process would have two caveats. First, contracts awarded under the minimum-tariff criterion would be renegotiated often (Guasch 2004). Second, vertically-integrated companies might offer a lower tariff to control the market and cross-subsidize the transport activity with the benefits of upstream activities.

ESTABLISHING LONG-TERM CONTRACTS

Most transmission facilities either belong to integrated companies or are subject to long-term, take-or-pay contracts. These contracts will continue to play an important role in Southern Cone gas supply and may be critical to underwriting large-scale investments in gas field development and long-distance transport infrastructure, especially related to launching large supply projects. However, these contracts should not frustrate competition by explicit inclusion of restrictive conditions or creating participants with dominant positions.

APPLYING OPEN SEASON TO NEW PIPELINE CAPACITY

Private investors with market power tend to build smaller infrastructure than is socially optimal because investor benefit is higher if supply is restricted and the gas price exceeds the competitive price. The reasons for the Southern Cone's failure to achieve socially optimal capacity are twofold: First, most transport companies are directly or indirectly controlled by large gas producers, who set transport capacity to fit their own strategy; second, large producers' business strategies are oriented more toward increasing market share than size.

Open season provides natural-gas shippers the opportunity to make nonbinding requests for service on the proposed pipeline. Requiring open season for new capacity is an appropriate tool for handling undersizing of transport capacity. Moreover, open season increases competition and facilitates application of the open-access principle. While applying the open-season principle to constructing new pipeline capacity is not common in Southern Cone countries, Brazil applied it to expand the GOB (*Gasbol)* pipeline. Including this practice to increase the capacity of new and existing pipelines will be an important step toward competition and integration.

A Proposal

Any initiative aiming to advance toward market integration should be able to capture the forces pushing for integration and offset those tending to block the process. Such a proposal should meet two conditions. First, it should be negotiated with mayor industry players to ensure they will remain in the market since their capacity and willingness to undertake a large portion of the required investment constitute a major positive force for market integration. Second, it should assure all companies willing to invest a competitive environment and level playing field. Investors in distribution should know they will have transport services independent of the origin of gas purchases; otherwise, the enormous investment required to bring gas to medium and small consumers will not occur.

The proposal presented in chapter 6—based on sound economic reasoning and applicable experience of the European Union—meets these two conditions. Recognizing the current political constraints and market maturity, this proposal relies on a multilateral treaty aimed at integrating Southern Cone gas markets and an ad-hoc forum for pushing forward and supervising the process. The multilateral treaty may be viewed as completing the 1999 Mercosur MOU and extending it with regard to two aspects: 1) that Bolivia and Chile, although not full members of Mercosur, should sign the agreement as they are key actors in Southern Cone market integration and 2) that the treaty should include country agreements on pro-competition guidelines, benchmarks, and forum composition and roles.

Competition guidelines would consider non-discrimination between domestic and international transactions; information disclosure; and regulated TPA, including pipeline rates, vertical-integration provisions, and open-season characteristics. Equally important would be a mandatory schedule for market opening and the principle of reciprocity to accommodate countries wishing to exceed the mandatory schedule. The implications of this treaty would be made concrete within the context of a permanent forum in which governments, regulators, investors, firms, experts, and the general public discuss key issues. Such a forum would help to identify the required degree and depth of unbundling—the major obstacles to market integration.

The principle of reciprocity is a powerful force driving the dynamics of market integration and is a key aspect of this proposal. Reciprocity increases the demand for completing a thorough regulatory framework and accelerating the transfer of benefits—greater coverage and reduced prices—to Southern Cone gas customers, including those in the electricity-generation sector.

Editor's Remarks and Summary of Recommendations

The analysis of gas supply and demand, industry structure, and regulations shows that counteracting forces are pushing for and against Southern Cone market integration. The uneven distribution of

consumption and reserves across countries creates many opportunities for integration; however, the region's low expected rate of consumption growth makes integration less attractive. Moreover, monetization of regional reserves would require trade with larger markets. The gas industry structure also has forces pushing for and against integration. Sector companies' financial strength and their willingness to use reserves at a faster pace are among the forces pushing for integration. At the same time, sector concentration, market power, and large dominant players may prevent competition and block others' investment. Most of the principles promoting integration and competition are embedded in country regulations. However, lack of precise regulations with regard to key aspects (e.g., open access and transport system operator), together with poor enforceability, is an obstacle to effective competition and integration.

In closing, the authors offer four recommendations.

- Include competition authorities' role in the market integration process in treaty provisions. General competition provisions should apply to the gas industry, which, in turn, requires empowering competition authorities with effective legal capacity to prosecute noncompetitive practices in the gas industry and evaluate the appropriateness of mergers from a regional perspective to avoid those that give a gas firm regional dominance.

- Promote the entry of new players to strengthen the distribution network. This recommendation is particularly relevant for Brazil, where network investments are frozen because of lack of incentive and distribution companies' poor financial capacity. Reducing the participation of Petrobrás and local government in certain distribution companies would increase distribution investment and gas consumption.

- Open the market to large consumers, particularly power plants, as soon as possible. This measure would allow new players market entry and increase consumption before large distribution networks are in place.

- Develop a negotiated process—similar to that of the Madrid Forum—that introduces benchmarks into the broad agreement, showing the desired

path of market integration. Although the Southern Cone forum should be responsible for setting specific integration goals, its benchmarks would be the framework for guiding and evaluating the process.

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Appendix: Overview of Southern Cone Submarkets

Submarket	Major country features	Industry organizational issue	Regulation	Medium-term business dynamics
Argentina-Chile	–After Argentina's macroeconomic crisis, gas-price controls favor domestic consumption. –Chile imports gas via seven pipelines from Argentina.	–Market forces drive gas transactions. –YPF is Argentina's sole producer. –Chile has four regional markets. –Vertical integration between Chile's power generation and gas transport is problematic.	–1995 bilateral economic agreement treaty supplements light-handed regulation (which includes negotiated TPA). –Market structure and evolution may have facilitated "yardstick" competition. –Unbundling is required.	–There is room for introducing standard spot transactions. –Sustained annual growth of Chilean consumption of 7.6% is expected. –Power generation would be half of total Chilean consumption by 2012.
Bolivia-Brazil	–Bolivia's economy and politics are sensitive to gas exports. –Brazil's imports shrank as demand fell after 2002. –Brazil imports gas via two pipelines from Bolivia. –In 2003, enormous reserves were discovered in the Santos Basin of Brazil.	–Petrobrás is 1) a monopolist in Brazil transport and commercialization, 2) a key partner of Brazilian and Bolivian production and international transport, and 3) a major shareholder in 18 out of 24 distribution firms. –YPFB manages export contracts from Bolivia. –Bolivian gas serves one of the three regional markets.	–TPA is negotiated. –Vertical integration provisions are weak. –Gas-fired power plants must purchase from Petrobrás or distributors. –Petrobrás requires unbundling.	–Consumption should increase if Brazil reviews energy policy and subnational gas networks are interconnected. –Brazil and Bolivia have open-access provisions, and commercialization dominance of Petrobrás and YPFB diminish trade opportunities.

Chapter 8

The Argentina-Bolivia-Chile Crisis

Edmar Luiz Fagundes de Almeida and Nicholas Trebat

Recent political and economic turbulence in Argentina and Bolivia have significant implications for cross-border gas projects and Southern Cone market integration. These two countries' energy policies are undergoing changes characterized by nationalistic measures and the state's increased role in the energy sector. Since both countries are regional gas exporters, their policy changes will affect regional integration.

Unlike the oil trade, cross-border gas trade requires enormous investments in transport infrastructure with sunk costs for investors. Therefore, political and regulatory instability are an important investment risk that futures and other instruments used to manage oil-trade risk cannot mitigate. Similarly, interdependence between importer and exporter countries can be a source of geopolitical conflict.

During the 1990s, the Southern Cone experienced energy-sector liberalization and rapid investment in energy production and utilization. Governments of the region attempted to work politically to create an environment within which to reduce private-sector risk of investing in energy integration, especially natural-gas integration. Despite their efforts, the process of regulatory convergence was far from achieved. Indeed, recent political moves that have affected cross-border gas trade in Argentina and Bolivia represent a significant setback for regional integration.

Argentine Crisis: Effects on the Gas Industry

During the 1980s, Argentina experienced deep economic and political instability. The foreign debt crisis resulting from increased global interest rates, the war with Britain for control of the Malvinas Islands, and political turmoil pushed the country into hyperinflation by the early

1990s. Economic policy to control inflation led to relays on parity of the exchange rate of peso and dollar and prohibition of injecting pesos into the economy without being fully backed by dollars. In 2001, Argentina underwent a profound economic and political crisis, as the government was unable to sustain the parity of peso and dollar. A protracted economic recession, coupled with international financial turmoil, forced authorities to devaluate the peso in 2001.

In January 2002, Argentina defaulted on its foreign debt and implemented the Economic Emergency Law (also known as Pesification Law). This Law declared null and void all adjustment clauses in dollars or other foreign currency, as well as all indexation clauses based on foreign index prices. National executive power has used this Emergency Law to re-negotiate concession contracts, taking into consideration the social effects of tariff realignment. Thus, this Law reduced regulatory agencies' power regarding the application of concession contracts.

Peso Devaluation

After passage of the Economic Emergency Law, contracts, prices, and tariffs quoted in dollars were converted into pesos, despite devaluation of the peso (from AR$1 to AR$3 per US$1). This currency devaluation set off a deep financial crisis in Argentina's gas industry. Wellhead prices established at about US$1.25 per million British thermal units (Btu) were fixed at AR$1.25 per million Btu. With the new exchange rate (AR$3 to US$1), the wellhead gas price fell to US$0.35 per million Btu. Thus, the Pesification Law meant the reduction of gas prices to about one-third of historical levels in dollars, which were already low by international standards.

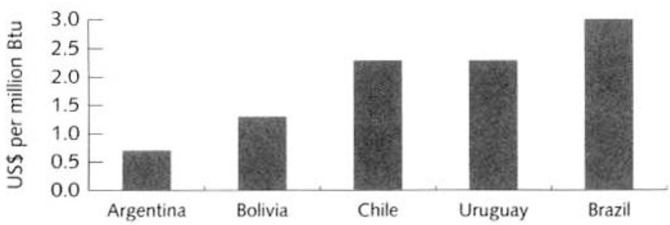
Similarly, gas transmission and distribution tariffs were reduced to one-third of their historical levels. The price of electricity was equally affected. In 2004, the wholesale-market price of electricity was only about US$12 per megawatt hour (MWh).[1] The reason for such a low price was that

1. In 2002, the government tried twice to increase gas and electricity tariffs to correct imbalances in Argentina's energy market. The judiciary prevented the government from doing so, arguing that this measure was against the Economic Emergency Law, which should be applied to all sectors of the economy.

calculation of the wholesale price considered the marginal cost of gas-based thermal generation. Thus, low gas prices resulted in a low wholesale electricity price. Conversely, the Pesification Law did not affect the price of liquid fuels (oil and oil products). These prices were fixed according to international prices,[2] creating significant price asymmetries between energy prices that led to large imbalances between energy supply and consumption.

Application of the Economic Emergency Law on the energy sector created important asymmetries in the regional, as well as domestic, energy markets. For example, while the gas price at Brazil's city-gate is US$2.5-3.4 per million Btu (averaging US$3 per million Btu), the price in Argentina is only about US$0.7 (figure 8-1). Argentina's domestic gas prices are by far the region's lowest. It should be noted that domestic gas prices do not apply to gas exported to Brazil, Chile, and Uruguay, which is a source of conflict between domestic and exports markets. While producers have an incentive to increase gas exports, domestic demand is booming, reducing available gas for export.

FIGURE 8-1. AVERAGE GAS PRICE AT CITY-GATES



Sources: Country regulatory agencies.

Companies' Financial Crisis

Dramatic reduction in natural-gas prices and tariffs caused a deep financial imbalance throughout the gas chain. A significant portion of the firms' costs increased with the devaluation process, particularly interest payment. During the decade of the "conversibilidad" plan, the

2. However, the government imposed a tax of up to 25 percent on oil-product exports (depending on product type), which allowed domestic prices to be quoted below the international level.

fixed exchange rate and higher domestic interest rates impelled companies to contract debt in dollars in the international market. Reduced revenue in dollars diminished firms' financial capacity, forcing them to adopt drastic adjustment measures. The most critical measures were to stop all investment and expansion plans, reduce non-essential personnel, cut non-essential expenditures (e.g., marketing or social-event sponsorship), and (in certain cases) declare unilateral default on foreign loans (Franicevich 2003).

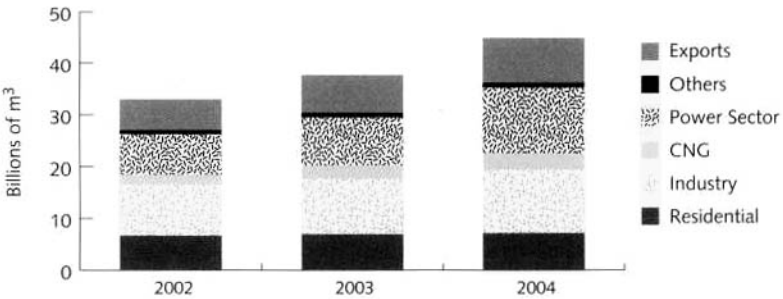
The most obvious effect of the crisis on the gas sector was freezing company investment plans. After devaluation, exploration activities in the upstream sector were reduced dramatically. The number of exploration wells was reduced from 120 in 1999 to only 17 in 2003 (Petrotecnia 2004, Giusano 2004).[3] In the gas transport sector, hardly any new capacity was added after the peso devaluation. As a result, investment in new reserves dropped and supply capacity was unable to cope with booming gas demand, leading to political questioning of private companies' interest in investing in expansion of the country's infrastructure. This perception of private firms failing to develop energy resources was fueled by the Kirchner administration's energy policy, characterized as nationalistic and state-directed (Repar 2004).

Post-crisis Evolution of Supply and Demand

Given the asymmetry in gas prices compared to liquid fuels, natural-gas demand expanded rapidly with the 2003 economic recovery; domestic gas demand increased 11 percent in 2003, and the growth rate grew further in early 2004 (figure 8-2). Gas demand between January and April 2004 was 18 percent higher than over the same period in 2003. Gas exports to neighboring countries increased even faster. In 2003, exports grew 23 percent, and, in the first quarter of 2004, they were 20 percent higher than in the first quarter of 2003. This increase can be explained, in part, by companies seeking to compensate domestic-market losses by selling at higher prices to the international market.

3. In November 2003, the Argentine Oil and Gas Institute organized a workshop to analyze the problem of reducing exploratory efforts in Argentina. This workshop pointed out several causes—beyond economic turmoil—that resulted in price and tariff decline: reduced geological prospects (reduction of average field size), investment competition in other areas of South America, and relatively high regulatory risks.

FIGURE 8-2. EFFECTIVE AND PROJECTED GAS DEMAND, 2002–04*



* Total estimated demand for 2004 assumes that the same growth pace will continue throughout the year.
Source: ENARGAS.

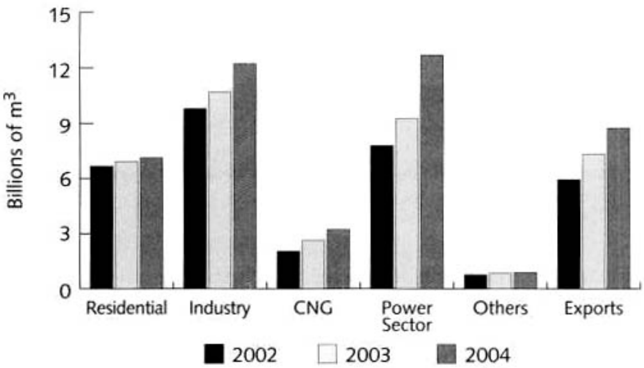
Figure 8-3 shows that natural-gas demand increased in all segments during 2002–04; however, the power, and transport (Compressed Natural Gas [CNG]), and industry sectors led this expansion. With regard to the power sector, the boom in gas demand had two main causes: rapid expansion of electricity demand (increasing 12.2 percent between April 2003 and April 2004) and reduced hydroelectric production due to an unusually dry season in 2003. With regard to transport, CNG market expansion was fueled by a dramatic increase in the price gap between CNG and liquid fuels. While gasoline prices averaged AR$2 per liter, CNG prices were only about AR$.60 per cubic meter ($m^3$).[4] Thus, the payback of investing in car conversion is now a question of months. Even CNG conversion of diesel-fueled cars has started. The same type of price asymmetry is driving industrial-sector demand.

These figures clearly show that low domestic gas prices are causing Argentina's gas bubble. During 2003, production capacity was able to cope with demand expansion, with gas production increasing 11 percent over the course of the year. Nevertheless, this effort to increase production reached its limit in 2004, given that the bubble was not followed by an equal increase in expansion of supply capacity. Since companies' investment capacity has been drastically reduced, transport capacity from the main basins to Buenos Aires has not increased since

4. 1 m^3 of CNG is equivalent to about 1 liter of gasoline in terms if energy content.

2001. Similarly, exploration efforts shrank and the reserves-to-production ratio has subsequently decreased. In 1999, this ratio was about 17 years, declining to 12 years in early 2004 (Petrotecnia 2004).

FIGURE 8-3. EFFECTIVE AND PROJECTED GAS DEMAND, 2002–04



Source: ENARGAS.

Gas shortage became a reality in 2004. Several distribution companies stopped signing new firm supply contracts. Peak demand for winter 2004 (July-September) was estimated to exceed total supply capacity by 5-17 million m³ per day if nothing were done to stop demand growth. The possibility of increased supply was limited by lack of transport capacity. Thus, it became clear that increased supply capacity would not be possible in the short run; in response, the government was forced to adopt a set of emergency measures to cope with the gas shortage.

Emergency Response to Gas Shortage

In early 2004, Argentina's government began to enact a series of decrees attempting to reduce gas demand and restore market balance without significantly increasing gas prices. The government opted to maintain domestic price controls and avoid the political cost associated with short-term price realignment.

In February 2004, the government enacted presidential decrees 180 and 181, which attempted to improve gas-supply conditions through several measures.

Decree 180 created an investment trust fund to be applied specifically to the gas sector. This fund was to be composed of tariff charges applicable to gas transport and distribution services, financed by multilateral institutions and investor resources for specific projects. By creating this fund, the government attempted to generate sufficient resources to invest in expansion of gas infrastructure and restore control over the pace of investment in the natural-gas industry. Decree 180 also created an electronic gas-sector market, whose objective was to improve technical and economic transparency of gas markets. The electronic market was to allow for development of spot and secondary gas markets. Currently, the country's spot market is a short-term, bilateral gas market (Presidencia de la Nación 2004).

Decree 181 required the Secretary of Energy to develop a scheme allowing for price realignment until the end of 2006. The aim was to allow progressive wellhead price realignment, with the pace varying according to the social effect of the price increase. To determine the maximum price increase, the Secretary conducted studies on the prices needed to allow for necessary upstream investment. In April 2004, the Secretary and gas producers agreed that the price for large consumers (industry, CNG, and power generators) would be realigned by June 2005, followed by the rest of the market by the end of 2006. Thus, this agreement will allow wellhead prices to increase to about the same level in dollars charged before devaluation (about US$1.2 per million Btu). Similarly, all concession contracts for gas transport and distribution will be renegotiated to recover tariff levels.

The measures of decrees 180 and 181 did not directly tackle Argentina's emergency gas shortage, but did highlight how the market will be normalized. As the gas shortage became inevitable, the government's first response was to curtail gas exports. Resolution 265 allowed for the government to reduce exports to ensure domestic supply and ration interruptible export contracts and volumes greater than 2003 levels if firm domestic gas demand were compromised. It also included the power sector as firm demand, increasing the probability of curtailing exports.

Given that export rationing would be insufficient to avoid large gas curtailments in the domestic market, the government decided to launch

a complete energy plan to tackle gas- and electricity-sector shortages. The National Energy Plan (NEP), announced in May 2004, proposed a set of demand- and supply-side measures for the gas and electricity sectors. The main measures can be summarized as follows:

- Implementation of a rationing program in the gas and electricity sectors. This program offers incentives for consumers that reduce demand levels (compared to the same period in 2003) and penalties for large consumers that exceed quotas.[5] The quota for large consumers was established at 95 percent of the 2004 demand level.

- Imports of Bolivian natural gas (up to 4 million m^3 per day),[6] Venezuelan fuel oil, and Brazilian electricity. These measures are expected to increase gas availability about 10 million m^3 per day, considering the reduction in gas demand for power generation.

- A program to expand gas and electricity infrastructure, with $4 billion in new investment during 2004–08.

- Restrictions on gas exports to Chile, by limiting maximum volumes and imposing a 20 percent duty on exports.

- Creation of ENARSA (*Energía Argentina Sociedad Anónima*), a state-owned energy company.[7] ENARSA's main objectives are to increase oil and gas reserves, augment gas-supply capacity, and improve gas and electricity transmission and distribution infrastructure. ENARSA will invest in the energy sector in partnership with private companies.

- Implementation of gas price and tariff realignment by December 2006 to restore the price in dollars that prevailed before devaluation.

5. This rationing program will negatively affect potential economic growth for 2004. Some estimates indicate that rationing will contribute to a 1-2 percent reduction of potential GDP growth. Before launching the rationing program, the government expected economic growth of 7 percent in 2004; a more recent projection is 5.5 percent growth.
6. Bolivian gas will cost about US$1.6 per million Btu, much higher than the price of nearby domestic gas (only US$ 0.44 per million Btu).
7. ENARSA capital will be divided as follows: 53 percent, federal government; 12 percent, provinces; and 35 percent, private investors.

The NEP represents an important shift in Argentine energy policy. On the one hand, the gas and electricity price and tariff recovery will allow companies' financial condition to improve. As a result, firms' investment capacity will tend to increase after 2006, when the price normalization program is fully implemented. On the other hand, the new plan is a clear sign that Argentina's government intends to radically change the state's role in the energy sector. The government intends to regain control over the rate of sector investment using the newly created investment trust fund and ENARSA. Another key change concerns gas export policy. The government made it clear that internal security of supply is a condition for increasing gas exports. Authorizations for new export projects will tend to be more difficult to obtain.

Since currency devaluation, the economic environment for Argentina's gas industry has changed radically. The government's role in the gas sector is expected to increase, and it will tend to replace private-company leadership in development of cross-border trade. However, in the short and medium term, Argentina will tend to increase imports from Bolivia. Argentina's role as a gas exporter in the Southern Cone region will depend on the increase in proven domestic reserves.

Bolivian Crisis: Effects on the Gas industry

Bolivia's fragile political balance deepened into a crisis in the aftermath of the 2002 elections. Political parties could not agree on a common position with regard to the Pacific liquefied natural gas (LNG) project, which aims to export LNG to the United States using Chilean ports. This project encountered tough political opposition in Bolivia for two main reasons: 1) questioning of the economic benefits for the country and 2) opposition to using a Chilean port to export gas. Many Bolivians still harbor resentment toward Chile since Bolivia's defeat in the Pacific War more than 100 years ago.

As an alternative to using Chilean ports, it was suggested that gas could be exported to the U.S. through Peru by combining a Bolivian project with Peru's Camisea project developed by Hunt. However, the Chilean option was economically and technically more viable than the longer

pipeline option of Peru. Thus, project investors did not support the Peru option. Moreover, contracting gas sales through Peru was further complicated by competition from Peru's own reserves. The former Bolivian government found itself in conflict with investors, who concluded that 1) an export project through Peru would cost more than US$300 million more than through Chile and 2) construction of a liquefaction plant in Peru would stimulate production in Peru's Camisea gas field, forcing Bolivian gas to compete with Peruvian production.[8]

Although Bolivia's historical conflict with Chile contributed to popular opposition to the project (which planned to use a Chilean port to export gas to California through a Mexican regasification terminal), a large part of public protest centered on the dubious distribution of the project's economic benefits in Bolivia. The Pacific LNG consortium, headed by foreign multinationals Repsol and British Gas (BG), aimed to sell Bolivian gas in the United States at about US$3.50-4.0 per million Btu. Under terms of the 1996 Hydrocarbons Law, the Bolivian government would collect royalty revenues amounting to 18 percent of the wellhead export price. Therefore, selling gas in the U.S. market at this price would imply a wellhead price of about US$0.70 per million Btu, translating into Bolivian revenues of about US$0.13 per million Btu. Two underlying factors explain why opposition groups considered such prices too low. First, under gas-supply agreements with Brazil, the price of Bolivia's export gas had escalated far beyond reasonable levels because of poorly designed price-escalation formulas. Second, it was perceived that Bolivian companies would have little, if any, role in the project (Vargas 2003, Shultz 2003).

In addition to doubts about economic benefits, Bolivia's past and recent experiences with multinational corporations diminished popular support for the project.[9] The former government was slow to respond to its critics and ineffective in defining benefits of the LNG project. Moreover, LNG

8. After the project to export gas through Chile was interrupted, regional players considered exporting additional gas to Brazil's Atlantic coast to supply a liquefaction terminal; for these exports to be competitive, however, the wellhead price of Bolivian gas and Bolivia-Brazil pipeline transport costs would have to fall significantly.

9. Over the past two centuries, Bolivia underwent three major cycles with regard to non-renewable commodity exports: silver, guano (raw material used to process fertilizer), and rubber in the 19th century and tin in the 20th century. That none of these cycles laid the basis for significant economic development created general suspicion that the results with natural gas would be the same; see Kruse (2003).

projects have limited windows of opportunity; if missed, the next opportunity could be decades later. In the end, the marketplace displaced the Bolivian project with a new project in Indonesia.

New Hydrocarbons Law

Amid tremendous pressure—and following the death of 80 Bolivians during six weeks of popular protest—Bolivia's president formally resigned in October 2003, leaving the country under military protection with asylum granted in the United States. The vice-president, who replaced him, quickly announced plans for a new law to regulate hydrocarbons, which replaced the 1996 Hydrocarbons Law. After months of debate, the new law is not yet approved; however, Supreme Decree 24806, established in 1997, was revoked.[10]

At this point, however, revocation is mostly symbolic. What will truly alter the rules of the game for Bolivia's oil and gas industry is approval of the new hydrocarbons law. The new government has published several versions (the first was released February 8, 2004). Though varying slightly in content, the new law is based on: 1) creating a complementary hydrocarbon tax, 2) bolstering the role of state company YPFB (*Yacimientos Petrolíferos Fiscales Bolivianos*) throughout the industry chain, and 3) promoting gas industrialization (i.e., the use of gas as an input in higher value-added processes, such as production of petrochemicals, fertilizers, and gas-to-liquids [GTL] in projects located in Bolivia).

The complementary tax, known as ICH, is a tax on oil, natural gas, and liquefied petroleum gas (LPG) sales. According to industry analysts, the new government was, until recently, considering setting this tax level at around 15 percent, allowing producers to deduct this payment from the surtax charges they must pay each year on oil and gas revenues. In addition, the ICH was expected to be a progressive tax, with production in larger fields paying a higher percentage than in smaller ones.

10. Supreme Decree 24806 established that hydrocarbon resources at the wellhead are the property of private oil and gas producers. *La Prensa* (Jan. 14, 2004) reported: "With the decision (revocation), the new government has nullified the polemical decree 24806…by which the companies were the proprietors of the hydrocarbons, to the extent that they had authority to define prices, conditions, and types of products that will be exported and commercialized."

To boost YPFB, new exploration contracts between producers and the government can give the state company as much as a 50 percent stake in all oil and gas projects. YPFB will also increase its stake throughout the oil and gas chain, including transport, refining, and distribution. An increased role for YPFB has been a key demand of opposition groups, especially those opposed to LNG projects involving only foreign transnational corporations. Industry analysts claim that YPFB's participation in gas-supply projects (mainly for gas export) will dissuade large suppliers from investing in Bolivia. The government, however, says it will arrange to maintain exports (gas or LNG) competitive. The main opposition group supports a system in which the multinationals act as contractors for exploration and production services on behalf of YPFB.

Prior to 1997 capitalization, YPFB was the national oil company. The capitalization process was undertaken because YPFB lacked the capital necessary to develop Bolivia's reserves. Since capitalization, private companies have invested more than US$3.5 billion in proven Bolivian reserves. Threat of changing the rules has resulted in a significant drop in ongoing investment and field services provided by foreign technology companies in Bolivia.

Gas industrialization means use of natural gas for domestic consumption, generally as a raw material in productive processes with greater value-added products, such as in production of petrochemicals, steel, urea, and ammonia. The concept is to use Bolivia's natural resources not only for commodity export—as a source of foreign exchange—but also as a means of promoting activities that generate income, jobs, and technical progress. One idea is to add a provision to the new hydrocarbons law establishing that, for each cubic foot of natural gas exported, a certain portion should be industrialized, that is, consumed by Bolivian industry. Operating companies and economists have voiced considerable opposition, however, since this provision could lead to the same type of market decisions that contributed to Argentina's current gas supply and demand imbalances.

Referendum on Hydrocarbons Policy

In late April 2004, the new government announced a July 18 public referendum on the country's new hydrocarbons policy. The official

purpose was to help guide the executive power's action on controversial issues. Given the level of Bolivian discontent and political turmoil, the government aimed at acquiring political legitimacy to send a new energy law to congress (PFC Energy 2004).

The referendum consisted of five questions:

1) Do you agree with revocation of Hydrocarbons Law 1689 promoted by Gonzalo Sanchez de Lozada?

2) Do you agree that the Bolivian state should recover its status as proprietor of all hydrocarbons at the wellhead?

3) Do you agree that YPFB should be reconstituted, recovering state ownership of privatized oil companies in such a way that it may participate throughout the productive chain of the hydrocarbons industry?

4) Do you agree with President Carlos Mesa's policy of using gas as a strategic resource to gain a useful and sovereign exit to the Pacific Ocean?

5) Do you agree that Bolivia should export gas within the context of a national policy oriented toward Bolivian consumption; promoting gas industrialization within the national territory; imposing taxes on and/or charging royalties to oil companies of up to 50 percent of the value of oil and gas production; and directing resources from gas exports and industrialization mainly toward education, health, roads, and jobs?

The phrasing of these five questions clearly illustrates the government's interest in nationalizing oil and gas resources, increasing government revenue from oil and gas production, increasing YPFB's role and market power in the Bolivian hydrocarbons industry, and reorienting Bolivia's gas policy away from gas exports primarily toward domestic consumption.

On July 18, 2004, the new government obtained a victory public referendum, with the majority of voters responding "yes" to all five questions. Thus, the Bolivian government is now politically backed to

radically change national energy policy. The real scope of these changes will depend on the country's political evolution, which will reflect on the political process that will occur in the national congress. In the end, this political process will define how the government and congress will interpret the voters' position on the referendum.

The idea of nationalizing hydrocarbons resources is embedded in question 2, which asks whether the state should regain ownership of resources at the wellhead. The implication of this question is unclear and is a source of political debate. Political groups identified with MAS (*Movimiento al Socialismo*) are struggling to revert all hydrocarbons to state ownership. Taken to an extreme, this would mean nullifying existing contracts and direct government involvement, through YPFB, in extraction and hydrocarbons sales. Adoption of this type of nationalization would require about US$8 billion to compensate oil companies (Energia & Negocios 2004 a and b).

At the same time, more moderate groups pledge nationalization of resources, whereby private companies would extract oil and gas resources and companies would be paid for services provided. Therefore, the referendum is based on a question that remains ambiguous with regard to a key point: What does ownership at the wellhead imply in terms of the state's new role in the industry and for companies currently operating in Bolivia? Moreover, how are proven reserves discovered since treatment of capitalization is to be compared with new reserves.

Country Responses: Implications for Integration

Deep changes in Argentine and Bolivian energy policies have significant implications for Southern Cone market integration. Countries in the region are rethinking the role of integration, considering changes in the gas-market scenario. The role of each country in the Southern Cone gas market is affected. Argentina has resumed gas imports from Bolivia. Brazil, once viewed as a potentially large gas importer, is changing its gas and electricity policies, and predicted levels of imports have been revised downward from those expected when the Bolivia-Brazil supply chain was built. Chile—the country most vulnerable to the recent turmoil in Argentine and Bolivian markets—is exploring LNG importation from

outside the region. The country relies entirely on Argentina for its natural-gas supply and has been directly affected by Argentina's gas shortage. Thus, Chile's energy policy is being revised in response to recent events in Argentina.

Gas Exports to Argentina

Since 2003, Argentine players have sought to negotiate import contracts with Bolivian authorities. The first import project was not linked to Argentina's gas shortage, but to the expansion of Argentine gas demand in northeastern provinces, where gas infrastructure was poorly developed. In November 2003, Technit and Argentina's government announced plans to construct a US$1 billion pipeline that would link Bolivian and Argentine basins. To be called the *Gasoducto del Noroeste Argentino*, the pipeline would, by 2006, transport 10 million m^3 per day of imported Bolivian gas. This proposed project was good news for Southern Cone gas integration. Competitiveness of imported gas is associated with shorter distances between consumption regions in northeastern Argentina and the rich gas fields of southern Bolivia. Until now, project negotiations between Argentina and Bolivia concerning the volumes and price conditions for gas supply have not been concluded. One factor affecting pricing is the high price of gas for Brazil, which is tied to a market basket of liquid fuels that has increased beyond all expectations since sales to Brazil were initiated.

In April 2004, the governments of Argentina and Bolivia reached a purchase and sales agreement for 4 million m^3 per day to Argentina over six months to reduce the country's gas shortage.[11] This agreement was possible because of existing gas transport infrastructure between the two countries, which has been used to export Bolivian gas to Argentina over more than three decades. Price conditions were another key point. Bolivia agreed to sell gas at a lower price than the exporting contracts to

11. The agreement between Argentina and Bolivia is the object of tough questioning by Bolivian opposition groups, who allege that the agreement runs counter to President Mesa's political promise of not signing new export contracts before approval of the energy law. Moreover, the gas to be exported is rich gas; it will be sold at higher prices, and heavy fractions will be processed at an Argentine plant near the Bolivian border. Thus, opposition groups accuse Mesa's government of losing an opportunity to industrialize Bolivia's natural gas.

Brazil: about US$0.98 per million Btu at the wellhead; this deal will be an important reference for future contracts in the region. In addition, the contract contains a clause prohibiting re-exportation of gas to Chile. This reinforces the Bolivian government's position of using gas as a diplomatic tool to push its land-for-gas political agenda with Chile. In June 2004, Petrobrás Bolivia and Repsol began exporting 4 million m^3 per day of gas produced in the San Alberto field. Export of Bolivian gas into Argentina has probably freed up additional Argentine gas for export, and there have been recent announcements of increased gas deliveries from Argentina to Chile.

The extent to which Argentina will become a significant gas importer from Bolivia will depend on the evolution of Argentina's gas balance. The country is the region's largest gas consumer. If Argentine gas prices remain at low levels over a long period, existing Argentine gas reserves will be rapidly depleted, and new exploration will not be undertaken. Private companies' incentive to invest in exploration will be a function of the country's gas price level. In addition, Argentina's main gas players have large stranded reserves in Bolivia. Thus, these players should be more interested in monetizing their reserves in Bolivia than investing in costly exploration projects in Argentina.

Gas Exports to Chile

In early 2004, Argentine gas exports to Chile reached 20 million m^3 per day. Of this total, 11 million m^3 per day went to electricity generators, 5 million m^3 per day to large industries and residential consumers, and 4.8 million m^3 per day to the Methanex plant in Tierra del Fuego. After Argentina imposed restrictions on exports to Chile, gas trade between the two countries fell to only 15 million m^3 per day. This reduction primarily affected power generators in northern and central Chile (Regions II and V, respectively).

Gas-fired power generation represents about 26 percent (1.8 gigawatts [GW]) of installed capacity in the central grid or Central Interconnected System (SIC) (*Sistema Interconectado Central*) and more than 57 percent (2.1 GW) of capacity in the northern grid or Northern Interconnected

System (SING) (*Sistema Interconectado del Norte Grande*). Therefore, reduction of Argentine gas exports to Chile is having a significant effect on the amount and cost of power supply in Chile. To compensate the reduction of gas availability, more expensive generation options are being dispatched. In addition to volume restrictions, Argentina's government imposed a 20 percent tax on natural-gas exports. Although exporting companies are supposed to pay this tax, certain contracts to Chile have provisions that pass the tax increase on to final Chilean consumers. Thus, Argentina's tax increase affects Chilean consumers, particularly with regard to the cost of gas-fired power generation.

Chilean public opinion and energy players negatively perceive Argentina's gas rationing to Chile. They allege that export rationing violates the energy-integration agreements between the two countries, which explicitly mention that Chilean consumers will not be treated differently than Argentine consumers in case of gas shortage. Chilean players insist that Argentine Order No. 265 violates these agreements (Gonzalez 2004).

The perception that Argentina is discriminating against Chilean consumers is fueling resentment in public opinion and motivating a debate over the countries' energy policy. Political opposition and environmental groups accuse the government of favoring energy companies to the detriment of supply security. Thus, the government is increasing support of more expensive energy options, such as hydroelectric projects, renewables, and coal.

Over the next decade, Chile's power demand is expected to increase about 4,000 MW. The Chilean government is seeking ways to supply this demand that will reduce dependence on Argentine gas. One alternative is coal generation using imported and domestic coal (Argus Latin American Power Watch 2004). Currently, Chile's coal generation capacity totals about 700 MW. However, the coal sector, led by AES Gener, has pledged to supply half of the 4 GW of generation capacity needed over the next decade.

Chile is also considering diversifying supply sources to reduce dependence on Argentina. Political problems with Bolivia make importation of

Bolivian gas—the most obvious choice—difficult. Chileans negatively view Bolivia's decision to impose conditions on gas exports to Argentina to prohibit re-exports to Chile; thus, Bolivian exports to Chile are unlikely over the medium term. As the referendum (question 4) suggests, the new government intends to use Bolivian gas resources to convince gas-deprived Chile to offer the country a sovereign exit to the Pacific Ocean in order to export LNG to the United States. According to Chilean chancellor Soledad Alvear, Chile is unlikely to consider such a possibility.[12]

Recently, the Chilean government requested that the ENAP, Chile's national oil company, study the possibility of importing LNG from the Pacific Basin. This would include the construction of a regasification plant, at an estimated cost of US$400-500 million. Nevertheless, LNG gas supply at the city-gate would cost at least US$1.0 per million Btu more than the current Argentine export price.

Current regional market instability makes increasing gas exports to Chile improbable in the short-to-medium term. Chile's response is is to seek greater diversity of energy supplies by expanding the country's electricity sector. Available options are to increase use of hydropower, coal-based, and renewable generation. The Chilean senate is analyzing new regulation to promote renewable energy development; nevertheless, natural-gas imports remain the country's cheapest energy option. If current obstacles to gas imports are lifted, Chile should increase its current import levels.

Gas Exports to Brazil

The Argentine and Bolivian crisis significantly affects gas exports to Brazil. Before the crisis, Brazil was expected to absorb a large share of

12. The current Bolivian administration is attempting to open negotiations with regard to binding treaties of 1904 and 1929; it suggests that sovereign access to a Chilean port would be the starting point for such negotiations. At the same time, the Chilean government maintains that the 1929 treaty already ended this political dispute and that it will not re-open any political discussion on the subject. Commenting on discussions between Bolivian and Chilean officials concerning gas exports, Alvear said: "We did not discuss the question of the exit to the sea. This topic was not on the agenda. What was on the agenda...was the possibility that Bolivia export gas to other countries through Chilean ports" (see http://www.gasbrasil.com.br).

cross-border gas trade. Given the country's current prospects for increasing gas consumption, five international pipeline projects have been proposed; when completed, they would have a total transport capacity of about 90 million m^3 per day. To date, only three of the five pipelines—two from Bolivia and one from Argentina—have been completed and export gas to Brazil: GTB (*Gas Transboliviano*)-TBG (*Transportadora Brasileira Gasoduto*), GOB (*GasBol*)-GOM (*GasMat*), and TGM (*Transportadora de Gas del Mercosur*)-TSB (*Transportadora Sul Brasileira de Gas*). The GTB-TBG pipeline extends from Rio Grande near Santa Cruz to Porto Alegre; the GOB-GOM runs from KP 242 on the GTB line to Cuiabá; and the TGM-TSB runs between Aldea Brasilera, Argentina and Porto Alegre (built only as far as Uruguaiana). Construction of the Cruz del Sur pipeline, which would link Argentine reserves to southern Brazil via Uruguay, was halted in Montevideo for lack of Brazilian demand. Finally, the ambitious Mercosul pipeline, designed to link Bolivian reserves to Paraguay and southern Brazil (near Curitiba), remains on the drawing board.

As figure 8-4 shows, Brazilian gas imports have grown fairly steadily over the past four years, surpassing 22 million m^3 per day by the end of 2003. Nevertheless, this value is low compared to current capacity of the three international pipelines in operation (36 million m^3 per day) and the take-or-pay (TOP) contracts signed with Bolivia.[13]

The slow pace of Brazilian gas-market development, caused largely by regulatory uncertainties in the gas and electricity sectors, has delayed import projects from Argentina; the recent Argentine gas shortage represents another hurdle to overcome. Completion of the two pipelines from Argentina to Brazil now depends not only on expansion of Brazilian gas demand, but also on availability of uncommitted Argentine gas to increase exports. Thus, prospects for completing the Uruguaiana-Porto Alegre pipeline, thereby closing the Southern Cone gas-ring, are more remote than before the Argentine gas crisis.

13. The TOP provisions of the YPFB supply contract with Petrobrás to export 30 million m^3 per day from Bolivia to Brazil increased from 17 to 24 million m^3 per day in March 2004. Thus, Petrobrás is accumulating losses with the gas supply contract from Bolivia since it imported less than 20 million m^3 per day during the first half of 2004.

FIGURE 8-4. NATURAL GAS IMPORTS, JANUARY 2000–APRIL 2004

Source: National Petroleum Agency (ANP).

The main determinant in expanding imports from Bolivia is the effect of that country's high gas price on the evolution of Brazilian demand and production capacity. Two key changes in the Brazilian gas scenario affect trade between Bolivia and Brazil. The first concerns the outlook for Brazilian demand, which Brazil's new administration has revised downward because of regulatory and policy changes in the electricity sector. The government is reducing emphasis on gas-fired generation to expand the country's power sector (however, the reduction is not as great as initially planned). The new electricity model is expected to allow for greater participation of hydrogeneration projects in power-sector expansion (Almeida and Pinto, Jr. 2004).

In June 2004, Petrobrás announced its Strategic Plan for 2004–10, which included significant changes, the most important of which is the company's focus on gas-market development in sectors other than power generation. The company intends to work toward mass distribution of natural gas, with emphasis on low-volume consumers in the industrial, commercial, and transport sectors. Petrobrás' strategic plan for 2000–05 predicted a demand of 70 million m^3 per day in 2005. Of this total, 50 percent would be for thermal power plants. Given power-sector policy changes, the Strategic Plan for 2004–10 expects 2010 demand at 77.7 million m^3 per day. Thus, the market originally forecast for 2005 has been delayed five years, and the market share of gas-fired power plants has been reduced to only 35 percent of installed generating capacity.

Another key change in Brazil's gas scenario is the outlook for domestic production. The recent discovery of about 419 billion m^3 off the coast of São Paulo represents another challenge to Bolivia's chances of exporting large quantities of gas to Brazil at the current wellhead price. Petrobrás' new Strategic Plan predicts steady growth in domestic gas delivery (sales and own-consumption), from 21.6 million m^3 per day in 2002 to 62.0 million m^3 per day in 2010. Petrobrás expects the first field (Mexilhão) from the Santos Basin discovery to start production in 2009. If this growth materializes, the opportunity for increasing Bolivian imports beyond the current contracted level (32 million m^3 per day) will be much lower.

Despite the referendum's emphasis on using gas to stimulate domestic industry, Brazil continues as the largest potential export market for Bolivian gas. The main reason is the Bolivia-Brazil pipeline, which until now has been the core of Bolivia's energy policy. According to Brazilian officials, the price of Bolivian gas is too high to compete with substitute fuels (e.g., fuel oil, firewood, and biomass). Since July 2003, Brazil has been negotiating a reduction in Bolivian wellhead prices, with little success to date. On the other side, Bolivian officials explain that the high import price reflects high transport tariffs on GTB and TBG pipelines (the latter of which is controlled and operated by Petrobrás). The reality, however, is that tariffs on Bolivia-Brazil pipelines are significantly lower on a unit-distance basis than are any other cross-border pipelines in the Southern Cone.

Negotiations to reduce the price of Bolivian gas stalled at the end of 2003. Brazilian energy authorities agreed to wait for passage of Bolivia's new energy law before resuming negotiations. Bolivia's agreement to sell gas to Argentina at lower wellhead prices than the gas supply contract to Brazil will surely drive re-negotiation to reduce the commodity price for Brazil. In addition, Petrobrás will seek greater flexibility in current TOP clauses. Bolivia, on the other hand, is attempting to gain Brazilian support for projects in Bolivia that promote gas industrialization (gas chemical and steel projects).

Brazil's new government has already demonstrated an ability to work within the context of Bolivia's political constraints. Petrobrás has initiated a viability study to invest in a new gas-chemical project along

the Bolivia-Brazil border in response to recent negotiations between the two countries' new governments. Moreover, Brazil plans to conduct studies to identify projects for adding value to Bolivian gas.[14]

Final Considerations

As this chapter demonstrates, the private-investor solutions that Argentina and Bolivia seek for the gas sector represent a major setback for regional integration. The non-project risks that have recently emerged negatively affect cross-border trade. Moreover, Argentina's low price controls are changing that country's regional role from exporter to importer. At the same time, political disputes hinder Chile's ability to import gas from Bolivia. Finally, Brazil's import prospects are less promising than originally envisaged because of changes in Brazilian energy policy, which slow demand growth.

The Southern Cone situation requires a regional vision, combined with political negotiation between countries, to avoid anti-integration solutions. Lack of political negotiation could drive the regional market toward accelerated disintegration as each country attempts to identify domestic solutions to current instability. The advantages of integration should be clear to all concerned governments. Natural-gas trade is a critical revenue source for Bolivia, South America's poorest country. To date, Brazilian imports have generated about US$2 billion in revenues for Bolivia. On the other hand, cross-border trade increases security of supply. Argentina's gas connection to Bolivia and power connection to Brazil play a vital role in mitigating the country's gas and electricity shortages, thereby supporting the country's return to economic well-being.

Given these advantages, Southern Cone governments should work toward developing a single regional gas market. Advancing toward integration would improve security of supply by increasing the number of interconnections, promoting price convergence, and (it is hoped) depoliticizing the gas trade.

14. If implemented, these projects would not represent an obstacle to Bolivia's capacity to export gas to Brazil and even outside the region, given Bolivia's enormous untapped reserves.

Despite the factors driving toward regional market integration, certain risks inherent in the natural gas industry are inflated by the economic and institutional contexts of the Southern Cone: 1) regional macroeconomic instability, especially exchange-rate volatility; 2) lack of a coordinated, regional energy policy; and 3) regulatory asymmetries in the energy sector.

In sum, for comprehensive gas integration to move forward proceed, Southern Cone countries should continue working on the necessary political negotiations to increase economic integration generally. Both political and macroeconomic convergence are essential to reduce gas-trade risks, which depend on foreign and local investors' long-term engagement. Finally, negotiations remain necessary to reach agreement on the basic principles of integration: convergence of gas prices and harmonization of energy policies and regulatory frameworks.

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PART III

Industry Positions

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Chapter 9

View of the Initial Condition and Next Steps*

Integrating natural-gas industries across Southern Cone countries poses complex challenges: establishing a competitive regulatory framework and harmonizing national legislations. Sector companies agree that greater market integration would benefit the natural-gas industry and consumers alike. Likewise, they concur that the region's current socioeconomic and political crises will demand political negotiation between countries, requiring tremendous effort and years of hard work. What follows are the views of five industry leaders—Latin America Petroleum Company Association, British Gas Group, Petrobrás, Repsol, and Totalfina—on initial conditions for and steps in the integration process, including elements of an integration agenda and country challenges and prospects.

Latin America Petroleum Company Association

Today, Latin America and the Caribbean (LAC) faces complex challenges, including increasing poverty and rising unemployment. Moreover, some 75 percent of the population believes the region is headed in the wrong direction. At this juncture, reestablishing and maintaining high growth are essential; regional integration is the strategy that assures sustained economic growth; it provides opportunities to trade with neighboring countries in deeper, more advanced ways than a free trade zone or opening of global markets. Moreover, it broadens the opportunities for reciprocal cooperation, complementarities, and scale economies; while fostering better international integration.

* The industry views were prepared by Latin America Petroleum Company Association, Amanda Pereira; British Gas, company gas-specialists group; Petrobrás, Flávio Tojal; Repsol, Miguel Angel Remón; and Totalfina, Joël Cordier.

Europe's successful experience has shown that regional integration brings increased exports and competitiveness, as well as a higher standard of living. The use of now-reimbursable funds has played and important role in the process. Regional integration implies political stability (peace and democracy), macroeconomic stability, open markets, and adequate regulatory frameworks. Within this process, government leadership is fundamental in lending political and institutional support. The energy sector is not an end in itself; rather, it is a means to achieving sustained growth and sustainable development.

Integration Today: Opportunities and Barriers

During 1996–2003, South America's Southern Cone witnessed great advances in natural-gas infrastructure. Installed capacity grew from 107 million to 185 million m^3 per day, an investment of nearly US$4.8 billion. Currently, gas export stands at 40 million cubic meters (m^3) per day, and could reach 83.6 million m^3 by 2010. If one adds to that investments in development of reserves and downstream investment, the total reaches US$20 billion (about US$3 billion annually).

The opening of Argentina's energy sector in the 1990s; the country's gas infrastructure previously developed by GdE (*Gas del Estado*); and the opening of Bolivian, Brazilian, and Chilean markets all allowed for such growth. Once adequate conditions had developed, the business sector's dynamism—both private and state companies—played a key role in the search for new reserves in Argentina, Bolivia, and Brazil; markets for their monetization; and the construction of gas pipelines.

The process of Southern Cone market integration has resulted in critical lessons:

– Progress has been by project and with relevant business dynamism (state-owned and private companies).

– The integration process has lacked structure.

– Protocols signed between countries have not been implemented.

- Structural reforms occurred at varying rates in the countries involved.

- Severe institutional and macroeconomic crises have posed important difficulties.

Integration opportunities within the region and in markets overseas present other options for monetizing reserves. Contributing factors include a favorable political and economic environment, return to economic growth, natural resources availability, investments in natural gas and power-transmission infrastructure (both existing and potential), and potential regional and international markets.

In the subregion, gas reserves have grown more than production, especially in Bolivia, where investment in exploration and production (E&P) has led that country to become the most relevant supplier for the next decade. Together with reserve discoveries in Brazil, Bolivia is shaping the future of the region's natural gas supply.

Southern Cone markets are complementary: Net exporters of energy (with a high volume of reserves and markets) are balanced by potential consumer markets, including Brazil and Chile. There is also potential for exporting liquefied natural gas (LNG) to overseas markets—mainly to the U.S. through Mexico.

The barriers to development of integrated regional markets can be classified as political, cultural, physical, economic, and regulatory. For example, the Bolivian crisis and the conflict between Chile and Bolivia pose political and cultural challenges that must be resolved. The region's economic crisis has also slowed the process of integration. In Argentina, one of the region's exporters, low natural gas prices have led to market distortions and investor mistrust, along with legal uncertainty and lack of investment protection. Thus, it is critical to restore investor confidence, providing an appropriate framework for attracting investors to the region. Because the amount of investment needed exceeds government capacity, innovative funding mechanisms must be found, whereby all actors involved will have a favorable environment within which to develop projects.

Regulatory asymmetries, restrictions on exports and imports, and discrimination also constitute important barriers to energy integration in the Southern Cone. It is essential for all players to reach consensus on the benefits of regional energy integration and to work toward it; within this context, an agenda is needed to guide discussions and facilitate the process. Civil society also plays a vital role, as the Bolivian crisis of 2003 clearly demonstrates; thus, mechanisms must be found to incorporate civil society into the process.

Next Steps

Political, economic, and regulatory instability dampen the prospects for energy integration. Energy projects depend highly on availability of funds, which will be forthcoming only within the context of macroeconomic stability and legal certainty, together with treaties among countries that favor integration.

The integration process requires a developed institutional structure, uniform regulations, and integrated financial structures. Clear rules must be established for all players, with principles sustained and respected with regard to government commitments through energy ministries and regulatory organizations.

Creating an integrated energy market requires opening of national markets, harmonization of technical and economic regulation, and development of infrastructure. The outcome of Brazil's thermoelectric plan and the crises in Argentina and Bolivia have reduced confidence in legal certainty and enforcement of contracts and, in turn, investment in the region.

Joint action of all players is critical for reestablishing clear, fair, realistic, and efficient rules of the game. These rules must be under permanent discussion and correction to avoid being changed in favor of special interest groups, sectors, or particular countries. Governments should focus on achieving convergence of energy policies and establishing clear rules to attract investment. Regulatory organizations should establish stable, transparent, and achievable regulations. Businesses should expand, profit from, and protect their investments. Consumers should have reliable access to energy sources, a clean environment, and fair prices.

Each year, the Latin America Petroleum Company Association (ARPEL) organizes an energy integration symposium, with the participation of all players, to reach consensus on main topics of the process. The first ARPEL symposium was held in Punta del Este, Uruguay in October 2003. The symposium concluded the need for:

- governments' defining of roles and shared objectives on economic development;
- promoting greater commercial integration through a variety of means (e.g., discussion or bilateral agreements);
- promoting the Energy Charter Treaty or similar agreements to restore investor confidence in the region and supplement the regulatory frameworks of each country;
- coordinating the efforts and activities of organizations involved in the integration process;
- clearly defining regulatory agencies' role in the process; and
- identifying ways to contribute to civil society's understanding of integration and its potential benefits.

These conclusions formed the basis for planning the second symposium, held in December 2004 in Punta del Este, Uruguay. This forum included presentations and discussion of relevant LAC energy-integration cases and breakout group sessions, where players openly discussed and sought to reach consensus on how to support the process and move it forward.

British Gas Group

A competitive, integrated Southern Cone gas market has considerable benefits. Consumers benefit from a more stable and secure supply brought by interconnected networks and access to many market participants. They also gain from increased competition and lower monopoly rents and prices. In addition, a gas-integrated market permits

greater efficiency in infrastructure operation. Consumers and network operators share the benefits of less idle capacity and larger economies of scale. Producers also profit since they can sell to a broader group of customers and spread downturn risks across countries. A competitive, integrated market improves pricing transparency, making it easier for potential consumers and investors to evaluate business opportunities, thereby promoting new investment.

Challenges to Initiating the Process

Integration of gas industries across countries poses important challenges with regard to setting up a pro-competitive regulatory framework and harmonization among national legislations. In addition, it requires the creation of regional institutions for implementing the agreed upon rules. A group of regulatory preconditions pertain to the gas industry; moreover, there are fundamental drivers for market integration: third-party access (TPA), open season for new transmission pipelines, timely information on capacity availability and operational conditions, and clear-cut principles for setting tariffs. Furthermore, international experience indicates that these measures will be effective only when accompanied by accounting, legal, and management unbundling of transport and supply activities and some form of regulated access. Both prerequisites greatly facilitate suppliers' access to the network and avoid discriminatory treatment.

Harmonization not only means convergence of rules of conduct; it also entails the elimination of regulatory requirements and pricing distortions that discriminate against export and domestic markets. Some type of regional institution (e.g., a regulatory council) is required to ensure the effective implementation of the guidelines approved for harmonization. Antitrust agencies will need to minimize their differing approaches and coordinate to curb the exercise of market power across regional borders. These institutions require states to share their sovereignty in exchange for growing interdependence and promotion of mutual gains across the region.

This set of prerequisites—closely related to the gas industry—is a necessary but insufficient condition for achieving enduring integration. Indeed, stable and predictable rules must underpin the concessions, authorizations, and licenses granted to operators within each country; furthermore, an independent judicial body must uphold the contracts and repeal attempts of unilateral renegotiations by regional states. Without credible government commitment to guarantee that basic rules of the game will not be changed arbitrarily, private investment will lag, eroding the impetus of regional integration efforts. Moreover, government intervention in contracts and tariffs distorts incentives for trading gas, raises concerns of unfair competition in neighboring countries, and increases the risk of unsustainable supplies and reduced demand prospects. These issues are particularly important to South American countries and their quest for energy integration (natural gas and electricity) in the Southern Cone.

During the 1990s, the energy sectors of South American countries underwent profound changes. State-financing constraints, the need to attract private investment to cope with growing demand and deteriorating services, and the need to promote competition and efficiency led to large-scale deregulation and privatization. Growing private investment helped to reshape the region's natural gas industry and contributed to a marked rise in proven reserves, a sharp increase in consumption, and inception of an integrated network encompassing Argentina, Bolivia, Brazil, Chile, and Uruguay. Between 1990 and 2000, natural gas consumption in these countries grew 7 percent, on average; and proven reserves increased 52 percent, mainly in Bolivia and Brazil (IEA 2003). During 1996–2001, seven pipelines were constructed, connecting production areas in Argentina to markets in Chile. In 1999, the 3,150 kilometer (km) Bolivia-Brazil pipeline was completed, and a project linking northern Argentina and southern Brazil was finalized. In Argentina, gas penetration is among the highest in the world and large in all end-uses; natural gas demand also has enormous growth potential in Southern Cone countries overall. It can contribute to diversification of the energy balance, thereby reducing the vulnerability of hydrogeneration, to foster comparative industry advantages to deliver interior heating and cooling and fuel the fast-growing transport sector. Important obstacles,

however, preclude sustained industry growth in the region. To unleash the benefits of greater regional integration, a set of preconditions must be met to promote a level playing field for all parties, set guarantees against arbitrated decision-making, sustain credibility, and uphold predictable regulatory outcomes.

Country Challenges

ARGENTINA

In the early 1990s, Argentina embarked on broad privatization and restructuring of the natural gas sector. The new regulatory framework established pointed to a clear separation of production, transmission, and distribution activities, with limitations on cross-participation of companies operating in different segments. Nondiscriminatory TPA to transmission and distribution networks was introduced; and ENARGAS, an independent regulatory body, was created. ENARGAS was in charge of setting maximum transmission and distribution tariffs according to a price-cap formula that was to adjust tariffs for inflation every six months. Tariffs were reviewed every five years to consider efficiency gains and additional investments.

The reform succeeded in attracting private investment, fostering network expansion, and overcoming capacity constraints, which frequently hindered supply during periods of peak demand (e.g. winter months). According to the IEA (2003), over the 1992–2000 period, transmission capacity rose 60 percent and length of the distribution network increased 58 percent in Argentina. Between 1993 and 2001, privatized distribution companies alone invested US$1.9 billion in infrastructure.

By 1999, macroeconomic instability had started to cripple Argentina's economy; recession was persistent and deterioration of the balance of payment grew, culminating in a 400 percent devaluation of the peso in 2001. Energy-sector companies were hit particularly hard. The Economic Emergency Law revoked the pegging of tariffs to inflation, which meant that gas distribution and transport companies had their

tariff adjustment suspended, their tariff frozen in terms of pesos, and their concession contracts unilaterally renegotiated by the government. After years of recession and mounting unpaid bills, companies faced a sharp rise in their cost of debt service (denominated in U.S. dollars) and the impossibility of readjusting their tariffs. Upstream activities also suffered, given the fall in wellhead price (in dollar terms), decline in domestic demand, and financial constraints, which debilitated distribution companies and other end-users' capacity of payment. This situation led to a halt in investment and loss of confidence in the institutional framework, which today hinders expansion of supply and demand and represents a major obstacle to an integrated gas market.

While Argentina witnessed a much-needed resumption in GDP growth in 2003, medium-term prospects for the gas industry remained uncertain. Following economic recovery, natural-gas production and consumption increased; however, continued lack of investment threatened further development of domestic and regional markets. During 2000–03, proven reserves declined nearly 15 percent, and the reserves-to-production ratio fell to 15 years (from about 20 years in the mid-1990s). Large investment would be required to increase reserves and production to meet export contracts with Brazil and Chile, while serving resumed domestic demand. In addition, expansion of transport capacity would be needed to avoid infrastructure bottlenecks during peak periods. Meanwhile, opportunities would emerge for increasing Bolivian exports to compensate overlooked markets in Argentina and Chile, thereby meeting Bolivia's need to diversify export destinations (considering that demand growth in Brazil's market would be below expectation). Indeed, this scenario demonstrates the effectiveness of integrated-market benefits.

Argentina's situation also illustrates how domestic distortion can hamper medium-term prospects for integration. For example, the tariff freeze has widened the gap between export and domestic tariffs. Such discrimination raises concerns of unfair competition in gas-intensive industries, in which importing and exporting countries also compete. In addition, exporting countries are hurt by the risk of supply disturbance and unfulfilled contracts, given Argentina's promotion of unsustainable demand levels.

BOLIVIA

The Bolivian experience—somewhat similar to that of Argentina—was one of economic reform and privatization, resulting in a steady flow of foreign investment; according to the IEA (2003), foreign investment reached 10.5 percent of GDP by 1999. Opening of the country's energy sector to private companies led to a surge in E&P activities, which increased proven reserves seven times during 1997–2002. Today, Bolivia boasts the region's largest non-associated gas reserves. Bolivia's regulatory framework (stated in Law No. 1689) encompasses many of the above-mentioned prerequisites for competitive gas markets. Regulated TPA, minimum unbundling requirements, and limits on vertical integration are among the issues the Law considers.

Nevertheless, macroeconomic downturn and political instability have undermined the stability of Bolivia's regulatory framework. The recent change in government has revealed judicial insecurity, which paralyzed investment in the country. The gas industry has been at the center of political debate, resulting in proposal of a new Hydrocarbon Law. These changes reflect the government's aims to increase royalties and other compensations, allow for domestic markets to increase natural gas consumption, and enlarge its role in industry investment. This situation, however, has sparked fears that such measures would make gas less competitive in importing markets (e.g., Brazil) and postpone further growth in demand. Moreover, there is concern that the new set of rules will increase discrimination against export markets since transport tariffs for domestic consumption in Bolivia are already significantly lower than for exports. In Bolivia, as in Argentina, these issues dampen prospects for integration by increasing supply-side risk and concerns about cross subsidies and unfair competition within importing countries.

BRAZIL

In Brazil's oil and gas sector, reform basically aimed at establishing the rules needed to allow private agents to participate in activities that the state-owned Petrobrás alone had previously performed. The broad objective was to promote entry of new agents, thereby stimulating

competition and attracting new investment. Despite incorporating TPA into natural-gas transport networks, the Brazilian legal apparatus failed to provide the regulator, National Petroleum Agency (ANP), the instruments required to carry out effective compliance.

The legal framework established in 1997 (Law 9478/97) pointed to a regime of negotiated access, in which the ANP would intervene in cases of dispute. The Law does not detail unbundling requirements; vertically integrated companies are required only to set up branches for their transport activities. It soon became evident that this regulatory setting failed to provide a predictable and flexible context for TPA. This shortcoming was clearly demonstrated in two instances in which TBG (*Transportadora Brasileira Gasoduto Bolivia-Brasil*) requested access for transport services through the GOB (*GasBol*) pipeline. After a long and costly negotiation process, the request ended in conflict between the parties, resulting in direct intervention by the ANP.

Furthermore, the legal framework, created mainly for price deregulation and the opening of E&P activities for private entities, avoids such issues as transport tariff principles, open season for new infrastructure, information provision, and capacity resale. Operator authorizations to build and operate transport pipelines—as opposed to the concessions granted distribution companies—also overlook these issues.

In addition, no effective market-monitoring scheme is yet in place to prevent dominant and integrated (vertically and horizontally) agents from exercising their market power. Most important, no clear guidelines are available to separate corporate objectives and Petrobrás' operation from government decision-making and policy formulation. This difficulty undermines the entry of new agents and promotion of market competition.

Brazil's lack of a pro-competitive environment hinders regional integrated markets. Indeed, participants from other countries are reluctant to commit to a scheme that fails to guarantee a level playing field within the region's largest consuming country.

CHILE

Although credibility and legal security are less of an issue for Chile, the country's natural-gas framework has significant room for improvement. Legislation allows for TPA on a nondiscriminatory basis, but has no mandate to separate transport and distribution businesses from production and commercialization. The framework offers no guarantees that operators will provide information, contracts, and operational conditions that support a level playing field for affiliate and non-affiliate market participants. These deficiencies hamper the regulator's ability to monitor and prevent anti-competitive behavior, making the access obligation potentially ineffective in fostering competition and promoting entry of new suppliers.

Creating a competitive, integrated market in the Southern Cone region will require two sets of interlinked preconditions. The first set requires:

- Establishment of a stable, predictable environment for private investors. Restoring judicial security and creating a predictable legal framework and minimum guarantees for compensation (in cases of unilaterally bridged contracts) are urgently needed.

- Nondiscriminatory application of regulatory guidelines to attract new private investment (since private and public companies will continue to share Brazil's market environment).

- Enforcement of clear rules to minimize conflicts of interest between Brazil's policy-formulation rules and the corporate objectives of state owned enterprises (SOEs).

- Bolivian legislative changes that clearly state private agents' role, financial and regulatory obligations, and requirements to meet domestic and export market demand.

- Building of a relatively autonomous, regulatory reputation to attract new agents in all countries of the region. Regulatory procedures should be transparent and flexible and use a simple mechanism to ensure an open relationship with consumers and investors.

– Intensified coordination of regulatory agencies and antitrust entities to more effectively prevent anti-competitive conduct.

The second set of preconditions involves harmonization and design of a pro-competitive regulatory environment in the Southern Cone. Specifically, it requires:

– Minimum unbundling—legal, accounting, and managerial—requirements across the region to prevent anti-competitive conduct and make TPA measures effective.

– Adjusting regulatory text toward regulated access, with pre-established terms, contracts, and tariffs (since negotiated access proved costly and time-consuming).

– Conducting competitive bidding for transport and ancillary services for infrastructure expansion. Such schemes increase opportunities for new entrants and lead to a more efficient network expansion.

– Establishing a transitional period for terminating practices involving price and market discrimination, which erode support for integration.

– Creating an institutional body (like the Madrid Forum) to champion discussion and implementation of rulings. Such a body should be based on Mercosur's institutional design and the Memorandum of Understanding. The agreements should include specific measures for achieving a competitive regional market. Consumers, who stand to benefit most from integration, should participate from the outset in pushing negotiations forward and helping to overcome obstacles.

Petrobrás

Thanks to recent natural-gas discoveries in southern Bolivia and southeastern Brazil and the expected demand increase in Southern Cone countries, the region now has reserve production that guarantees meeting projected needs over the next 50 years. No doubt, Petrobrás is well-positioned to play a dominant role in meeting those needs (box 9-1).

BOX 9-1. PETROBRÁS POWER: SHAPING SOUTHERN CONE TRADE

Over the past three years, Petrobrás has implemented an aggressive strategy of international diversification that focuses on South America's Southern Cone. In 2002, it acquired two major companies: Argentinean Pérez Companc, S.A. and the Argentinean oil company, Santa Fe; the combined investment of more than US$1.1 billion places Petrobrás among the region's most important gas players.

Well-positioned in all segments of the Southern Cone gas chain, Petrobrás now handles about 30 percent of the region's gas production and participates in key transport pipelines. In addition to controlling 95 percent of Brazil's transport pipeline capacity, Petrobrás participates in Bolivia's GTB (*Gas TransBoliviano*) (30.8 million m^3 per day) and Transierra (17 million m^3 per day) and Argentina's TGS (*Transportadora de Gas del Sur*) (62 million m^3 per day). Petrobrás also holds significant assets in the region's distribution segment and gas-based power generation.

UPSTREAM ASSETS IN THE SOUTHERN CONE, 2003

Country	Proven natural-gas reserves (billions of m^3)	Natural-gas production (millions of m^3 per day)	Processing capacity (millions of m^3 per day)	Electricity generation capacity (millions of m^3 per day)
Brazil	350	43.2	31	2,400
Bolivia	240	4.5	26	–
Argentina	93	8.1	78	1,921

Sources: ANP and IEA (2003).

Given Petrobrás' vertically integrated position across the Southern Cone gas chain, the company can implement cross-border strategies to monetize its gas reserves. Thus, Petrobrás' corporate strategy will strongly affect the region's future market integration.

Petrobrás' 2004–10 strategic plan focuses on gas-market development in sectors other than power generation. The company will emphasize mass

continued next page

BOX 9-1. PETROBRÁS POWER: SHAPING SOUTHERN CONE TRADE *continued*

diffusion of natural gas to low-volume consumers in the industrial, commercial, and transport sectors. The strategic plan predicts a market of 77 million m^3 per day by 2010, of which thermal power plants would account for 35 percent. It forecasts that steady growth in domestic gas delivery will reach 62 million m^3 per day by 2010. If production from the Santo Basin discovery begins in 2009, Bolivian imports will remain at the already contracted level of 32 million m^3 per day.

Although prospects for Bolivia-Brazil gas trade have been reduced, Petrobrás remains in favor of integration. Brazil's President Lula encourages this positive attitude, having made regional market integration a priority of his administration.

Increased regional consumption of natural gas should be a priority for energy policy because of the resource's low environmental impact and high transport and storage costs. However, greater consumption will require enormous investments to make trade possible; in turn, harmonization of the countries' regulatory and institutional frameworks will be required to ensure free trade across the region.

Institutional and Regulatory Harmonization

Before a regionally integrated market is fully developed and consolidated, policies must be established that allow for harmonization of Southern Cone countries' interests. Without giving appropriate consideration to the varying levels of development of these countries' respective gas markets, specifications of each energy grid, and the characteristics of industrial and power-generation sectors (the main consumers), integration will not be viable.

Harmonization requires that economic agents guide institutions and policy development toward market integration, regardless of political constraints. The regulatory rules and guidelines that document the model should guide all agents involved in the sector. The model should take a comprehensive and realistic approach, accounting for authorities, investors, companies, and users.

For harmonization to succeed, it is recommended that:

- Legislative bodies of the respective countries formally approve laws embodying the harmonization of policies and regulations. In this way, civil society will have the opportunity to discuss the model and relevant policies with the representatives. Moreover, if the policies become law, they will carry greater weight and be less susceptible to changes associated with the political cycle.

- Sector policy define the institutional architecture and roles of public and private agents. The policy should carefully define regulatory institutions, whose structure civil society must validate before the policy is legislated into law.

- Sector policies not be a set of single-handedly established government directives seeking short-term conditions and unrelated to other economic sectors. On the contrary, sector policies should result from collective choices with regard to sector options in each country's economy.

By following these recommendations, the regulations of each specific sector would reflect not only the sequence of events leading to their formulation, country constitution, set of applicable laws, and sector policies and regulations; they would also embody each society's respective culture and traditions. Such considerations lead to two additional observations:

- Adopting regulatory and institutional models developed in other countries is not the best option since it is unlikely that any two countries will have similar political, economic, and social identities.

- Harmonizing the models adopted by neighboring countries that share markets and transport and storage infrastructure is probably the best—and possible the only—option; however, considering each member country's uniqueness, implementation of the harmonization process should proceed cautiously.

Attempting to adopt other countries' regulatory and institutional models and forcing rapid sectoral reform may explain the failure of other efforts to develop and consolidate the LAC infrastructure sector and the widespread reluctance to undertake infrastructure integration initiatives.

Lack of Sector Consolidation

A sector policy must be stable, and at the same time, sensitive to situational changes. It should establish the roles of involved agents and guide actions within the sector, while observing what happens in other sectors. Moreover, it should accord with national interests and signal the future vision. Therefore, the rules that guide agent relationships and decisions must be continually adjusted to ensure their appropriateness at each stage of sector development. The particular dynamics of sector policies and regulations more than justify the regulator's importance as an independent observer of the sector's fiscal evolution and a corrector of policy-related deviations, in accordance with policy orientation.

The trade-off between the demands of stable regulations and ongoing adaptation of sector policies to a changing environment may be negligible when analyzing consolidated sectors in developed economies; however, they are crucial for understanding the decisions of non-consolidated sectors in emerging economies. Therefore, one cannot expect to understand the obstacles to gas integration and suggest alternatives without understanding each country sector—its dynamics, current stage of development, and level of interdependence with other sectors. In the case of Brazil, for example, one should note that the gas industry is still evolving; thus, any integration proposal that might put sector development at risk would not be socially supported. The needs of the gas-transport segment illustrate the type of trade-off that appears in the unconsolidated sectors of emerging economies.

Brazil has one large gas pipeline: Bolivia-Brazil. In addition, an older network is distributed partly in the Southeast (interconnecting the states of Rio de Janeiro, Minas Gerais, and São Paulo) and in the Northeast (interconnecting the coastal states, from Bahía to Ceará). It should be emphasized that these older domestic networks are modest in size and could

not support the increased demand that would occur through sector consolidation. Constructing the infrastructure necessary to sustain sectoral growth in a uniform, integrated way would require enormous resources and specific policies to guarantee equilibrium between supply and demand in the various consumption centers. Otherwise, the country's gas industry would be restricted to the main development poles—Rio de Janeiro and São Paulo—located close to the Campos and Santos Basins and the Bolivian gas fields. Regulatory and institutional solutions that aim to promote integration will fail if they jeopardize development of a cross-country transport system.

Brazil, like other countries, remains far from consolidating its natural gas industry. It seeks to clearly define its potential in order to develop a structural model that best suits its characteristics and limitations. Without sector consolidation, it is difficult to adopt institutional and regulatory solutions that work well in other countries but that overlook the unique dynamics of each economy where they will be applied. Thus, importing institutional solutions should be avoided. Moreover, experience shows that importing models designed for countries with other economic and political features fails to promote integration and make provoke social rejection of all integration efforts.

Elements of an Integration Agenda

Constructing a solid, regionally integrated natural-gas industry demands developing a common agenda that considers the various levels of sector maturity in the countries seeking integration, their strategic interests (private and collective), and country restrictions on supporting a given regional model. Discussing such an agenda would provide the basis for developing an ad-hoc regional model to guide establishment of a regional sector policy that addresses, at a minimum, the following five points:

- Price and tariff-formation criteria, with the potential for adopting a common currency for gas, and perhaps energy, transactions between countries of the region;

- Mechanisms that guarantee supply;

- Conditions for applying free-access rules to the transport, storage, and distribution infrastructure, including sector-structure requirements (e.g., separation of accounting, managerial, and economic activities) and conflict-resolution mechanisms between market participants;

- Monitoring, predicting, and managing supply-and-demand imbalances through responsive actions that signal the specific E&P and infrastructure investment needs and that promote solutions; and

- Establishing an independent, regional institutional architecture to regulate the sector.

The long road toward establishing such a policy will require years of hard work and enormous political ability and effort from Southern Cone countries (always bearing in mind that there are no *prêt a porter* models). When identifying the barriers that hinder the regional integration process, the Southern Cone countries should, both individually and collectively, re-evaluate their respective gas industries in order to work toward a better future for the region.

Repsol

Global Market Growth

Over the past decade, natural gas has grown in worldwide importance; according to all projections, its growth will intensify during the first half of the 21st century. Global consumption is expected to rise 67 percent during 2001–25, according to the latest estimates of the Energy Information Administration (EIA), outpacing coal as of 2010. Electricity generation will remain the main—if not the sole—reason for this course of events. The search for environmentally friendly alternatives compatible with the state of technology makes gas—the fossil fuel with the lowest carbon content—the first option for feeding new installed generation capacity. In addition, international gas trade is significantly increasing for both traditional gas pipelines and in the form of LNG; indeed, 23 percent of global gas consumption is the product of international transactions. During 1995-2002, pipeline trade increased 46

percent; while LNG trade rose 62 percent over the same period, stimulated by advances in technology that lowered associated costs.

Thus, opportunities are rapidly opening for producers who seek to monetize their reserves and consumers in need of gas. If these trends continue, the natural-gas market will increasingly emulate a commodities market. Gas consumption in a given country will depend little on domestic availability or supplies in nearby countries. Suitable infrastructure for imports and exports, adequate skills, and economic and financial capacity will suffice.

Southern Cone Gas Market

The Southern Cone boasts abundant proven and probable gas reserves. These are concentrated in Argentina and Bolivia, while other countries in the region either lack the resource or enough supply to satisfy domestic consumption. Thus, regional conditions are ripe for gas development and trade that will allow monetization of producer reserves and satisfaction of consumer needs (see chapter 7).

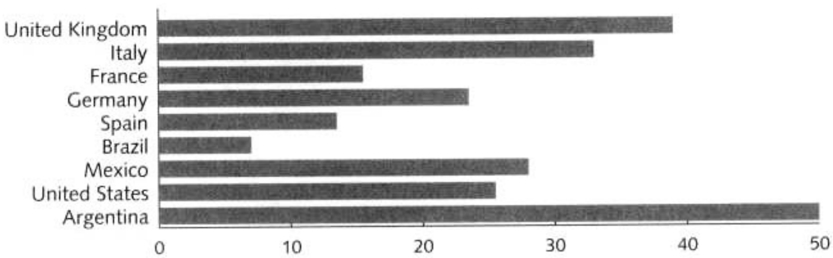
For many years, a substantial portion of these gas resources was hardly exploited because of lack of infrastructure connecting the various markets, among other reasons. Significant reserves were incapable of being exploited because appropriate infrastructure was lacking for their transport, exportation, and subsequent distribution or industrialization. Brazil, Chile, and Uruguay were deprived, in whole or in part, of the benefits of their gas reserves.

Deregulation, along with the trade and integration agreements of the 1990s, has partially corrected the infrastructure gaps through construction of a gas pipeline network connecting Bolivia with Brazil and Argentina with Brazil, Chile, and Uruguay. Figure 9-2 (pp. 294–95) illustrates the dramatic increase in the region's gas transport infrastructure.

These integration infrastructures have permitted the development of several deposits, as well as a gradual, massive integration of gas into the new markets. The participation of gas in the energy matrix, which, at the start of

the decade, was non-existent or nearly so in Brazil and Chile, increased to 19 percent in Chile and 7 percent in Brazil. Although penetration in both Brazil and Chile is advanced, Argentina continues to stand out as the only country where the natural-gas market can be considered mature. Official 2001 statistics list gas at 46 percent participation within primary energy. Based on recent increased consumption, it is estimated that the current figure approaches 50 percent of primary energy, making Argentina's gas participation the highest in the world (figure 9-1).

FIGURE 9-1. PERCENT GAS PARTICIPATION IN THE ENERGY BALANCE SHEET FOR SELECTED COUNTRIES



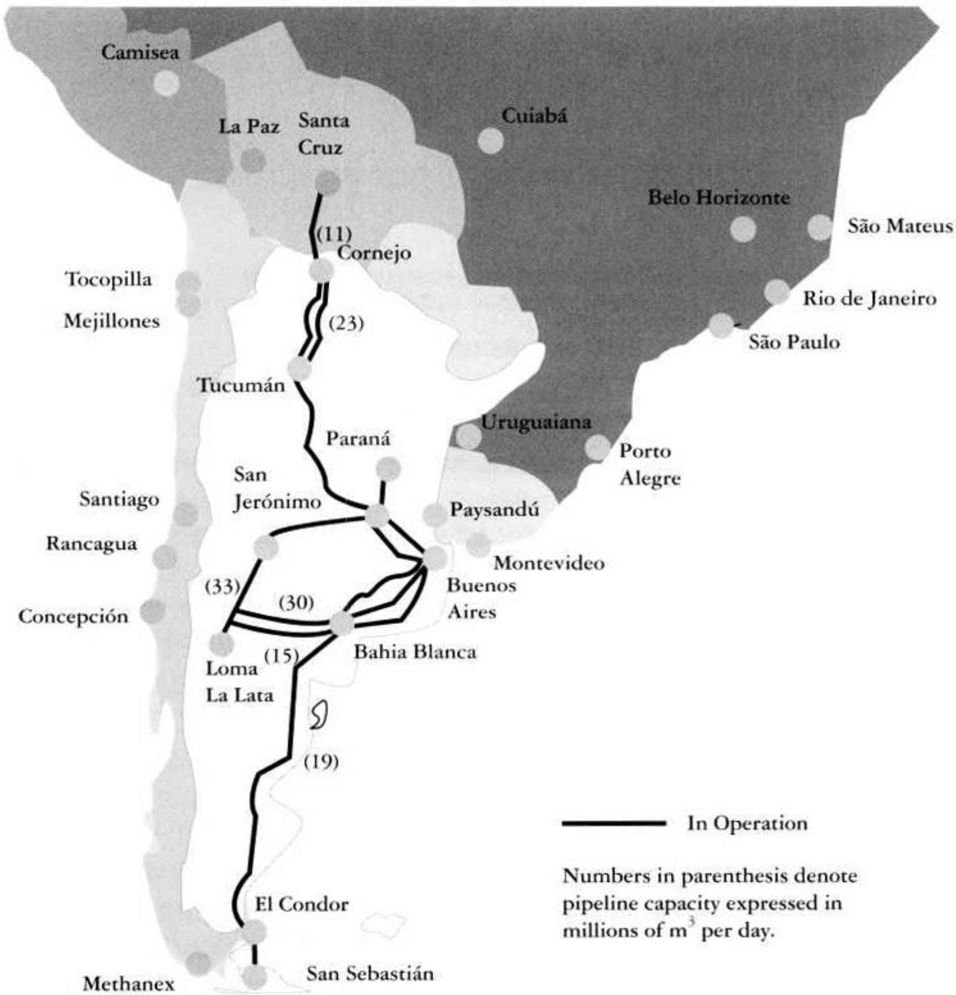
Sources: Estimated (Argentina), Ministry of Mines and Energy (Brazil), BP Amoco Statistical Review 2003 (other countries).

Natural-gas consumption penetrates all areas of Argentina's economic activity. Argentina has also enjoyed an exporter position, achieved in the late 1990s, now threatened by distortions. This year, Argentina will resume importation of Bolivian gas over the old gas pipeline between the two countries, at a rate of approximately 4 million m^3 per day.

Brazilian and Chilean markets (whose production, consumption, and share of gas participation in the energy matrix are noted above) are more incipient. Both countries began development with arrival of gas-export pipelines; it is hoped they will continue to do so in the future. In both countries, and especially Brazil, gas penetration will be closely linked to the potential of thermal generation and a regulatory framework that allows for electricity-sector growth.

FIGURE 9-2. COMPARISON OF GAS TRANSPORT INFRASTRUCTURE

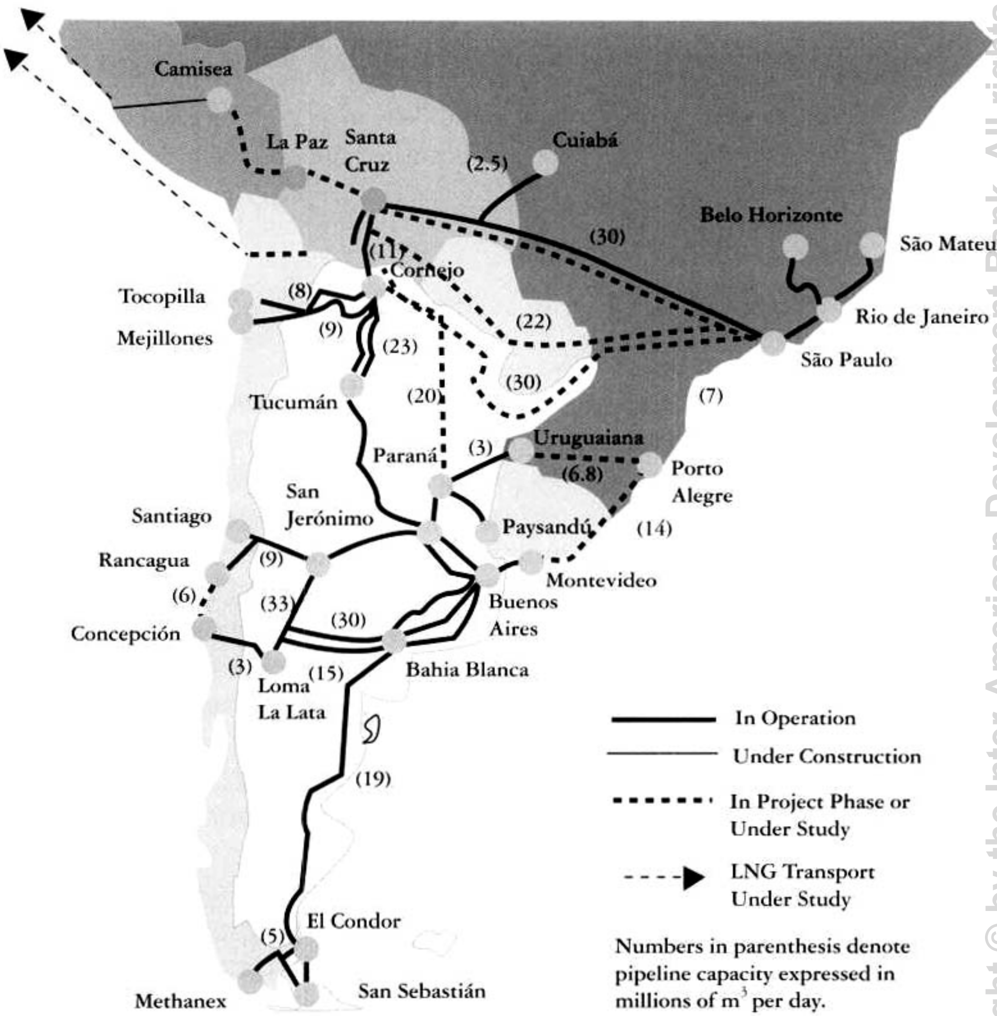
Early 1990s



Source: Repsol.

FIGURE 9-2. COMPARISON OF GAS TRANSPORT INFRASTRUCTURE-*continued*

2004



Source: Repsol.

Needed Investment

Development of the Southern Cone gas market will require major investments to service internal distribution networks and meet international transport needs. Since most of this investment has yet to be defined, it is not possible to quantify investment needs. Nonetheless, it is worth noting that only a portion of the projects announced (including those already under construction or most likely to be implemented) will demand, according to these authors' estimates, approximately US$10 billion over the next decade (these figures exclude E&P investments). These investments include:

- South/Southeast Brazil. Expansion of the Bolivian pipeline, construction of the Uruguaian-Porto Alegre pipeline, and expansion of the transport and distribution systems and electrical power plants under construction.

- Petrobrás Mallas Project. Expansion of the internal pipeline network in southeastern and northeastern Brazil (with more than 1,200 km of gas trunk lines).

- Argentina. Expansion of the transport capacity of TGN (*Transportadora de Gas del Norte, S.A.*) and TGM (*Transportadora de Gas del Mercosur, S.A.*) and the Northeast Bolivian pipeline.

- Southern Chile. Expansion of the Central Valley pipeline and associated thermal power plants.

- Bolivia. In addition to the transport infrastructure needed to connect southern deposits with the gas pipeline to Brazil, it is necessary to consider Pacific LNG's North America export project, the first major project to export energy outside the region.

Availability of capital is key to implementing these projects. This, in turn, demands an environment of macroeconomic stability and legal certainty, as well as treaties favoring integration between countries. Otherwise, all projects, along with system integration and new market development, will fall behind.

Finally, it should be noted that development of export markets, which encourages transport and distribution infrastructure investment, generates increased E&P investment, to the extent that monetization of the reserves associated with the exploration activity becomes viable. An example of the relationship between transport investment and increased reserves is Bolivia, which has experienced spectacular reserves growth since pipeline construction opened doors to the Brazilian market.

What Happened in the 1990s?

During the 1980s, Argentina's natural-gas consumption was significant; however, participation of natural gas in primary energy consumption did not exceed 35 percent. The new economic policy of the early 1990s—based on private-sector participation, liberalization, competition among certain segments of the gas and electricity sectors, and regulation of monopolistic segments—transformed the scenario in all fields of activity. This new environment spilled beyond Argentina's borders. Indeed, Chile's gasification resulted, in large measure, from Argentina's surplus gas production and favorable conditions for private investment in constructing export pipelines. Thus, it is worth reflecting on what happened during this period.

Success lay in the regulatory framework that went into effect: open procurement, promotion of private enterprise, freedom to dispose of foreign currency, and exemption from export duties; along with a favorable environment toward risk capital. Together, these factors provided the signals that unleashed an abundant investment flow, mobilizing more than US$78 billion for the energy sector in the decade 1990-2000 of which nearly US$58 billion corresponded to the gas sector: US$40 billion for upstream investment and US$18 billion for downstream investment.

During 1990–2001, Argentina's natural-gas production doubled. Proven reserves not only did not decline; they increased 32 percent, reaching 764 billion m^3 by the end of that period. This rise in gas production is the flip side of what happens when major investments are made in oil and gas exploration, which, during that period, totaled US$42 billion. Deregulation of wellhead prices and open procurement provided adequate incentive for both drilling and gas exploration

projects, the latter of which had been nearly non-existent owing to an inappropriate economic and financial environment.

Between 1990 and 2000, US$1.633 billion was invested in Argentine oil and gas trunk lines. The networks of TGS, TGN, and TGM were expanded from 10,195 km to 12,321 km during 1992–2001, and transport capacity rose from 65.5 to 120.8 million m^3 per day.

Advances in export infrastructure made it possible to connect Argentina and Chile in a few years, using five gas pipelines with a transport capacity of 34 million m^3 per day. Moreover, several pipeline projects for export to Brazil, which should be added to those now in operation, connect to Uruguay. In addition, Uruguay receives Argentine gas through the oil pipelines to Paysandú and Montevideo, the latter of which crosses the Río de la Plata.

The nine distributors that succeeded GdE, which cover nearly the entire country, developed notably (and are even closer to the end customer). During 1992–2001, the distribution network expanded by more than 42,000 km (from 66,765 to 109,533 km), representing a 64 percent increase and an investment of approximately US$7.5 billion. Number of users increased 32 percent, from 4.6 to 6.0 million. The ratio of gas pipelines to users increased, reflecting efforts to incorporate new consumers.

Transport and distribution activities remained regulated; fees were set in dollars and provided an adequate return on investment. That they were set in dollars and were adjusted based on cost variations allowed for flexibility in the companies' industrial and financial organization, with respect to imported industrial inputs and external debt.

Deregulation of the electricity sector was one of the best measures to promote Argentina's gas expansion. During 1990–2000, US$16.5 billion was invested in electricity in Argentina. Within the generation segment, combined-cycle power plants were built, equivalent to 6,000 megawatts (MW), putting an end to high prices and electricity rationing, and ushering in an era in which consumption increased at an annual rate of 5.5 percent (starting in 1992), with the wholesale price cut nearly in half. Argentina became a leading country in combined-cycle technology, with world-class generators. Gas was

the new power plants' major turbine fuel because of its low cost and environmental advantages. Several integrated gas and electricity projects were developed, including Capex, Filo Morado, and Pluspetrol Energy.

The comparative advantages of Argentine gas were also reflected in a petrochemical boom (e.g., expansion of PBB, Indupa, Profertil, and Compañía Mega). During 1990–2000, US$2.8 billion was invested in Argentine petrochemicals. As a result, petrochemical production multiplied several times fold, with a 600 percent increase in urea, 100 percent in ethylene, 70 percent in polyethylene, and 280 percent in polypropylene. All of these products positively affected the trade balance.

Extra-regional Export Project

Growth of Bolivian gas reserves has opened a discussion in this country on options for their monetization. The reserves not only exceed the Bolivian market's capacity to absorb them; they even exceed the importation capacity of neighboring countries. It should be noted that, at the current rate of production, proven and probable reserves (which ought not be classified as reserves precisely, given their lack of marketing) can last 160 years.

One option for marketing reserves is the export project to the west coast of North America, promoted by Pacific LNG, to satisfy projected LNG import needs for the U.S. and Mexico. Pacific LNG's shareholders include Repsol YPF and BP Amoco. The aim is to develop and monetize reserves of the Margarita deposit, within the Caipipendi exploration block in Bolivia. The gas would be treated in the deposit, and the liquid and liquefied petroleum gas (LPG) would be separated. Then, the dry gas would be transferred to the Pacific coast for liquefaction in a two-train plant, with a capacity of 22 to 33 million mt^3 per day Finally, this LNG would be shipped to west-coast markets of the U.S. and Mexico.

Over the past year, this project has been the subject of great controversy. Nonetheless, shareholders maintain a degree of optimism that it will be implemented, fundamentally because it is economically rational. The Pacific LNG project would result in a 14 percent increase in Bolivia's

GDP, create more than 5,000 jobs over the life of the project, and provide more than US$2 billion in investment and US$6.5 billion in tax revenues.

Current Problems

Solid growth of the Southern Cone's gas industry is at risk. Although the situation varies by country, current problems have the common effect of retarding industry development and, in some cases, threaten to create setbacks.

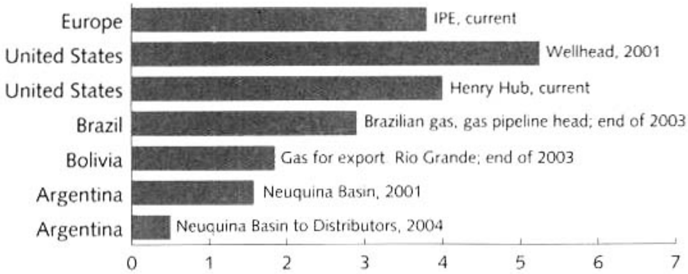
While continued investment is needed to develop gas infrastructure, spreading legal uncertainty since 2002 makes it difficult to find investors willing to commit to capital-intensive projects with long recovery periods. Argentina has witnessed a severe contractual breakdown, with pesification (re-conversion of assets and liabilities into Argentine pesos) and freezing of gas wellhead prices and transport and distribution fees, which have reached a point of economic counterproductivity.

Argentina's gas wellhead prices before devaluation were already among the lowest in the world. In 2001, wellhead prices for the Neuquina Basin were approximately US$1.5 per million British thermal units (Btu). During the same period, average U.S. wellhead prices were about US$4.0 per million Btu (figure 9-3).

Initial low prices, political uncertainty, and price declines led to a drop in investment in gas exploration and development in 2002, which was also reflected in a drop in production and reserves. Subsequent to the events in question, no major additions to the transport and distribution networks occurred. On the other hand, demand incentive, in the form of rock-bottom gas price, encouraged substitution of certain energy sources with others that were not justified from the standpoint of availability and long-term pricing. For example, in 2003, compressed natural gas (CNG) consumption increased more than 30 percent, and its growth continues to accelerate. These increases have created bottlenecks since supply cannot keep pace with demand growth and rigid price controls do not permit supply and demand to reach equilibrium. Despite planned

importation from Bolivia, the volume of export contracts to Chile had to be reduced, setting a negative precedent and representing a step backward in the integration process.

FIGURE 9-3. GAS PRICES TO PRODUCERS
(US$ per million Btu)



Sources: Energy Information Administration (EIA) and IPE (Strategic Planning Institute).

In Bolivia, political conflicts have created an atmosphere hardly conducive to investment activities. Hydrocarbon companies and the North American export project have been the ongoing targets of attacks aimed at influencing public opinion. Parliament is analyzing bills that would negatively affect the current situation.

In Brazil, the unresolved issue of regulatory uncertainty affects the country's gas-market development, potentially the region's most extensive. High dependence on hydroelectricity (more than 80 percent of generating capacity is hydroelectric) puts Brazil on a continual energy seesaw. During periods of heavy precipitation, hydroelectric generation is abundant and cheap, and thermal power plants cannot even dispatch their energy. However, when climate conditions are reversed, as they were two years ago, lack of a thermal reserve leads directly to rationing and service interruption.

Summary of Current Challenges

The Southern Cone has the potential capacity to progress in gas development. To do so, however, it must confront and overcome today's challenges, many of which have intensified. The basic challenges are as follows:

- Argentina must re-determine natural-gas and electricity prices and rates, making them compatible with investment in exploration, consistent with sustainable consumption potential, and conducive to maintenance and expansion of system transport and distribution infrastructure.

- Bolivia must pose realistic options for exploiting and profiting from its natural resources, and must encourage, rather than reject, efficient projects that allow the country to mobilize its wealth of natural resources.

- Electricity from Brazil's hydroelectric and thermal generation must be treated as complementary, not competing, sources. In this regard, rules for constituting a thermal reserve must be developed. In addition, transport rates must be regulated to allow for efficient use of those resources and recovery on investment.

- Regional integration must be reviewed and perfected, with common rules for all countries; these rules must take precedence over national regulations in order to harmonize transactions and resolve conflicts. Above all, legal certainty and respect for capital investment must be accelerated throughout the region; together with clear rules, these are essential for the continued investment needed to ensure gas-market development and diversification of energy supply.

Totalfina

Totalfina is a leading multinational, Southern Cone energy company. According to its 2003 annual report, the group has about 110,000 employees and operations in more than 130 countries. Together with its subsidiaries and affiliates, Totalfina is the world's fourth largest, publicly-traded, integrated oil and gas company, as measured by market capitalization. In 2003, the group recorded net income of EUR7.34 billion (adjusted for special item), a 17 percent increase over the previous year. Its businesses cover the entire oil and gas chain, from crude-oil and natural-gas E&P to downstream power generation, transport, refining, product marketing, and international crude oil and product trading. Totalfina is also a world-class chemicals manufacturer.

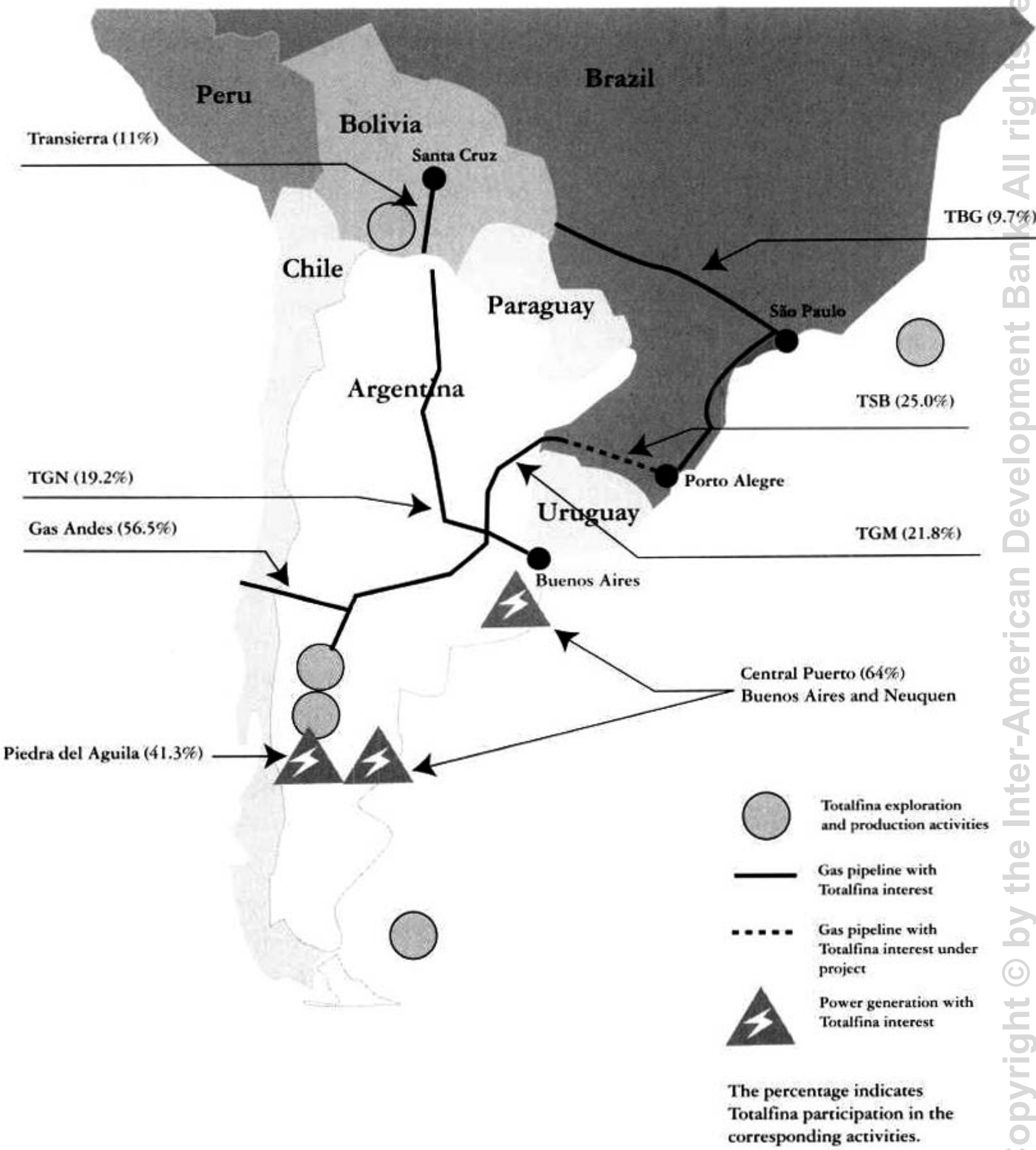
Totalfina's global businesses are divided into three segments. The upstream segment encompasses oil and natural-gas E&P operations, along with gas and power activities; while the downstream segment covers trading and shipping, refining and marketing of Total, Elf, Fina, and Elan brand petroleum products, automotive and other fuels, and such specialties as LPG and aviation fuel and lubricants through the group's retail network and other outlets worldwide. Chemicals include base chemicals and commodity polymers integrated with refinery operations; intermediates and performance polymers; and such specialties as rubber, resins, adhesives, and electroplating.

Totalfina has a long history in the Southern Cone, mainly through its upstream activities and, to a lesser extent, through chemicals and downstream activities. In 1978, the group initiated upstream activities in Argentina, when it obtained an exploration license in Tierra del Fuego. Since then, the group has constantly invested in the region, notably to develop gas resources within Southern Cone countries and support gas integration through participation in pipeline network development (figure 9-4).

With a cumulative investment of US$2.5 billion, Argentina epitomizes Totalfina's long-term regional commitment. In 2003, Totalfina was the country's second largest operative gas producer. Totalfina's main E&P activities are located in the Neuquina Basin (San Roque, 24.7 percent interest; Aguada Pichana, 27.3 percent interest) and offshore in the Tierra del Fuego Province (CMA, 1 block; 37.5 percent interest). Totalfina also participates in 6,400 km of high-pressure gas pipelines, including export pipelines (Gas Andes and TGM), and is the second largest power generator through its major shareholding in Central Puerto, S.A. and Piedra del Aguila (totaling about 16 percent of the country's generation capacity).

Since 1996, Totalfina has participated in the main events of Bolivia's hydrocarbons industry, including discoveries in the Itaú fields (1999) (as operator) and San Alberto (1998) and San Antonio (1999) (as partner). To discoveries. Today, it holds 41 percent interest in the Itaú field and 15 percent interest in the San Alberto and San Antonio fields, representing

FIGURE 9-4. TOTALFINA'S PARTICIPATION IN SOUTHERN CONE PIPELINE NETWORKS



Source: Totalfina.

reserves of 233 billion m^3, which have been certified by DGMN (*Dirección General de Movilización Nacional*). Totalfina has a 11 percent share of the current Gas Sales Agreement (GSA) between Bolivia and Brazil.

In Brazil, Totalfina participates in two exploration blocks, BC2 and BMC14, in association with Petrobrás and other companies. In gas transport, the group's most significant investment is its 9.7 percent share in TBG. This 3,000-km pipeline, representing an investment of about US$2 billion, has been a milestone in Southern Cone gas integration, linking southern Brazil's consumer region to Bolivia. Totalfina is also a founding partner of TSB (*Transportadora Sul Brasileira de Gas*), a gas pipeline project that should connect Uruguaiana, at the Argentina/Brazil border, to Porto Alegre.

Totalfina is Chile's major shareholder and operator of Gas Andes, a 440-km network linking Santiago to the Neuquina production basin.

Country Outlook

The Southern Cone is endowed with large, diversified energy resources. Significant natural-gas reserves are found mainly in Argentina, Bolivia, and Brazil, where substantial new discoveries have been made. The Southern Cone gas industry has reached a critical juncture, and must now design a long-term scheme to replace the commonly accepted vision of the past decade.

During the 1990s, Argentina was the region's dominant gas market. Successful implementation of a stable regulatory framework led to dynamic investment in all segments of the country's gas industry, consequently permitting regional integration with pipeline development across the Andes; this, in turn, allowed for development of the Chilean gas market. Concurrently, construction of the Bolivia-Brazil pipeline opened the country's energy sector to private companies and assigned value to Bolivian gas reserves, thereby helping to move the integration process forward. Argentina came to dominate the regional market, and Bolivia completed its regional gas offer, turning to potential long-distance exports outside the region.

Since the year 2000, economic and political difficulties in most Southern Cone countries have led certain governments to adopt emergency measures, which have had distorting effects on the regional energy sector, endangering national gas markets and the integration process. At the same time, new gas discoveries and reassessment of reserves in mature basins have been achieved, shedding new light on the regional gas balance. Fundamental drivers—widely available gas, key infrastructure in place, and gas as an attractive option for energy diversification—can sustain efficient, regionally-integrated market development; even so, the industry faces significant challenges. In the sections that follow, the authors review these challenges by country.

ARGENTINA

Argentina is one of the world's most gas-intensive countries, with natural gas accounting for approximately 50 percent of its primary energy consumption. This intensity is the result of a large gas resource base; successful industry restructuring and privatization in 1992, which, until 2001, led to dynamic investment in all segments (production, transport, and distribution) and price levels that have ensured competitiveness in power generation and the industrial sector, while enabling exploration and development of new reserves.

Dramatic changes in Argentina's gas market over the past two years are leading toward an energy crisis. As a result, governments have adopted emergency measures that have had distorting side effects, endangering the gas industry.

Pesification, followed by a 2002 government freeze on gas prices (which remains in force), has combined with economic recovery and drier climatic conditions (since mid-2003) to generate a sharp increase in gas demand. The current wellhead price is below US$0.6 per million Btu, compared to the average of US$5.0 per million Btu in North America over the past two years. The gas industry has subsidized large segments of Argentina's economy, and has artificially stimulated demand. To supply this fast-growing demand and provide the volumes for current and future exports to Chile, Argentina faces a daunting challenge:

increasing production levels to satisfy all potential demand in the face of maturing production basins and depreciated gas prices.

Over the long term, Argentine production will probably not be able to satisfy growing domestic demand (89 million m^3 per day in 2003, estimated to reach 110 million m^3 per day in 2010 and 130 million m^3 per day in 2015, averaging 4 percent annual growth). This deficit is gradually emerging, and will become even more evident if producers and consumers continue receiving wrong price signals. Current end-user prices are doping demand, and fail to offer incentives for production and long-term investment.

Satisfying Argentina's long-term gas demand will require revitalization of both national production and Bolivian imports. Neither is likely to happen unless Argentina returns to a stable, economically sound regulatory framework.

CHILE

Limited domestic reserves in Chile's remote southern region have constrained the country's gas market. However, since the late 1990s, the outlook has changed fundamentally, with construction of several pipelines across the Andes mountains and delivered Argentine gas to power generators, as well as industrial, residential, and commercial markets (especially in the central Santiago region). As a result, the share of natural gas in Chile's primary energy consumption surged from 10 percent in 1995 to 23 percent in 2000.

In the coming years, Chilean gas demand should continue increasing at an average rate of 5 percent per year, resulting from gas-based power generation (the current 22 million m^3 per day is projected to jump to 35 million m^3 per day in 2015; of this amount, Santiago accounts for 16 million m^3 per day and Chile's southern region 12 million m^3 per day).

Recent events—notably the shortage of gas delivery from Argentina—and perspectives on the evolution of that country's gas market make it likely that Argentina will not supply Chile's increased gas demand,

unless Argentina includes Chile in its gas balance (i.e., importing gas from Bolivia to supply Buenos Aires and exporting gas from Neuquen to supply Santiago).

Chilean gas demand growth presents a global issue at the Southern Cone level. Regional integration will only be achieved through regional cooperation that guarantees the necessary fiscal stability and respect for signed contracts required to secure sufficient long-term investments.

BRAZIL

Historically, natural gas has had limited importance in Brazil's energy matrix, with about 4 percent participation. Reasons included lack of proven domestic reserves and ready availability of other resources, such as oil (Brazil is approaching self-sufficiency), hydroelectricity, and renewable energy (biomass).

In the mid-1990s, this situation began to change when Bolivian discoveries and Argentina's decision to begin exporting gas positioned Brazil to increase access. At the same time, the country recognized the need to diversify its energy matrix to include greater gas participation.

These factors created significant growth perspectives for local and international players in the gas and electricity industries. Developing Brazil's gas market has proven potential, if one considers the market share in other Southern Cone countries and Brazil's regional economic importance (accounting for more than 50 percent of the region's GDP). In recent years, billions of dollars were invested in Brazil, Bolivia, and Argentina (to a lesser extent) to develop reserves, infrastructure, and markets. Completion of the Bolivia-Brazil pipeline represents a milestone in development of the Brazilian market; since 1999, it has linked Bolivian gas reserves to southern, southeastern, and midwestern Brazil.

After years of accelerated growth, Brazil's gas market has experienced a slowdown in sales, underscoring its two major shortcomings: lack of a regulatory framework promoting gas use and a level playing field for all actors.

The 2003 offshore discovery in the Santos Basin should catalyze a new dynamism in Brazil's gas industry. Demand is expected to increase with expanded distribution networks and access to cheaper gas. In southern and west-central Brazil, sales may rise from their current level of 30 million m^3 per day to 80 million m^3 per day by 2015, representing a 9 percent annual growth rate.

Domestic production is expected to satisfy most increased national demand, provided that timely funds are available to develop the reserves. New Bolivian imports over the current contractual level of 30 million m^3 per day and/or Argentine imports will then have to compete with Brazilian production.

This scenario can only be achieved if a legal framework that promotes natural gas as a key energy is put in place. In this regard, the new power-sector legislation should confirm that it fully recognizes the benefits of gas-fired power plants in Brazil's electricity system. Moreover, Brazil should adopt a comprehensive set of gas-industry rules, which provide clear TPA conditions, tariff principles, transport data, and administrative coherence between the federal and state governments. So that all actors—including private companies—might play an active role, the country should address such issues as vertical integration and limits on dominant position.

In Brazil, energy regulation and financing capacity are key to achieving a scenario of sustained market growth. Private companies' market role, however, still requires improving.

BOLIVIA, PARAGUAY, AND URUGUAY

The Bolivian market will remain limited, despite tremendous national resources (ranging from 3 to 5 million m^3 per day). Paraguay and Uruguay will remain small gas consumers, stemming from lack of national resources and high hydrological potential for power generation.

Regional Integration Versus Separate Paths

In 2003, Southern Cone natural-gas consumption was 140 million m^3 per day, with Argentina accounting for 89 million m^3 per day. Regional demand is projected to increase to approximately 210 million m^3 per day by 2010. Southern, southeastern and midwestern Brazilian markets account for about 40 percent of the total expected demand growth by 2010. Despite the maturity of its gas market, Argentina accounts for about 35 percent; Chile accounts for another 20 percent, while other Southern Cone countries (Bolivia, Paraguay, and Uruguay) comprise about 3 to 5 percent.

To satisfy these demand levels, the industry faces two main challenges: maturity of all Argentine production basins (except for the offshore Austral Basin) and the remote location of new production in relation to consumption centers.

THE CASE FOR REGIONAL INTEGRATION

Argentina will remain a key market in the Southern Cone region. It will become a major consumer country, changing its position from exporter to importer and playing a central role between Bolivia, Brazil, and Chile in the regional market. As a transit country and regulator of future gas flows, Argentina will play a paramount role over the next decade.

Bolivia should become a supplier to Argentina's gas market to meet increased national demand and to supply Brazil and Chile. Chile will remain dependent on Argentina and indirectly on Bolivia to cover increased demand. With development of national resources, natural gas will play a larger role in energy supply. Assuming that current political instability and diplomatic tensions are overcome, Bolivian and Brazilian production should capture most of the region's demand growth.

Bolivia's emerging role in the map of future gas flows involves significant development of gas transport capacities, especially along the Bolivia-Buenos Aires, Argentina-Central Chile, and (eventually) Argentina-South Brazil axes.

The large capital expenditures required to construct new gas pipelines make it necessary to secure significant guaranteed transport volumes to ensure that pipeline projects are economically feasible with competitive transport tariffs. Historically, long-term contracts, especially those linked to gas-fired power generation projects, have often provided the critical volumes needed to make new gas pipelines feasible, simultaneously permitting supply to new industrial, commercial, and residential customers at attractive prices. All measures to facilitate the financing of cross-border gas pipelines must be favored.

For future network development, the Bolivia-to-Buenos Aires investment in transport capacity until 2020 could amount to about US$3. Increased transport capacity could be assured by progressively expanding the existing TGN network, which would allow Argentina to cope with its short-term energy crisis and optimize long-term transport capacity, developing the network in line with market needs. Such a scheme can only be envisaged if the pipeline companies involved have the financial strength to sponsor these types of projects and sign the required long-term contracts; moreover, market rules must be fair, nondiscriminatory, transparent, and stable, enabling all players to participate. The same conditions will be needed to develop transport capacity from Argentina to central Chile and from Argentina to southern Brazil.

Because of the large amount of money required to finance such major developments as expanding Argentina's northern gas network, long-term contracts and other such tools must be considered; the most crucial conditions are recovery of Argentina's gas transport industry and re-establishment of the contracts law.

TOWARD SEPARATE PATHS?

Considering recent events related to transnational gas sales, Southern Cone countries could favor implementing alternatives to regional gas integration. In this scenario, Chile would most probably turn to LNG or switch to coal or liquid fuels to secure new energy supplies for its growing market—both options being more expensive than cost-effective allocation of gas supplies between Argentina, Bolivia, and Chile.

Argentina might restrict all development of its gas fields and pipelines to its domestic market. In such a case, the country might decide to expand transport capacity from Tierra del Fuego to Buenos Aires, despite the insufficient volume of reserves discovered to justify such an expansion. This action would also delay the opportunity to import gas from Bolivia.

Implementing such an alternative would entail enormous expenses in new gas infrastructure, including construction of an LNG terminal in Chile and long-distance pipeline(s) in Argentina. These developments would represent much greater investments than the US$3 option for regional gas integration and their construction would also require a transparent, nondiscriminatory, and stable business environment.

If the easing of political tensions between Southern Cone countries is not realized, alternatives to regional gas integration will be put on track. Chile could diversify its gas supply, relying on LNG. Argentina and Brazil could prioritize development of their gas fields and pipelines, disregarding additional costs related to non-optimal development of regional energy resources. The results might further distort energy prices between countries, delaying the inevitable entry of Bolivian gas to neighboring country markets.

Conclusions and Recommendations

The Southern Cone landscape should change considerably over the coming decade, given the disparity in geographical location of gas resources and consumption centers. Assuming that regional integration policies are favored, Bolivia should become a major regional supplier, selling gas to Argentina; in turn, Argentina should become a central market for all gas exchanges in the region and sales to Chile and eventually Brazil. The latter will depend mainly on its own resources to satisfy domestic demand growth. As a result, the transport network linking Bolivia to Argentina must expand significantly, requiring large amounts of financing. This can only be achieved if political instabilities, diplomatic tensions, and the economic difficulties of Argentina's energy sector are overcome and juridical security is restored.

Cost-effective allocation of gas supplies among Southern Cone countries can only be achieved if each regulation is built on the stable foundation of fair, nondiscriminatory, transparent, and economically viable national-gas markets. Regional integration should not be viewed as a magic fix for solving the countries' current problems. It is more likely to succeed if incorporated into stabilized legal and economic gas frameworks in each respective country.

Transparent, nondiscriminatory TPA must be granted in all gas transport and distribution networks. Convergence of national TPA conditions with transport services must be sought, emphasizing transnational networks to facilitate gas imports and exports. Free circulation of gas should be granted, and real import or export competition should be improved. Independent, national-level regulators should be put in place and empowered to resolve conflicts in each market, and inter-market mechanisms should be created to settle disputes regarding international gas flows. Convergence of national regulations should be promoted. Moreover, coordination between national antitrust authorities should be sought in order to attain coherent approaches on dominant position and vertical integration issues. Finally, all measures should be taken to facilitate the financing of transnational gas pipelines and avoid artificial entry barriers.

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INFRASTRUCTURE

In South America's Southern Cone, the natural gas industry offers the best prospects for energy integration. The region's countries abound in gas resources and enjoy significant complementarities. Between 1995 and 2002, more than 7,500 km of cross-border pipelines were built, increasing economic links and energy interdependence between Argentina, Bolivia, Brazil, and Chile. However, recent events in Argentina and Bolivia are dampening expectations for further integration.

Gas Market Integration in the Southern Cone offers a comprehensive analysis of the gas industry's evolution in the Southern Cone, highlighting the drivers of and obstacles to regional market integration. The book is unique in that its authors not only identify barriers to integration; they also present a concrete proposal—based on a wealth of experience in other world regions—for overcoming them to advance toward regional integration. This book is a must-read for anyone interested in gaining a deeper understanding of the most urgent issues for the Southern Cone gas sector.

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